BNL-81741-2008

KAERI/RR-2931/2008

Joint Development of Seismic Capability Evaluation Technology for Degraded Structures and Components

Annual Report for Year 1 Task

Identification and Assessment of Recent Aging-Related Degradation Occurrences in U.S. Nuclear Power Plants

November 2008

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ABSTRACT

In the past, safety assessments of nuclear power plants (NPPs), using methods such as seismic probabilistic risk assessments (PRAs), usually utilized best estimate or design values for material properties of structures, systems, and components (SSCs) without consideration of any aging effects. In order to develop a realistic evaluation of the seismic safety of a plant, the potential effects of age-related degradation on (SSCs) should be considered.

To address the issue of aging degradation for the safety of NPPs, the Korea Atomic Energy Research Institute (KAERI) has embarked on a five-year research project to develop a realistic seismic risk evaluation system which will include the consideration of aging of structures and components in NPPs. Three specific areas that are included in the KAERI research project, related to seismic PRA, are probabilistic seismic hazard analysis, seismic fragility analysis including the effects of aging, and a plant seismic risk analysis.

To support the development of seismic capability evaluation technology for degraded structures and components, KAERI entered into a collaboration agreement with Brookhaven National Laboratory (BNL) in 2007. The collaborative research effort is intended to continue over a five year period with the goal of developing seismic fragility analysis methods that consider the potential effects of age-related degradation of SSCs, and using these results as input to seismic PRAs.

This report describes the research effort performed by BNL for the Year 1 scope of work. This research focused on collecting and reviewing degradation occurrences in US NPPs and identifying important aging characteristics needed for the seismic capability evaluations that will be performed in the subsequent evaluations in the years that follow. The report presents results of the statistical and trending analysis of this data and compares the results to prior aging studies. In addition, this report provides a description of current regulatory requirements, regulatory guidance documents, generic communications, industry standards and guidance, and past research related to aging degradation of SSCs. Finally, this report provides the conclusions reached from this research effort, which includes a summary of the findings from the identification and evaluation effort of degradation occurrences, an assessment of the degradation trending results, and insights into the important aging characteristics that should be considered in the tasks to be performed in the Year 2 through 5 research efforts.

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1 INTRODUCTION

1.1 Background

The Korea Atomic Energy Research Institute (KAERI) is in the process of performing research to improve the evaluation methods to assess the seismic safety of new and existing operating power plants. These evaluation methods can be used to perform Periodic Safety Reviews (PSRs) and license renewal application (LRA) reviews. In addition, they can also be used to upgrade the seismic safety of a nuclear power plant (NPP). In the past, such evaluation methods included a seismic probabilistic risk assessment (PRA) which usually utilized design values without consideration of any aging effects. In order to develop a realistic evaluation of the seismic safety of a plant, the potential effects of age-related degradation on structures, systems, and components (SSCs) within a NPP should be considered.

To address the issue of aging degradation on the safety of NPPs, KAERI has embarked on a five-year research project to develop a realistic seismic risk evaluation system which will include the consideration of aging of structures and components in NPPs. Three specific areas that are included in the KAERI research project, related to seismic PRA, are probabilistic seismic hazard analysis, seismic fragility analysis by considering age-related degradation, and a plant seismic risk analysis. The major objectives of the KAERI project are:

- Reduction of the uncertainty in a PSHA (Probabilistic Seismic Hazard Analysis)
- Development of site-specific evaluation response spectra for a seismic PRA
- Development of seismic fragility analysis methodology by considering a realistic capacity and response of structures and components that includes the effects of aging
- Development of time-dependent and nonlinear analysis technology for nuclear structures and components
- Development of seismic risk quantification models and tools for Korean NPPs
- Evaluation of the aging effect on the seismic risk of a NPP

To meet the above objectives, KAERI entered into a collaboration agreement with Brookhaven National Laboratory (BNL) in 2007. The collaborative research effort is intended to continue over a five year period with the goal of developing seismic capability evaluation technology for degraded structures and components. The final results of this project will be utilized to update and improve the seismic PRA technology in Korea. The advanced seismic PRA tools developed by KAERI with input from the research performed by BNL, will be used for evaluations of the seismic safety of operating NPPs in Korea during the process of their PSR, for license renewal evaluations of old NPPs, and for future plants.

1.2 Project Objectives

The objective of the research effort being performed by BNL, as part of the collaborative research agreement, is to provide technical assistance to KAERI in developing seismic capability evaluation technology for degraded structures and components, which can be used to assess the safety of NPPs in Korea. This will be achieved by conducting research in the area of how age-related degradation effects can be considered in performing seismic PRAs of NPPs. The research effort by BNL will be conducted over a five-year period from 2007 through 2012. The ultimate goal of the development of seismic capability evaluation technology for degraded structures and components is divided into five sets of individual objectives associated with the each of the five years. The objectives of the individual tasks to be performed in each of the five years is described below.

Year 1 Objectives:

The Year 1 objective is for BNL to collect and review degradation occurrences in US NPPs and identify important aging characteristics needed for the seismic capability evaluations that will be performed in the subsequent evaluations in the years that follow. It is anticipated that aging characteristics such as the component type, aging effects, aging mechanisms, identification method, evaluation method, plant name, and date of occurrence would be considered for review. The information presented in this report provides a description of the research effort performed by BNL to meet the Year 1 objectives.

Year 2 Objectives:

The Year 2 objective is for BNL to identify modeling methodologies to represent the long-term behavior of materials used in NPPs. BNL will perform a literature search for time-dependent models that can approximate the degradation effects of the key materials used for the structures and passive components. It is envisioned that the degradation models identified would potentially cover the most common time-dependent changes in material properties (e.g., strength, ductility, modulus), loss of material (e.g., corrosion, erosion), and cracking.

Year 3 Objectives:

The Year 3 objective is for BNL to select one structure or component, with prior approval from KAERI, and develop the seismic fragility capacity. The seismic fragility for this structure or component will be developed for the undegraded condition and various levels of degradation for the most common aging effect identified in the earlier Year 1 Task described above. The intent of this task is to provide a pilot study that demonstrates how the seismic fragility calculation methodology can be performed.

Year 4 Objectives:

The Year 4 objective is for BNL to provide technical assistance to KAERI staff who will perform seismic fragility calculations for the other remaining important structures and components. The seismic fragility calculation for the other important structures and components are not necessarily expected to be the same as that performed in the Year 3 Task, due to the differences in the structure/components, materials, aging effects, and/or failure modes.

Year 5 Objectives:

The Year 5 objective is for BNL to provide technical assistance to KAERI to develop guidance for establishing degradation acceptance criteria for structures and components. This may follow a similar approach that was utilized in the NRC aging research project that was performed by BNL recently and is reported in NUREG/CR-6715 and NUREG/CR-6876. The focus of BNL assistance will be on providing expertise in structural analysis and fragility analysis.

1.3 Year 1 Research Scope

The scope of the Year 1 research effort was to identify, collect and evaluate age-related degradation occurrences in United States (US) NPPs. This required developing a list of structures and components suitable for KAERI's seismic capability evaluations. Then, degradation occurrences for these structures and components were identified and reviewed. This information was evaluated in order to identify the important aging characteristics, and finally a trending analysis was performed to make a comparison to the results of past aging studies and to plan for the future tasks under the five-year research project.

A list of applicable structures and components was developed, with KAERI's approval, in order to define the scope of what types of structures/components should be reviewed for degradation occurrences. Similar to the study reported in NUREG/CR-6679, that did not include active components, it was recommended that this list cover only structures and passive components (SPCs), but not active components. Active components such as pumps, valves, and electrical equipment are components which must move or change their state in order to perform their intended functions, and can typically be monitored for aging effects by monitoring their performance. By monitoring pressure, flow, electrical signal, etc., the potential aging degradation of active components can be identified, while for passive components, the extent of aging is usually difficult to identify and may even go undetected. In addition, active components are usually subjected to periodic inspection, testing, and maintenance where aging effects would be detected and corrected over time.

KAERI provided a list of structures and components that are considered to be the most risk significant by KAERI engineers from the work that has already been performed by KAERI. Reviewing this list along with the list of 18 SPCs described in NUREG/CR-6679, 10 categories of SPCs were identified for the scope of the degradation review to be included in this study for KAERI as follows:

1. Anchorage
2. Concrete
3. Containment
4. Exchanger
5. Filter
6. Piping system
7. Reactor pressure vessel (RPV)
8. Structural steel
9. Tank
10. Vessel

These SPC categories will be explained in more detail in Section 3 of this report.

The identification of degradation occurrences for these SPCs was performed using publicly available documents related to the nuclear power industry, primarily in the US. The documents reviewed for the current research program, reported herein, include Licensing Event Reports (LERs), US Nuclear Regulatory Commission (NRC) generic correspondences, documents related to license renewal activities, industry reports, NUREG reports, BNL and other national lab reports. LERs are reports that must be submitted by NPP licensees to the NRC if certain potential problems occur such as: any event or conditions that occurred in the plant which resulted in a condition of the plant being seriously degraded or the plant being in an unanalyzed condition that significantly degraded plant safety. More details about LERs are reported in Section 3 of this report.

The prior research reported in NUREG/CR-6679 collected and evaluated degradation occurrences for SPCs in US NPPs over the period 1985 to 1997. Therefore, the current BNL research for

KAERI was intended to focus on the more current period from 1997 to the present. That way, there would not be any overlap and an assessment can be made for the current period and the results may be compared to the conclusions reached from the prior period.

1.4 Report Organization

This report consists of five sections. Section 2 presents a summary of the past aging research studies which include programs and studies conducted by BNL, NRC, and other research institutes and the nuclear industry. Although, describing this information was not intended to be part of this research task, it is useful to provide this description in the report to present a framework of what aging technology information is available from past studies and the regulatory requirements and guidance documents related to aging. Section 3 of the report describes the review of the recent LERs and the corresponding statistical and trending analysis. Section 4 summarizes the review of the recent generic communications and LRAs. Section 5 provides the conclusions reached from this research effort, which includes a summary of the findings from the identification and evaluation effort of degradation occurrences, and an assessment of the degradation trending analysis.

2 PAST AGING RESEARCH STUDIES

There is substantial existing aging technology information from prior aging research studies and current industry programs. This includes both NRC and industry sponsored research programs. This section first describes NRC requirements/guidance related to aging degradation and then summarizes past NRC research programs, industry programs, and other technical information. Much of the information presented below is based on aging technology information reported in the prior BNL research program NUREG/CR-6679. Relevant information in this section, if not specially noted, refers to nuclear power plants in the U.S.

2.1 NRC Requirements/Guidance

This section summaries current NRC requirements and available guidance related to degradation of structures and passive components (SPCs), including requirements and guidance for containments, water-control structures, and masonry walls, and rules for maintenance and license renewal.

Containments
Periodic leak rate testing of containments is required in accordance with 10 CFR Part 50, Appendix J. The leak rate testing of a containment has three types of tests: A, B, and C. Type A tests are performed to measure the primary reactor containment overall integrated leakage rate, Type B tests are performed to detect local leaks for penetrations, and Type C tests are conducted to measure containment isolation valve leakage rates. Prior to performing a Type A test, a general visual inspection of the accessible interior and exterior surfaces of the containment structures and components must be performed to identify any evidence of structural deterioration which may affect either the containment structural integrity or leak-tightness.

Regulatory Guides 1.35 and 1.35.1 provides additional requirements for prestressed concrete containments for ungrouted tendons. Regulatory Guide 1.35 describes a basis acceptable to the NRC staff for developing an appropriate inservice inspection and surveillance program for ungrouted tendons in prestressed concrete containments. Regulatory Guide 1.35 provides guidance for performing visual inspections, prestress monitoring tests (lift-off tests), tendon material tests and inspections, inspection of filler grease, evaluation of inspection results, and reporting requirements. Regulatory Guide 1.35.1 provides a basis acceptable to the staff for developing appropriate presstressing tolerance bands for tendons so that these limits can be compared against the lift-off forces measured in the sample inspection program of Regulatory Guide 1.35.

10 CFR 50.55a has been revised to provide more precise requirements, assure that the critical areas of containments are routinely inspected, and take corrective action for defects that could compromise a containment's structural integrity. The final rulemaking, which was effective on September 9, 1996, endorsed the 1992 Edition with 1992 Addenda of Section XI, Subsection IWE (Class MC Containments) and Subsection IWL (Class CC Containments) of the ASME Code. Since the final rulemaking, subsequent revisions of 10 CFR 50.55a have been issued and now the current version also endorses as acceptable the 1995 Edition with the 1996 Addenda, the 1998 Edition through the 2000 Addenda, and the 2001 Edition through the latest edition and addenda. All of these endorsements are subject to certain limitations and conditions. Licensees must incorporate Subsection IWE and Subsection IWL into inservice inspection programs for containments. The rulemaking includes exemptions from and additional requirements to those in Subsections IWE and IWL.

Water-Control Structures
Water-control structures include structures such as intake structures, canals, dams, earthen embankments and slopes associated with emergency cooling water systems or flood protection. For these structures, Regulatory Guide 1.127 describes a basis acceptable to the staff for developing an appropriate inservice inspection and surveillance program. Guidance is provided for the compilation of engineering data, onsite inspection program, technical evaluation, frequency of inspections, and preparation of reports.

Masonry Walls
A major re-evaluation effort of masonry walls in the nuclear industry was initiated by the NRC IE Bulletin 80-11 "Masonry Wall Design." This effort initiated by the bulletin was intended to demonstrate the structural adequacy of reinforced and unreinforced masonry walls. Of the seventy plants originally in the scope of 80-11, two were shut down; three were reviewed under the Systematic Evaluation Program (SEP); one plant had no safety-related masonry walls; four were qualified by analytical methods verified by full-scale testing; and the remaining sixty plants were qualified in accordance with the Structural Engineering Branch (SEB) Interim Criteria.

NRC issued Information Notice No. 87-67, "Lessons Learned from Regional Inspections of Licensee Actions in Response to IE Bulletin 80-11," in December 1987. This notice described a number of deficiencies uncovered during site audits, which were grouped as:

- Unanalyzed Conditions - existing cracks in unreinforced masonry
- Improper Assumptions - mortar properties, boundary conditions, presence of reinforcement
- Improper Classification - specification of safety-related versus non-safety walls
- Lack of Procedural Controls - walk-down surveys, record keeping, modification activities

The information notice also indicated that "NRC inspectors observed that mechanisms did not exist at certain facilities to ensure that the physical conditions of masonry walls remained as previously analyzed."

Then an internal NRC report entitled, "Status of Multi-Plant Action (MPA) B-59, Masonry Wall Design" was issued in August 1988. This report recommended that the MPA be considered closed and also summarized the current status of each plant included in the action. The report also stated that the Office of Inspection and Enforcement had responsibility of inspection related activities.

10 CFR 50.65 – Maintenance Rule
Another important regulation, 10 CFR 50.65 entitled, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," was published by the NRC on July 10, 1991. This regulation, which was referred to as the Maintenance Rule, became effective on July 10, 1996. The goal of the Maintenance Rule is to monitor the effectiveness of maintenance activities for safety significant plant equipment in order to minimize the likelihood of failures and abnormal events caused by the lack of effective maintenance. The final rule requires that licensees monitor the performance or condition of structures, systems, and components (SSCs) against licensee-established goals in a manner sufficient to provide reasonable assurance that the SSCs will be capable of performing their intended functions. Such monitoring needs to be established commensurate with safety and, where practical, take into account industry operating experience.

Other documents that provide additional technical information and guidance, related to the Maintenance Rule, include: Regulatory Guide 1.160, Rev. 2, “Monitoring the Effectiveness of Maintenance at Nuclear Power Plants;” NUMARC 93-01, Rev. 2, “Nuclear Energy Institute - Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants;” NRC Inspection Manual - Inspection Procedure 62706, “Maintenance Rule;” NRC Inspection Manual - Inspection Procedure 62002, “Inspection of Structures, Passive Components, and Civil Engineering Features at Nuclear Power Plants;” and NRC Inspection Manual - Inspection Procedure 62003, “Inspection of Steel and Concrete Containment Structures at Nuclear Power Plants.”

10 CFR Part 54 - License Renewal Rule

Nuclear power plants in the U.S. were initially licensed to operate for 40 years. To extend the life of these plants, requirements for obtaining the renewal of an operating license, for an additional 20 years, are presented in 10 CFR Part 54 - License Renewal Rule. Under 10 CFR Part 54, applicants are required to identify all SSCs that are within the scope of the rule. A screening review is then required to identify those SSCs that are “passive and long-lived” structures and components. For the passive, long-lived structures and components, the applicant must demonstrate that the effects of aging will be managed so that the intended function(s) will be maintained consistent with the current licensing basis through the period of extended operation.

In addition, applicants are also required to identify and update all time-limited aging analyses (TLAAs) which are part of the current licensing basis. An example would be a design basis fatigue analysis of a piping system which assumed a specified number of loading events based on a 40-year period of operation. For prestressed concrete containments, a TLAA is required to demonstrate that the prestressing tendons, which lose the tendon prestress loads over time, are still adequate for the additional 20 years of operation beyond the initial 40 years assumed in design.

In September 2005, the NRC issued Regulatory Guide 1.188, Rev. 1, “Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Licenses.” This regulatory guide indicates that the application should include (1) general information, (2) an integrated plant assessment (IPA), (3) an evaluation of time-limited aging analyses (TLAAs), (4) a supplement to the plant’s final safety analysis report (FSAR), (5) any necessary changes to the plant’s technical specifications (along with related justifications), and (6) a supplement to the plant’s environmental report. The FSAR supplement should provide a summary description of the programs and activities that the applicant will use to manage the effects of aging for the period of extended operation, which is determined by the IPA and the evaluation of TLAAs. This regulatory guide also endorses the industry guidance document NEI 95-10, Revision 6 for use in implementing the license renewal rule.

Another NRC document that provides guidance for license renewal of NPPs is NUREG-1800, Revision 1, “Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants” (SRP-LR), published in September 2005. This SRP-LR was prepared to provide guidance for staff reviewers in performing safety reviews of applications to renew licenses of nuclear power plants in accordance with 10 CFR Part 54. A companion document also published by the NRC in September 2005 is NUREG-1801, Revision 1, entitled, Generic Aging Lessons Learned (GALL) Report. This two volume document provides very specific guidance for use by applicants and the NRC staff reviewers to ensure effective, efficient and consistent satisfaction of the LR Rule requirements. The revised SRP-LR references the GALL Report for descriptions of generic aging management programs which the staff has evaluated and found applicable to license renewal.

2.2 NRC Programs

Some of the major NRC research programs related to aging degradation of structures and passive components (SPCs) in nuclear power plants are summarized below. A more complete listing of the NRC programs in this area is presented in NUREG/CR-6679.

2.2.1 Nuclear Plant Aging Research (NPAR) Program

In 1985 the NRC sponsored a research program to identify and resolve technical safety issues related to aging of SSCs in operating nuclear power plants. The principal goals of the program were to understand the effects of age-related degradation in NPPs and how to manage and mitigate them effectively. NUREG-1144, Rev. 2 describes the objectives of the program, the current status of research, and summarizes the utilization of the research results in the regulatory process. As a result of the NPAR program approximately 100 NUREG/CR reports have been developed as of June 1991, plus numerous published papers and proceedings.

A listing of past research activities under the NPAR program through September 1993 is presented in NUREG-1377, Rev. 4. This NUREG contains summaries of NRC sponsored reports that were generated in the NPAR Program. Each summary describes the objectives of the research, the contractor, and authors, and outlines significant research results. Although most of the items included in this NUREG cover hardware oriented plant components and systems, there are some summaries given for structural and passive components.

2.2.2 Structural Aging (SAG) Program

In 1988, the NRC sponsored a major research program on structural aging referred to as SAG. The objective of the SAG Program was to develop the technical bases for addressing aging of safety-related concrete structures and providing guidance for use in evaluating continued service of these concrete structures. Over 90 technical reports and papers have been published describing the results of the program.

The SAG Program consisted of a management task and three technical task areas. The objective of the management task was to effectively manage the technical tasks related to the safety issues of aging NPP concrete structures. The first technical task was to develop a materials property database. This consisted of a reference source containing data and information on the time variation of material properties under exposure to applicable environmental stressors (mechanisms) and aging factors. The materials database covered various concrete types, steel reinforcements, prestressing tendons, structural steels, and rubber materials. The information contained in the database can be used to predict deterioration of structural components in NPPs and in developing limits on detrimental environmental exposures.

The second technical task described a methodology that can be used to (1) make quantitative assessments of environmental stressors or aging factors that could affect safety-related concrete structures at NPPs and (2) provide recommended in-service inspection (ISI) or sampling procedures for use in evaluating the structural condition and for trending the performance of these components. Also included in this task are the identification and evaluation of techniques for mitigation of stressors or aging factors that may affect critical concrete components, and an assessment of techniques for repair, replacement, or retrofitting of deteriorated concrete components.

The third technical task developed a quantitative methodology for continued service determinations. This included development of predictive models to assess the current and future reliability and performance of concrete structures.

A summary of the entire SAG Program is provided in NUREG/CR-6424. This report describes the SAG Program including a description of safety-related concrete structures and longevity considerations; inservice inspection, condition assessment, and remedial measure considerations; evaluation of NPP reinforced concrete structures; reliability-based methodology for condition assessments; and summary, conclusions, and recommendations. The NUREG includes an excellent description of the aging mechanisms and aging effects for concrete and associated steel components of reinforced concrete structures. Appendix B to the NUREG provides a listing of the numerous reports and papers that were developed under the SAG Program.

Some of the conclusions as reported in NUREG/CR-6424 are:

- The performance of the reinforced concrete structures in NPPs has been good. However, as these structures age, incidences of degradation due to environmental stressor effects are likely to increase to potentially threaten their durability. Items of note would be corrosion of steel reinforcement due to carbonation of the concrete or presence of chloride ions, excessive loss of prestressing force, leaching of concrete, and leakage of post-tensioning system corrosion inhibitor through cracks in the concrete.
- Techniques for detecting the effects of environmental stressors are sufficiently developed to provide qualitative data.
- Methods for conducting condition assessments of reinforced concrete structures are fairly well established. Few standards or criteria are available for interpreting the results obtained from condition assessments. Current inspection requirements for NPP reinforced concrete structures are fairly limited with the exception of concrete containments.
- Techniques for repair of concrete structures are well established and when properly selected and applied are effective. At the time, no codes or standards are available for repair of reinforced concrete structures, although some are being developed. Criteria that may be used to determine when a repair action should be implemented are not available.
- A reliability-based methodology has been developed that can be used to facilitate quantitative assessments of current and future structural reliability and performance of reinforced concrete structures in NPPs.

2.2.3 Nuclear Power Plant Generic Aging Lessons Learned (GALL)

Another important research effort sponsored by the NRC is presented in NUREG/CR-6490 entitled, "Nuclear Power Plant Generic Aging Lessons Learned (GALL)." This report describes the research effort to perform a systematic review of plant aging information in order to assess materials and component aging issues related to continued operation and license renewal of operating plants. A literature review was performed for mechanical, structural, thermal-hydraulic components and systems, and electrical components and systems.

The results of these reviews were tabulated and included in a two-volume report. The NUREG concluded, "all ongoing significant component aging issues are currently being addressed by the regulatory process. However, the aging of what are termed passive components have been highlighted for continued scrutiny." The NUREG lists the aging issues significant to passive components. Most of the structural components evaluated pertain to the RPV (instrumentation and CRD housing nozzles, closure studs, jet pump and holddown beams, reactor internals, core shroud, etc.); piping and feedwater nozzles and interfacing tanks and components; concrete shield walls; and other concrete elements.

The NUREG also concluded, "passive components are not as extensively or thoroughly covered by current plant maintenance procedures. Furthermore, surveillance and monitoring methods and instrumentation and procedures have not been as extensively developed or employed for passive components subjected to the highlighted aging mechanisms, nor are some of the passive component aging mechanisms as well understood." In addition, the NUREG points out that passive components are often the most costly and most difficult to replace. Therefore, the knowledge base for predicting applicable aging effects behavior and significance is very important for passive components.

2.2.4 Assessment of Inservice Conditions of Safety-Related Nuclear Plant Structures (NUREG-1522)

NUREG-1522, entitled "Assessment of Inservice Conditions of Safety-Related Nuclear Plant Structures" was published by the NRC in June 1995. This report describes the condition of structures and civil engineering features at operating nuclear power plants and provided information that would help identify, monitor, and correct degraded conditions of these structures. The NUREG contains descriptions of age-related degradation, which were obtained from many different sources. The most significant information came from site visits, conducted by the NRC staff and its contractor BNL, at six older nuclear power plants (licensed before 1977).

Some of the observations noted in the report identify certain types of structures (e.g. water intake structures, masonry walls, anchorages, tanks, buried piping, and inaccessible areas) as requiring special considerations. The report also concludes that based on the observations and information collected, structures and civil engineering features should be periodically inspected and a systematic maintenance program be implemented to ensure the expected useful life of the structures.

2.3 Industry Programs

2.3.1 NUMARC Industry Reports (IRs)

Nuclear Management and Resources Council (NUMARC), under the sponsorship by the DOE and EPRI directed the preparation of ten industry reports (IRs). The IRs covered items such as PWR and BWR vessels, internals, primary coolant boundary, containments, and Class I structures. The purpose of the IRs is to address age-related degradation of these components on a generic basis. The IRs would provide the technical basis, which could be referenced by licensees in support of their license renewal application.

Each IR identifies the components that comprise the subject item (e.g. BWR containment) and evaluates each component in terms of possible age-related degradation mechanisms. Thus, certain aging mechanisms were eliminated and only those age-related degradation mechanisms that could affect the component were identified and described. In addition, the IRs evaluated the capability of programs to manage aging mechanisms that are applicable, and where generic effective programs cannot be shown to be capable of managing the effects of age-related degradation, aging management options for plant-specific programs are described.

2.3.2 NEI – Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants

The Nuclear Energy Institute (NEI) has developed an industry guidance document (NUMARC 93-01, Rev. 2) entitled, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." This guideline was developed to assist the industry in implementing the Maintenance Rule (10 CFR 50.65). The guideline describes the process for the identification of the SSCs within the scope of the Maintenance Rule and the process of establishing plant-specific risk significant criteria and performance criteria.

NUMARC 93-01 provides guidelines that include methodologies to select plant structures, systems, and components; establishing risk and performance criteria/goal setting and monitoring; identification of SSCs subject to effective preventive maintenance programs; evaluation of systems to be removed from service; and periodic maintenance effectiveness assessments.

The NUMARC document specifically addresses monitoring of structures under the Maintenance Rule (MR). The applicability of the MR to structures was a subject of considerable confusion within the industry during initial implementation of the MR. It is clearly stated in Section 10.2.3 of NUMARC 93-01, that structures which perform intended functions, in accordance with the criteria provided in NUMARC 93-01, are within the scope of the MR and require a monitoring program which ensures that degradation is detected before there is loss of any intended function.

NRC Regulatory Guide 1.160, Rev. 2 endorses NUMARC 93-01, Rev. 2 as an acceptable method to satisfy the general requirements of the Maintenance Rule. Regulatory Guide 1.160, Rev. 2 also addresses monitoring of structures under the Maintenance Rule and provides specific guidance for satisfying the requirements of the Maintenance Rule, as it pertains to structures.

2.3.3 American Concrete Institute (ACI) Codes and Standards

The American Concrete Institute (ACI) has developed a number of codes and standards that relate to degradation of reinforced concrete structures. ACI 201.1R-68, "Guide for Making a Condition Survey of Concrete in Service" provides a system for reporting on the condition of concrete in service. This guide includes a checklist for making a survey of the condition of concrete, provides a definition of the terms associated with the durability of concrete, and presents actual photographs to demonstrate the different types of aging effects.

ACI 201.2R-77, "Guide to Durable Concrete" discusses the more important causes of concrete degradation and gives recommendations on how to prevent such damage. Topics covered include freezing and thawing, aggressive chemical exposure, abrasion, corrosion of steel and other materials embedded in concrete, chemical reactions of aggregates, repair of concrete, and the use of coatings to enhance concrete durability.

ACI 207.3R-79, "Practices for Evaluation of Concrete in Existing Massive Structures for Service Conditions" describes methods for evaluating the physical properties of concrete in existing concrete structures. The report covers the review of preconstruction data, construction, operation and maintenance records; review of in-service inspections; condition surveys; nondestructive testing; and destructive testing.

ACI 224.1R-93, "Causes, Evaluation, and Repair of Cracks in Concrete Structures" summarizes the causes of cracks in concrete and the means for their control. The report also describes evaluation procedures and methods for crack repair such as epoxy injection, routing (enlarging the crack) and sealing, stitching (U-shaped metal units), use of additional reinforcement, and grouting.

ACI 349.3R-96, "Evaluation of Existing Nuclear Safety-Related Concrete Structures" presents recommendations for developing an effective evaluation procedure for nuclear safety-related concrete structures. The report describes the selection process of critical structures, the various degradation mechanisms, inspection techniques, evaluation criteria, evaluation frequency, qualifications of evaluation team, and repairs. Under the evaluation criteria recommendations, ACI 349.3R-96 presents a three tiered evaluation criteria: acceptance without further evaluation, acceptance after review, and conditions requiring further evaluation. It is in this area that the technical basis for some of the acceptance criteria need to be developed, expanded, and documented.

Other ACI standards such as ACI 224R-90, "Control of Cracking in Concrete Structures" and 222R-89, "Corrosion of Metals in Concrete" are listed in the Reference section of ACI 349.3R-96. ACI 349.3R-96 also lists related standards from ASCE, ASME, and ASTM.

2.3.4 American Society of Civil Engineers Standard

American Society of Civil Engineers (ASCE) Standard ASCE 11-90, "Guideline for Structural Condition Assessment of Existing Buildings" provides guidelines and a methodology for the structural assessment of existing buildings. Assessment techniques are provided for conventional buildings (non-nuclear) constructed from materials consisting of concrete, metals, masonry, and wood. The standard describes assessment procedures, condition assessment of materials, and evaluation procedures. Tables are presented in the guideline, which provide for each test method, a description of the application, principle of operation, user expertise, advantages, limitations, and references. Also included in the guideline are tables, which identify the various test methods which are most appropriate to evaluate chemical and physical properties of the material.

2.4 Other Sources of Technical Information

2.4.1 Information from Japan

Substantial technical information, regarding age-related degradation of structures and passive components is also available from international sources. A review of Japanese literature for degraded concrete structures was conducted by BNL under a separate research program for the NRC. A report by Park (September 1998) entitled "Effects of Aging Degradation on Seismic Performance of Reinforced Concrete Structures: Summary of Japanese Literature in Related Areas" summarizes the results of the review.

The 1998 report by Park provides a summary of a literature survey of available Japanese publications. Key observations are described in detail regarding age-related degradation mechanisms and seismic performance of degraded reinforced concrete structures. The report covers experimental studies on reinforced concrete members such as shear walls and beams in degraded conditions. Some of the observations and preliminary conclusions noted are:

- Vertical cracks in beams (normal to member axis) reduce the bending stiffness. However, vertical cracks do not significantly reduce the bending strength. Vertical cracks, in general, do not affect shear strength, unless they are located at the compression failure zone. Horizontal cracks (along component axis) affect the shear strength more than the bending strength.

- The orientation of cracks in concrete shear walls determines whether cracks affect the seismic capacity of components. Cracks would affect the shear capacity if they coincide with cracks caused by applied seismic loads or when they alter the failure mode.
- The size and number of cracks indirectly affect the seismic performance of all concrete structural members since the extent of corrosion is largely affected by crack size.
- There are indications that some initial levels of corrosion of steel reinforcement would increase the flexural strength of beams.

2.4.2 Organization for Economic Co-operation and Development (OECD) – Nuclear Energy Agency (NEA)

The Nuclear Energy Agency (NEA) is an intergovernmental body within the OECD located in Paris, France. The objective of the NEA is to assist its member countries in the development of nuclear energy as a safe, environmentally acceptable, and economical energy source through co-operation among its participating countries. Currently there are 28 countries including the United States that are members of the NEA. One of the committees within NEA, the Committee on the Safety of Nuclear Installations (CSNI) has a Working Group on Integrity of Components and Structures (IAGE). The main areas investigated by this working group include: the integrity of metal components; the integrity and ageing of concrete structures; and the seismic behavior of structures and components. A number of studies related to aging of structures and components were performed by the Working Group on IAGE and its predecessor the Principal Working Group (PWG-3) entitled "Integrity of Structures and Components."

An OECD - NEA Workshop on Finite Element (FE) Analysis of Degraded Concrete Structures was sponsored by the U.S. NRC and the OECD-NEA. This workshop was held at BNL on October 29-30, 1998. During the workshop over seventeen papers were presented related to the topic of the workshop. Many of the papers described technical approaches to utilize FE analysis methods for degraded concrete structures. A list of CSNI reports produced by or relevant to PWG-3 subgroups on the aging of concrete structures and the seismic behavior of structures is provided in NUREG/CR-6679.

2.5 Review of Recent BNL Aging Program

BNL has participated in a number of aging related research programs such as the NUREG-1522 study and technical assistance for NUREG-1801 (GALL). This section of the report will present a summary of an NRC sponsored BNL research study of aging degradation of NPP SPCs. A multi-year research program was performed to assess age-related degradation of SPCs for U.S. nuclear power plants. The objective of this program was to develop the technical basis for the validation and improvement of analytical methods and acceptance criteria which can be used to make risk-informed decisions and to address technical issues related to degradation of structures and passive components. This research program consisted of two phases. The Phase I effort included collection and evaluation of plant degradation occurrences, an assessment of the available technical information on age-related degradation, and a scoping study to identify which structures and passive components should be studied in the subsequent phases of the research program. Based on the results of the Phase I effort, selected SPCs were evaluated in Phase II to assess the effects of age-related degradation using existing and enhanced analytical methods. In addition, the Phase II effort included developing recommendations to the NRC staff for making risk-informed decisions related to degradation of structures and passive components.

Phase I: Assessment of Age-Related Degradation of NPP SPC

The description and results of the Phase I effort are reported in NUREG/CR-6679. Three activities were performed in this assessment effort. In the first activity, instances of age-related degradation were collected and evaluated. Licensee Event Reports, NRC generic communications, NUREG reports, and industry reports were reviewed to collect degradation data, which were stored in a database as summaries of important parameters. Then, trending analyses were performed to evaluate the data and develop important observations. The trending analyses provided conclusions such as what SPCs were most susceptible to age-related degradation, the most common aging mechanisms and aging effects, and the trend of the degradation occurrences over time. The second activity included the compilation of additional technical information related to aging such as NRC requirements/guidance, NRC programs, industry programs, degradation information from other countries, and other reports/papers on aging degradation. The third activity was a scoping study to identify those SPCs that warrant further detailed evaluation in Phase II. The scoping study was performed based on four key factors: degradation occurrences, seismic risk significance, adequacy of existing NRC and industry programs, and importance to current licensing basis/license renewal. The results of the scoping study determined that of the 18 original SPCs included in the research program, the five SPCs that should be included in the Phase II effort for more detail study are concrete structures (other than containment), buried piping, flat bottom atmospheric tanks, anchorages, and masonry walls.

It should be emphasized that a very extensive degradation reference database was created during the Phase I work which is presented in Appendix B to NUREG/CR-6679. This database covered the codes, industry standards, guidelines, NUREG reports, technical papers, presentations (at conferences), regulatory documents, and other reports that were collected and reviewed in Phase I. The regulatory documents included Code of Federal Regulations (CFRs); NRC generic correspondences such as Inspection and Enforcement Bulletins (IEs), Information Notices (INs), Generic Letters (GLs), etc.; NRC inspection reports; NRC regulatory guides; and NRC SECY papers. The reference database included over 160 documents in total, each of which consists of the type of document, the identification or ID (document no.), title of the document, date of publication, author/organization, a summary description, types of components covered, and potential aging issues identified in that document.

Phase II: Detailed Evaluations of Identified Components for Assessment of the Effects of Age-Related Degradation on SPCs

Of the five components that were identified during Phase I that warrant further detailed evaluation in Phase II, studies for two of them were completed. A detailed study was performed for reinforced concrete elements and buried piping and the results of these studies were presented in two NUREG reports. The objectives of the detailed studies in Phase II were to develop and improve analytical methods that can be used to assess the effects of age-related degradation on the structural performance of the SPCs, quantify the impact of age-related degradation of structures and passive components on overall plant risk, and develop degradation acceptance criteria that can be used to assist the staff in making risk-informed decisions for age-degraded SPCs.

Reinforced Concrete Components

NUREG/CR-6715 summarizes BNL's study that addressed the concerns related to aging degradation of reinforced concrete structures at NPPs. The aging effects due to reinforced concrete degradation mechanisms were studied and the corresponding analytical methods and degradation acceptance limits for concrete flexural and shear wall members were developed. Fragility modeling procedures for undegraded and degraded reinforced concrete structural components subjected to earthquake loadings were studied. These probability-based quantitative methods provided a basis for evaluation of reinforced concrete structures in nuclear plants for continued service and for development of guidelines for in-service inspection and maintenance. Probability-based degradation acceptance criteria (DAC) were also developed to assist the NRC staff in making risk-informed decisions regarding degradation of reinforced concrete components.

Buried Piping

NUREG/CR-6876 presents the results of the second detailed study performed by BNL which addressed the effects of degradation on buried piping. The purpose of this study was similar to the concrete study, which is to develop analytical methods that can be used to assess the effects of aging degradation of buried piping and to develop degradation acceptance criteria (DAC) that can be used to assess the condition of degraded buried piping. A risk-informed approach was taken to evaluate the most common aging effects in buried piping, which consists of general wall thinning and localized loss of material/pitting. Degradation over time was included in the methodology development. Fragility modeling procedures for degraded buried piping were developed and the effect of degradation on fragility and core damage frequency (CDF) was determined. The development of DAC considered the effects of degradation over time so that the number of years required for the buried pipe to reach a level of degradation that represents a potentially significant plant risk can be determined. NUREG/CR-6876 included necessary conditions for the usage of DAC, including the types of buried piping systems, configurations, materials, applicable pipe loads (e.g., pressure, surcharge, live load, etc.) and other conditions. It was recognized in this study that seismic induced stresses in buried piping are self-limiting since deformations or strains are limited by seismic motion of the surrounding media. DAC and related methodology developed in this report were intended to provide guidance to the NRC staff for making timely assessment whether observed degraded conditions potentially have an immediate significant effect on plant risk. However, as is the case in the concrete study, the DAC are not intended for industry applications as a tool to justify existing degraded conditions.

3 LICENSEE EVENT REPORTS

Licensee event reports (LERs) are one of the first sources utilized for collecting and reviewing age-related degradation occurrences of structures and passive components (SPCs) at nuclear power plants (NPPs) in the U.S. LERs, which are governed by 10 CFR 50.73, are considered to be a consistent and complete source of information for obtaining degradation records. This section describes the list of SPCs in more detail, methods used to identify and retrieve LERs, development of an LER review assistance program, summary of results, and trending analysis. Reviews and findings using other sources are documented in Section 4 of this report.

3.1 Structure and Passive Component List

Based on the discussions between BNL and KAERI, a list of structures and passive components (SPCs) introduced in Section 1 were established as a combination of a list of structure and components provided by KAERI and a list of 18 components reported in NUREG/CR-6679. Eight component categories from NUREG/CR-6679, namely the cable tray systems, conduit systems, cooling tower, electrical conductors, HVAC duct, insulation/seal, structural seismic gap, and water-control structures, are not included in this search effort because they are not considered to be risk significant according to the component list provided by KAERI.

This section describes the selected SPCs in more detail by including their subcomponents and the information relevant to later discussion in this report.

Anchorage

Anchorage covers all structural components that serve as a connection between a concrete element and a piece of equipment. Anchorages include embedded anchors, expansion anchors, grout (used beneath baseplates), and steel embedments.

Concrete

The concrete category includes reinforced concrete buildings, water intake structures, pump house, underground structures, concrete walls/floors/ceilings/mats/foundations, canals, fuel pools, pits, pedestals, prestressed concrete structures, manholes. It also includes masonry walls and block walls.

Containment

Containment is a special type of structure in nuclear power plants used as a final barrier to prevent the release of radioactive materials to the environment following a postulated accident that may occur inside the containment. Therefore, the containment is not categorized as either concrete or structural steel components. The containment category includes the steel shell or concrete shell, prestressing system if applicable, penetrations, torus (if applicable), bellows, liners, and supports. The prestressing system includes tendons, tendon anchorages, and grease used in the tendon conduits to prevent degradation of the tendons.

Exchanger

The exchanger category includes steam generator, heat exchanger, condenser (including ice condensers used in the design of some US plants), and supports.

Filter

Filters include mechanical & HVAC - screens, separators, strainers, absorbers, relevant supports, and housings. It should be noted that the subcomponents for filters do not include regular maintenance items which are examined or replaced on a regular basis.

Piping system
Piping systems include piping, underground piping, fittings, small bore piping & tubing, sleeves, and pipe supports. Hydraulic or mechanical assemblies of snubbers are not considered since they are active components and subject to periodic inspection and maintenance if needed.

RPV
Subcomponents of reactor pressure vessels (RPVs) include the shell, internals, passive components for control rod drive mechanisms (CRDMs), and relevant supports. Although pressurized, RPVs are distinguished as an individual component from other vessels because of their unique and important roles in nuclear power plants.

Structural steel
The structural steel category includes steel frames, trusses, platforms, supports, bolts, nuts, studs, fasteners, liners, doors, covers, hatches, and support to all types of equipment.

Tank
Tanks are those vessels that are subject only to atmospheric pressure.

Vessel
Vessels are pressurized, and include subcomponents pressurizer, other pressurized vessels, and their supports.

Degradation occurrences included in this report do not necessarily correlate to the number of degraded elements at a specific plant and date. If several degraded elements are found at the same plant and the same date, they are grouped into one degradation occurrence if they are the same subcomponent.

It should be noted that the subcomponents in some of these component categories are not always the same as those used for NUREG/CR-6679. In particular, the penetrations under the containment category and the piping, fittings, small bore piping, tubing, and sleeves under the piping system category, were removed from further review (after some initial tabulation in NUREG/CR-6679) because they were being addressed by other existing NRC programs. In addition, the 105 degraded piping system components reported in NUREG/CR-6679 were only a part of all degradations that actually occurred, because the total number of piping system degradation occurrences were found to be too numerous. For this research, the counting of the degradation occurrences using LERs was more thorough in the sense that none was intentionally discarded. These differences were taken into account in the statistical comparison and the trending analysis.

For each component where degradation was identified, a degradation occurrence record (DOR) was developed. The DOR includes the following fields in the database: ML number, LER reference number, Event Date, Plant Name, Docket Number, System, Component, Subcomponent, Aging Effects, Aging Mechanisms, How Identified, Evaluation Method, and Repair method. These fields are explained in the subsections below.

3.2 Licensee Event Reports

Since this research must be based on publicly available information, LERs were chosen to be one of the primary sources for review. The LERs were also selected as the primary source for the following reasons: standardized requirement in accordance with 10 CFR 50.73, continuous in time, completeness of information, good coverage of significant events, well formatted, and easy accessibility.

Since January 1, 1984, an LER is required by 10 CFR 50.73 to be submitted within 60 days after the occurrence of a significant event, following an immediate notification (required by 10 CFR 50.72). Each LER and its revisions are generally required to address specific events and plant conditions. Unrelated events or conditions, including cases of the same or similar components but different causes or separate events/activities, should be reported in different LERs. Voluntary LERs are encouraged to be submitted even if the events are not required by 10 CFR 50.73 and other requirements, but are believed by the licensee to be safety significant. An LER may be canceled by letter provided that the cancellation has a sound and logical basis.

LERs have been used by the NRC staff to study potentially generic safety problems, and assess trends and patterns of operational experience, as well as in other applications [NUREG-1022]. As specifically required by 10 CFR 50.73, a licensee shall report the following items when writing LERs:

1. Plant shutdown by technical specifications
2. Operation or condition prohibited by technical specifications
3. Deviation from technical specifications under 10 CFR 50.54 (x)
4. Degraded or unanalyzed condition
5. External threat or hampering
6. System actuation
7. Event or condition that could have prevented fulfillment of a safety function
8. Common-cause inoperability of independent trains or channels
9. Radioactive release
10. Internal threat or hampering
11. Transport of a contaminated person offsite
12. News release or notification of other government agency
13. Loss of emergency preparedness capabilities
14. Single cause that could have prevented fulfillment of the safety functions of trains or channels in different systems

For each of these 14 reportable items, NUREG-1022 provides detailed description, discussion, and many application examples.

LERs are also required by 10 CFR 50.73 to contain a brief abstract; a clear, specific, and narrative description of the event; an assessment of the safety consequences and implications of the event; corrective actions; and references to any previous similar events. In addition, LERs start with a signed cover letter and usually have a very instructive title. Most LERs utilize NRC FORMs 366/366A/366B, which include information such as facility name, docket number, event date, LER number, report date, etc. Compared to other sources of information as described in NUREG/CR-6679, LERs have the advantage of information completeness and rule-based format, which can facilitate automation in their processing.

3.3 Keyword Search Approach through NRC ADAMS System

The LERs used in NUREG/CR-6679 were processed through the Sequence Coding & Search System (SCSS) that was created and maintained for the NRC by the Nuclear Operations Analysis Center at the Oak Ridge National Laboratory (ORNL). This database system contains over 35,000 LERs from 1980 to 1997, of which NUREG/CR-6679 covered the period of 1985 to 1997.

SCSS provides a searchable way to process the LERs. However, this system is not accessible anymore which precludes its use in this search effort. Development of a system similar to SCSS would require a sizable effort beyond the available resources for this project. Therefore, the identification and review process of recent LERs will be based on the NRC ADAMS system.

3.3.1 NRC ADAMS System

Quoting from the NRC website, "The **A**gencywide **D**ocuments **A**ccess and **M**anagement **S**ystem (ADAMS) is an information system that provides access to all image and text documents that the NRC has made public since November 1, 1999, as well as bibliographic records (some with abstracts and full text) that the NRC made public before November 1999. The NRC continues to add several hundred new documents daily. ADAMS permits full-text searching and enables users to view document images, download files, and print locally."

More specifically, public documents since November 1, 1999 are provided in the NRC ADAMS system as image and text files through the publicly available records system (PARS); public documents before that date are mostly provided only as bibliographic records through the public legacy library (PLL). Web-based access and Citrix-based access are the two methods for using ADAMS, the former with a web-based search engine for documents after November 1999 and the latter with the downloadable Citrix software. Excellent help documents are provided on the NRC website for usage of these two methods. Because PLL does not include full text for all records and does not include recent records, web-based ADAMS access, i.e., PARS, was chosen in this research. Moreover, NUREG/CR-6679 covered LERs between 1985 and 1997; utilization of PARS fortunately extended that period after 1999 with just 1998 omitted. However, since the search of degradation occurrences aims at identifying any trend shift, omitting one year does not statistically affect the conclusion.

The NRC ADAMS system features simple and advanced search methods, additionally with a full range of sorting and other result representation options. It has three query methods, namely Concept, Boolean, and Pattern modes. Detailed instruction on the usage of these modes and comparisons of their advantages are available through the ADAMS help documents. The search results can be further filtered and refined to obtain records that are more relevant. In ADAMS system, any of its documents can be identified by a unique accession number (MLxxxxxxxxx).

3.3.2 Development of the Keyword Search Approach

Using the advanced search method with "LER" as the document type field, a total of 4323 LERs had been found through PARS, as of 04/16/2008 (many new documents including new LERs are constantly collected in the ADAMS system). Since the number of LERs is too large to be reviewed with the allowable resources, various query methods and associated options were initially explored to identify an appropriate method to process the LERs for identification of degradation occurrences of the SPCs. This subsection is a brief summary of the development of the keyword search approach, which serves as the justification of the applicability of this method.

All three query modes of the ADAMS system were evaluated to identify the best search strategy. Both the Concept mode and the Boolean mode returned virtually the entire set of LERs using an extensive list of aging/degradation related keywords (with appropriate Boolean operators), such as: *aging, degradation, deterioration, corrosion, cracking, failure, spalling, rupture, peeling, thinning, "loss of material," "excessive deformation," wear, "loss of preload," "stress relaxation," "water accumulation," fouling, plugging, loosening, leaking, wear, pwscc, scc, igscc, iga, tgscc, odscc, hsc, embrittlement, organism, erosion, vibration, "chemical attack", fatigue, and rust*. The use of quotes was required when using multiple words within a single phrase.

Pattern search had many unrelated expansion of the original search terms, and therefore, was judged no better than the previous two modes. Therefore, the decision was made to develop keywords for each of the 10 component categories. In addition, the exploration also showed that the keywords in the "Filter with" field appeared to be an appropriate approach.

The options for using the ADAMS system were chosen to be:

Filter With Field: *keywords with Boolean operations*
Document Type: *LER*
Number of Docs to Retrieve: *99999*
Number of Docs to Display: *99999*
Sort by: *Document Date in Descending Order*

The result fields for the returned document records include: Title, Accession Number (ML #), Docket Number, Document Number, Estimated Page Count, and Document Summary.

By trial and error, the keywords used in the "Filter With" field for the Anchorage were selected to be *anchor* or grout or "steel embedment."* The use of the star character permits retrieval of various forms of the word anchor such as anchors, anchorage, anchored, or anchoring. Using this keyword set, ADAMS returned 80 LERs, which were judged to be a reasonable number that can be reviewed within the project resource limit provided other component categories would return similar number of LERs. The degree of coverage of these 80 LERs over the entire potential degradation occurrences of anchorages were not known.

Similarly, using a keyword set of *concrete or masonry or rebar*, 99 LERs were returned by the ADAMS system for the concrete component category. However, this keyword list was not considered to cover the entire population of this category in the ADAMS database. For example, more than 2000 LERs were returned using a much more rigorous enumeration of the possible subcomponents, which were formed as a Boolean expression: *(concrete or intake or pumphouse or underground or mat or mats or foundation or canal or pit or pedestal or prestress or manhole or masonry or block or pool) and (crack or degradation or aging or deterioration or corrosion or failure or spalling or rupture or peeling or wear or preload or relaxation or fouling or plugging or leaking or embrittle or erosion or chemical or attack or fatigue or rust)*.

From the trial results for the anchorage and the concrete component categories, there were two issues in this keyword approach: (1) the number of returned LERs and (2) the degree of coverage of the component population. One may get a reasonable number of LERs to process but leave the coverage in question, or achieve a high confidence in population coverage but retrieve too many LERs that cannot be processed within the resources available to perform this research study. Another problem is that some LERs may be returned for more than one component categories and therefore will need to be reviewed multiple times. The resultant total number of LERs reviewed may be even larger than the total number of LERs (4323) for a fair coverage of the population. In summary, this keyword approach appeared to be an art of balance in creating an appropriate list of keywords: it can either (1) reduce the number of returned LERs to a reasonable level for processing but with the potentially degraded coverage or, (2) increase the coverage level of the population but with too many returned LERs to be processed. In the meantime, developing the keyword list required repetitive accesses of the ADAMS system to check the returned LER list and represented a sizable effort.

Therefore, the development of the keyword search approach was determined to be inefficient and was stopped after the concrete component category. Accordingly, all LERs after 1999 were reviewed individually so that a full coverage was achieved and any LER was avoided being reviewed more than once.

3.4 Development of LER Reading Assistance Tool

3.4.1 Summary of the Development Process

The initial approach for processing every individual LER is first to retrieve all LERs, sorted by document date in descending order, through the ADAMS system and then to review them in that order. This approach required bookkeeping each current LER being reviewed and retrieving the list of all LERs after each interruption such as computer shutdown at the end of each day, work breaks during the day, and internet/web server issues. On average, each LER has about five to six pages, with the longest being 311 pages. After an initial experiment for the first a day or so, it was estimated that each LER requires about 5 minutes to review which is equivalent to reviewing 96 LERs/day. The total estimated effort could be 45 days, which would result in no time for database development, statistical analysis, and annual report preparation. This difficulty led to the development of computerized tools to assist the LER review.

Since the NRC ADAMS system may not be accessible at all time, for example, the ADAMS server may be down or the internet connection may be lost unexpectedly, all LERs were downloaded at once and the review was carried out locally. Only the text files (in HTML format) were downloaded in order to facilitate the computer assistance in processing and to avoid the unnecessary download time and consuming a large amount of disk space if the image files were downloaded. The actual retrieval of the 4323 HTML files utilizes an in-house web crawler, which was developed in Python (computer language) and was capable to automatically login the ADAMS system, submit the advanced search form, and retrieve the HTML files. There were a small number of LERs that could not be downloaded automatically and were logged by the spider for manual download. The entire retrieval process took about three hours and the downloaded files consumed 116 MB of disk space.

As the HTML files include a lot of tags that are not meaningful, the HTML files are then translated into pure text files by trimming out these tags and some other irrelevant text. The resulting text files have a total size of 73 MB on a disk.

Figure 3-1 through Figure 3-4 show a sample LER in text format, showing its beginning part, abstract part, cause part, and action part, respectively. These various parts are common for most LERs as required by the 10 CFR 50.73, and are used to speed up the review of these LERs. In contrast, Figure 3-5 shows the image of the same LER, with the NRC form 366 that shows the abstract part.

Compared to image files (pdf or tiff format), text files have the advantages of being: locally available; easy for computers to process; relatively easy to decode the LER number, event date, plant name, and docket number from these text LERs; and easy to locate the four helpful sections in the LERs (cause, title, abstract, and corrective action). However, the text files are no better than the image files than the pdf files to human readers. In addition, a small number of LERs are only available in image format. The goal of developing an assistance tool for LER processing was to (1) automatically decode relevant information such as LER number, event date, plant name, and docket number, (2) automatically color-code the four sections, (3) automatically identify the plant type, (4) automatically color-code the entire text such that reading of the LER is more effective, and (5) manage the saved degradation occurrences. This tool can effectively process all text LERs and can retrieve an image file from the NRC ADAMS system on rare cases where a text LER is not available locally or not sufficient to make a decision.

Because of our extensive experience in developing Python programs, the initial development of the assistance tool, so called LER Reader, required only an effort of 4 days (including the development of the web crawler); later improvement of the LER Reader involved more time during the processing of the LERs. This development ended up with 1009 lines of hand written codes and thousands of lines of generated codes. It should be noted that the improvement of the tools does not require a reprocessing of the reviewed LERs because the LER Reader only assists us to review but not to make the decisions. The improvement was intended to increase the review speed not to lower the quality of the review.

3.4.2 Introduction of the LER Reader GUI

Figure 3-6 shows the annotated graphical user interface (GUI) of the LER Reader. The large box labeled as “LER Text” on the right hand side is used to display the parsed LER texts; while those tables, boxes, and buttons on the left hand side provide the controlling functionalities. The table on the upper-left corner labeled as “Degradation Occurrence Record (DOR)” is used to enter the DORs either automatically by the LER Reader or manually, depending on the fields.

Tool Set One includes buttons and a text box to control the process of LERs. Clicking “Reload Terms” reload the component list, system list, subcomponent list, aging effects list, and aging mechanism list, each of which is stored in one text file. Button “Save” is for saving the DOR filled in the table. The text box with “-1” indicates the current LER id within the range of 0 to 4322. Button “Next ML” advances to next LER and triggers the auto parsing of the new LER. Buttons “I” and “O” can be used to zoom in or out the LER text, i.e., to increase or decrease the font size for the LER text. Button “>Pdf” can be used to retrieve from the NRC website and show the corresponding pdf file as needed for rare cases. The four buttons “>Title”, “>Abstract”, “>Cause”, and “>Action” are intended to jump in the “LER Text” box to the corresponding section of the LER text. A few convenient short cut commands for these navigation functions are also available by pressing the right mouse button. Pressing the middle mouse button reformats the text for better readability.

The text box labeled as “LER Title and Plant Type” shows the title of the LER and the decoded plant type, which can be “PWR”, “BWR”, or “???”. A plant type of “???” indicates either this LER is not about any of the 104 NPPs in the US or the LER Reader cannot determine the plant type.

The text box labeled as “Saved Recorded Statistics and Other Information” is used to show various information or result of the LER Reader. Figure 3-7 shows the DOR statistics shown in this box.

Tool Set Two includes a status label for the number of save DORs and two buttons for control of the display of saved DORs in the text box below. The button “Refresh” is required to click if the user wants to browse through the saved DORs; the simple summary of the saved DORs will be shown in the text box below after this button is clicked. Clicking “Next Saved LER” iterates through the saved DORs.

3.4.3 Application of the LER Reader

Upon loading an LER by clicking the “Next ML” button, the LER Reader does the following steps:

1. Parse the LER to obtain the LER Reference number, event date, plant name, and the docket number; unsuccessful items will appear as empty in the DOR table.
2. Parse the LER to locate the positions of the Title, Abstract, Cause, and Corrective Action; unsuccessful items will have a default value 0, which is the start of the text LER.
3. Jump to the Cause section in the "LER Text" box, which may show the beginning of the LER if the parsing of the Cause section failed in step 2.
4. Check if the DOR was already saved in the database, which may use a revision of the current LER; a warning dialog will show if an existing DOR is found.
5. Show the title and the plant type.
6. Colorize the LER text; yellow suggests the LER is about something not related to degradation of SPCs while red suggests it is related to degradation.

The procedure to review an LER starts with loading an LER by clicking the "Next ML" button. Upon successful loading, one may read the entire LER for identification of any degradation occurrences. However, the utilization of the LER Reader to speed up the review process requires the following suggested steps:

1. Advance to next LER if a dialog shows a DOR existed in the database.
2. Read the title and the plant type; if the plant type is "???", the LER is most likely not related to the NPP. The title is usually very instructive.
3. Read the Cause section and other sections if needed for any recordable DOR; click the right mouse button to iterate through the four sections in the order of Cause, Title, Abstract, and Corrective Actions; or scroll through the whole LER.
4. If the LER text is not meaningful, try to directly load the PDF file from the NRC website by clicking ">Pdf", or by visiting the NRC ADAMS system directly with the ML number. Copying the HTML content from the NRC website to the "LER Text" box will trigger the LER Reader to parse and save it automatically.

Figure 3-8 through Figure 3-16 show various use scenarios of the LER Reader. It is obvious that colorizing LERs as described previously greatly increases the absorption of information for the users. The nature of the event can be determined by looking at the highlighted words or phrases, after a brief experience of the colorized LERs.

For the majority of cases, the correct LER reference number, event date, plant name, and docket number can be determined automatically by the LER Reader. There is no need for the user to identify this information in the LER and then enter these values into the table. The LER Reader can appropriately colorize the relevant words and phrases and can correctly identify all or most of the four important sections. The reviewer usually does not need to scroll through the whole LER to find all the necessary information.

The combination of the LER Reader and the associated LER text files saved a lot of manual accesses to the ADAMS system and avoided the time consuming download of the image files. There was also no need to carefully maintain the order of the 4323 LERs and to keep track of the current LER after resuming from an interruption.

During review of the LERs, all DORs were saved to a text file, which later can be imported into an Microsoft (MS) Access database for statistical analysis.

Compared to the estimated speed of reviewing 96 LERs/day for the approach that utilizes the NRC ADAMS system directly, review of 200 to 300 LERs/day was achieved on average using the LER Reader approach. The total amount of time including the program development was about half of the original estimate of 45 days. As the experience in using the LER Reader and in reviewing LERs grew, the process of identifying and tabulating applicable LERs became faster. Indeed, more than 350 LERs were processed on the last day. Had more LERs been available for processing, the saving by the LER Reader approach would be more significant. In addition, the use of the LER Reader ensures much greater accuracy since much of the data was automatically transcribed into the database once the user noted the applicability of the LER.

3.5 Results Assessment

3.5.1 Database Integration

The text file of DORs saved by the LER Reader were imported as the DOR table to an MS Access database, which include the fields: ML number, LER Reference number, Event Date, Plant Name, Docket Number, System, Component, Subcomponent, Aging Effects, Aging Mechanisms, How Identified, Evaluation Method, and Repair method.

During the trending analysis to be presented later in this report, there was a need to compute the plant age when a particular degradation event occurred. To this end, the date that the construction permit (CP) was issued was selected as the starting time of the plants. The CP date and the operation license (OL) date were obtained from the U.S. NRC 2007-2008 Information Digest, Appendix A [NUREG-1350, 2007]. A database table was then created for all 104 operating NPPs in the U.S. by incorporating the plant information from the NRC website and these CP and OL dates. The fields of this table include plant name, docket number, reactor type, location, owner/operator, NRC region, CP issued, and OL issued, as shown in Table 3-1. The NRC regions showing the NPP distribution in the U.S. are shown in Figure 3-17.

The DOR table and the U.S. plant information table are related by the docket numbers. Additional queries, reports, forms, macros, and pages were created to assist the database integration and statistical analysis. In order to perform the trending analysis, the database used in NUREG/CR-6679 was updated to include the plant information table. A number of PivotTables in MS Excel were utilized to connect to the databases and to generate data during the statistical analysis.

3.5.2 DOR Assessment

DORs are summarized in Table 3-2 and Table 3-3, presenting the primary information and the secondary information for the DORs, respectively. The two tables are one-to-one correlated by the field ID. The primary information table includes fields ID, component, subcomponent, system, aging effects, aging mechanics, plant and event date, which are significant in describing a DOR. The secondary information table provides supplemental information for the DORs, which consists of how identified, evaluation method, repair method, docket number, LER reference number, and ML number, and also includes ID, component, and subcomponent for easy identification. DORs in the primary information table are in the alphabetical order of the fields component, subcomponent, and system, which together identify the specific SPCs. DORs in the secondary information table are in the ascending order of ID. An entry of “NA” in these tables signifies that there was no or insufficient information available in the LER for that entry. Although a docket number can be used to uniquely identify a plant or a particular unit in a plant if there are multiple units at the site, the plant name and the unit number are still provided in these tables for convenient reference. Table 3-4 shows the abbreviations used for the aging mechanism field.

In the DOR tables, there are three entries under an additional component category "other", which includes those DORs that were determined not suitable for any of the 10 SPC categories. Excluding these three entries, A total of 223 DORs were identified from the LERs for the period of 1999 to the present (4/16/2008), including just a few from 1998 as well.

Figure 3-18 shows the distribution of the SPC degradation occurrences by component categories, with the number of the degradation occurrences annotated over the bars. As would be expected, the piping systems have the most degradation occurrences reported in the LERs, about 36% of the total DORs. Exchangers and RPVs have the next two largest number of degradation occurrences, representing about 22% and 17% of the total DORs, respectively. The other seven component categories represent less than 25% of the total DORs; they are vessels, filters, containments, structural steel, tank, concrete, and anchorage in descending order of the number of degradation occurrences. It should be noted that the number of degradation occurrences for a particular category is also a function of the quantity of components in that category that is present at a plant. So for example, the number of degradation occurrences for piping was expected to be large, because there are many piping systems at a NPP and many of these piping systems can be quite long.

The total number of DORs for structural type components, i.e., containments, structural steel, concrete, and anchorages, is only 18, about 8% of all DORs. However, this does not necessarily indicate that there have been fewer degradations occurring in these structures. Rather, it is because of the nature of the structural degradation and the nature of LER reporting requirement that are judged to result in fewer instances of degradation. As described previously, LERs report any degradation situations that seriously affect the plant safety or result in any unanalyzed conditions that could significantly compromise the plant safety. The events reported in LERs are often from operating experiences. Structural degradations usually have less immediate impact on plant safety, and therefore, are less likely to be observed and reported in LERs. However, structural degradations can be significant risk factors to plant safety when a severe environmental event, for example, a large earthquake, occurs. Most structural degradations can be found in literatures that involved results from special inspection efforts. For example, NUREG-1522 covers data obtained from walkdowns conducted at six older vintage plants [NUREG-1522, 1995].

Other distributions over various measures are provided in the next subsection, with comparisons to data reported in NUREG/CR-6679.

3.6 Trending Analysis

To evaluate the possible trends in degradation occurrence data, the DORs in the past decade (approximately 1999 to 2008 collected in this study) and those reported in NUREG/CR-6679 (approximately 1985 to 1997) were compared. In order to make a sound comparison, a few differences between the current data collection using the recent LERs and those reported in NUREG/CR-6679 should be noted. These are highlighted in the following:

1. Difference in Information Sources: unlike the current set of data collected in this study which rely on LERs 1999-2008, NUREG/CR-6679 covered a larger set of information sources, which included LERs 1985-1997, NUREGs, NRC/IE Information notices, Correspondences, Generic Letters, NRC Bulletins, IR Circulations, SECY documents, and other publicly available documents.
2. Difference in LER retrieval methods: one-by-one evaluation for LER 1999-2008 versus computer based search for LER 1985-1997 through SCSS at ORNL.

3. Difference in component lists: 10 component categories for current collection versus 18 component categories for NUREG/CR-6679.
4. Difference in subcomponent lists: all SPCs for current collection versus reduced scope for NUREG/CR-6679 (e.g., piping, fittings, small bore piping & tubing, sleeves, penetrations, etc.).

These differences were considered in the comparisons presented in the trending analysis. Hereafter, the various comparisons utilize either the original data from NUREG/CR-6679 that includes all sources or only those related to LER 1985-1997 for consistency with the data collected in this research. The corresponding labels in the figures to be introduced are self-explained regarding their information sources.

Figure 3-19 shows the distributions of the degradation occurrences by components for three series of data: LER 1999-2008, NUREG/CR-6679, and LER 1985-1997, respectively. The bar chart is in the same order as reported in NUREG/CR-6679. Similarly, Figure 3-20 shows a normalized version of the same figure with the total numbers of DORS in each series as the basis. Considering LER 1999-2008 and NUREG/CR-6679, exchangers, piping system, and RPVs are the first three categories with the greatest number degradation occurrences. Since the piping system DORs for LER 1985-1997 were determined to be very large and did not include all of the occurrences in the SCSS database, the actual number of DORs of piping system for LER 1985-1997 are artificially low. These figures also show that filters were the second largest category using LER 1985-1997. Both LER data series confirm the observation in the previous section that LERs do not report many structural DORs, especially containment, concrete, and anchorage.

Figure 3-21 shows the distribution comparison of the SPC degradation occurrences over time, with the top figure showing the two series from NUREG/CR-6679 and with the bottom figure showing the series representing LER 1999-2008. First of all, the strong correlation over the years between the two series from NUREG/CR-6679 indicates that LER 1985-1997 represent a significant portion of the NUREG/CR-6679 data. Regardless of the partial years 1997, 1998, and 2008, the yearly DORs varies somewhat in cycles, which might correspond to inspection intervals that often are scheduled at refueling or are required by special NRC mandatory inspection requirements. On a yearly basis, there appear to be slightly more DORS from LER 1998-2008 than from LER 1985-1997. This observation may be due to the difference in reviewing LERs; the computer search approach for LER 1985-1997 may not have the same level of coverage of the degradation population as the one-by-one review approach for LER 1999-2008.

Excluding the three partial years, DORs from LER 1985-1996 and LER 1999-2007 are correlated to their plant ages at event (PAAE), which is defined as (Event Date – CP Issued Date). Table 3-5 and Table 3-6 show the number of DORs and the number of NPP units that these DORs belong to as a function of PAAE, for LER 1999-2007 and LER 1985-1996, respectively. Taking the row of a PAAE equal to 33 as an example, it shows that there were 20 NPP units which had 30 DORs at the time that these units were 33 years old as defined by PAAE. The fourth columns in these two tables list the average number of DORs that were obtained by dividing the number of DORs by the number of affected NPP units.

Figure 3-22 visualizes the number of DORs and the number of associated NPP units distributed over the PAAE. For both data series LER 1985-1996 and LER 1999-2007, the distributions show central peaks at 24 years and 33 years (PAAE), respectively, on curves related to DOR distribution and NPP unit distribution. These peaks and the hill shape distributions may suggest the distribution of construction time of the U.S. NPP population. As the two data series are approximately apart by 10 years, the associated curves show similar shifts, in particular with the peaks apart by 9 years. It is important to note that the upward shift between the two series shows the increase of the numbers of DORs and the affected units, indicating increasing age-related degradations. The peaks increase from 22 to 30 (36%) for the number of DORs and from 15 to 20 (33%) for the number of affected NPP units. The overall shift in the hill shape appears to represent linear increases in the numbers of DORs and affected NPP units. It should be noticed that the smaller numbers of DORs and affected NPP units at higher PAAE than the peak PAAE do not indicate there were less degradation for older plants, rather there were a smaller number of older plants in the operating NPP fleet. A similar observation occurs for the lower PAAE because there were fewer relatively younger plants during the 1999-2007 review period.

Figure 3-23 shows the numbers of DORs and the associated NPP units with the two data series combined. The combination was achieved by adding the related numbers for the overlapped PAAEs. The trend lines considered data up to a PAAE of 36 years, which was selected because shortly after this PAAE, the number of DORs and plants drops off rapidly which if included would skew the resulting trend lines. The trend lines show that both the number of DORs and the numbers of associated NPP units increase as PAAE increases. In addition, the increase in the number of DORs rises faster than the increase in the number of NPP units.

Figure 3-24 shows the relation of the average degradation occurrences with PAAE. As an example, the peak point in this figure shows that for plants at an age of 34 years, about 1.8 DORs per plant were reported in LERs. The dotted line designates the series LER 1985-1996 while the solid line represents the series LER 1999-2007. It appears that the average number of DORs per plant increase as the plant gets older, with a slightly higher rate for older plants as shown by the steeper slope using LER 1999-2007. The slightly higher degradation rate using more recent LERs reflects the fact that older plants show in general more degradation occurrences, and may reflect as well the lowered coverage of the possible degradation population by limiting the number of DORs in NUREG/CR-6679 (e.g. piping system) and potentially by using the computerize search approach for LER 1985-1997. By literally reading the two trend lines, the older plants (using LER 1999-2007) appear to have about 3 times more average DORs than the younger plants (using LER 1985-1997); however, this observation may not fully represent the real situation because of the differences in processing the two LER series. In addition, this observation may not be true for structural type components, as the data from LERs are less representative of the structural components. The variations in these two curves are judged to be relatively large due to the fact that these degradations are rare events and the number of DORs is relatively small.

Figure 3-25 shows the relationship of the average DORs per plant to the PAAE using the combined data series. The trend line in Figure 3-25 shows that combining the two series results in a slightly increasing average degradations per plant over PAAE and is essentially an average of the prior two trend lines shown in Figure 3-24.

Figure 3-26 shows the comparison for the distributions of the SPC degradation occurrences with respect to major aging effects among the three data series for steel components (more precisely metal components). Cracking is the most predominant aging effect for all three data series. Failure is the second most significant aging effect for LER 1998-2008 because it includes a number of aging effects that do not fall into any listed categories. DORs with aging effects of loss of material and wall thinning appear to be obtained from information sources other than LERs.

Figure 3-27 shows the comparison of the distributions of the SPC degradation occurrences by major aging mechanisms among the three data series. SCC is the most significant aging mechanism for all data series. Compared to the two NUREG/CR-6679 data series, LER 1999-2008 shows a large DOR contribution from fatigue, which is the second most significant degradation for this series. This may be due to the possibility that some components are approaching their fatigue life as NPPs get older. Moisture, organisms, chemical attack, and foreign object are shown to be less important mechanisms for LER 1998-2008; lessons learned from the past may have helped to avoid such aging mechanisms.

Figure 3-28 shows the comparison of the distributions of the SPC degradation occurrences by cracking type among the three data series. Primary water stress corrosion cracking (PWSCC) is the most common cracking type for both LER data series, partly indicating the preferences of the LER reporting system. On the other hand, intergranular stress corrosion cracking (IGSCC) was found to be the most common cracking type for the NUREG/CR-6679 data series, but it was a much less common cracking type for the other two LER data series. This suggests that other information sources provided those extra IGSCC DORs for the NUREG/CR-6679 data series.

Figure 3-29 shows the comparison of distributions of the SPC degradation occurrences by system types among the three data series. It is obvious using all series that the system most vulnerable to degradation is the reactor coolant system (RCS), as expected because the RCS includes many subcomponents that are constantly subjected to harsh environments such as high temperature, high pressure, high fluid velocity, boron acid, radiation, etc.

Table 3-1 U.S. 104 Operating Nuclear Power Plants

Plant Name	Docket	Reactor Type	Location	Owner/Operator	NRC Region	CP Issued	OL Issued
Oyster Creek	5000219	BWR	9 MI S of Toms River, NJ	Exelon Generation Co., LLC	1	12/15/1964	7/2/1991
Nine Mile Point 1	5000220	BWR	6 MI NE of Oswego, NY	Constellation Energy	1	4/12/1965	12/26/1974
Dresden 2	5000237	BWR	9 MI E of Morris, IL	Exelon Generation Co., LLC	3	1/10/1966	2/20/1991
Ginna	5000244	PWR	20 MI NE of Rochester, NY	Constellation Energy	1	4/25/1966	9/19/1969
Indian Point 2	5000247	PWR	24 MI N of New York City, NY	Entergy Nuclear Operations, Inc.	1	10/14/1966	9/28/1973
Dresden 3	5000249	BWR	9 MI E of Morris, IL	Exelon Generation Co., LLC	3	10/14/1966	1/12/1971
Turkey Point 3	5000250	PWR	25 MI S of Miami, FL	Florida Power & Light Co.	2	4/27/1967	7/19/1972
Turkey Point 4	5000251	PWR	25 MI S of Miami, FL	Florida Power & Light Co.	2	4/27/1967	4/10/1973
Quad Cities 1	5000254	BWR	20 MI NE of Moline, IL	Exelon Generation Co., LLC	3	2/15/1967	12/14/1972
Palisades	5000255	PWR	5 MI S of South Haven, MI	Entergy Nuclear Operations, Inc.	3	3/14/1967	2/21/1971
Browns Ferry 1	5000259	BWR	10 MI NW of Decatur, AL	Tennessee Valley Authority	2	5/10/1967	12/20/1973
Browns Ferry 2	5000260	BWR	10 MI NW of Decatur, AL	Tennessee Valley Authority	2	5/10/1967	8/2/1974
Robinson 2	5000261	PWR	26 MI from Florence, SC	Progress Energy	2	4/13/1967	9/23/1970
Monticello	5000263	BWR	30 MI NW of Minneapolis, MN	Nuclear Management Co.	3	6/19/1967	1/9/1981
Quad Cities 2	5000265	BWR	20 MI NE of Moline, IL	Exelon Generation Co., LLC	3	2/15/1967	12/14/1972
Point Beach 1	5000266	PWR	13 MI NNW of Manitowoc, WI	FPL Energy Point Beach, LLC	3	7/19/1967	10/5/1970
Oconee 1	5000269	PWR	30 MI W of Greenville, SC	Duke Energy Power Company, LLC	2	11/6/1967	2/6/1973
Oconee 2	5000270	PWR	30 MI W of Greenville, SC	Duke Energy Power Company, LLC	2	11/6/1967	10/6/1973
Vermont Yankee	5000271	BWR	5 MI S of Brattleboro, VT	Entergy Nuclear Operations, Inc.	1	12/11/1967	2/28/1973
Salem 1	5000272	PWR	18 MI S of Wilmington, DE	PSE&G Nuclear	1	9/25/1968	8/13/1976
Diablo Canyon 1	5000275	PWR	12 MI WSW of San Luis Obispo, CA	Pacific Gas & Electric Co.	4	4/23/1968	11/2/1984
Peach Bottom 2	5000277	BWR	17.9 MI S of Lancaster, PA	Exelon Generation Co., LLC	1	1/31/1968	10/25/1973
Peach Bottom 3	5000278	BWR	17.9 MI S of Lancaster, PA	Exelon Generation Co., LLC	1	1/31/1968	7/2/1974
Surry 1	5000280	PWR	17 MI NW of Newport News, VA	Dominion Generation	2	6/25/1968	5/25/1972
Surry 2	5000281	PWR	17 MI NW of Newport News, VA	Dominion Generation	2	6/25/1968	1/29/1973
Prairie Island 1	5000282	PWR	28 MI SE of Minneapolis, MN	Nuclear Management Co.	3	6/25/1968	4/5/1974
Fort Calhoun	5000285	PWR	19 MI N of Omaha, NE	Omaha Public Power District	4	6/7/1968	8/9/1973

Plant Name	Docket	Reactor Type	Location	Owner/Operator	NRC Region	CP Issued	OL Issued
Indian Point 3	5000286	PWR	24 MI N of New York City, NY	Entergy Nuclear Operations, Inc.	1	8/13/1969	12/12/1975
Oconee 3	5000287	PWR	30 MI W of Greenville, SC	Duke Energy Power Company, LLC	2	11/6/1967	7/19/1974
Three Mile Island 1	5000289	PWR	10 MI SE of Harrisburg, PA	Exelon Generation Co., LLC	1	5/18/1968	4/19/1974
Pilgrim 1	5000293	BWR	4 MI SE of Plymouth, MA	Entergy Nuclear Operations, Inc.	1	8/26/1968	9/15/1972
Browns Ferry 3	5000296	BWR	10 MI NW of Decatur, AL	Tennessee Valley Authority	2	7/31/1968	8/18/1976
Cooper	5000298	BWR	23 MI S of Nebraska City, NE	Nebraska Public Power District	4	6/4/1968	1/18/1974
Point Beach 2	5000301	PWR	13 MI NNW of Manitowoc, WI	FPL Energy Point Beach, LLC	3	7/25/1968	3/8/1973
Crystal River 3	5000302	PWR	7 MI NW of Crystal River, FL	Progress Energy	2	9/25/1968	1/28/1977
Kewaunee	5000305	PWR	27 MI E of Green Bay, WI	Dominion Generation	3	8/6/1968	12/21/1973
Prairie Island 2	5000306	PWR	28 MI SE of Minneapolis, MN	Nuclear Management Co.	3	6/25/1968	10/29/1974
Salem 2	5000311	PWR	18 MI S of Wilmington, DE	PSE&G Nuclear	1	9/25/1968	5/20/1981
Arkansas Nuclear 1	5000313	PWR	6 MI WNW of Russellville, AR	Entergy Nuclear Operations, Inc.	4	12/6/1968	5/21/1974
D.C. Cook 1	5000315	PWR	11 MI S of Benton Harbor, MI	Indiana/Michigan Power Co.	3	3/25/1969	10/25/1974
D.C. Cook 2	5000316	PWR	11 MI S of Benton Harbor, MI	IndianaMichigan Power Co.	3	3/25/1969	12/23/1977
Calvert Cliffs 1	5000317	PWR	40 MI S of Annapolis, MD	Constellation Energy	1	7/7/1969	7/31/1974
Calvert Cliffs 2	5000318	PWR	40 MI S of Annapolis, MD	Constellation Energy	1	7/7/1969	8/13/1976
Hatch 1	5000321	BWR	11 MI N of Baxley, GA	Southern Nuclear Operating Co., Inc.	2	9/30/1969	10/13/1974
Diablo Canyon 2	5000323	PWR	12 MI WSW of San Luis Obispo, CA	Pacific Gas & Electric Co.	4	12/9/1970	8/26/1985
Brunswick 2	5000324	BWR	2 MI N of Southport, NC	Progress Energy	2	2/7/1970	12/27/1974
Brunswick 1	5000325	BWR	2 MI N of Southport, NC	Progress Energy	2	2/7/1970	11/12/1976
Sequoyah 1	5000327	PWR	9.5 MI NE of Chattanooga, TN	Tennessee Valley Authority	2	5/27/1970	9/17/1980
Sequoyah 2	5000328	PWR	9.5 MI NE of Chattanooga, TN	Tennessee Valley Authority	2	5/27/1970	9/15/1981
Duane Arnold	5000331	BWR	8 MI NW of Cedar Rapids, IA	Florida Power & Light Co.	3	6/22/1970	2/22/1974
FitzPatrick	5000333	BWR	8 MI NE of Oswego, NY	Entergy Nuclear Operations, Inc.	1	5/20/1970	10/17/1974
Beaver Valley 1	5000334	PWR	17 MI W of McCandless, PA	FirstEnergy Nuclear Operating Co.	1	6/26/1970	7/2/1976
Saint Lucie 1	5000335	PWR	12 MI SE of Ft. Pierce, FL	Florida Power & Light Co.	2	7/1/1970	3/1/1976
Millstone 2	5000336	PWR	3.2 MI WSW of New London, CT	Dominion Generation	1	12/11/1970	9/26/1975
North Anna 1	5000338	PWR	40 MI NW of Richmond, VA	Dominion Generation	2	2/19/1971	4/1/1978
North Anna 2	5000339	PWR	40 MI NW of Richmond, VA	Dominion Generation	2	2/19/1971	8/21/1980

Plant Name	Docket	Reactor Type	Location	Owner/Operator	NRC Region	CP Issued	OL Issued
Fermi 2	5000341	BWR	25 MI NE of Toledo, OH	Detroit Edison Co.	3	9/26/1972	7/15/1985
Davis-Besse	5000346	PWR	21 MI ESE of Toledo, OH	FirstEnergy Nuclear Operating Co.	3	3/24/1971	4/22/1977
Farley 1	5000348	PWR	18 MI SE of Dothan, AL	Southern Nuclear Operating Co.	2	8/16/1972	6/25/1977
Limerick 1	5000352	BWR	21 MI NW of Philadelphia, PA	Exelon Generation Co., LLC	1	6/19/1974	8/8/1985
Limerick 2	5000353	BWR	21 MI NW of Philadelphia, PA	Exelon Generation Co., LLC	1	6/19/1974	8/25/1989
Hope Creek 1	5000354	BWR	18 MI SE of Wilmington, DE	PSE&G Nuclear	1	11/4/1974	7/25/1986
San Onofre 2	5000361	PWR	4 MI SE of San Clemente, CA	Southern California Edison Co.	4	10/18/1973	9/7/1982
San Onofre 3	5000362	PWR	4 MI SE of San Clemente, CA	Southern California Edison Co.	4	10/18/1973	9/16/1983
Farley 2	5000364	PWR	18 MI SE of Dothan, AL	Southern Nuclear Operating Co.	2	8/16/1972	3/31/1981
Hatch 2	5000366	BWR	11 MI N of Baxley, GA	Southern Nuclear Operating Co., Inc.	2	12/27/1972	6/13/1978
Arkansas Nuclear 2	5000368	PWR	6 MI WNW of Russellville, AR	Entergy Nuclear Operations, Inc.	4	12/6/1972	9/1/1978
McGuire 1	5000369	PWR	17 MI N of Charlotte, NC	Duke Energy Power Company, LLC	2	2/23/1973	7/8/1981
McGuire 2	5000370	PWR	17 MI N of Charlotte, NC	Duke Energy Power Company, LLC	2	2/23/1973	5/27/1983
La Salle 1	5000373	BWR	11 MI SE of Ottawa, IL	Exelon Generation Co., LLC	3	9/10/1973	4/17/1982
La Salle 2	5000374	BWR	11 MI SE of Ottawa, IL	Exelon Generation Co., LLC	3	9/10/1973	2/16/1983
Waterford 3	5000382	PWR	20 MI W of New Orleans, LA	Entergy Nuclear Operations, Inc.	4	11/14/1974	3/16/1985
Susquehanna 1	5000387	BWR	7 MI NE of Berwick, PA	PPL Susquehanna, LLC	1	11/2/1973	11/12/1982
Susquehanna 2	5000388	BWR	7 MI NE of Berwick, PA	PPL Susquehanna, LLC	1	11/2/1973	6/27/1984
Saint Lucie 2	5000389	PWR	12 MI SE of Ft. Pierce, FL	Florida Power & Light Co.	2	5/2/1977	6/10/1983
Watts Bar 1	5000390	PWR	10 MI S of Spring City, TN	Tennessee Valley Authority	2	1/23/1973	2/7/1996
Summer	5000395	PWR	26 MI NW of Columbia, SC	South Carolina Electric & Gas Co.	2	3/21/1973	11/12/1982
Columbia Generating Station	5000397	BWR	12 MI NW of Richland, WA	Energy Northwest	4	3/19/1973	4/13/1984
Shearon Harris 1	5000400	PWR	20 MI SW of Raleigh, NC	Progress Energy	2	1/27/1978	1/12/1987
Nine Mile Point 2	5000410	BWR	6 MI NE of Oswego, NY	Constellation Energy	1	6/24/1974	7/2/1987
Beaver Valley 2	5000412	PWR	17 MI W of McCandless, PA	FirstEnergy Nuclear Operating Co.	1	5/3/1974	8/14/1987
Catawba 1	5000413	PWR	6 MI NW of Rock Hill, SC	Duke Energy Power Company, LLC	2	8/7/1975	1/17/1985
Catawba 2	5000414	PWR	6 MI NW of Rock Hill, SC	Duke Energy Power Company, LLC	2	8/7/1975	5/15/1986

Plant Name	Docket	Reactor Type	Location	Owner/Operator	NRC Region	CP Issued	OL Issued
Grand Gulf 1	5000416	BWR	25 MI S of Vicksburg, MS	Entergy Nuclear Operations, Inc.	4	9/4/1974	11/1/1984
Millstone 3	5000423	PWR	3.2 MI WSW of New London, CT	Dominion Generation	1	8/9/1974	1/31/1986
Vogtle 1	5000424	PWR	26 MI SE of Augusta, GA	Southern Nuclear Operating Co.	2	6/28/1974	3/16/1987
Vogtle 2	5000425	PWR	26 MI SE of Augusta, GA	Southern Nuclear Operating Co.	2	6/28/1974	3/31/1989
Perry 1	5000440	BWR	7 MI NE of Painesville, OH	FirstEnergy Nuclear Operating Co.	3	5/3/1977	11/13/1986
Seabrook 1	5000443	PWR	13 MI S of Portsmouth, NH	Florida Power & Light Co.	1	7/7/1976	3/15/1990
Comanche Peak 1	5000445	PWR	4 MI N of Glen Rose, TX	TXU Generating Company LP	4	12/19/1974	4/17/1990
Comanche Peak 2	5000446	PWR	4 MI N of Glen Rose, TX	TXU Generating Company LP	4	12/19/1974	4/6/1993
Byron 1	5000454	PWR	17 MI SW of Rockford, IL	Exelon Generation Co., LLC	3	12/31/1975	2/14/1985
Byron 2	5000455	PWR	17 MI SW of Rockford, IL	Exelon Generation Co., LLC	3	12/31/1975	1/30/1987
Braidwood 1	5000456	PWR	24 MI SSW of Joilet, IL	Exelon Generation Co., LLC	3	12/31/1975	7/2/1987
Braidwood 2	5000457	PWR	24 MI SSW of Joilet, IL	Exelon Generation Co., LLC	3	12/31/1975	5/20/1988
River Bend 1	5000458	BWR	24 MI NNW of Baton Rouge, LA	Entergy Nuclear Operations, Inc.	4	3/25/1977	11/20/1985
Clinton	5000461	BWR	6 MI E of Clinton, IL	Exelon Generation Co., LLC	3	2/24/1976	4/17/1987
Wolf Creek 1	5000482	PWR	3.5 MI NE of Burlington, KS	Wolf Creek Nuclear Operating Corp.	4	5/31/1977	6/4/1985
Callaway	5000483	PWR	10 MI SE of Fulton, MO	Ameren UE	4	4/16/1976	10/18/1984
South Texas 1	5000498	PWR	12 MI SSW of Bay City, TX	STP Nuclear Operating Co.	4	12/22/1975	3/22/1988
South Texas 2	5000499	PWR	12 MI SSW of Bay City, TX	STP Nuclear Operating Co.	4	12/22/1975	3/28/1989
Palo Verde 1	5000528	PWR	36 MI W of Phoenix, AZ	Arizona Public Service Co.	4	5/25/1976	6/1/1985
Palo Verde 2	5000529	PWR	36 MI W of Phoenix, AZ	Arizona Public Service Co.	4	5/25/1976	4/24/1986
Palo Verde 3	5000530	PWR	36 MI W of Phoenix, AZ	Arizona Public Service Co.	4	5/25/1976	11/25/1987

Table 3-2 Degradation Occurrence Records (Primary Information)

ID	COMPONENT	SUBCOMPONENT	SYSTEM	AGING EFFECTS	AGING MECHANISMS	PLANT	EVENT DATE
89	Anchorage	Nut	RHRSW - residual heat removal service water	Loss of material	Corrosion	Hatch 1	11/17/2003
136	Concrete	Floor	Radwaste building cable spreading room (CSR)	Cracking	Spallation	Columbia Generating Station	5/3/2002
203	Concrete	Walls & floors	Various structures	Cracking & spalling	NA	D.C. Cook 2	5/29/2000
23	Containment	CAC cooling coil / fitting	CAC - Containment air cooler	Wall thinning	Corrosion	Palisades	1/19/2007
27	Containment	CAC cooling coil / fitting	CAC - Containment air cooler	Wall thinning	Erosion	Palisades	11/1/2006
25	Containment	CAC cooling coil / fitting	CAC - Containment air cooler	Wall thinning	Erosion	Palisades	11/29/2006
215	Containment	Liner	Containment	Degraded weld repair	NA	D.C. Cook 1	1/17/2000
213	Containment	Liner	Containment	Pitting	Corrosion	D.C. Cook 1	3/5/1998
55	Containment	Small bore piping & tubing	RCS - reactor coolant system	Cracking	Vibration	Hope Creek 1	6/7/2005
56	Containment	Test cap	Containment	Missing	Vibration	Oyster Creek	7/12/2005
47	Containment	Torus	Containment	Cracking	Fatigue	FitzPatrick	6/27/2005
115	Exchanger	CAC components	Containment	Fouling, pitting, rusting	Corrosion	Davis-Besse	3/8/2002
48	Exchanger	CAC cooling coil	Containment	Wall thinning	Erosion	Palisades	10/9/2005
87	Exchanger	Condenser (including ice) & supports	Condenser and condensate system	Failure	Erosion	Duane Arnold	11/25/2003
108	Exchanger	Condensor / piping	RCS - reactor coolant system	Loss of material	Corrosion	Saint Lucie 2	4/1/2003
50	Exchanger	Condensor / Small bore piping & tubing	RCS - reactor coolant system	Cracking	Fatigue	Cooper	9/23/2005

ID	COMPONENT	SUBCOMPONENT	SYSTEM	AGING EFFECTS	AGING MECHANISMS	PLANT	EVENT DATE
113	Exchanger	Condensor / tubing	RCS - reactor coolant system	Tear of plug	Under investigation	Palo Verde 1	3/27/2003
51	Exchanger	Door	Containment	Failure	Corrosion	McGuire 1	9/17/2005
73	Exchanger	Elbow	CFCU - containment fan coil unit	Wall thinning	Erosion	Prairie Island 2	11/17/2004
195	Exchanger	ESW room cooler	ESW - essential service water	Fouling	Macrofouling by Asiatic clamshells	Callaway	9/14/2000
24	Exchanger	Exchanger	CCW - component cooling water	Failure	Unknown	Calvert Cliffs 1	1/17/2007
103	Exchanger	Heat exchanger	CSS - containment spray	Fouling	Corrosion	Catawba 1	5/11/2003
93	Exchanger	Heat exchanger	CSS - containment spray	Fouling	Corrosion	Catawba 1	10/9/2003
22	Exchanger	Heat exchanger	EW - Essential cooling water	Fouling	Inorganic fouling	Palo Verde 2	12/22/2006
155	Exchanger	Heat exchanger	SWS - service water system	Loss of material	NA	Crystal River 3	10/4/2001
45	Exchanger	Heat exchanger / Soft iron gasket	RHRSW - residual heat removal service water	Loss of material	Corrosion	Browns Ferry 2	4/16/2005
179	Exchanger	Inlet-sie tubesheet	RCS - reactor coolant system	Fouling	Corrosion at nearby pipe	D.C. Cook 1	2/15/2001
77	Exchanger	Nozzle weld	RCS - reactor coolant system	Cracking	PWSCC	Catawba 2	9/16/2004
57	Exchanger	Piping	CCW - component cooling water	Disintegration	Unknown	South Texas 2	7/11/2005
53	Exchanger	Piping weld	Condenser and condensate system	Cracking	Fatigue	Turkey Point 4	12/25/2004
54	Exchanger	Piping weld	RCS - reactor coolant system	Cracking	Fatigue	Palisades	9/1/2005
63	Exchanger	Piping weld	RCS - reactor coolant system	Cracking	PWSCC	Wolf Creek 1	4/15/2005
167	Exchanger	Radiator cooling fin	EDG - emergency diesel generator	Excessive deformation	Corrosion	Saint Lucie 1	5/22/2001

ID	COMPONENT	SUBCOMPONENT	SYSTEM	AGING EFFECTS	AGING MECHANISMS	PLANT	EVENT DATE
138	Exchanger	Small bore piping & tubing	CCW - component cooling water	Cracking	SCC	Kewaunee	5/5/2002
52	Exchanger	Small bore piping & tubing	EDG - emergency diesel generator	Cracking	Vibration	River Bend 1	9/9/2005
49	Exchanger	Small bore piping & tubing	RCS - reactor coolant system	Cracking	ODSCC	Diablo Canyon 1	11/11/2005
82	Exchanger	Small bore piping & tubing	RCS - reactor coolant system	Cracking	PWSCC	Diablo Canyon 1	4/8/2004
40	Exchanger	Small bore piping & tubing	RCS - reactor coolant system	Cracking	SCC	Diablo Canyon 2	5/3/2006
119	Exchanger	Steam deflector plate	RCS - reactor coolant system	Broken	Fatigue	Duane Arnold	2/1/2003
157	Exchanger	Steam generator - nozzle to vessel weld	RCS - reactor coolant system	Cracking	PWSCC	Catawba 2	9/19/2001
126	Exchanger	Steam generator - tubing	RCS - reactor coolant system	Cracking	NA	Oconee 2	10/31/2002
202	Exchanger	Steam generator - tubing	RCS - reactor coolant system	Cracking	ODIGA/ODSCC	Kewaunee	5/15/2000
226	Exchanger	Steam generator - tubing	RCS - reactor coolant system	Cracking	ODSCC	Comanche Peak 1	10/4/1999
117	Exchanger	Steam generator - tubing	RCS - reactor coolant system	Cracking	ODSCC	Comanche Peak 1	10/6/2002
222	Exchanger	Steam generator - tubing	RCS - reactor coolant system	Cracking	ODSCC	South Texas 2	10/24/1999
173	Exchanger	Steam generator - tubing	RCS - reactor coolant system	Cracking	ODSCC	South Texas 2	3/19/2001
191	Exchanger	Steam generator - tubing	RCS - reactor coolant system	Cracking	ODSCC & PWSCC	Diablo Canyon 1	10/28/2000
120	Exchanger	Steam generator - tubing	RCS - reactor coolant system	Cracking	ODSCC & PWSCC	Diablo Canyon 2	2/13/2003
121	Exchanger	Steam generator - tubing	RCS - reactor coolant system	Cracking	ODSCC & PWSCC	Diablo Canyon 2	2/13/2003
176	Exchanger	Steam generator - tubing	RCS - reactor coolant system	Cracking	ODSCC / PWSCC	Comanche Peak 1	4/2/2001

ID	COMPONENT	SUBCOMPONENT	SYSTEM	AGING EFFECTS	AGING MECHANISMS	PLANT	EVENT DATE
217	Exchanger	Steam generator - tubing	RCS - reactor coolant system	Cracking	ODSCC / PWSCC	Farley 2	11/1/1999
185	Exchanger	Steam generator - tubing	RCS - reactor coolant system	Cracking	PWSCC	Indian Point 2	2/15/2000
205	Exchanger	Steam generator - tubing	RCS - reactor coolant system	Cracking	PWSCC	Indian Point 2	3/23/2000
180	Exchanger	Steam generator - tubing	RCS - reactor coolant system	Cracking	PWSCC	Indian Point 2	3/23/2000
142	Exchanger	Steam generator - tubing	RCS - reactor coolant system	Cracking at tube support plate	ODSCC	Diablo Canyon 1	5/19/2002
131	Exchanger	Steam generator - tubing	RCS - reactor coolant system	Defective	NA	Callaway	11/5/2002
208	Exchanger	Steam generator - tubing	RCS - reactor coolant system	Degradation	IGA/SCC	Turkey Point 3	3/11/2000
210	Exchanger	Steam generator - tubing	RCS - reactor coolant system	Rupture	PWSCC	Indian Point 2	2/15/2000
8	Exchanger	Tube plug	AR - Condenser air removal	Failure	Corrosion / Galvanic interaction	Palo Verde 2	10/6/2007
216	Filter	Charcoal	Control room makeup and cleanup filtration	Degradation	Aging/end of life	South Texas 1	8/12/1999
190	Filter	Charcoal	ECF - emergency containment filter	Failure	Aging/end of life	Turkey Point 4	10/5/2000
223	Filter	Charcoal	SBGT - standby gas treatment	Degradation	NA	FitzPatrick	10/14/1999
225	Filter	Damper	CR - control room	Failure	Gradual loosening of a set screw	Three Mile Island 1	3/10/1999
43	Filter	Damper	Emergency exhaust system	Failure	Ice load	Callaway	3/10/2006
214	Filter	Nuts holding in Charcoal tray	ECCS Pump room exhaust filtration	Loosening	NA	Calvert Cliffs 1	1/28/2000
98	Filter	Screens	CW/ESW - Circulating water and ESW	Failure	Corrosion	D.C. Cook 1	4/24/2003
165	Filter	Screens	SWS - service water system	Failure	Organisms - fish	Point Beach 2	6/27/2001

ID	COMPONENT	SUBCOMPONENT	SYSTEM	AGING EFFECTS	AGING MECHANISMS	PLANT	EVENT DATE
36	Filter	Sealant (RTV)	CREFS - Control room emergency filtration	Failure	Aging/degraded	Point Beach 1	5/30/2006
161	Filter	Strainer basket	ESW - essential service water	Failure	NA	D.C. Cook 1	8/29/2001
160	Filter	Strainer basket	ESW - essential service water	Failure	NA	D.C. Cook 2	8/29/2001
106	Filter	TWS - traveling water screen	CW/ESW - Circulating water and ESW	Failure	Corrosion	D.C. Cook 1	4/24/2003
164	Other	Flood panel	NA	Deterioration	NA	Prairie Island 1	7/10/2001
114	Other	Gypsum board assembly	Fire barrier penetration	Surface cracking	Aging/degraded/vibration	Monticello	3/13/2003
125	Other	Static line hanger	345 KV transmission line	Failure	Mechanical wear	Palisades	12/1/2002
34	Piping system	Cooling coil	SWS - service water system	Cracking	Erosion	Duane Arnold	6/30/2006
163	Piping system	Cooling coil	SWS - service water system	Loss of material	Flow induced erosion	Vermont Yankee	9/25/2001
158	Piping system	Drain trap outlet plug	HPCI - high pressure coolant injection	Failure	FAC - Flow Accelerated Corrosion	Duane Arnold	9/2/2001
30	Piping system	Elbow	HPCI/RCIC	Cracking	Erosion	Peach Bottom 2	10/7/2006
211	Piping system	Elbow	RCS - reactor coolant system	Cracking	Thermal fatigue	Oconee 1	2/16/2000
33	Piping system	Fitting	EDG - emergency diesel generator	Cracking	Fatigue	Kewaunee	8/17/2006
14	Piping system	Fitting	EHC - electro hydraulic control system	Cracking	Mechanical loads	Browns Ferry 1	5/24/2007
197	Piping system	Fitting	EHC - electro hydraulic control system	Leak	NA	FitzPatrick	8/27/2000
26	Piping system	Fitting	HVAC - Heating, ventilation and air conditioning	Loosening	Vibration	Dresden 2	11/8/2006
86	Piping system	Fitting	RCS - reactor coolant system	Cracking	Fatigue	Oconee 1	1/8/2004

ID	COMPONENT	SUBCOMPONENT	SYSTEM	AGING EFFECTS	AGING MECHANISMS	PLANT	EVENT DATE
193	Piping system	Fitting	RR - reactor recirculation	Cracking	Fatigue	Dresden 3	3/21/1999
13	Piping system	Hose	RCS - reactor coolant system	Cracking	IGSCC	Clinton	6/18/2007
78	Piping system	Nozzle	CCW - component cooling water	Cracking	Fatigue	Diablo Canyon 1	7/21/2004
70	Piping system	Nozzle	RCS - reactor coolant system	Cracking	PWSCC	Calvert Cliffs 2	2/26/2005
224	Piping system	Nozzle	RCS - reactor coolant system	Cracking	PWSCC	Palo Verde 1	10/2/1999
172	Piping system	Nozzle	RCS - reactor coolant system	Cracking	PWSCC	Palo Verde 1	3/31/2001
109	Piping system	Nozzle	RCS - reactor coolant system	Cracking	PWSCC	Palo Verde 3	3/29/2003
169	Piping system	Nozzle	RCS - reactor coolant system	Cracking	PWSCC	Saint Lucie 1	4/14/2001
91	Piping system	Nozzle	RCS - reactor coolant system	Cracking	PWSCC	Waterford 3	10/24/2003
5	Piping system	nozzle-to-elbow dissimilar metal butt weld	RCS - reactor coolant system	Loss of material	PWSCC	Davis-Besse	1/4/2008
39	Piping system	Nozzle-to-elbow weld	RCS - reactor coolant system	Cracking	PWSCC	Davis-Besse	3/18/2006
181	Piping system	Nozzle-to-pipe weld	RCS - reactor coolant system	Cracking	PWSCC	Summer	10/12/2000
149	Piping system	Pipe-to-elbow weld	SWS - service water system	Loss of material	Erosion	Indian Point 2	10/29/2001
20	Piping system	Piping	Auxiliary steam piping system	Plugging	Corrosion	Quad Cities 2	2/28/2007
32	Piping system	Piping	Condenser and condensate system	Broken	Fatigue	Davis-Besse	9/6/2006
177	Piping system	Piping	EDG - emergency diesel generator	Cracking	Fatigue	Grand Gulf 1	2/19/2001
67	Piping system	Piping	ESW - essential service water	Wall thinning	Under-deposit corrosion and Microbiologically	Callaway	3/26/2005

ID	COMPONENT	SUBCOMPONENT	SYSTEM	AGING EFFECTS	AGING MECHANISMS	PLANT	EVENT DATE
					influenced corrosion (MIC)		
107	Piping system	Piping	HPCI - high pressure coolant injection	Cracking	Mechanical loads	Duane Arnold	4/20/2003
7	Piping system	Piping	HPCI - high pressure coolant injection	Leaking	Corrosion	Browns Ferry 3	11/30/2007
19	Piping system	Piping	HPCI - high pressure coolant injection	Wall thinning	FAC - Flow Accelerated Corrosion	Dresden 3	3/2/2007
187	Piping system	Piping	Main generator hydrogen cooling	Cracking	Fatigue	Arkansas Nuclear 1	1/5/2001
204	Piping system	Piping	Moisture separator reheater	Rupture	FAC - Flow Accelerated Corrosion	Callaway	8/11/1999
194	Piping system	Piping	RCS - reactor coolant system	Broken	Fatigue	Columbia Generating Station	9/18/2000
139	Piping system	Piping	RHR - residual heat removal	Cracking	TGSCC - chemical attack	Surry 2	4/13/2002
116	Piping system	Piping	SWS - service water system	Fouling, pitting, rusting	Corrosion	Davis-Besse	3/8/2002
2	Piping system	Piping	UHS - ultimate heat sink	Wall thinning/Failure	General and pitting corrosion	Byron 1	10/19/2007
3	Piping system	Piping	UHS - ultimate heat sink	Wall thinning/Failure	General and pitting corrosion	Byron 2	10/19/2007
200	Piping system	Piping weld	CCSW - containment cooling service water	Leak	NA	Dresden 2	6/28/2000
133	Piping system	Piping weld	ECCS - emergency core cooling system	Cracking	Fatigue	Millstone 2	8/3/2002
198	Piping system	Piping weld	EHC - electro hydraulic control system	Leak	NA	FitzPatrick	8/27/2000
129	Piping system	Piping weld	HPI - high pressure injection	Cracking	Fatigue w/ initiating defects	Arkansas Nuclear 1	10/5/2002
134	Piping system	Piping weld	RCP - reactor coolant pump	Cracking	Fatigue	Calvert Cliffs 1	7/24/2002
75	Piping system	Piping weld	RCS - reactor coolant system	Cracking	Fatigue	Hope Creek 1	10/10/2004

ID	COMPONENT	SUBCOMPONENT	SYSTEM	AGING EFFECTS	AGING MECHANISMS	PLANT	EVENT DATE
85	Piping system	Piping weld	RCS - reactor coolant system	Cracking	Fatigue	Palo Verde 1	2/3/2004
71	Piping system	Piping weld	RCS - reactor coolant system	Cracking	Fatigue	Saint Lucie 2	2/10/2005
72	Piping system	Piping weld	RCS - reactor coolant system	Cracking	Fatigue	South Texas 2	2/9/2005
81	Piping system	Piping weld	RCS - reactor coolant system	Cracking	Fatigue	Summer	3/30/2004
44	Piping system	Piping weld	RCS - reactor coolant system	Cracking	Fatigue	Vogtle 2	2/1/2006
88	Piping system	Piping weld	RCS - reactor coolant system	Cracking	Fatigue	Wolf Creek 1	11/17/2003
58	Piping system	Piping weld	RHR SDC- RHR shutdown cooling	Cracking	Fatigue	FitzPatrick	7/4/2005
127	Piping system	Piping weld	RR - reactor recirculation	Cracking	Fatigue	Dresden 3	10/8/2002
152	Piping system	Piping weld	RR - reactor recirculation	Cracking	Fatigue	Hope Creek 1	10/10/2001
66	Piping system	Piping weld	RS - Recirculation system	Cracking	Fatigue	Hope Creek 1	3/27/2005
68	Piping system	Piping weld	RS - Recirculation system	Cracking	Fatigue	Susquehanna 2	3/20/2005
83	Piping system	Piping weld	RS - Recirculation system	Cracking	IGSCC	Quad Cities 2	3/9/2004
123	Piping system	Piping weld	RS - Recirculation system	Cracking	Vibration	Dresden 3	12/7/2002
46	Piping system	Piping weld	SDCS - Shutdown cooling system	Cracking	Fatigue	San Onofre 2	1/11/2006
220	Piping system	Piping weld	Steam Generator Channel Head Drain Isolation	Cracking	NA	Point Beach 1	11/4/1999
137	Piping system	Piping weld	SWS - service water system	Wall thinning	Corrosion	Indian Point 3	6/7/2002
11	Piping system	Piping/Elbow	HPCI - high pressure coolant injection	Wall thinning/leaking	Erosion	Dresden 2	7/26/2007

ID	COMPONENT	SUBCOMPONENT	SYSTEM	AGING EFFECTS	AGING MECHANISMS	PLANT	EVENT DATE
6	Piping system	Reactor coolant pump seal weld	RCS - reactor coolant system	Cracking/leaking	Fatigue	Saint Lucie 2	12/21/2007
150	Piping system	Small bore piping & tubing	Containment	Broken	Mechanical loads	Vermont Yankee	10/25/2001
207	Piping system	Small bore piping & tubing	Control room air conditioning chiller	Leak	Wear/deterioration	Oconee 1	3/9/2000
201	Piping system	Small bore piping & tubing	EHC - electro hydraulic control system	Cracking	Corrosion fatigue	Robinson 2	6/21/2000
104	Piping system	Small bore piping & tubing	EHC - electro hydraulic control system	Cracking	Fatigue	River Bend 1	2/22/2003
9	Piping system	Small bore piping & tubing	EHC - electro hydraulic control system	Cracking/leaking	Mechanical wear	Browns Ferry 1	9/3/2007
206	Piping system	Small bore piping & tubing	Electric board room air conditioning unit	Broken	Aging & fatigue	Watts Bar 1	1/2/1999
219	Piping system	Small bore piping & tubing	Extraction Steam System Moisture Separator Reheater Drain Tank	Failure	Wear	FitzPatrick	11/5/1999
111	Piping system	Small bore piping & tubing	PCIS - primary containment isolation system	Cracking	Fatigue	Peach Bottom 2	4/12/2003
65	Piping system	Small bore piping & tubing	RCS - reactor coolant system	Loss of material	TGSCC	Salem 2	4/4/2005
146	Piping system	Small bore piping & tubing	RSS - recirculation spray system	Fouling	Corrosion	Beaver Valley 2	1/11/2002
12	Piping system	Snubber	EDG - emergency diesel generator	Cracking	Temperature - heat treatment	Palisades	2/22/2007
18	Piping system	Socket weld	RCS - reactor coolant system	Cracking	Fatigue	Hatch 2	3/9/2007
10	Piping system	Socket weld fitting	RCS - reactor coolant system	Cracking/leaking	Fatigue (high cycle)	Saint Lucie 2	8/18/2007
209	Piping system	Suction line weld	Charging pump	Cracking	NA	Waterford 3	3/6/2000
122	Piping system	Support	HPCI - high pressure coolant injection	Failure	Hydrodynamic transient / water hammer	Dresden 3	7/5/2001
186	Piping system	Support	Main generator hydrogen cooling	Failure	Vibration	Arkansas Nuclear 1	1/5/2001

ID	COMPONENT	SUBCOMPONENT	SYSTEM	AGING EFFECTS	AGING MECHANISMS	PLANT	EVENT DATE
124	Piping system	Thermal sleeve	HPI - high pressure injection	Cracking	Fatigue	Davis-Besse	11/29/2002
76	Piping system	Underground piping	AFW - auxiliary feedwater	Wall thinning	Galvanic corrosion	Surry 2	5/21/2004
35	Piping system	Valve-piping weld	RCS - reactor coolant system	Cracking	Fatigue	Nine Mile Point 1	6/11/2006
212	Piping system	Weld	RCS - reactor coolant system	Cracking	PWSCC	Arkansas Nuclear 1	2/15/2000
189	RPV	CRD - housing	RCS - reactor coolant system	Cracking	TGSCC	Palisades	11/2/1999
80	RPV	CRDM - control rod drive mechanism	RCS - reactor coolant system	Cracking	PWSCC	Point Beach 1	5/6/2004
174	RPV	CRDM - control rod drive mechanism (nozzle)	RCS - reactor coolant system	Cracking	PWSCC	Arkansas Nuclear 1	3/24/2001
128	RPV	CRDM - control rod drive mechanism (nozzle)	RCS - reactor coolant system	Cracking	PWSCC	Arkansas Nuclear 1	10/7/2002
79	RPV	CRDM - control rod drive mechanism (nozzle)	RCS - reactor coolant system	Cracking	PWSCC	Arkansas Nuclear 1	4/30/2004
156	RPV	CRDM - control rod drive mechanism (nozzle)	RCS - reactor coolant system	Cracking	PWSCC	Crystal River 3	10/1/2001
143	RPV	CRDM - control rod drive mechanism (nozzle)	RCS - reactor coolant system	Cracking	PWSCC	Davis-Besse	2/27/2002
183	RPV	CRDM - control rod drive mechanism (nozzle)	RCS - reactor coolant system	Cracking	PWSCC	Oconee 1	12/4/2000
99	RPV	CRDM - control rod drive mechanism (nozzle)	RCS - reactor coolant system	Cracking	PWSCC	Oconee 1	9/23/2003
168	RPV	CRDM - control rod drive mechanism (nozzle)	RCS - reactor coolant system	Cracking	PWSCC	Oconee 2	4/28/2001
130	RPV	CRDM - control rod drive mechanism (nozzle)	RCS - reactor coolant system	Cracking	PWSCC	Oconee 2	10/15/2002

ID	COMPONENT	SUBCOMPONENT	SYSTEM	AGING EFFECTS	AGING MECHANISMS	PLANT	EVENT DATE
59	RPV	CRDM - control rod drive mechanism (nozzle)	RCS - reactor coolant system	Cracking	PWSCC	Oconee 3	2/18/2001
175	RPV	CRDM - control rod drive mechanism (nozzle)	RCS - reactor coolant system	Cracking	PWSCC	Oconee 3	2/18/2001
148	RPV	CRDM - control rod drive mechanism (nozzle)	RCS - reactor coolant system	Cracking	PWSCC	Oconee 3	11/12/2001
112	RPV	CRDM - control rod drive mechanism (nozzle)	RCS - reactor coolant system	Cracking	PWSCC	Oconee 3	5/2/2003
74	RPV	CRDM - control rod drive mechanism (nozzle)	RCS - reactor coolant system	Cracking	PWSCC	Palisades	10/16/2004
153	RPV	CRDM - control rod drive mechanism (nozzle)	RCS - reactor coolant system	Cracking	PWSCC	Three Mile Island 1	10/12/2001
145	RPV	CRDM - upper housing	RCS - reactor coolant system	Cracking	TGSCC	Palisades	6/21/2001
151	RPV	CRDM penetration	RCS - reactor coolant system	Cracking	PWSCC	Surry 1	10/28/2001
170	RPV	CRDM Seal housing	PCS - primary coolant system	Cracking	TGSCC	Palisades	3/31/2001
221	RPV	CRDM Seal housing	RCS - reactor coolant system	Cracking	TGSCC	Palisades	10/16/1999
162	RPV	Feedwater nozzle	RCS - reactor coolant system	Fouling	Inorganic fouling	Vermont Yankee	8/21/2001
16	RPV	Nozzle	RCS - reactor coolant system	Cracking	PWSCC	Byron 2	4/9/2007
141	RPV	Nozzle	RCS - reactor coolant system	Cracking	PWSCC	Oconee 1	4/1/2002
105	RPV	Nozzle	RCS - reactor coolant system	Cracking	PWSCC	Saint Lucie 2	4/30/2003
100	RPV	Nozzle	RCS - reactor coolant system	Cracking	SCC	South Texas 1	4/12/2003
21	RPV	Nozzle weld	RCS - reactor coolant system	Cracking	IGSCC	Duane Arnold	2/18/2007

ID	COMPONENT	SUBCOMPONENT	SYSTEM	AGING EFFECTS	AGING MECHANISMS	PLANT	EVENT DATE
218	RPV	Nozzle-safe end weld	RR - reactor recirculation	Cracking	IGSCC	Duane Arnold	11/5/1999
95	RPV	Nozzle-to-cap weld	RCS - reactor coolant system	Cracking	IDSCC - Interdendritic SCC	Pilgrim 1	10/1/2003
118	RPV	Penetration	RCS - reactor coolant system	Cracking	PWSCC	North Anna 1	3/4/2003
132	RPV	Penetration	RCS - reactor coolant system	Cracking	PWSCC with initial hot-short cracking	North Anna 2	9/14/2002
60	RPV	Piping	RCS - reactor coolant system	Cracking	PWSCC	Palo Verde 2	4/23/2005
31	RPV	Piping	RCS - reactor coolant system	Cracking	PWSCC	Palo Verde 2	10/7/2006
41	RPV	Piping weld	CS - core spray	Cracking	IGSCC	Brunswick 1	3/21/2006
42	RPV	Sleeve	HPI - high pressure injection	Cracking	Fatigue	Davis-Besse	11/29/2002
101	RPV	Steam dryer	RCS - reactor coolant system	Cracking	Fatigue	Quad Cities 2	6/12/2003
135	RPV	Steam dryer	RCS - reactor coolant system	Failure	Fatigue	Quad Cities 2	7/11/2002
154	RPV	Thermocouple (T/C) nozzles	RCS - reactor coolant system	Cracking	PWSCC	Three Mile Island 1	10/12/2001
102	RPV	Vent line	RCS - reactor coolant system	Cracking	Corrosion and fatigue	Quad Cities 1	5/20/2003
171	Structural steel	Bolt	EFW - emergency feedwater	Loosening	Vibration	Three Mile Island 1	2/1/2001
159	Structural steel	Door	Containment	Failure	NA	D.C. Cook 2	1/23/2001
184	Structural steel	Door	Fire protecton	Failure	Corrosion and dirt buildup	Kewaunee	1/18/2001
166	Structural steel	Door	Turbine Driven Auxiliary Feedwater Pump enclosuer door	Degraded closure mechanism	NA	Millstone 2	6/12/2001
182	Structural steel	Pump hold-down beam	RS - Recirculation system	Failure	IGSCC	Quad Cities 1	1/9/2002

ID	COMPONENT	SUBCOMPONENT	SYSTEM	AGING EFFECTS	AGING MECHANISMS	PLANT	EVENT DATE
178	Structural steel	Screw	RCS - reactor coolant system	Failure	PWSCC	Summer	4/13/1999
196	Structural steel	Weld	CREACUS - control room emergency cleanup	Cracking	NA	San Onofre 2	9/1/2000
17	Tank	Filter tanks and internal components	SWS - service water system	Cracking	Corrosion	Kewaunee	5/30/2006
147	Tank	Floating cover	CST - condensate storage tank	Deterioration	Wear accelerated by Nitrogen	Callaway	12/3/2001
61	Tank	Piping weld	ECCS - emergency core cooling system	Cracking	SCC - Chemical attack	Salem 1	4/19/2005
28	Tank	SLC tank	SLC - standby liquid control	Cracking	SCC - Chemical attack	Quad Cities 1	10/12/2006
1	Tank	Tank shell - sensor connection	SLC - standby liquid control	Cracking	TGSCC	Dresden 2	1/18/2007
15	Vessel	Nozzle weld	RCS - reactor coolant system	Cracking	IDSCC - Interdendritic SCC	Pilgrim 1	4/26/2007
29	Vessel	Nozzle-safe end weld	RCS - reactor coolant system	Cracking	PWSCC	Wolf Creek 1	10/11/2006
90	Vessel	Pressurizer	RCS - reactor coolant system	Cracking	PWSCC	Three Mile Island 1	11/4/2003
97	Vessel	Pressurizer - filters and screens	RCS - reactor coolant system	Failure	Corrosion	Davis-Besse	4/10/1998
144	Vessel	Pressurizer - heater sleeve penetrations	RCS - reactor coolant system	Cracking	PWSCC	Millstone 2	2/19/2002
199	Vessel	Pressurizer heater sleeves	RCS - reactor coolant system	Cracking	PWSCC	Arkansas Nuclear 2	7/30/2000
192	Vessel	Pressurizer heater sleeves	RCS - reactor coolant system	Cracking	PWSCC	Palo Verde 2	10/4/2000
188	Vessel	Pressurizer heater sleeves	RCS - reactor coolant system	Cracking	PWSCC	Waterford 3	10/17/2000
96	Vessel	Pressurizer nozzle	RCS - reactor coolant system	Cracking	PWSCC	Crystal River 3	10/4/2003
38	Vessel	Pressurizer nozzle	RCS - reactor coolant system	Cracking	PWSCC	San Onofre 3	3/29/2006

ID	COMPONENT	SUBCOMPONENT	SYSTEM	AGING EFFECTS	AGING MECHANISMS	PLANT	EVENT DATE
94	Vessel	Pressurizer sleeves	RCS - reactor coolant system	Cracking	PWSCC	Millstone 2	10/11/2003
92	Vessel	Pressurizer sleeves	RCS - reactor coolant system	Cracking	PWSCC	Waterford 3	10/26/2003
4	Vessel	Resistance Temperature Detector	RCS - reactor coolant system	Leaking	Mechanical joints not intact	Turkey Point 3	9/8/2007
37	Vessel	Sleeve	RCS - reactor coolant system	Cracking	IGSCC	Braidwood 1	4/25/2006
140	Vessel	Sleeve	RCS - reactor coolant system	Cracking	PWSCC	Arkansas Nuclear 2	4/15/2002
69	Vessel	Sleeve	RCS - reactor coolant system	Cracking	PWSCC	Arkansas Nuclear 2	3/9/2005
64	Vessel	Sleeve	RCS - reactor coolant system	Cracking	PWSCC	Millstone 2	4/10/2005
110	Vessel	Sleeve	RCS - reactor coolant system	Cracking	PWSCC	Palo Verde 3	3/29/2003
84	Vessel	Sleeve	RCS - reactor coolant system	Cracking	PWSCC	Palo Verde 3	2/29/2004
62	Vessel	Sleeve	RCS - reactor coolant system	Cracking	PWSCC	Waterford 3	4/19/2005

Table 3-3 Degradation Occurrence Records (Secondary Information)

ID	COMPONENT	SUBCOMPONENT	HOW IDENTIFIED	EVALUATION METHOD	REPAIR METHOD	DOCKET	REF	ML NUMBER
1	Tank	Tank shell - sensor connection	Maitenance	Visual	Replacement	5000237	LER 07-001-01	ML080910066
2	Piping system	Piping	Cleaning of corrosion	Visual	Replacement	5000454	LER 07-002-01	ML080660544
3	Piping system	Piping	Cleaning of corrosion	Visual	Replacement	5000455	LER 07-002-01	ML080660544
4	Vessel	Resistance Temperature Detector	Refueling outage	Visual	Replacement	5000250	LER 07-004-01	ML080720677
5	Piping system	nozzle-to-elbow dissimilar metal butt weld	Refueling outage	Visual	Repair	5000346	LER 08-001-00	ML080640204
6	Piping system	Reactor coolant pump seal weld	Maintenance	Visual / Liquid penetrant	Replacement of the seal package	5000389	LER 07-002-00	ML080580311
7	Piping system	Piping	Maintenance/Visual	Visual	Replacement	5000296	LER 07-004-00	ML080290046
8	Exchanger	Tube plug	Soidium level high in steam generator	N/A	Replaced/ Will determine for alternative (material) tube plug	5000529	LER 07-003-00	ML073480125
9	Piping system	Small bore piping & tubing	Video Monitoring	Visual	Replacement of fretted EHC tubing and installed a wood isolation block	5000259	LER 07-008-00	ML073090091
10	Piping system	Socket weld fitting	Unidentified leakage/walk down	Visual	Repalce seal injection piping	5000389	LER 07-001-00	ML072970529
11	Piping system	Piping/Elbow	Visual	Visual	Replacement	5000237	LER 07-003-00	ML072750663
12	Piping system	Snubber	Test	visual	replacement	5000255	LER 07-006-00	ML072500072
13	Piping system	Hose	Alarms	Visual	Replacement	5000461	LER 07-003-00	ML072350078
14	Piping system	Fitting	Alarms indicating an EHC leak	Visual	Replacement of tube	5000259	LER 07-002-00	ML072040345
15	Vessel	Nozzle weld	Repair	Ultra-sonic testing	A full structural weld overlay	5000293	LER 07-003-00	ML071840196

ID	COMPONENT	SUBCOMPONENT	HOW IDENTIFIED	EVALUATION METHOD	REPAIR METHOD	DOCKET	REF	ML NUMBER
16	RPV	Nozzle	Inspection at refuel outage	Liquid penetrant test (PT) examination	Repair	5000455	LER 07-001-00	ML071590211
17	Tank	Filter tanks and internal components	N.A.	Inspection	Replaced	5000305	LER 06-005-00	ML071640378
18	Piping system	Socket weld	Leaking	Visual	Replaced	5000366	LER 07-004-00	ML071230404
19	Piping system	Piping	N/A	Visual	Replacement	5000249	LER 07-001-00	ML071280263
20	Piping system	Piping	Pressure controller failed	Troubleshooting	Debris removed	5000265	LER 07-001-00	ML071280295
21	RPV	Nozzle weld	scheduled examination	UT - Ultrasonic test	overlay flawed weld with material resistant to SCC	5000331	LER 07-003-00	ML071150319
22	Exchanger	Heat exchanger	NRC Final significance determination letter	N.A.	Cleaned	5000529	LER 06-006-01	ML070950342
23	Containment	CAC cooling coil / fitting	leaking	visual	Plugging tubes to isolate the H-bend flaw	5000255	LER 07-002-00	ML070871046
24	Exchanger	Exchanger	Leaking	N.A.	Replacement	5000317	LER 07-001-00	ML070810509
25	Containment	CAC cooling coil / fitting	Leaking	Visual	plugging tubes to isolate the H-bend flaw	5000255	LER 06-008-00	ML070370354
26	Piping system	Fitting	Failed to maintain control room temperature	Visual	Repaired	5000237	LER 2006-005-00	ML070170356
27	Containment	CAC cooling coil / fitting	Leaking	Visual	Installing blanks on the inlet and outlet flanges of the cooling coil	5000255	LER 06-006-00	ML063610189
28	Tank	SLC tank	Leaking	Visual	Remove source of chemical	5000254	LER 06-004-00	ML063530355
29	Vessel	Nozzle-safe end weld	In-service examination	NA	Weld overlay	5000482	LER 06-003-00	ML063490047
30	Piping system	Elbow	Leaking	Visual	Replacement	5000277	LER 06-003-00	ML063420059

ID	COMPONENT	SUBCOMPONENT	HOW IDENTIFIED	EVALUATION METHOD	REPAIR METHOD	DOCKET	REF	ML NUMBER
31	RPV	Piping	In-service examination	NA	Removed and repaired by welding	5000529	LER 06-005-00	ML063450132
32	Piping system	Piping	air in-leakage	Boroscope	Plugged and capped	5000346	LER 06-003-00	ML063120173
33	Piping system	Fitting	Leaking	NA	Repaired	5000305	LER 06-009-01	ML071140152
34	Piping system	Cooling coil	Leaking	Visual	Repair	5000331	LER 06-003-00	ML062490486
35	Piping system	Valve-piping weld	Leaking	Visual	NA	5000220	LER 06-001-00	ML062290262
36	Filter	Sealant (RTV)	Scheduled test	Penetration and system bypass test	Applying new RTV over degraded RTV	5000266	LER 06-001-00	ML062200498
37	Vessel	Sleeve	Leaking	Failure analysis throught test	Plug and seal weld	5000456	LER 06-001-01	ML062000190
38	Vessel	Pressurizer nozzle	Inspection	Visual	Repaired with Inconel 690 material	5000362	LER 06-003-00	ML061500428
39	Piping system	Nozzle-to-elbow weld	Planed examination	Ultrasonic exam	A full structural weld overlay	5000346	LER 06-002-00	ML061440286
40	Exchanger	Small bore piping & tubing	Refueling	Eddy current testing	Removed from service by plugging	5000323	LER 06-002-00	ML061450136
41	RPV	Piping weld	Visual examination during refuel	Ultrasonic test	Structurally replace the weld with a clamp	5000325	LER 06-002-00	ML061530280
42	RPV	Sleeve	Examingation with reactor defueled	Borescope examination	Replaced	5000346	LER 02-009-02	ML061420150
43	Filter	Damper	Post maintenance testing	N.A.	Repair	5000483	LER 06-003-00	ML061360329
44	Piping system	Piping weld	Increase in radioactivity	Robotic camera	Replaced	5000425	LER 06-001-00	ML060960448
45	Exchanger	Heat exchanger / Soft iron gasket	Leaking	N.A.	Iolated first and planned to repair	5000260	LER 05-004-01	ML060930599
46	Piping system	Piping weld	Leaking	Laboratory analysis	Replacement	5000361	LER 06-001-00	ML060680086

ID	COMPONENT	SUBCOMPONENT	HOW IDENTIFIED	EVALUATION METHOD	REPAIR METHOD	DOCKET	REF	ML NUMBER
47	Containment	Torus	Leaking	Lab analysis and fracture mechanics eval	ASME code repair of the Torus crack	5000333	LER 05-003-01	ML053630257
48	Exchanger	CAC cooling coil	Leaking	NA	Plugging	5000255	LER 05-006-00	ML053430217
49	Exchanger	Small bore piping & tubing	Refueling	Eddy current testing	Removed from service by plugging	5000275	LER 05-001-00	ML053410394
50	Exchanger	Condensor / Small bore piping & tubing	Leaking	NA	Remove the slop drain lines from the condenser	5000298	LER 05-004-00	ML053260429
51	Exchanger	Door	Testing during shutdown	NA	Cleaned and lubricated	5000369	LER 05-004-00	ML053410422
52	Exchanger	Small bore piping & tubing	EDG inoperable	NA	Reparied using a new fitting	5000458	LER 05-003-00	ML053180172
53	Exchanger	Piping weld	NA	NA	Plugged	5000251	LER 04-004-01	ML053180169
54	Exchanger	Piping weld	Hydrogen leak	NA	Griding out the socket weld and re-welding	5000255	LER 05-005-00	ML053050420
55	Containment	Small bore piping & tubing	Drywell floor draing leakage	Visual	Removed	5000354	LER 05-003-01	ML052850369
56	Containment	Test cap	In-service test	NA	Installed a new cap	5000219	LER 05-003-00	ML052630373
57	Exchanger	Piping	NA	NA	Repaired	5000499	LER 05-004-00	ML052630031
58	Piping system	Piping weld	Leaking	Visual	Repairment and Installation of a shim plate	5000333	LER 05-004-00	ML052510052
59	RPV	CRDM - control rod drive mechanism (nozzle)	Visual inspection	Non-destrictive testing (Eddy current, ultrasonic, dye penetrant)	Remove all crack and weld repair	5000287	LER 01-001-01	ML052380420
60	RPV	Piping	Preplanned in-service exmamination	Eddy current testing	Machining	5000529	LER 05-001-00	ML051880073
61	Tank	Piping weld	Leaking	NA	Replaced	5000272	LER 05-002-00	ML051790154
62	Vessel	Sleeve	Leaking	Visual inspection during refueling	Repalcement	5000382	LER 05-001-00	ML051710355

ID	COMPONENT	SUBCOMPONENT	HOW IDENTIFIED	EVALUATION METHOD	REPAIR METHOD	DOCKET	REF	ML NUMBER
63	Exchanger	Piping weld	leaking	Visual	Machining and seal weld	5000482	LER 05-002-00	ML051720389
64	Vessel	Sleeve	leaking	In-service visual inspection during refueling	Encapsulates by a mechanical nozzle seal assembly	5000336	LER 05-002-00	ML051650242
65	Piping system	Small bore piping & tubing	Leaking	Visual	Replaced	5000311	LER 05-002-00	ML051650342
66	Piping system	Piping weld	Leaking	Visual	Affected pipe shortened to avoid resonance	5000354	LER 05-002-00	ML051540027
67	Piping system	Piping	Leaking	Ultrasonic	Replaced	5000483	LER 05-002-00	ML051460343
68	Piping system	Piping weld	Leakage test	Leakage test	Removed and weld a plug	5000388	LER 05-001-00	ML051440352
69	Vessel	Sleeve	Visual inspection	NDE	Applied mechanical nozzle seal assemblies	5000368	LER 05-001-00	ML051310236
70	Piping system	Nozzle	UT inspection	UT inspection	Overlay weld	5000318	LER 05-001-00	ML051180015
71	Piping system	Piping weld	Walkdown	Walkdown	Repaired and added tie-back support	5000389	LER 05-001-00	ML051050350
72	Piping system	Piping weld	Leakage	NA	Cutting off and plugging	5000499	LER 1361-972-72	ML050980111
73	Exchanger	Elbow	Leaking	NA	NA	5000306	LER 04-001-01	ML050890314
74	RPV	CRDM - control rod drive mechanism (nozzle)	Leaking	Ultrasonic/dye penetrant	Half-nozzle removed and replaced	5000255	LER 04-002-00	ML043560278
75	Piping system	Piping weld	Steam leak	NA	Repaired	5000354	LER 04-010-00	ML043560178
76	Piping system	Underground piping	Leaking	NA	Rerouted	5000281	LER 04-001-01	ML043280416
77	Exchanger	Nozzle weld	Exam during refueling	Visual	Machining and welding in a new plug	5000414	LER 04-001-00	ML043280501
78	Piping system	Nozzle	Leaking	NA	Replacement	5000275	LER 04-002-00	ML042790449

ID	COMPONENT	SUBCOMPONENT	HOW IDENTIFIED	EVALUATION METHOD	REPAIR METHOD	DOCKET	REF	ML NUMBER
79	RPV	CRDM - control rod drive mechanism (nozzle)	Inspection during refueling outage	Ultrasonic	Inside diameter temper bead half-nozzle weld	5000313	LER 04-002-00	ML041830363
80	RPV	CRDM - control rod drive mechanism	NDE as required by the First Revised NRC Order	Ultrasonic	Weld	5000266	LER 04-001-00	ML050870170
81	Piping system	Piping weld	Leaking	NA	Installed new nozzle	5000395	LER 04-001-00	ML042740125
82	Exchanger	Small bore piping & tubing	Eddy current testing during no mode	Eddy current testing	Plugged	5000275	LER 04-001-00	ML041400030
83	Piping system	Piping weld	Scheduled inservice inspection	Ultrasonic	Overlay weld	5000265	LER 04-002-00	ML041390526
84	Vessel	Sleeve	Boric acid walkdown	Visual	Mechanical nozzle seal assembly (MNSA)	5000530	LER 04-001-00	ML041270485
85	Piping system	Piping weld	NA	NA	Overlay weld	5000528	LER 04-001-00	ML041040027
86	Piping system	Fitting	Leaking	NA	New fitting installed	5000269	LER 04-001-00	ML040760839
87	Exchanger	Condenser (including ice) & supports	Air in-leakage	NA	Installed penetration weld	5000331	LER 03-006-00	ML040340345
88	Piping system	Piping weld	Leaking	NA	Shortened and welded	5000482	LER 03-004-00	ML040210791
89	Anchorage	Nut	NA	Visual	Replacement	5000321	LER 03-003-00	ML040210327
90	Vessel	Pressurizer	Inspection at refueling outage	visual	Replaced	5000289	LER 03-003-00	ML033580625
91	Piping system	Nozzle	Leakage found during refueling outage	NA	Welded repair	5000382	LER 03-003-00	ML033560242
92	Vessel	Pressurizer sleeves	Leakage found during refueling outage	NA	Mechanical nozzle seal assemblies	5000382	LER 03-003-00	ML033560242
93	Exchanger	Heat exchanger	Inspection	NA	To be replaced at next refueling outage	5000413	LER 03-006-00	ML033500337

ID	COMPONENT	SUBCOMPONENT	HOW IDENTIFIED	EVALUATION METHOD	REPAIR METHOD	DOCKET	REF	ML NUMBER
94	Vessel	Pressurizer sleeves	Inspection	Visual	Mechanical nozzle seal assemblies	5000336	LER 03-004-00	ML033460378
95	RPV	Nozzle-to-cap weld	Planned inspection	Visual	Automated structural weld overlay	5000293	LER 03-006-00	ML033360733
96	Vessel	Pressurizer nozzle	Inspection	Visual	"Halfnozzle" technique	5000302	LER 03-003-00	ML033320052
97	Vessel	Pressurizer - filters and screens	NA	NA	Replaced	5000346	LER 98-002-01	ML033170198
98	Filter	Screens	Fish impinging	NA	Replaced	5000315	LER 03-003-01	ML033180115
99	RPV	CRDM - control rod drive mechanism (nozzle)	Scheduled inspection at refueling outage	Visual	Reactor vessel head retired and replaced	5000269	LER 03-002-00	ML033090486
100	RPV	Nozzle	Leaking	Ultrosonic	Half-nozzles and weld	5000498	LER 03-003-01	ML032950483
101	RPV	Steam dryer	Inspection	NA	Repair (no detail)	5000265	LER 03-004-00	ML032461172
102	RPV	Vent line	Leaking	Ultrasonic	Replaced	5000254	LER 03-001-00	ML032120510
103	Exchanger	Heat exchanger	NA	NA	Chemically cleaned	5000413	LER 03-004-00	ML031970061
104	Piping system	Small bore piping & tubing	Leaking	NA	Modified to increase tubing wall thickness	5000458	LER 03-001-01	ML031820539
105	RPV	Nozzle	Inspection at refueling outage	Ultrasonic	Removed lower portion and relocated boundary weld	5000389	LER 03-002-00	ML031900041
106	Filter	TWS - traveling water screen	Main feed pump condenser fouling by fish	NA	Replaced with stainless steel panels	5000315	LER 03-003-00	ML031820557
107	Piping system	Piping	Leaking	Visual	Replaced	5000331	LER 03-004-00	ML031760687
108	Exchanger	Condensor / piping	Air in-leakage	NA	Replaced during refueling outage	5000389	LER 03-001-00	ML031550064
109	Piping system	Nozzle	Leakage found during refueling outage	NA	Replaced	5000530	LER 03-002-00	ML031540552

ID	COMPONENT	SUBCOMPONENT	HOW IDENTIFIED	EVALUATION METHOD	REPAIR METHOD	DOCKET	REF	ML NUMBER
110	Vessel	Sleeve	Leakage found during refueling outage	NA	Replaced	5000530	LER 03-002-00A	ML031540552
111	Piping system	Small bore piping & tubing	NA	NA	Replaced and added additional supports	5000277	LER 03-001-00	ML031490372
112	RPV	CRDM - control rod drive mechanism (nozzle)	Inspection at refueling outage	Visual	Reactor vessel head retired	5000287	LER 03-001-00	ML031490044
113	Exchanger	Condensor / tubing	Leaking	NA	Replaced	5000528	LER 03-002-00	ML031400058
114	Other	Gypsum board assembly	Waldown	Visual	Cosmetically repaired	5000263	LER 03-001-00	ML031400643
115	Exchanger	CAC components	NA	NA	Refurbishment/replacement	5000346	LER 02-008-01	ML031330192
116	Piping system	Piping	NA	NA	Refurbishment/replacement	5000346	LER 02-008-01A	ML031330192
117	Exchanger	Steam generator - tubing	Scheduled surveillance at refueling outage	Eddy current ply point testing data	Plugging or sleeving	5000445	LER 02-002-01	ML031210481
118	RPV	Penetration	Inspection at refueling outage	Visual	Reactor head replaced	5000338	LER 03-001-00	ML031200697
119	Exchanger	Steam deflector plate	Conductivity alarm	NA	Broken deflector plate replaced and repaired valve and plugged tubes	5000331	LER 03-001-00	ML030920458
120	Exchanger	Steam generator - tubing	Inspection	Eddy current	Plugging	5000323	LER 03-001-00	ML030780463
121	Exchanger	Steam generator - tubing	Inspection	Eddy current	Plugging	5000323	LER 03-001-00	ML030780463
122	Piping system	Support	NA	NA	Repaired	5000249	LER 02-005-01	ML030590240
123	Piping system	Piping weld	Leaking	NA	Minimized welding residual stress and eleminated mechanically induced stress	5000249	LER 02-006-00	ML030430376
124	Piping system	Thermal sleeve	Examination with reactor defueled	Borescope	Replaced	5000346	LER 02-009-00	ML030370013
125	Other	Static line hanger	NA	NA	Replaced	5000255	LER 02-002-00	ML030300342

ID	COMPONENT	SUBCOMPONENT	HOW IDENTIFIED	EVALUATION METHOD	REPAIR METHOD	DOCKET	REF	ML NUMBER
126	Exchanger	Steam generator - tubing	In-situ pressure testing	In-situ pressure testing	Plugging	5000270	LER 02-003-00	ML023600191
127	Piping system	Piping weld	Leaking	NA	Replaced	5000249	LER 02-003-00	ML023520043
128	RPV	CRDM - control rod drive mechanism (nozzle)	Inspection at refueling outage	Visual	Partially removed and applied new weld	5000313	LER 02-003-00	ML023400549
129	Piping system	Piping weld	Inspection at refueling outage	NA	Replaced with an enhanced configuration	5000313	LER 02-004-00	ML023400485
130	RPV	CRDM - control rod drive mechanism (nozzle)	Required inspection per NRC Bulletin 2001-01	Visual	Repair (no detail)	5000270	LER 02-002-00	ML023470024
131	Exchanger	Steam generator - tubing	Inspection at refueling outage	NA	Plugged	5000483	LER 2002-011-00	ML023310226
132	RPV	Penetration	Inspection at refueling outage	Visual + NDE	Replacement of RPV head	5000339	LER 02-001-00	ML023180480
133	Piping system	Piping weld	Increasing radiation trend	Visual	Affected welds and elbows replaced	5000336	LER 02-004-00	ML022840184
134	Piping system	Piping weld	Low level alarm	NA	NA	5000317	LER 02-003-00	ML022630111
135	RPV	Steam dryer	NA	NA	Replaced with thicker plate	5000265	LER 02-003-00	ML022610332
136	Concrete	Floor	Leaking	NA	Seal	5000397	LER 02-003-00	ML022270273
137	Piping system	Piping weld	Leaking	RT - Radiographic testing	Grinding out degraded area and weld buildup	5000286	LER 02-001-00	ML022000155
138	Exchanger	Small bore piping & tubing	Leaking	Laboratory analysis	Installed sleeves	5000305	LER 02-002-00	ML021920465
139	Piping system	Piping	Leaking	Scanning electron microscope	Replaced	5000281	LER 02-001-00	ML021710180
140	Vessel	Sleeve	Leaking	Visual	Mechanical Nozzle Seal Assembly	5000368	LER 02-001-00	ML021680047
141	RPV	Nozzle	Inspection at refueling outage	Ultrasonic	NA	5000269	LER 02-003-00	ML021570019

ID	COMPONENT	SUBCOMPONENT	HOW IDENTIFIED	EVALUATION METHOD	REPAIR METHOD	DOCKET	REF	ML NUMBER
142	Exchanger	Steam generator - tubing	Eddy current testing	Eddy current testing	Plugged	5000275	LER 02-002-00	ML021560548
143	RPV	CRDM - control rod drive mechanism (nozzle)	Ultrosonic exam	Ultrosonic exam	NA	5000346	LER 02-002-00	ML021220082
144	Vessel	Pressurizer - heater sleeve penetrations	Leaking	Visual	Mechanical Nozzle Seal Assembly	5000336	LER 02-001-00	ML021210508
145	RPV	CRDM - upper housing	Leaking	NDE	Replaced	5000255	LER 01-004-01	ML020870353
146	Piping system	Small bore piping & tubing	Degraded flow	NA	Cleaned	5000412	LER 02-001-00	ML020710575
147	Tank	Floating cover	Failure of motor driven auxiliary feedwater pump	NA	CST cover removed	5000483	LER 02-001-01	ML020720446
148	RPV	CRDM - control rod drive mechanism (nozzle)	Visual inspection at refueling outage	Ultrasonic	Repaired	5000287	LER 01-003-00	ML020350290
149	Piping system	Pipe-to-elbow weld	Leaking	Visual	Replacement of elbow	5000247	LER 01-006-00	ML020090594
150	Piping system	Small bore piping & tubing	Pump noise	Visual	Replaced	5000271	LER 01-005-00	ML020240466
151	RPV	CRDM penetration	Inspection at refueling outage	Visual	Repaired	5000280	LER 01-003-00	ML020520345
152	Piping system	Piping weld	Leaking	Radiographic examination	Weld removed and replaced	5000354	LER 01-006-00	ML020220237
153	RPV	CRDM - control rod drive mechanism (nozzle)	Leaking	Liquid penetration test	Machined and applied new weld	5000289	LER 01-002-00	ML020160399
154	RPV	Thermocouple (T/C) nozzles	Leaking	Liquid penetration test	Plugged	5000289	LER 01-002-00A	ML020160399
155	Exchanger	Heat exchanger	Elevated radionuclide activity in SW	NA	Isolated using plugs	5000302	LER 01-003-00	ML020430199
156	RPV	CRDM - control rod drive mechanism (nozzle)	Visual inspection	Ultrasonic	Ambient temperature temper bead repair technique	5000302	LER 01-004-00	ML020160225
157	Exchanger	Steam generator - nozzle to vessel weld	Walk down at refueling outage	Visual and penetrant test	Removed old weld (Alloy 600) and applied new weld (Inconel 52/152)	5000414	LER 803-831-36	ML020030237

ID	COMPONENT	SUBCOMPONENT	HOW IDENTIFIED	EVALUATION METHOD	REPAIR METHOD	DOCKET	REF	ML NUMBER
158	Piping system	Drain trap outlet plug	Steam leaking	NA	Replaced	5000331	LER 01-004-00	ML020310457
159	Structural steel	Door	Airlock door failed during removal of plant equipment	Visual	Repaired	5000316	LER 2001-002-01	ML020240312
160	Filter	Strainer basket	Surveillance test	NA	Replaced	5000316	LER 01-003-00	ML020220028
161	Filter	Strainer basket	Surveillance test	NA	Replaced	5000315	LER 01-003-00	ML020220028
162	RPV	Feedwater nozzle	Out of calibration	NA	NA	5000271	LER 01-004-00	ML013650369
163	Piping system	Cooling coil	Leaking	NA	Replacement	5000271	LER 20012009	ML070670447
164	Other	Flood panel	Preventive maintenance	NA	Repair	5000282	LER 01-003-00	ML012610162
165	Filter	Screens	Water level decreased	NA	NA	5000301	LER 01-002-00	ML012330129
166	Structural steel	Door	NA	NA	Weld buildup	5000336	LER 01-006-00	ML012320075
167	Exchanger	Radiator cooling fin	Leaking	NA	Replacement of radiator	5000335	LER 01-006-00	ML012050195
168	RPV	CRDM - control rod drive mechanism (nozzle)	Visual inspection at refueling outage	Dye-penetrant test	Machining and weld	5000270	LER 01-002-00	ML011830021
169	Piping system	Nozzle	Leaking	Visual	Replacement	5000335	LER 01-003-00	ML011700213
170	RPV	CRDM Seal housing	Inspection at refueling outage	NA	Installed new Inconel housing	5000255	LER 001-002-00	ML011560030
171	Structural steel	Bolt	Pump inoperable	NA	Tightened	5000289	LER 01-001-01	ML011500423
172	Piping system	Nozzle	Inspection at refueling outage	Eddy current testing	Cut and plug	5000528	LER 01-001-00	ML011500148
173	Exchanger	Steam generator - tubing	Inspection at refueling outage	Eddy current exam	Plugging	5000499	LER 01-003-00	ML011420313

ID	COMPONENT	SUBCOMPONENT	HOW IDENTIFIED	EVALUATION METHOD	REPAIR METHOD	DOCKET	REF	ML NUMBER
174	RPV	CRDM - control rod drive mechanism (nozzle)	Visual inpsection at refueling outage	Liquid penetrant exam	Embedded flaw repair	5000313	LER 01-002-00	ML011350195
175	RPV	CRDM - control rod drive mechanism (nozzle)	Visual inspection at planned maintenance outage	Eddy current examination, ultrasonic, dye penetrant	Remove crack indications and weld repair	5000287	LER 01-001-00	ML011140213
176	Exchanger	Steam generator - tubing	Inspection at refueling outage	Eddy current and point testing	Plugged	5000445	LER 01-004-00	ML011100238
177	Piping system	Piping	Leaking	NA	Repaired	5000416	LER 01-001-00	ML011140218
178	Structural steel	Screw	Difficulty in full gripper engagement	Ultrasonic, visual, and spring scale inspection	Changed nozzles	5000395	LER 99-004-02	ML011090006
179	Exchanger	Inlet-sie tubesheet	Low condenser vacuum	NA	Removed debris	5000315	LER 001-001-00	ML011020251
180	Exchanger	Steam generator - tubing	Primary to secondary leak	Eddy current inspection	Plugged or repaired	5000247	LER 00-003-01	ML010890367
181	Piping system	Nozzle-to-pipe weld	Leaking	Dye penetrant/Ultrasonic	Weld repair	5000395	LER 00-008-01	ML010790459
182	Structural steel	Pump hold-down beam	Jet pump failure	NA	Replaced	5000254	LER 02-001-00	ML020850677
183	RPV	CRDM - control rod drive mechanism (nozzle)	Boric acid deposit	Video inspection/eddy current/dye penetrant/ultrasonic	welded plug	5000269	LER 00-006-01	ML010710015
184	Structural steel	Door	Failed to close	NA	Lubricating and cycling	5000305	LER 01-001-00	ML010580336
185	Exchanger	Steam generator - tubing	Primary to secondary leak	NA	NA	5000247	LER 00-001-01	ML010580294
186	Piping system	Support	Pipe leaking	NA	Repaired and reinforced	5000313	LER 00-001-00	ML010400162
187	Piping system	Piping	Pipe leaking	Visual	Repaired	5000313	LER 00-001-00A	ML010400162

ID	COMPONENT	SUBCOMPONENT	HOW IDENTIFIED	EVALUATION METHOD	REPAIR METHOD	DOCKET	REF	ML NUMBER
188	Vessel	Pressurizer heater sleeves	Leakage discovered at refueling outage	NA	Pluuged	5000382	LER 00-011-00	ML003770501
189	RPV	CRD - housing	Inspection at refueling outage	Visual/dye penetrant/eddy current/ultrasonic	Repaired	5000255	LER 99-004-01	ML003769646
190	Filter	Charcoal	Penetration test at refueling outage	Penetration test	Replaced	5000251	LER 00-003-00	ML003768557
191	Exchanger	Steam generator - tubing	Eddy current testing	Eddy current testing	Plugged	5000275	LER 00-010-00	ML003768576
192	Vessel	Pressurizer heater sleeves	Inspection at refueling outage	Visual	Cut and weld a plug	5000529	LER 00-004-00	ML003768542
193	Piping system	Fitting	Leaking	NA	Replaced	5000249	LER 99-003-02	ML003765638
194	Piping system	Piping	Offgas condenser low-level alarm	NA	Re-welded	5000397	LER 00-007-00	ML003762455
195	Exchanger	ESW room cooler	Degraded ESW flow	Flow testing	Clearwell cleaned and chemically treated	5000483	LER 00-006-00	ML003760465
196	Structural steel	Weld	NA	NA	Repaired	5000361	LER 949-368-62	ML003756122
197	Piping system	Fitting	NA	NA	NA	5000333	LER 00-010-00	ML003756877
198	Piping system	Piping weld	NA	NA	NA	5000333	LER 00-010-00A	ML003756877
199	Vessel	Pressurizer heater sleeves	Inspection outage	Eddy current/Ultrasonic	Repaired for limited service life	5000368	LER 2000-001-00	ML003747697
200	Piping system	Piping weld	Test	NA	NA	5000237	LER 00-002-00	ML003738091
201	Piping system	Small bore piping & tubing	Leaking	NA	Repaired and improved support	5000261	LER 2000-001-00	ML003735247
202	Exchanger	Steam generator - tubing	In-service inspection	Eddy current	Plugged or repaired	5000305	LER 920-388-25	ML003725181
203	Concrete	Walls & floors	Visual	NA	Repair	5000316	LER 00-003-00	ML051030057

ID	COMPONENT	SUBCOMPONENT	HOW IDENTIFIED	EVALUATION METHOD	REPAIR METHOD	DOCKET	REF	ML NUMBER
204	Piping system	Piping	Pipe rupture	NA	Replaced with Chromium-Molybdenum piping	5000483	LER 1999-003-01	ML003712775
205	Exchanger	Steam generator - tubing	Leaking	Eddy current	Plugged or repaired	5000247	LER 00-03	ML003712955
206	Piping system	Small bore piping & tubing	Chiller tripped	NA	Repaired	5000390	LER 81-20	ML003708293
207	Piping system	Small bore piping & tubing	Leaking	NA	Fitting tightened	5000269	LER 50-26	ML003701577
208	Exchanger	Steam generator - tubing	Inspection at refueling outage	Eddy current	Plugged	5000250	LER 2000-001-00	ML003705889
209	Piping system	Suction line weld	Leaking	NA	Repaired	5000382	LER 00-003-00	ML003703686
210	Exchanger	Steam generator - tubing	Primary to secondary leaking	NA	Plugged	5000247	LER 00-001-00	ML020350573
211	Piping system	Elbow	Leaking	Visual & laboratory examination	Elbow replaced	5000269	LER 2000-001-00	ML003694353
212	Piping system	Weld	Leaking	NDE & Laboratory analysis	Weld pad buildup and fillet weld	5000313	LER 2000-003-00	ML003693846
213	Containment	Liner	Inspection	Visual & magnetic particle exam	Replacement of degraded seal	5000315	LER 98-011-03	ML003695085
214	Filter	Nuts holding in Charcoal tray	Surveillance test	Visual	Tightened	5000317	LER 410-495-20	ML003687837
215	Containment	Liner	Inspection	NA	Repair	5000315	LER 00-001-00	ML003687066
216	Filter	Charcoal	Sample analysis per surveillance requirement	Laboratory analysis	Replacement	5000498	LER 99-007-01	ML003674168
217	Exchanger	Steam generator - tubing	Eddy current inspection	Eddy current inspection	Plugged	5000364	LER 99-002-00	ML993480199
218	RPV	Nozzle-safe end weld	Ultrasonic examination at refuelling outage	Ultrasonic	NA	5000331	LER 99-00	ML993500158
219	Piping system	Small bore piping & tubing	Excessive water inventory in ESSMSRD tank	NA	Repaired	5000333	LER 99-012-00	ML993470148

ID	COMPONENT	SUBCOMPONENT	HOW IDENTIFIED	EVALUATION METHOD	REPAIR METHOD	DOCKET	REF	ML NUMBER
220	Piping system	Piping weld	Leaking	Dye penetrant	Ground out and re-welded	5000266	LER 1999-012-00	ML993420164
221	RPV	CRDM Seal housing	Inspection at refueling outage	Visual & dye penetrant & eddy current exam	Repaired	5000255	LER 99-00	ML993420206
222	Exchanger	Steam generator - tubing	Inspection	Eddy current	plugged	5000499	LER 99-007-00	ML993140290
223	Filter	Charcoal	Surveillance test	Tested by vendor	Replaced	5000333	LER 99-009-00	ML993250125
224	Piping system	Nozzle	Walkdown at refueling outage	Visual	Cut off the existing nozzle and installed new nozzle	5000528	LER 99-006-00	ML993140352
225	Filter	Damper	Negative pressure in CR	Visual	Temporary mechanical modification to secure the manual balancing damper	5000289	LER 99-003-01	ML993140218
226	Exchanger	Steam generator - tubing	Eddy current testing	Eddy current testing	Plugged	5000445	LER 98-006-00	ML993080064

Table 3-4 Abbreviation for Aging Mechanisms

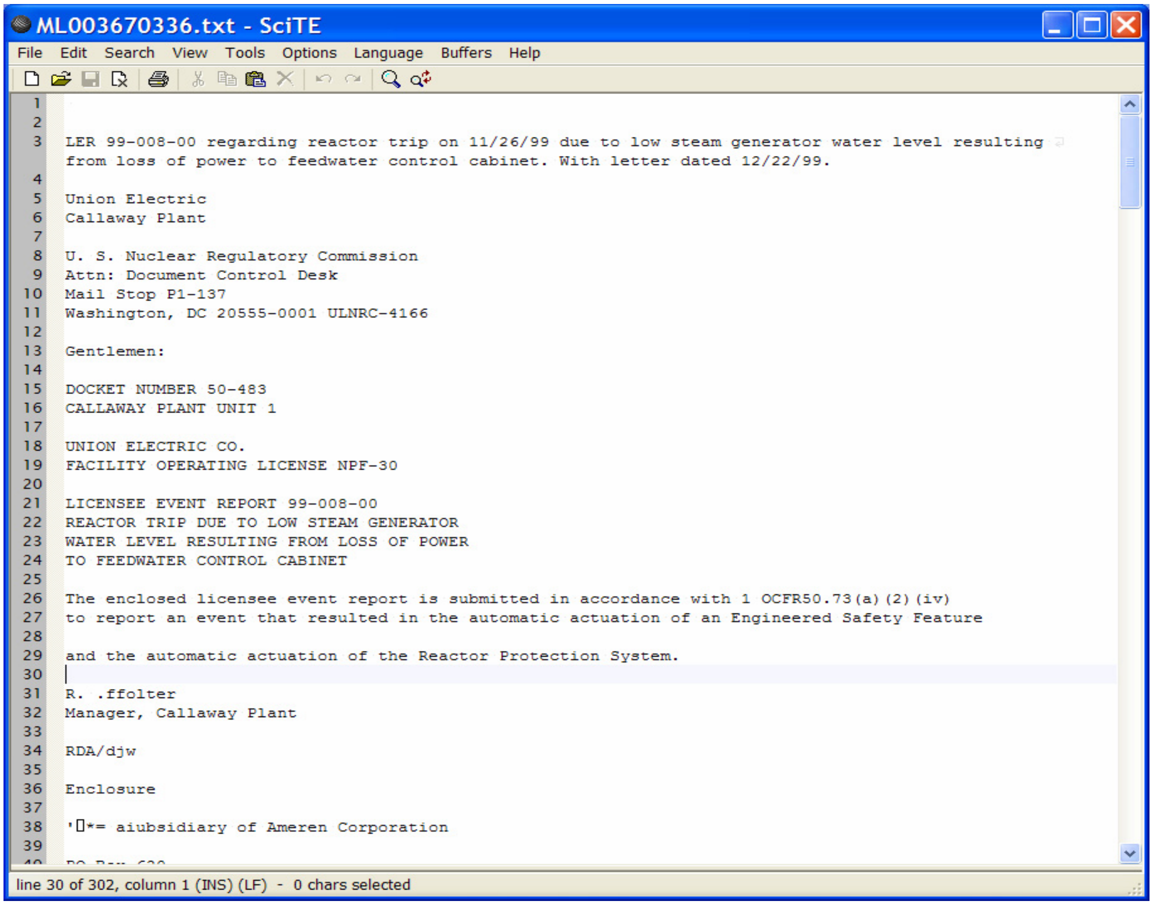
ABBREVIATION	DEFINITION
IGSCC	Intergranular stress corrosion cracking
IDSCC	Interdendritic SCC
HSC	Hydrogen stress corrosion
TGSCC	Transgranular SCC
SCC	Stress corrosion cracking
PWSCC	Primary water SCC
IGA	Intergranular attack
ODSCC	Outer diameter SCC
ODIGA	Outer diameter IGA
FAC	Flow accelerated corrosion

Table 3-5 Number of DORs and NPP Units by PAAE for LER 1999-2007

LER 1999-2007			
PAAE	**DORs**	**NPP Units**	**DORs/NPP Units**
23	2	2	1.000
24	4	4	1.000
25	3	3	1.000
26	11	9	1.222
27	10	9	1.111
28	11	10	1.100
29	10	8	1.250
30	11	7	1.571
31	21	15	1.400
32	19	14	1.357
33	30	20	1.500
34	22	12	1.833
35	18	15	1.200
36	16	14	1.143
37	10	10	1.000
38	7	5	1.400
39	6	5	1.200
40	7	5	1.400
41	5	4	1.250

Table 3-6 Number of DORs and NPP Units by PAAE for LER 1985-1996

LER 1985-1996			
PAAE	**DORs**	**NPP Units**	**DORs/NPP Units**
8	1	1	1.00
12	3	3	1.00
13	2	2	1.00
14	5	4	1.25
15	4	3	1.33
16	11	10	1.10
17	11	10	1.10
18	12	9	1.33
19	9	8	1.13
20	11	11	1.00
21	11	10	1.10
22	13	10	1.30
23	8	8	1.00
24	22	15	1.47
25	15	11	1.36
26	10	9	1.11
27	8	7	1.14
28	6	6	1.00
29	8	6	1.33
30	1	1	1.00

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LER 99-008-00 regarding reactor trip on 11/26/99 due to low steam generator water level resulting
from loss of power to feedwater control cabinet. With letter dated 12/22/99.

Union Electric
Callaway Plant

U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
Mail Stop P1-137
Washington, DC 20555-0001 ULNRC-4166

Gentlemen:

DOCKET NUMBER 50-483
CALLAWAY PLANT UNIT 1

UNION ELECTRIC CO.
FACILITY OPERATING LICENSE NPF-30

LICENSEE EVENT REPORT 99-008-00
REACTOR TRIP DUE TO LOW STEAM GENERATOR
WATER LEVEL RESULTING FROM LOSS OF POWER
TO FEEDWATER CONTROL CABINET

The enclosed licensee event report is submitted in accordance with 1 OCFR50.73(a)(2)(iv)
to report an event that resulted in the automatic actuation of an Engineered Safety Feature

and the automatic actuation of the Reactor Protection System.

R. .ffolter
Manager, Callaway Plant

RDA/djw

Enclosure

'□*= aiubsidiary of Ameren Corporation
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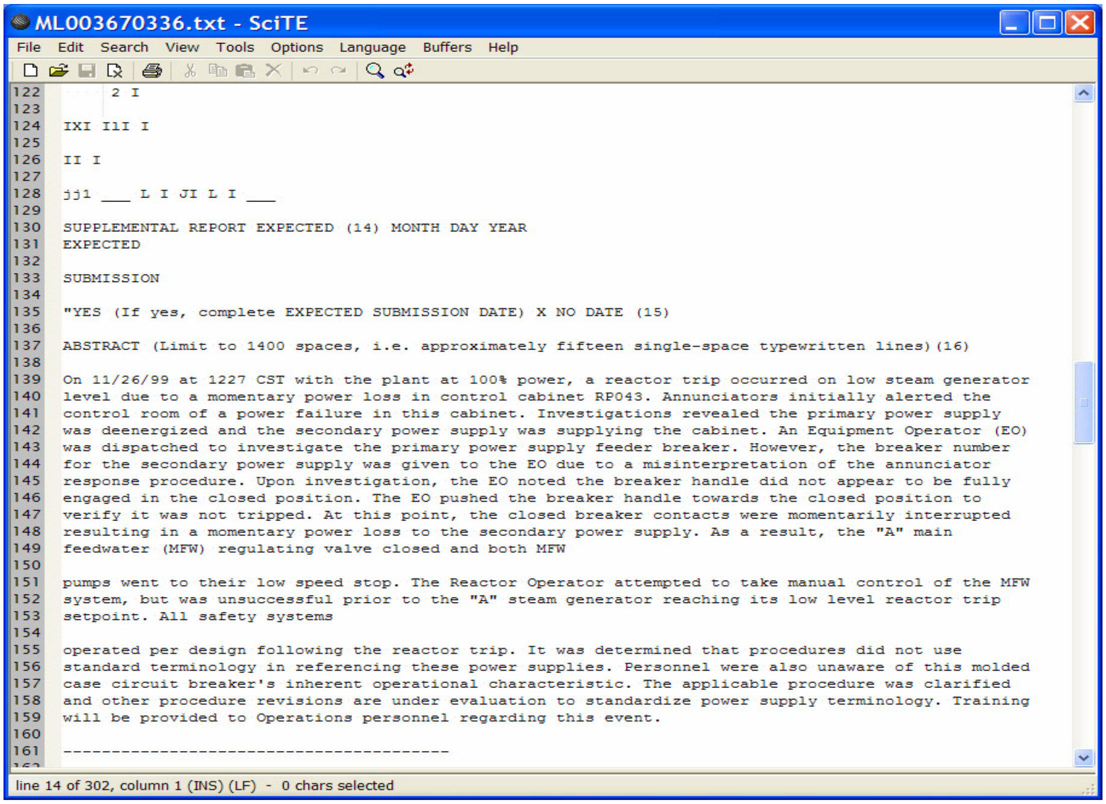
Figure 3-1 A Sample LER in Text Format (Beginning Part)



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II I

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SUPPLEMENTAL REPORT EXPECTED (14) MONTH DAY YEAR
EXPECTED

SUBMISSION

"YES (If yes, complete EXPECTED SUBMISSION DATE) X NO DATE (15)

ABSTRACT (Limit to 1400 spaces, i.e. approximately fifteen single-space typewritten lines)(16)

On 11/26/99 at 1227 CST with the plant at 100% power, a reactor trip occurred on low steam generator
level due to a momentary power loss in control cabinet RP043. Annunciators initially alerted the
control room of a power failure in this cabinet. Investigations revealed the primary power supply
was deenergized and the secondary power supply was supplying the cabinet. An Equipment Operator (EO)
was dispatched to investigate the primary power supply feeder breaker. However, the breaker number
for the secondary power supply was given to the EO due to a misinterpretation of the annunciator
response procedure. Upon investigation, the EO noted the breaker handle did not appear to be fully
engaged in the closed position. The EO pushed the breaker handle towards the closed position to
verify it was not tripped. At this point, the closed breaker contacts were momentarily interrupted
resulting in a momentary power loss to the secondary power supply. As a result, the "A" main
feedwater (MFW) regulating valve closed and both MFW

pumps went to their low speed stop. The Reactor Operator attempted to take manual control of the MFW
system, but was unsuccessful prior to the "A" steam generator reaching its low level reactor trip
setpoint. All safety systems

operated per design following the reactor trip. It was determined that procedures did not use
standard terminology in referencing these power supplies. Personnel were also unaware of this molded
case circuit breaker's inherent operational characteristic. The applicable procedure was clarified
and other procedure revisions are under evaluation to standardize power supply terminology. Training
will be provided to Operations personnel regarding this event.

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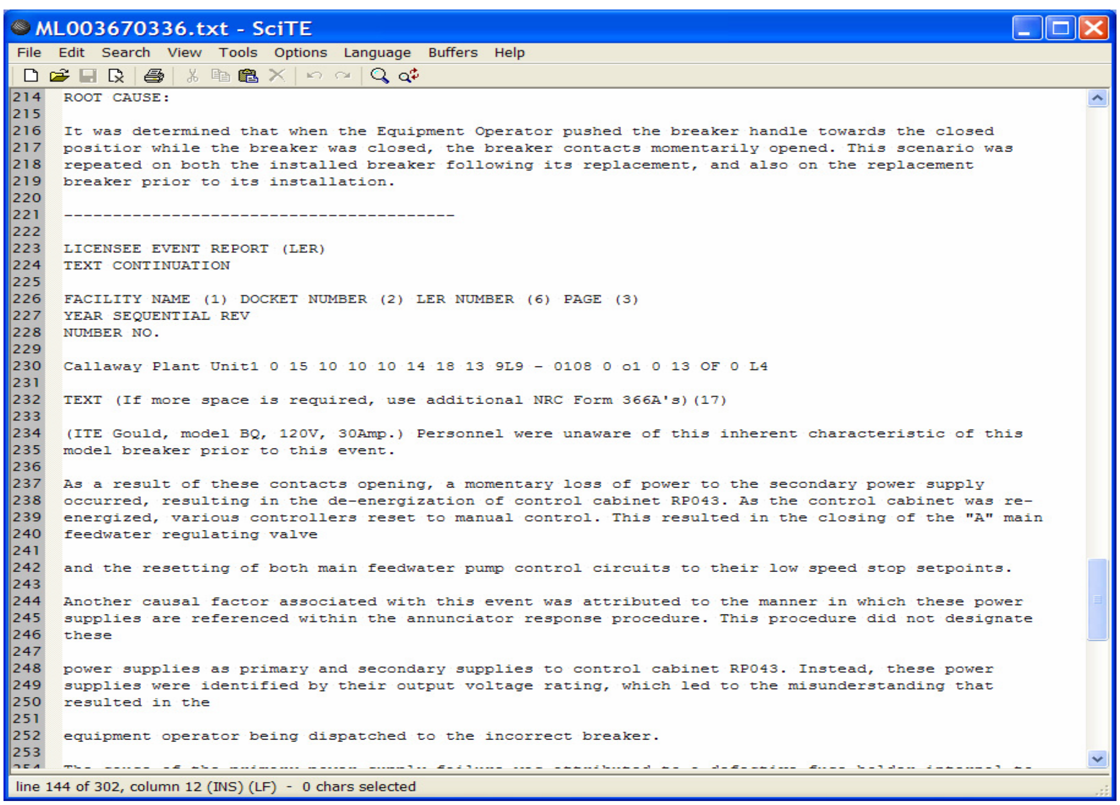
line 14 of 302, column 1 (INS) (LF) - 0 chars selected

Figure 3-2 A Sample LER in Text Format (Abstract Part)



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ROOT CAUSE:

It was determined that when the Equipment Operator pushed the breaker handle towards the closed
positior while the breaker was closed, the breaker contacts momentarily opened. This scenario was
repeated on both the installed breaker following its replacement, and also on the replacement
breaker prior to its installation.

----------------------------------------

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1) DOCKET NUMBER (2) LER NUMBER (6) PAGE (3)
YEAR SEQUENTIAL REV
NUMBER NO.

Callaway Plant Unit1 0 15 10 10 10 14 18 13 9L9 - 0108 0 o1 0 13 OF 0 L4

TEXT (If more space is required, use additional NRC Form 366A's)(17)

(ITE Gould, model BQ, 120V, 30Amp.) Personnel were unaware of this inherent characteristic of this
model breaker prior to this event.

As a result of these contacts opening, a momentary loss of power to the secondary power supply
occurred, resulting in the de-energization of control cabinet RP043. As the control cabinet was re-
energized, various controllers reset to manual control. This resulted in the closing of the "A" main
feedwater regulating valve

and the resetting of both main feedwater pump control circuits to their low speed stop setpoints.

Another causal factor associated with this event was attributed to the manner in which these power
supplies are referenced within the annunciator response procedure. This procedure did not designate
these

power supplies as primary and secondary supplies to control cabinet RP043. Instead, these power
supplies were identified by their output voltage rating, which led to the misunderstanding that
resulted in the

equipment operator being dispatched to the incorrect breaker.
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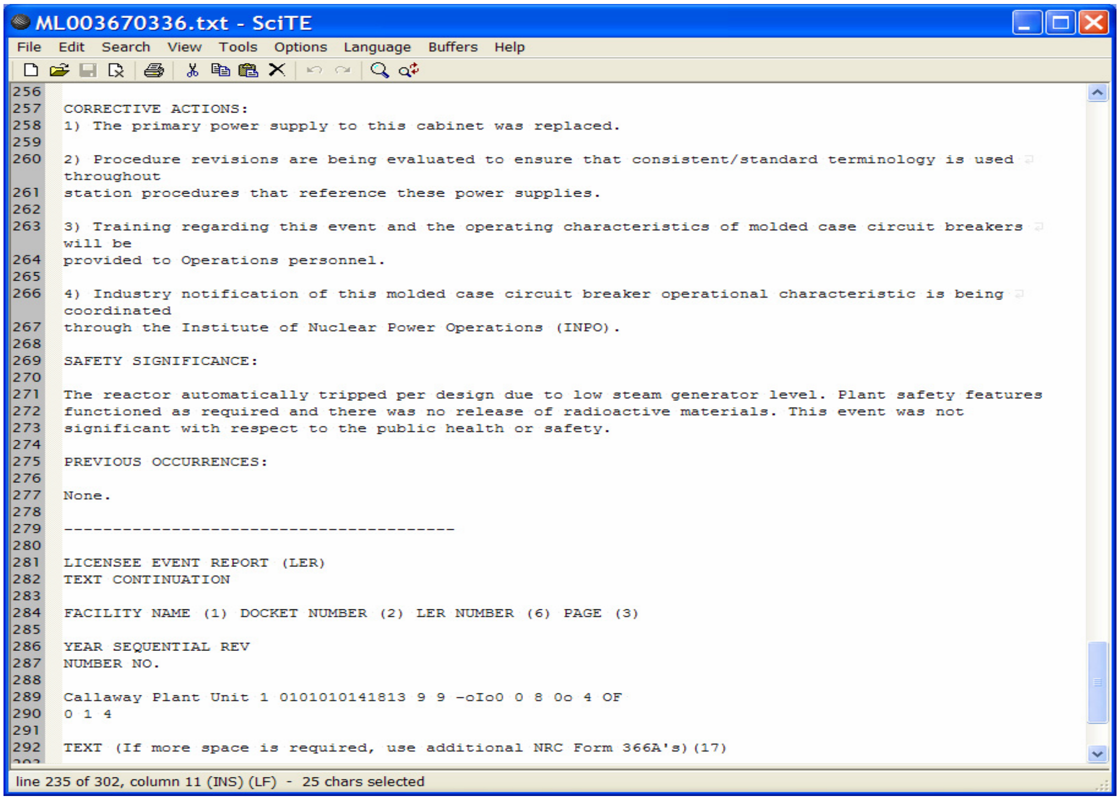
Figure 3-3 A Sample LER in Text Format (Cause Part)



ML003670336.txt - SciTE

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CORRECTIVE ACTIONS:
1) The primary power supply to this cabinet was replaced.

2) Procedure revisions are being evaluated to ensure that consistent/standard terminology is used
throughout
station procedures that reference these power supplies.

3) Training regarding this event and the operating characteristics of molded case circuit breakers
will be
provided to Operations personnel.

4) Industry notification of this molded case circuit breaker operational characteristic is being
coordinated
through the Institute of Nuclear Power Operations (INPO).

SAFETY SIGNIFICANCE:

The reactor automatically tripped per design due to low steam generator level. Plant safety features
functioned as required and there was no release of radioactive materials. This event was not
significant with respect to the public health or safety.

PREVIOUS OCCURRENCES:

None.

----------------------------------------

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1) DOCKET NUMBER (2) LER NUMBER (6) PAGE (3)

YEAR SEQUENTIAL REV
NUMBER NO.

Callaway Plant Unit 1 0101010141813 9 9 -oIo0 0 8 0o 4 OF
0 1 4

TEXT (If more space is required, use additional NRC Form 366A's)(17)
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Figure 3-4 A Sample LER in Text Format (Action Part)

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Callaway Plant Unit 1	0 5 0 0 0 4 8 3	1 OF 0 4

TITLE (4) **REACTOR TRIP DUE TO LOW STEAM GENERATOR WATER LEVEL RESULTING FROM LOSS OF POWER TO FEEDWATER CONTROL CABINET**

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REV. NO.	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
										0 5 0 0 0
1 1	2 6	9 9	9 9	- 0 0 8 -	0 0	1 2	2 2	9 9		0 5 0 0 0

OPERATING MODE (9): 1

POWER LEVEL (10): 1 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR : (*Check one or more of the following*) (11)

	20.2201(b)		20.2203(a)(2)(v)		50.73(a)(2)(i)		50.73(a)(2)(viii)
	20.2203(a)(1)		20.2203(a)(3)(i)		50.73(a)(2)(ii)		50.73(a)(2)(x)
	20.2203(a)(2)(i)		20.2203(a)(3)(ii)		50.73(a)(2)(iii)		73.71
	20.2203(a)(2)(ii)		20.2203(a)(4)	X	50.73(a)(2)(iv)		OTHER (*Specify in Abstract below or in Text, NRC Form 366A*)
	20.2203(a)(2)(iii)		50.36(c)(1)		50.73(a)(2)(v)		
	20.2203(a)(2)(iv)		50.36(c)(2)		50.73(a)(2)(vii)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (AREA CODE)
J. D. Schnack, Supervising Engineer, QA Regulatory Support	5 7 3 6 7 6 - 4 3 1 9

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO EPIX	CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO EPIX
X	J B	J X	W 1 2 0	Y					

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

ABSTRACT (Limit to 1400 spaces, i.e. approximately fifteen single-space typewritten lines)(16)

On 11/26/99 at 1227 CST with the plant at 100% power, a reactor trip occurred on low steam generator level due to a momentary power loss in control cabinet RP043. Annunciators initially alerted the control room of a power failure in this cabinet. Investigations revealed the primary power supply was deenergized and the secondary power supply was supplying the cabinet. An Equipment Operator (EO) was dispatched to investigate the primary power supply feeder breaker. However, the breaker number for the secondary power supply was given to the EO due to a misinterpretation of the annunciator response procedure. Upon investigation, the EO noted the breaker handle did not appear to be fully engaged in the closed position. The EO pushed the breaker handle towards the closed position to verify it was not tripped. At this point, the closed breaker contacts were momentarily interrupted resulting in a momentary power loss to the secondary power supply. As a result, the "A" main feedwater (MFW) regulating valve closed and both MFW pumps went to their low speed stop. The Reactor Operator attempted to take manual control of the MFW system, but was unsuccessful prior to the "A" steam generator reaching its low level reactor trip setpoint. All safety systems operated per design following the reactor trip. It was determined that procedures did not use standard terminology in referencing these power supplies. Personnel were also unaware of this molded case circuit breaker's inherent operational characteristic. The applicable procedure was clarified and other procedure revisions are under evaluation to standardize power supply terminology. Training will be provided to Operations personnel regarding this event.

Figure 3-5 A Sample LER in PDF Format (Abstract Part)

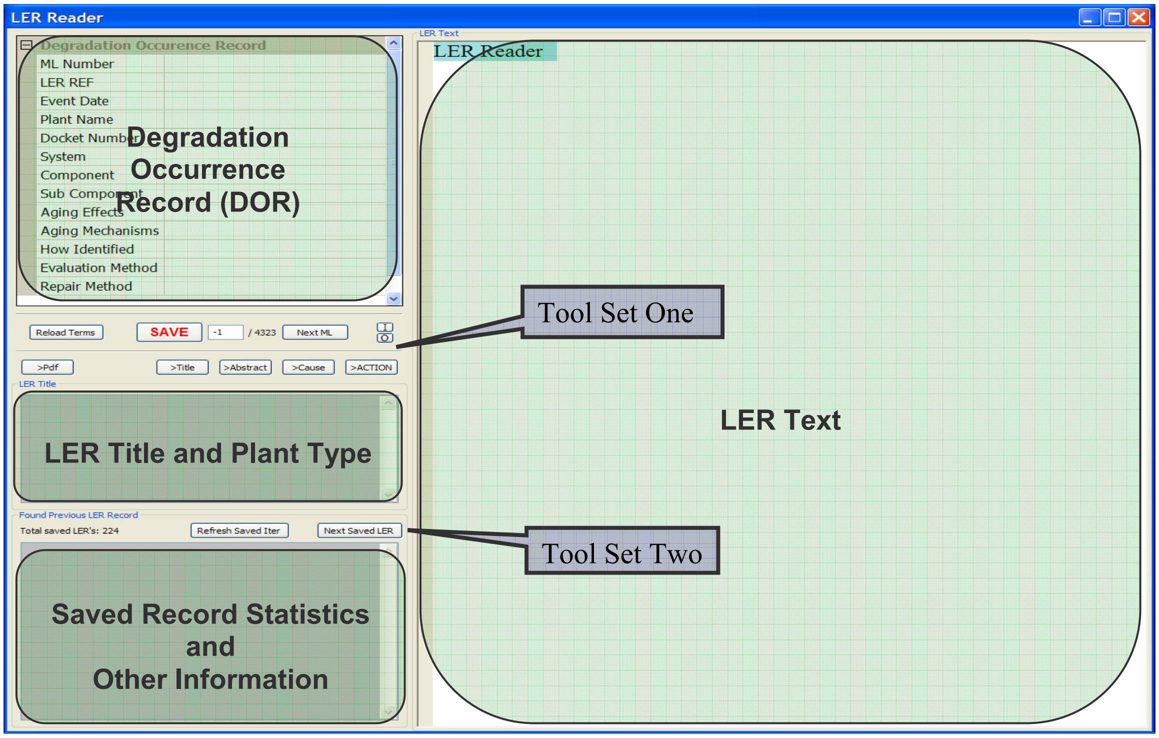

Figure 3-6 The Annotated LER Reader Graphical User Interface

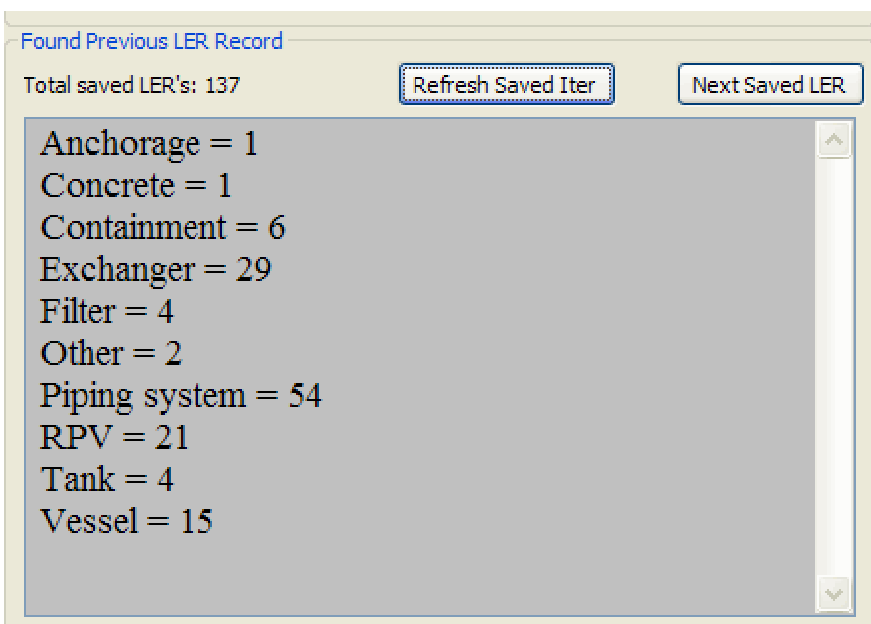

Figure 3-7 DOR Statistics in the LER Reader

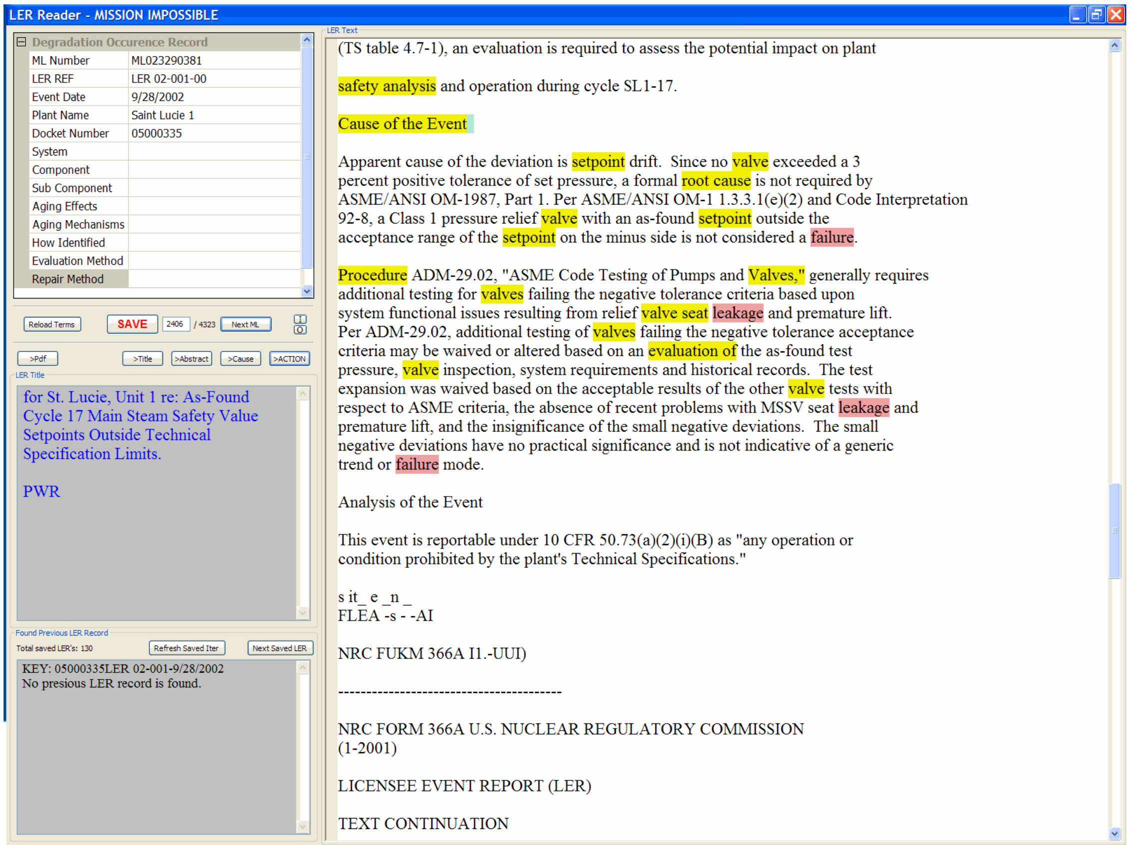

Figure 3-8 An LER Related to Valve

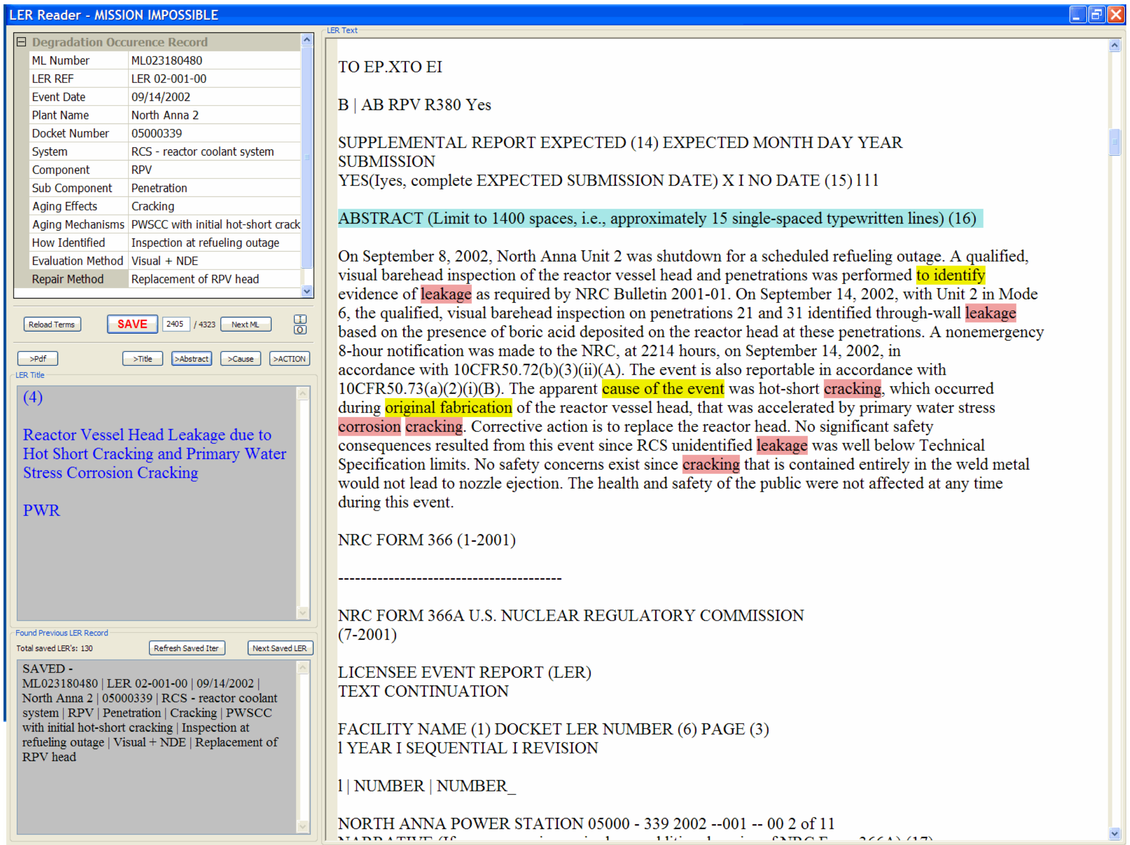

Figure 3-9 An LER and its DOR (Saved)

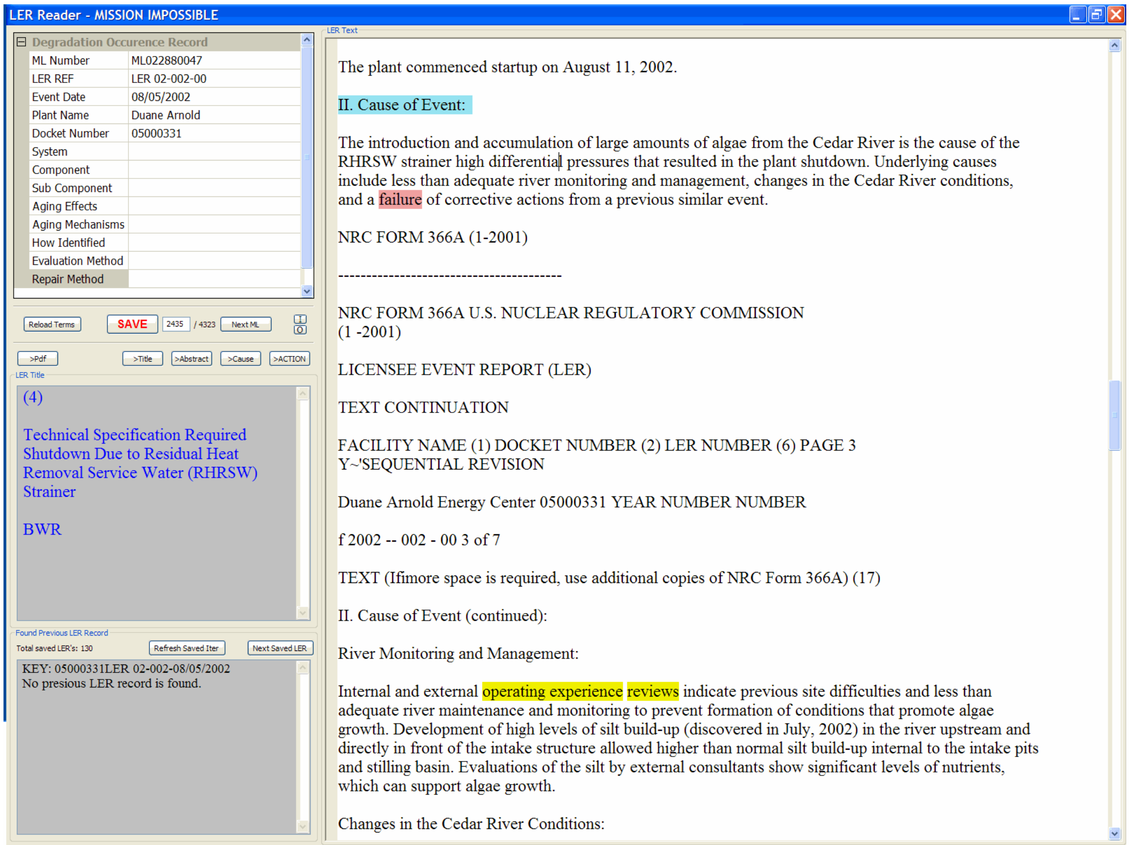

Figure 3-10 An LER Required Careful Review

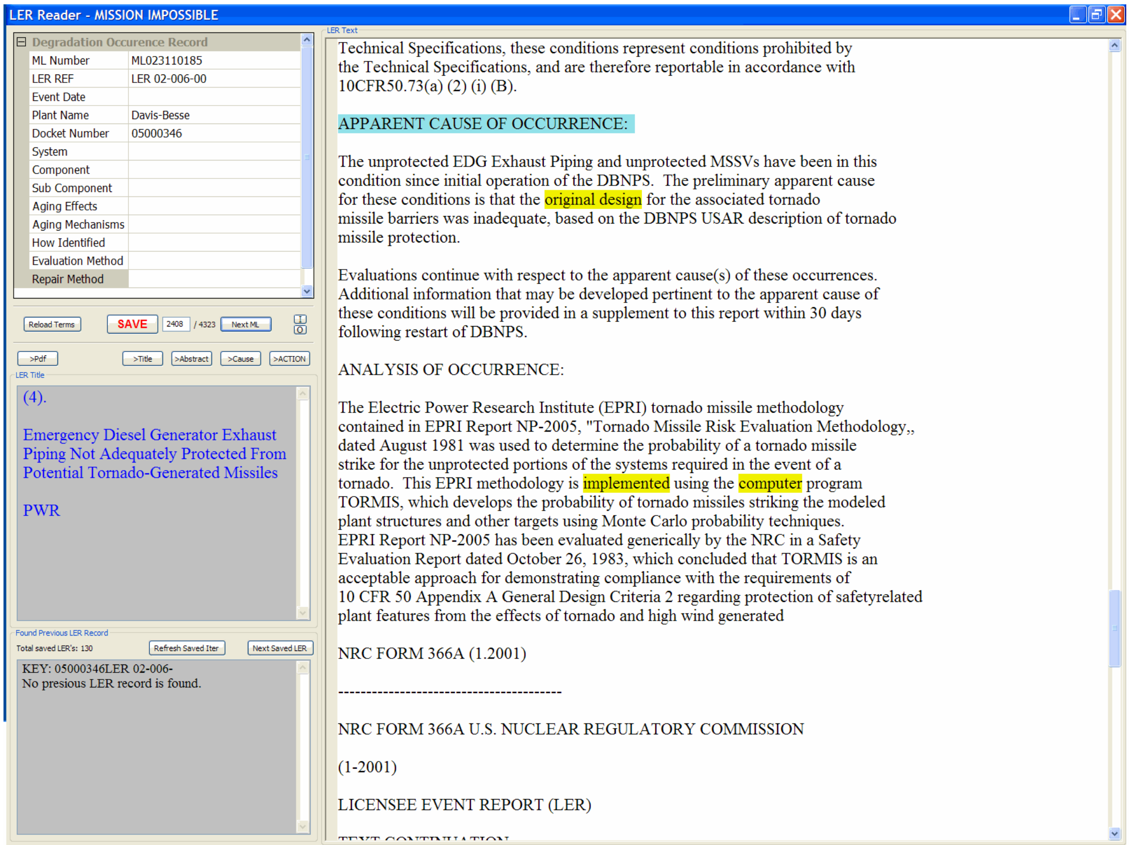

Figure 3-11 An LER Possibly Related to a Design Problem (Required Careful Review)

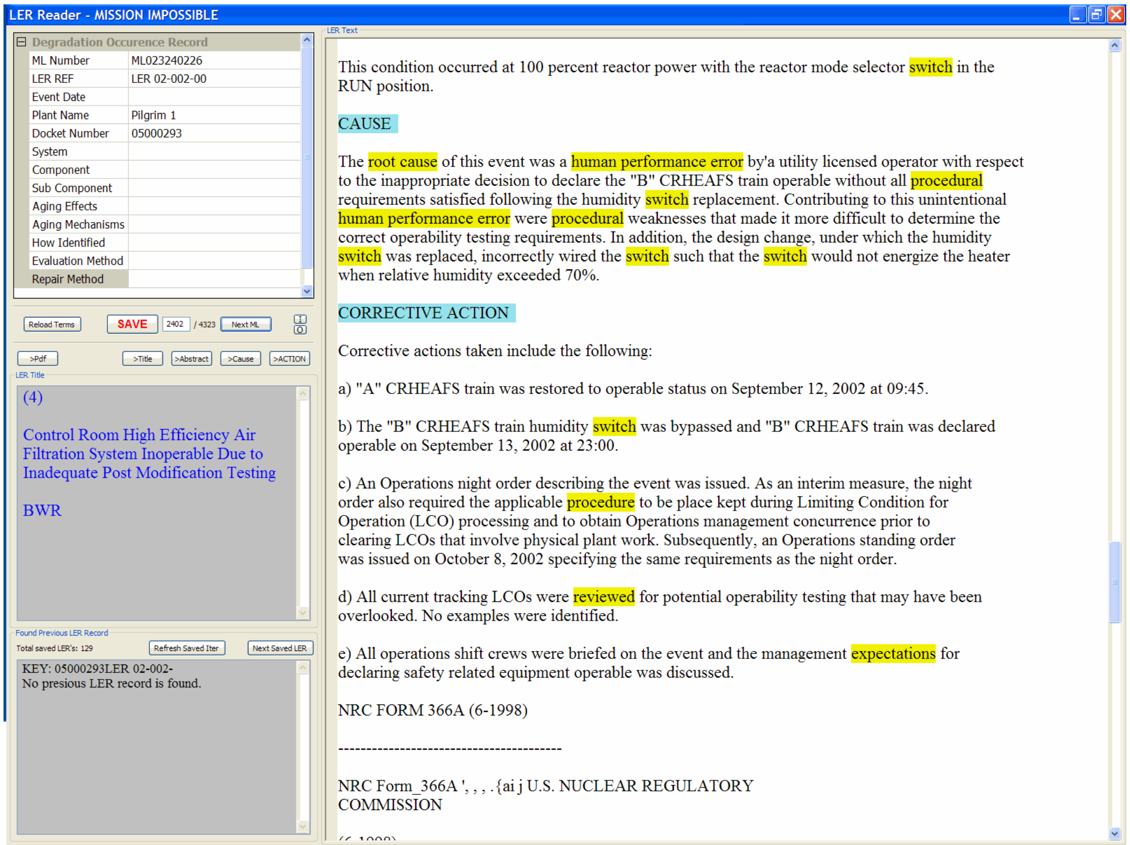

Figure 3-12 An LER Related to Human Error and Electric Parts

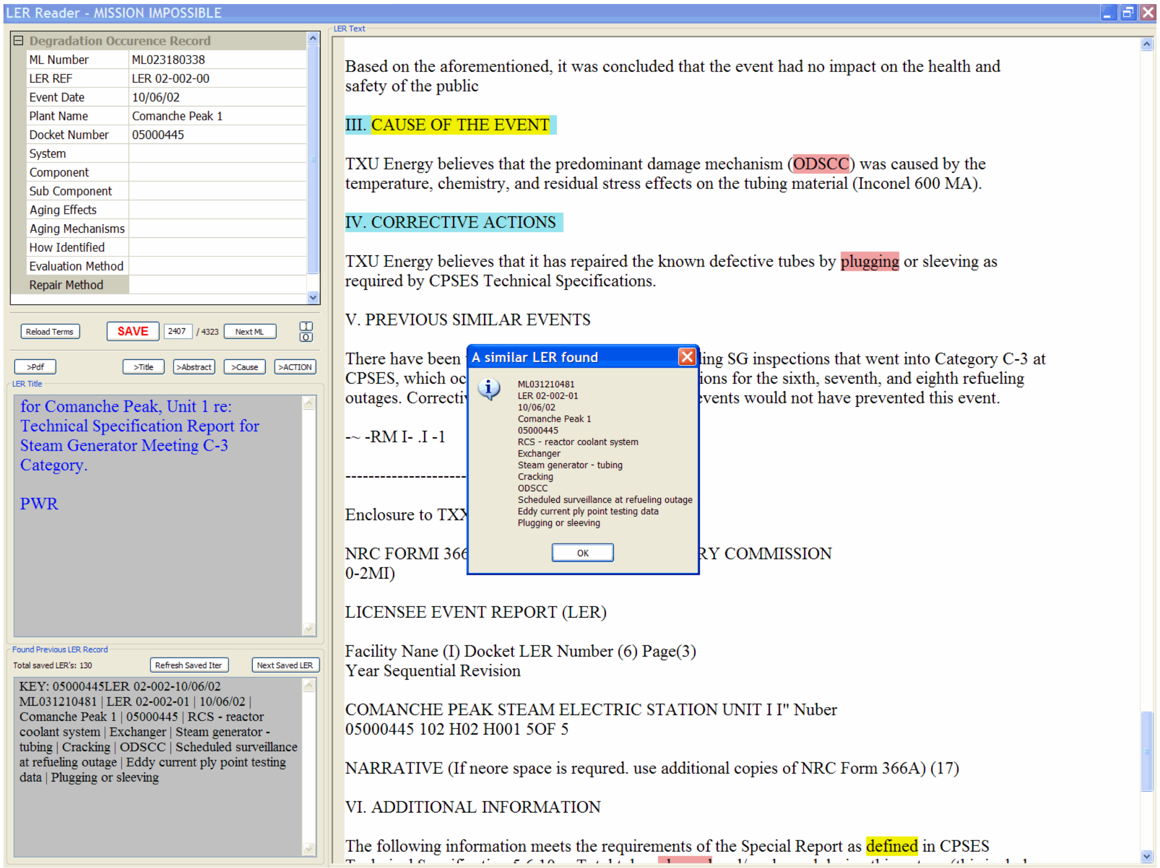

Figure 3-13 An LER with an Existing DOR

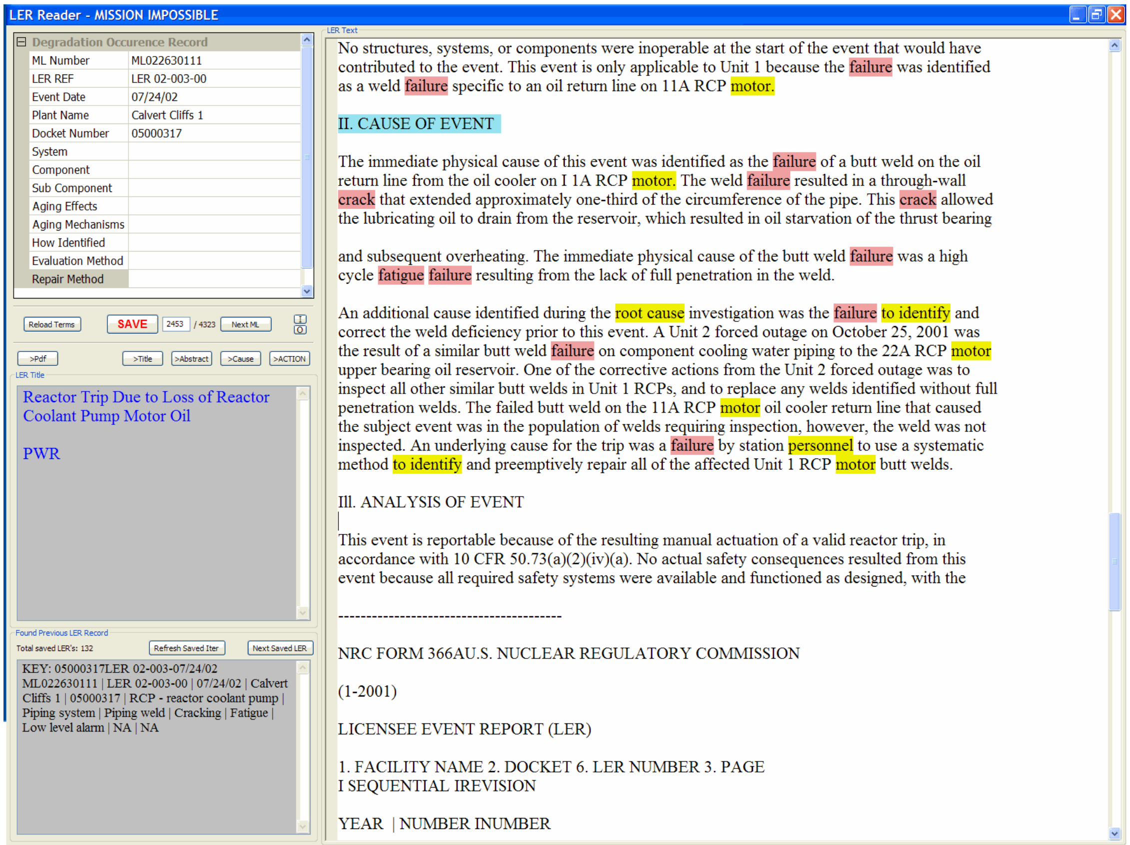

Figure 3-14 An LER with Two DORs

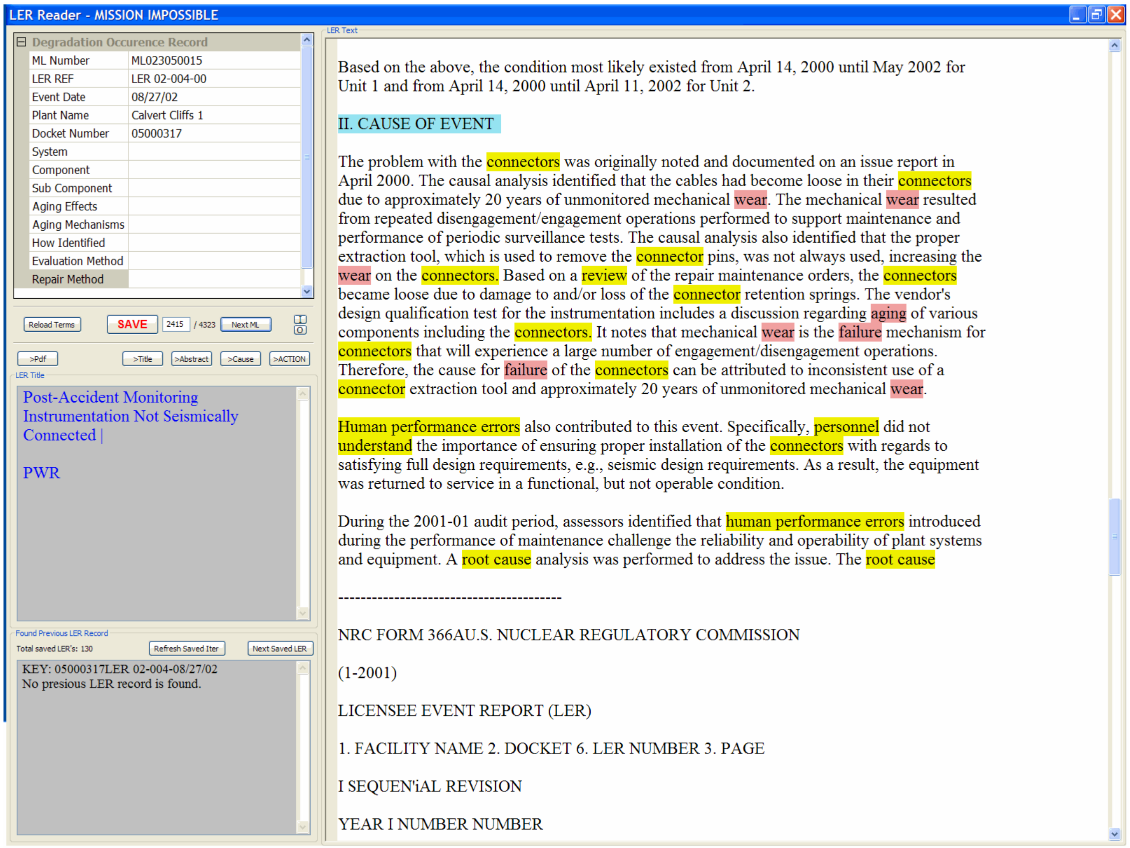

Figure 3-15 An LER Related to Human Error and Connectors

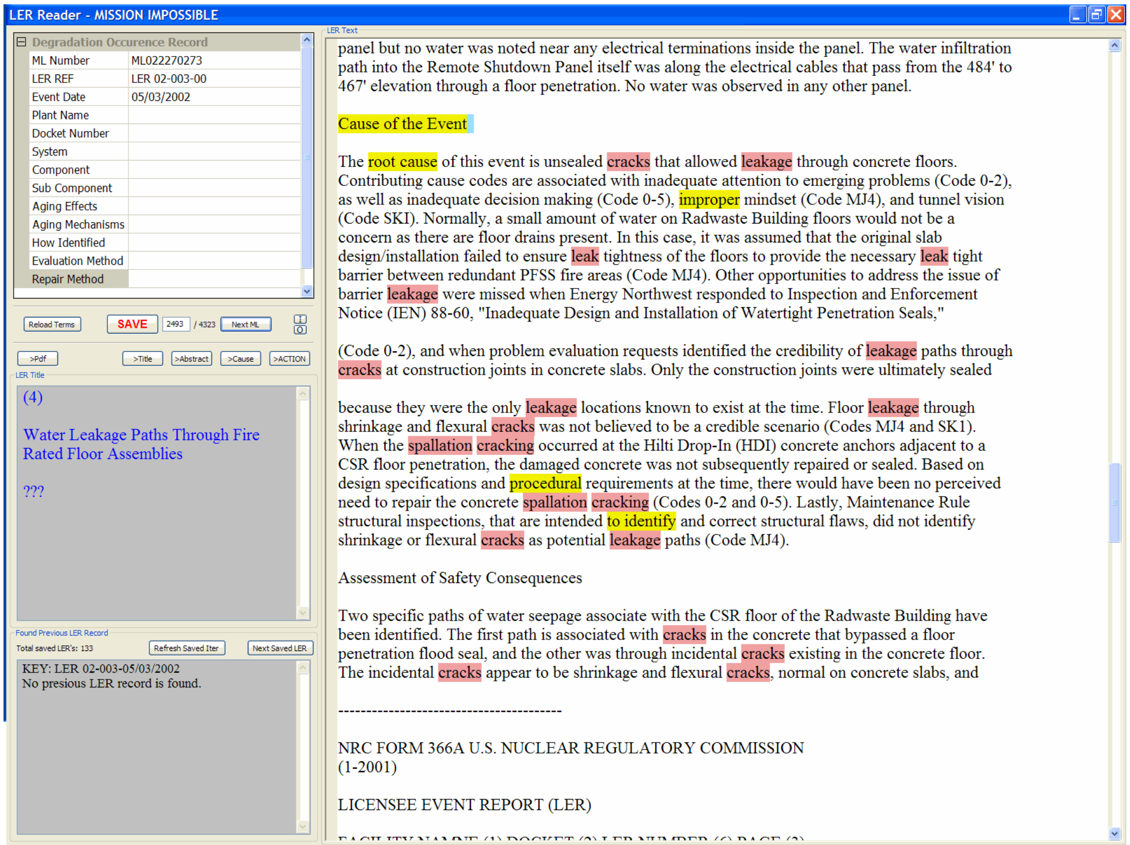

Figure 3-16 An LER Related to Concrete Degradation

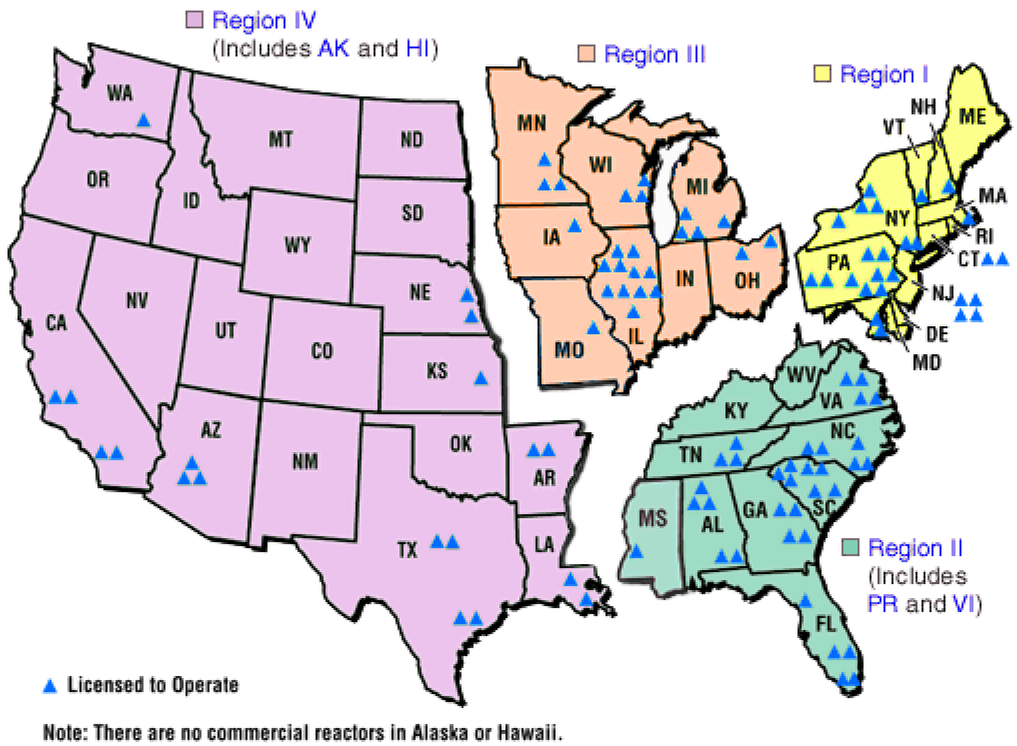

Figure 3-17 Distribution of 104 Operating US NPPs in Four NRC Regions [NRC Website]

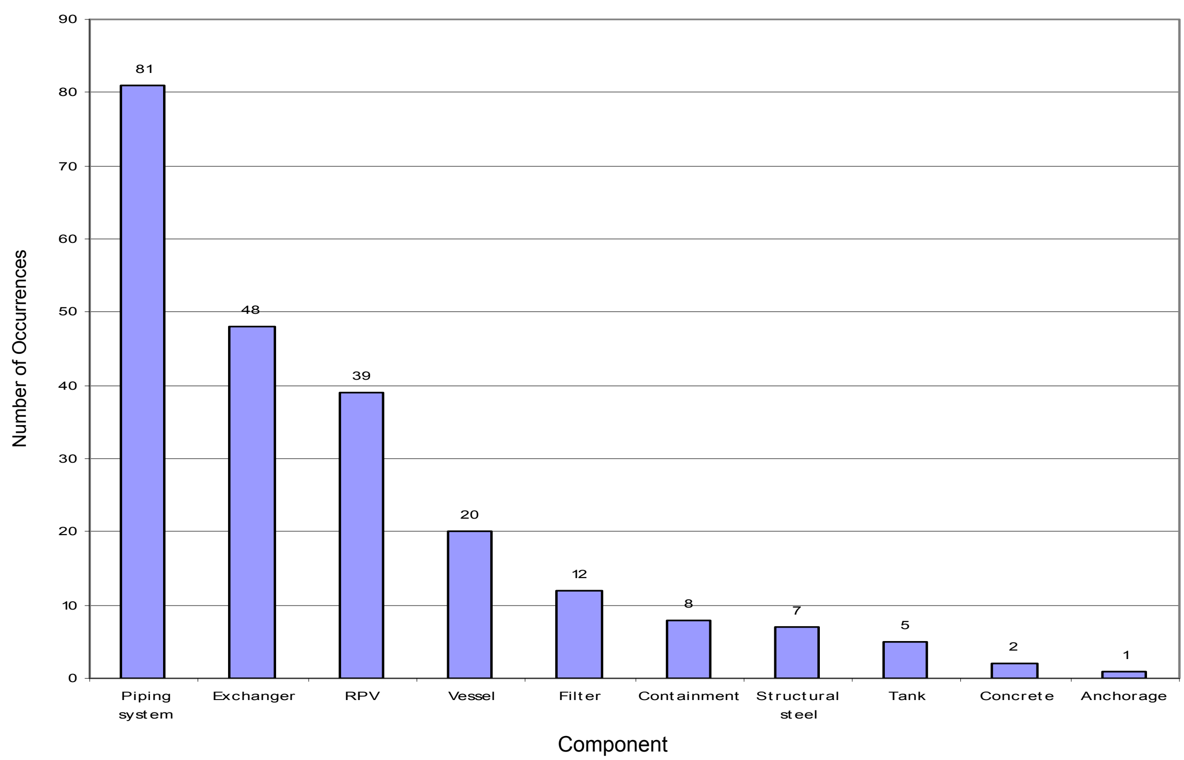

Figure 3-18 Distribution of SPC Degradation Occurrences over Component Category

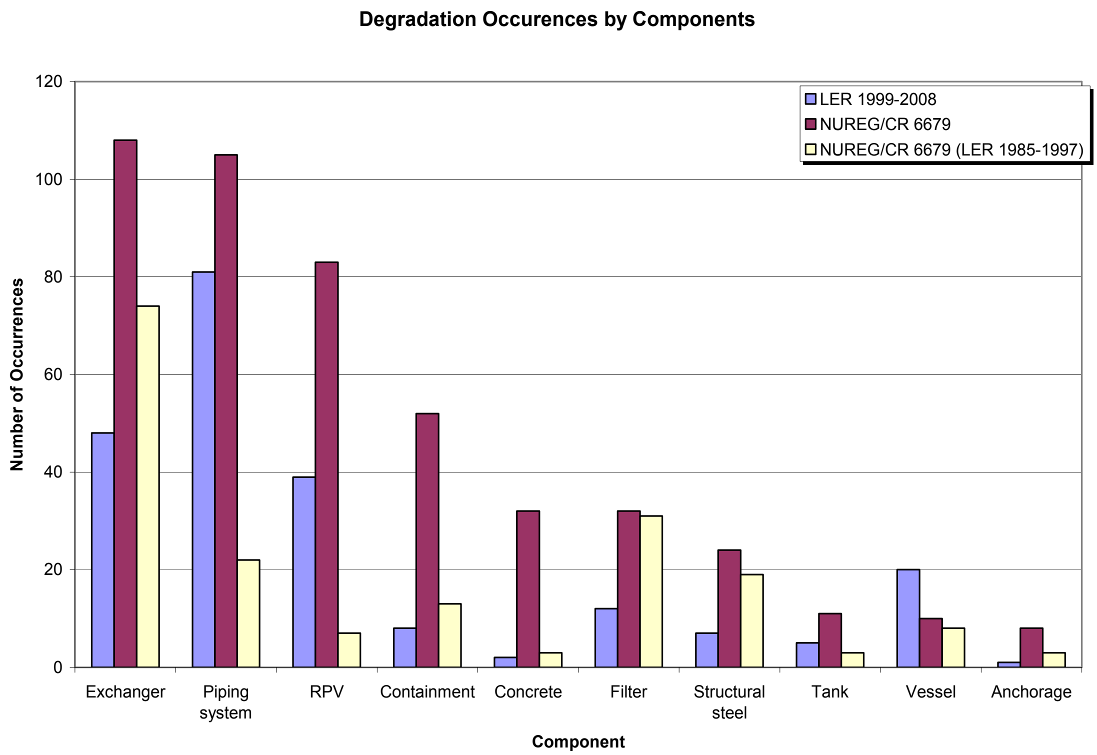

Figure 3-19 Distribution Comparison of SPC Degradation Occurrences over Component

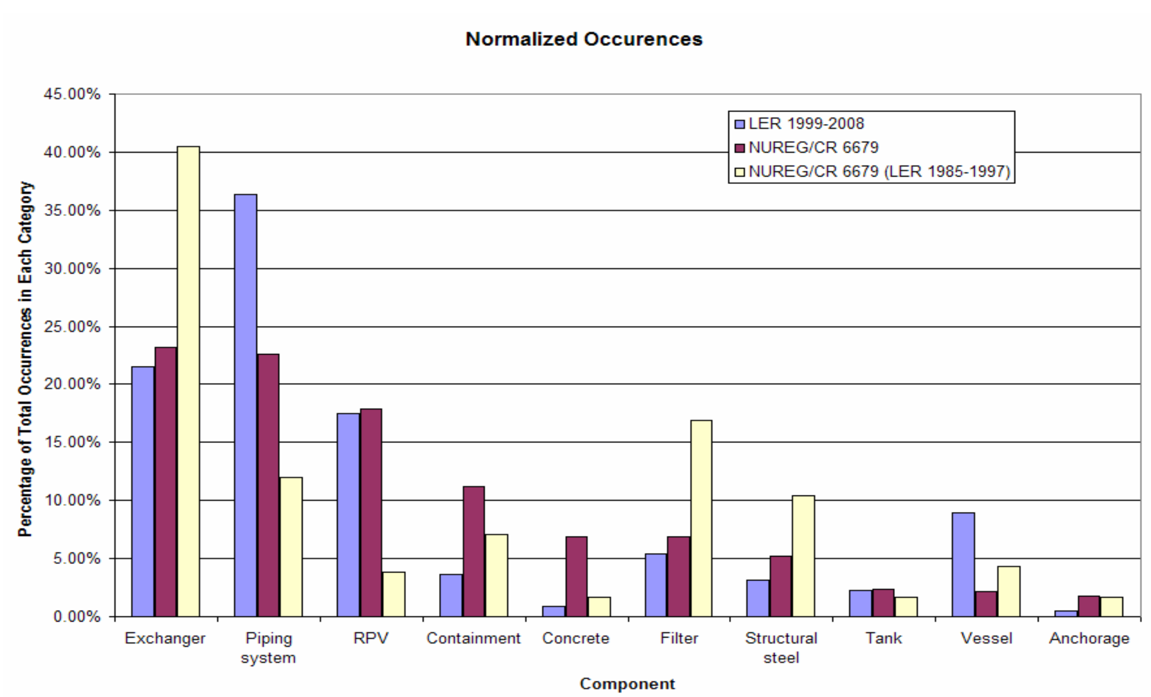

Figure 3-20 Comparison of Normalized Distribution of SPC Degradation Occurrences over Component

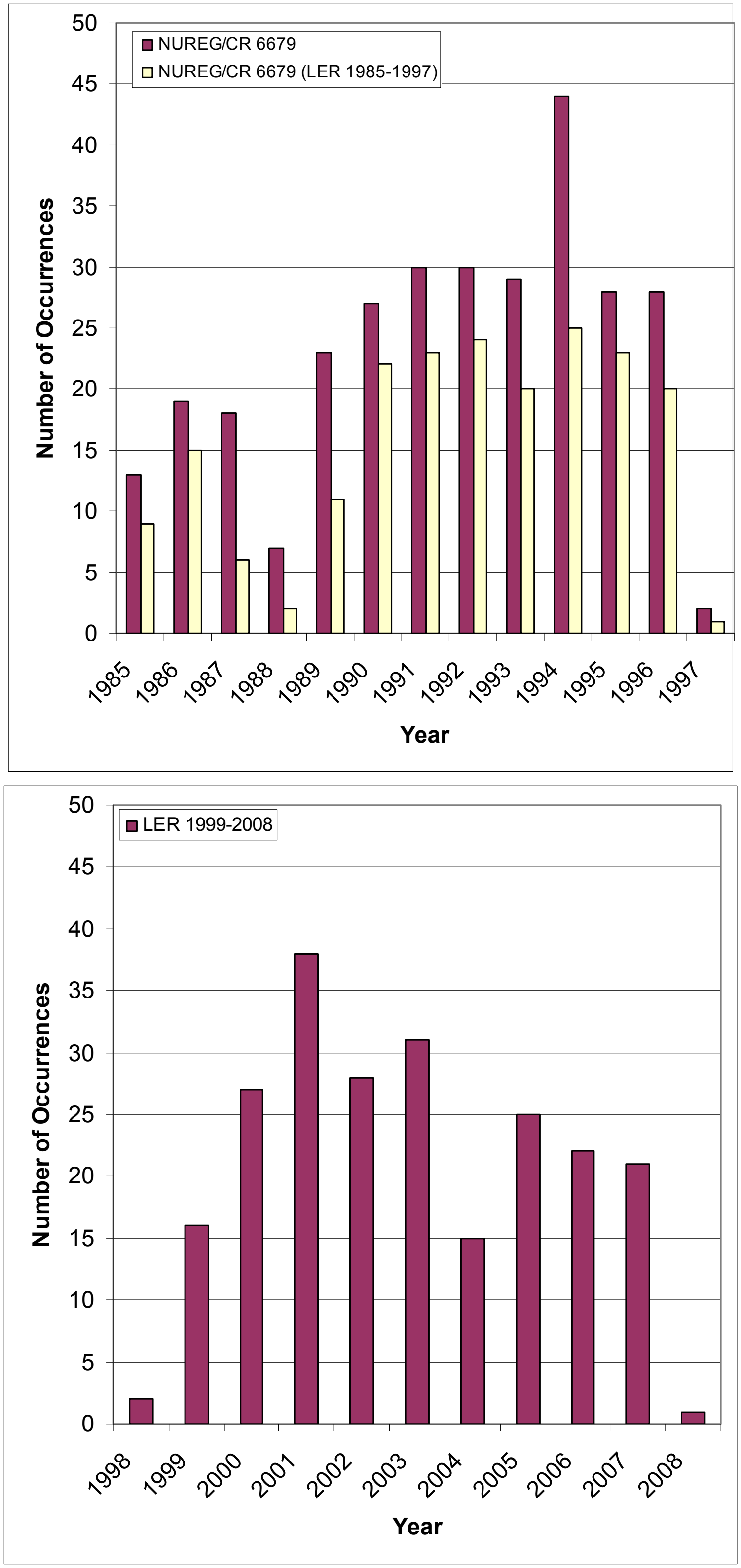

Figure 3-21 Distribution Comparison of SPC Degradation Occurrences over Time

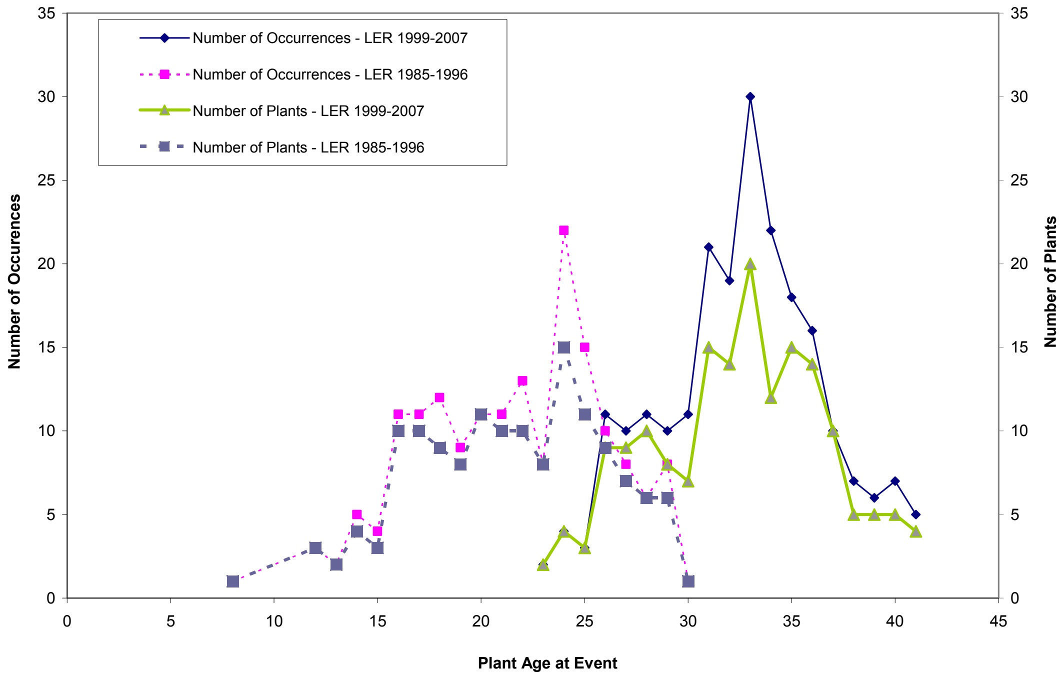

Figure 3-22 Number of Degradation Occurrences and NPP Units with Plant Age at Event

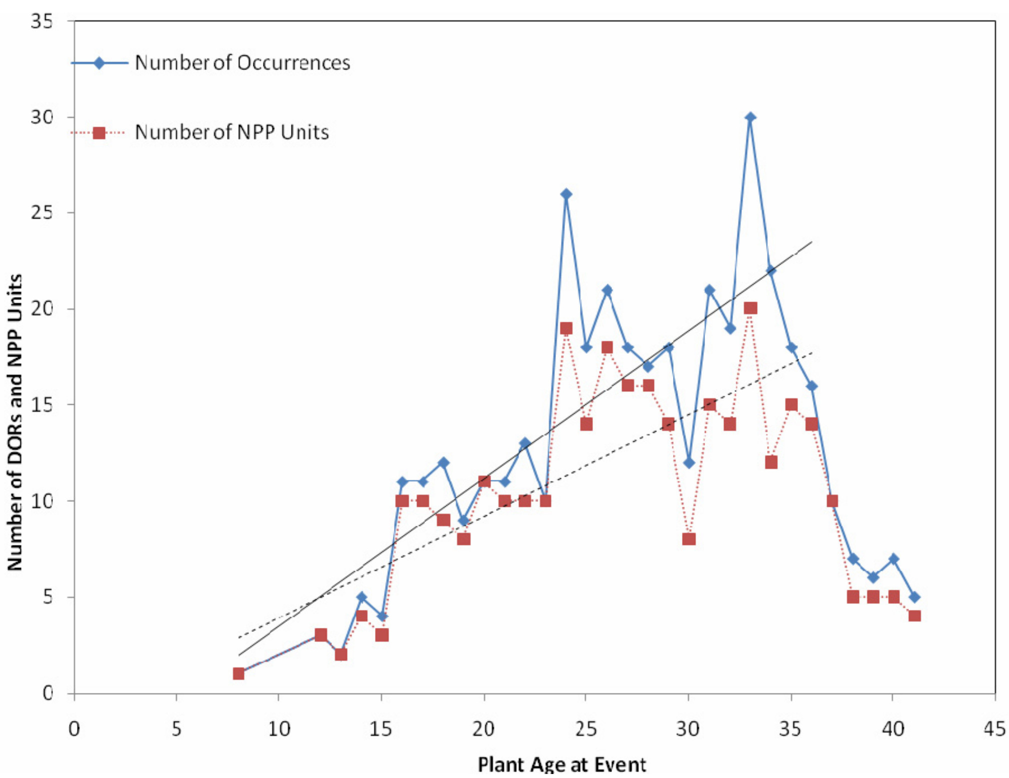

Figure 3-23 Number of Degradation Occurrences and NPP Units with PAAE for Combined Data Series

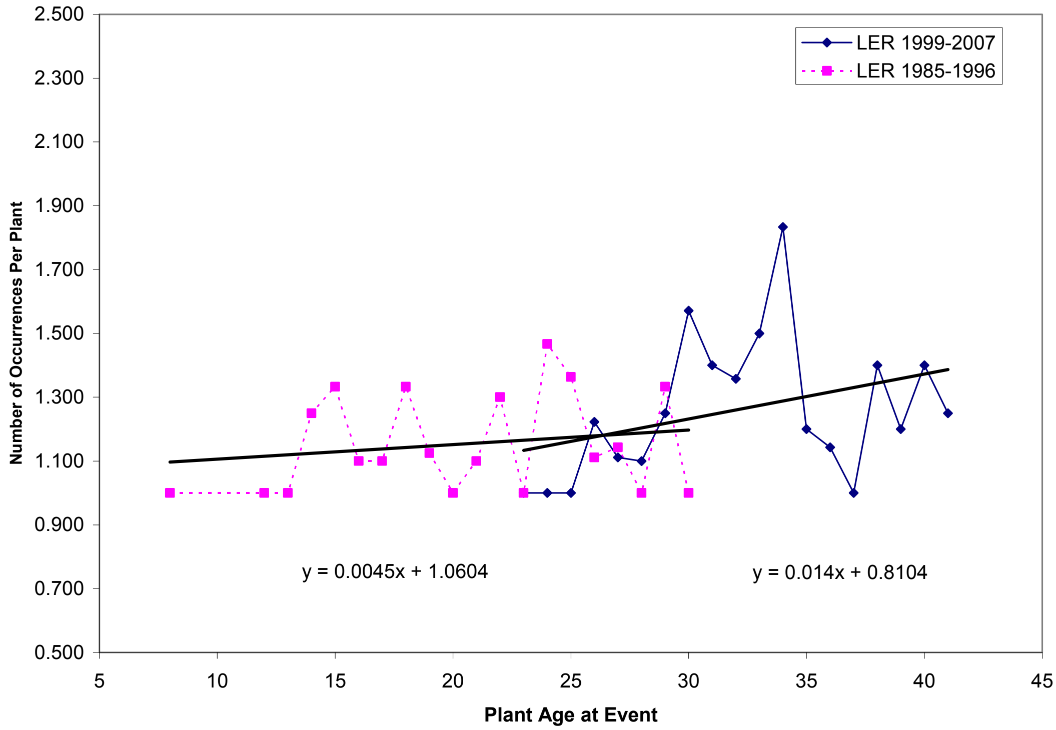

Figure 3-24 Average Degradation Occurrences with Plant Age at Event

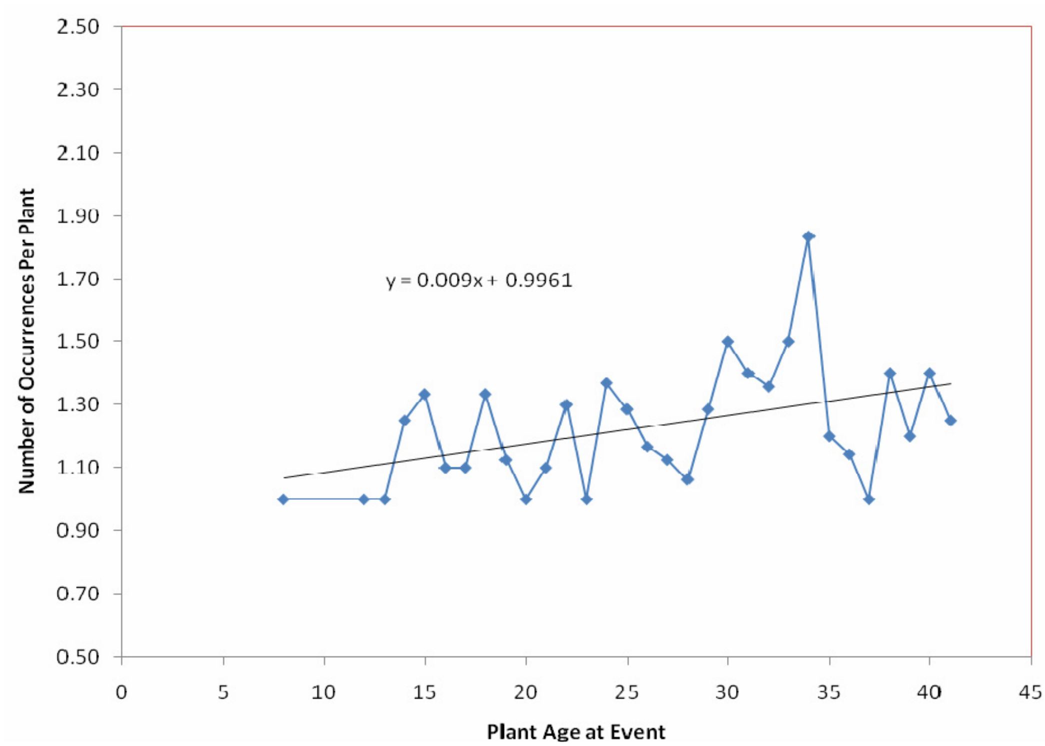

Figure 3-25 Relation of Average DORs per Plant versus PAAE with Combined Data Series

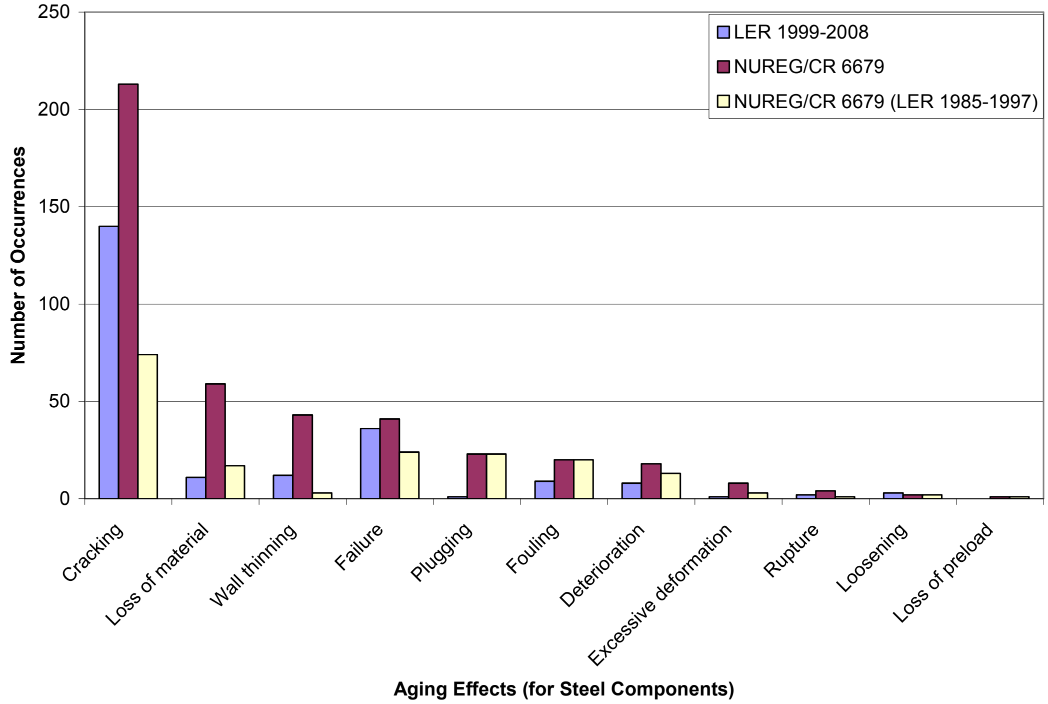

Figure 3-26 Distribution Comparison of SPC Degradation Occurrences over Aging Effect (for Steel Component)

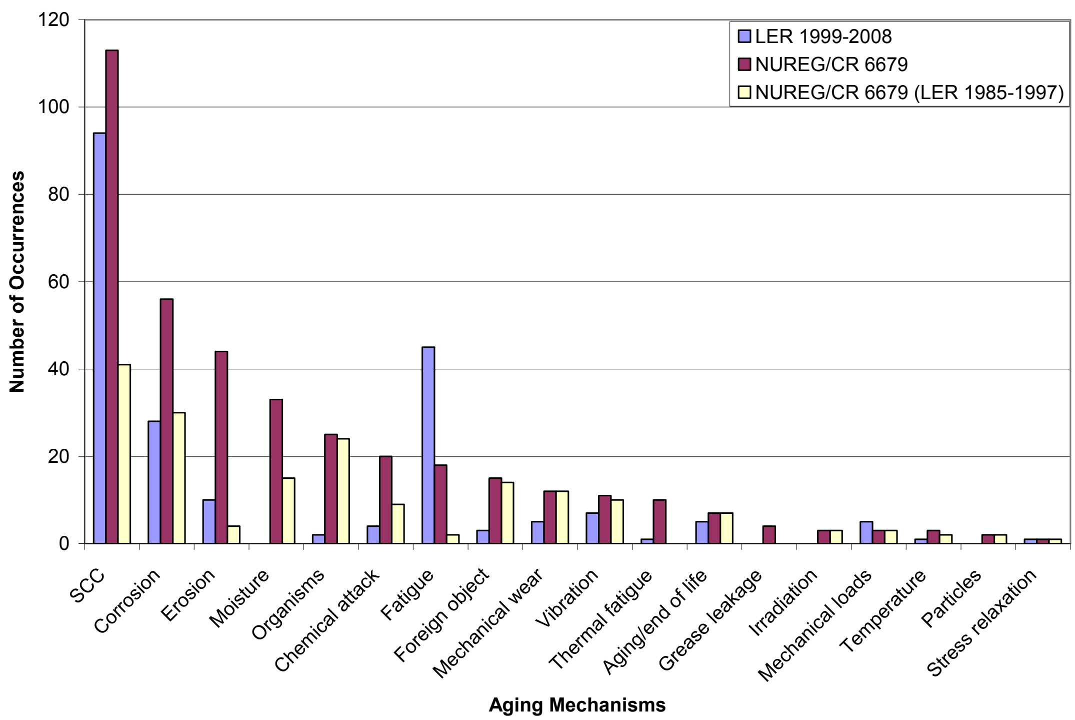

Figure 3-27 Distribution Comparison of SPC Degradation Occurrences over Aging Mechanism

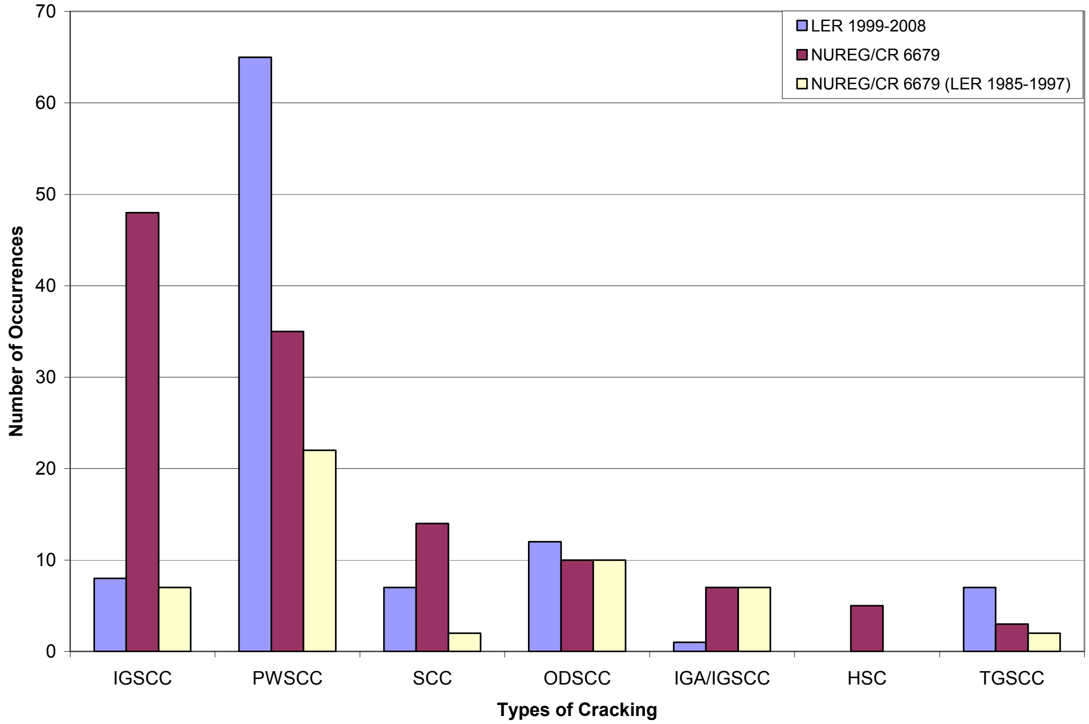

Figure 3-28 Distribution Comparison of SPC Degradation Occurrences over Cracking Type

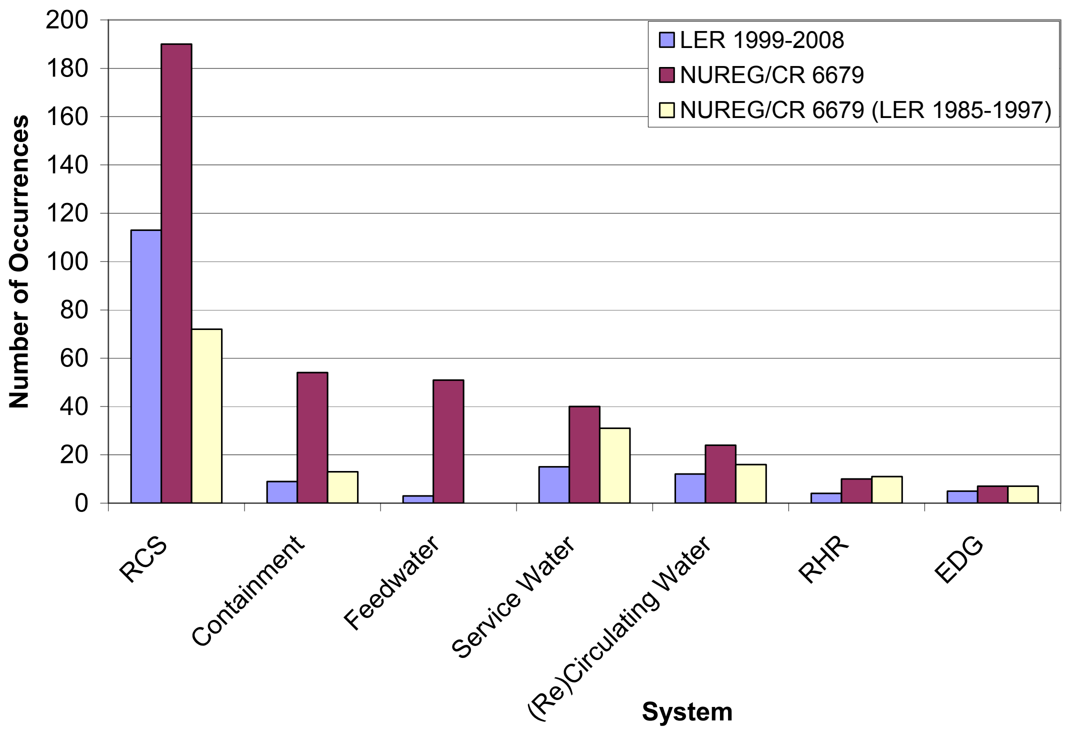

Figure 3-29 Distribution Comparison of SPC Degradation Occurrences over System

4 GENERIC COMMUNICATIONS AND LRAS

In addition to recent LERs, selected generic communications and license renewal applications (LRAs) were also reviewed to identify the characteristics of the age-related degradation of structures and passive components (SPC). Generic communications reviewed included Generic Letters (GL), Bulletins (BL), and Information Notices (IN) issued by the US NRC. Since these documents may not include all information needed for the degradation occurrence record (DOR) or may include duplicate DORs with respect to LERs, the findings are not incorporated into the same DOR tables described in Section 3 of this report. Therefore, the degradation information obtained from NRC generic communications is evaluated and described separately in this section of the report.

LRAs were also reviewed under this study because they provide useful information about aging degradation of SPCs. These applications are required to include information about aging by regulations (10 CFR 50.73) which cover the submittal of LRAs. These regulations specifically require applicants to describe their operating experience regarding age-related degradation for the various SPCs.

4.1 Generic Letters, Information Notices, and Bulletins

Generic communications are publicly available documents through the NRC web site. Generic communications are the NRC's primary method of communicating a common need or resolution approach to an issue or providing guidance on issues pertaining to a matter of regulatory interest. Generic communications also allow the NRC to communicate and share industry experiences and send information to specific classes of licensees and interested stakeholders. The type of generic communication issued is determined during NRC evaluations of the operating nuclear industry and regulatory activities. Once issued, a generic communication is placed in the Agencywide Documents Access and Management System (ADAMS) as an official NRC record. The generic communication is then electronically sent out to subscribers and posted to the NRC external Web site.

Three types of generic communications were reviewed in this study. They consist of Generic Letters (GLs), Bulletins (BLs), and Information Notices (INs). GLs are NRC communications to licensees for the purpose of transmitting important information and usually require action or response. BLs address significant issues of great urgency and usually require action or response. INs relate to safety, safeguards, or environmental issues on which licensees consider action as appropriate.

Similar to the review effort of LERs, the focus in this research study was on recent GLs, BLs, and INs, within the general time periods of 1997 through the first part of 2008. Since degradation occurrences did not occur or were not identified on the NRC web site for some of these years, the actual periods of degradation were 1997 to 2006 for GLs, 2001 to 2004 for BLs, and 1998 to 2007 for INs. All of the generic communications during these periods were reviewed to identify and document aging degradation for the ten categories of structures and passive components (SPCs) listed in Section 3.1. Document titles were instructive in determining which documents should be retrieved for more careful review. A total of 46 generic communication documents were reviewed, including 7 GLs, 6 BLs, and 33 INs.

The seven reviewed GLs are listed in the following using their index numbers and titles (in descending order of time):

1. 2006-01, “Steam generator tube integrity and associated technical specifications”

2. 2004-02, “Potential impact of debris blockage on emergency recirculation during design basis accidents at pressurized-water reactors”
3. 2004-01, “Requirements for steam generator tube inspection”
4. 98-04, “Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System After a Loss-of-Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment”
5. 97-06 (1997), “Degradation of Steam Generator Internals”
6. 97-05 (1997), “Steam Generator Tube Inspection Techniques”
7. 97-01 (1997), “Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations”

Similarly, the six reviewed BLs are listed below (in descending order of time):

1. 2004-01, “Inspection of Alloy 82/182/600 Materials Used in the Fabrication of Pressurizer Penetrations and Steam Space Piping Connections at Pressurized-Water Reactors”
2. 2003-02, “Leakage from Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity”
3. 2003-01, “Potential Impact of Debris Blockage on Emergency Sump Recirculation at Pressurized-Water Reactors”
4. 2002-02, “Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs”
5. 2002-01, “Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity”
6. 2001-01, “Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles”

The 33 reviewed INs are listed as well (in descending order of time):

1. 2007-37, “Buildup of Deposits in Steam Generator”
2. 2007-21, “Pipe Wear Due to Interaction of Flow-induced Vibration and Reflective Metal Insulation”
3. 2006-27, “Circumferential Cracking in the Stainless Steel Pressurizer Heater Sleeves of Pressurized Water Reactors”
4. 2006-17, “Recent Operating Experience of Service Water Systems Due to External Conditions”
5. 2006-08, “Secondary Piping Rupture at the Mihama Power Station in Japan”
6. 2006-01, “Torus Cracking in a BWR Mark I Containment”
7. 2004-21, “Additional Adverse Effect of Boric Acid Leakage: Potential Impact on Post-Accident Coolant pH”
8. 2004-11, “Cracking in Pressurizer Safety and Relief Nozzles and in Surge Line Nozzle”
9. 2004-09, “Corrosion of Steel Containment and Containment Liner”
10. 2004-08, “Reactor Coolant Pressure Boundary Leakage Attributable to Propagation of Cracking in Reactor Vessel Nozzle Welds”

11. 2004-05, “Spent Fuel Pool Leakage to Onsite Groundwater”
12. 2004-01, “Auxiliary Feedwater Pump Recirculation Line Orifice Fouling - Potential Common Cause Failure”
13. 2003-13, “Steam Generator Tube Degradation at Diablo Canyon”
14. 2003-11s1 and original 2003-11, “Leakage Found on Bottom-Mounted Instrumentation Nozzles”
15. 2003-08, “Potential Flooding Through Unsealed Concrete Floor Cracks”
16. 2003-05, “Failure to Detect Freespan Cracks in PWR Steam Generator Tubes”
17. 2003-02, “Recent Experience With Reactor Coolant System Leakage And Boric Acid Corrosion”
18. 2002-26 s1, s2, and original 2002-26, “Additional Flow-Induced Vibration Failures after a Recent Power Uprate”
19. 2002-02 s1, “Recent Experience With Plugged Steam Generator Tubes”
20. 2002-21 s1 and original 2002-21, “Axial Outside-Diameter Cracking Affecting Thermally Treated Alloy 600 Steam Generator Tubing”
21. 2002-13, “Possible Indicators of Ongoing Reactor Pressure Vessel Head Degradation”
22. 2002-11, “Recent Experience with Degradation of Reactor Pressure Vessel Head”
23. 2002-02, “Recent Experience with Plugged Steam Generator Tubes”
24. 2001-16, “Recent Foreign and Domestic Experience with Degradation of Steam Generator Tubes and Internals”
25. 2001-09, “Main Feedwater System Degradation in Safety-Related ASME Code Class 2 Piping Inside the Containment of a Pressurized Water Reactor”
26. 2001-05, “Through-Wall Circumferential Cracking of Reactor Pressure Vessel Head Control Rod Drive Mechanism Penetration Nozzles at Oconee Nuclear Station, Unit 3”
27. 2000-17 s1, s2, and original 2000-17, “Crack in Weld Area of Reactor Coolant System Hot Leg Piping at V. C. Summer”
28. 2000-09, “Steam Generator Tube Failure at Indian Point Unit 2”
29. 1999-10, Rev. 1 and 1999-10, “Degradation of Prestressing Tendon Systems in Prestressed Concrete Containments”
30. 1998-45, “Cavitation Erosion of Letdown Line Orifices Resulting in Fatigue Cracking of Pipe Welds”
31. 1998-27, “Steam Generator Tube End Cracking”
32. 1998-26, “Settlement Monitoring and Inspection of Plant Structures Affected by Degradation of Porous Concrete Subfoundations”
33. 1998-11, “Cracking of Reactor Vessel Internal Baffle Former Bolts in Foreign Plants”

A summary for each of these documents is presented in Table 4-1, which includes additional information under the heading “Topic” and “SPC Affected.” Table 4-2 summarizes for each type of generic communication the number of generic communications that address a particular component / subcomponent, and Table 4-3 aggregates the results in Table 4-2 by removing the types of generic communications. It should be noted that the number of generic communications addressing a component is different from the number of degradation occurrences because one generic correspondence may refer to multiple events with regard to one component. As can be seen from Table 4-3, steam generators (exchangers), RPVs, and Piping systems are the top three components with the greatest number of generic correspondences, which are about 28%, 28%, and 15% of the total 46 documents. Although these numbers do not equal to what have been found using LERs as described in Section 3, for reasons as stated above, they constitute a total of 71%, which is very similar to 75% found in Section 3. There are 6 generic correspondences on structural type components (containment, concrete, spent fuel pool), which is about 13% of the total number of reviewed generic correspondences. This ratio is just slightly higher than the 8% as determined in Section 3, indicating that generic communications addressed more structural type components.

In summary, the results of the review of generic letters generally confirm what has been found or explained in Section 3 for LER evaluations.

4.2 License Renewal Applications

The Atomic Energy Act and NRC regulations limit commercial power reactor licenses to an initial 40 years but also permit such licenses to be renewed. This original 40-year term for reactor licenses was based on economic and antitrust considerations - not on limitations of nuclear technology. Due to this selected period, however, some structures and components may have been engineered on the basis of an expected 40-year service life. Since the expense of design and construction of NPPs has been so great, it is generally much more cost effective to extend the operating life of a NPP beyond the 40-year license given to plants. Therefore, the NRC has established a timely license renewal process and clear requirements for renewing the operating license of NPPs. These requirements are codified in 10 CFR Part 54, "Requirements for Renewal of Operating Licenses For Nuclear Power Plants" and 10 CFR Part 51, "Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions." These requirements assure safe plant operation for the extended plant life. Renewal of license, when approved is granted for an additional 20 years.

Documents related to LRA are useful because they identify applicable aging effects and operating experience which would describe aging degradation of structures and components at the plants. At the NRC website, there were 24 completed (reviewed and approved) applications for license renewal. These are presented below.

- Calvert Cliffs, Units 1 and 2
- Oconee Nuclear Station, Units 1, 2 and 3
- Arkansas Nuclear One, Unit 1
- Edwin I. Hatch Nuclear Plant, Units 1 and 2
- Turkey Point Nuclear Plant, Units 3 and 4
- North Anna, Units 1 and 2, and Surry, Units 1 and 2
- Peach Bottom, Units 2 and 3
- St. Lucie, Units 1 and 2
- Fort Calhoun Station, Unit 1
- McGuire, Units 1 and 2, and Catawba, Units 1 and 2
- H.B. Robinson Nuclear Plant, Unit 2
- R.E. Ginna Nuclear Power Plant, Unit 1
- V.C. Summer Nuclear Station, Unit 1
- Dresden, Units 2 and 3, and Quad Cities, Units 1 and 2
- Farley, Units 1 and 2
- Arkansas Nuclear One, Unit 2
- D.C. Cook, Units 1 and 2
- Millstone, Units 2 and 3
- Point Beach, Units 1 and 2 (BWR)
- Browns Ferry, Units 1, 2, and 3
- Brunswick, Units 1 and 2

- Nine Mile Point, Units 1 and 2
- Monticello
- Palisades (PWR)

There are also 12 LRAs under review at the time that this study was performed and these are listed below.

- Oyster Creek - Application received July 22, 2005
- Pilgrim 1 - Application received January 27, 2006
- Vermont Yankee - Application received January 27, 2006
- James A. FitzPatrick - Application received August 1, 2006
- Susquehanna - Application received September 15, 2006
- Wolf Creek - Application received October 4, 2006
- Harris - Application received November 16, 2006
- Indian Point - Application received April 30, 2007
- Vogtle - Application received June 29, 2007
- Beaver Valley - Application received August 28, 2007
- Three Mile Island, Unit 1 - Application received January 8, 2008
- Prairie Island - Application received April 15, 2008

Since each LRA is quite large and the total number of LRAs are too numerous to review in the current study, two LRAs were selected for review in this study. The criteria used for selection of the two LRAs are as follows:

- One of each PWR & BWR
- Recent LRA - more likely to reflect knowledge gained from prior LRA submittals & comments from NRC
- More complete information on Operating Experience
- More detailed

Using these criteria, the two LRAs selected are Palisades (PWR) and Point Beach Units 1 & 2 (BWR). The content of LRAs is listed below, with a partial aging management program list shown under the heading Appendix. As indicated earlier, this information is specifically required by 10 CFR Part 54. More information about LRAs and the content of the application is given in Section 2.1 of this report.

- Administrative Information
- Scoping and Screening Methodology for Identifying Structures and Components Subject to Aging Management Review, and Implementation Results
- Aging Management Review Results
- Time-Limited Aging Analyses
- Appendix – Aging Management Programs
  - Alloy 600 Inspection Program
  - ASME Section XI, Subsections IWB, IWC, IWD, IWF Inservice Inspection Program
  - Bolting Integrity Program
  - Boric Acid Corrosion Program
  - Buried Services Corrosion Monitoring Program
  - Closed Cycle Cooling Water Program
  - Containment Inservice Inspection Program
  - Containment Leakage Testing Program
  - Others

For each Aging Management Program (AMP) included in an LRA, there is an "Operating Experience" discussion that is very informative for aging-related degradation review. However, the information presented in these operating experience discussions is not as detailed as in the LERs.

Table 4-4 and Table 4-5 present a detailed review of these two LRAs, which include summaries of the AMP and operating experiences. The operating experience for each AMP discusses industry-wide observations and plant specific issues. The information presented in Tables 4-4 and 4-5 are summaries of the actual publicly available LRAs presented on the NRC web site. These summaries are excerpts of the AMPs and operating experience obtained from the LRAs and are shortened/edited to convey the important elements needed for this study. As the information is not considered complete enough for a direct comparison to the results using LERs, information in these two tables are used qualitatively. As can be seen in the tables, degradation in components related to piping systems, RPVs, and exchangers occur more often than the other components being studied. This observation is consistent with the results from the review of LERs because the industry and plant-specific operating experience on aging in the LRAs was most likely already in the LERs that the plant(s) submitted in the past. However, the LRAs would have identified additional cases of degradation if they would have occurred.

Table 4-1 NRC Generic Communications for Information Related to Aging Degradation

[Available on the NRC Web Site]

Type	No.	Title	Topic	SPC Affected
Generic Letter (GL)	2006-01	Steam Generator Tube Integrity and Associated Technical Specifications	The U.S. Nuclear Regulatory Commission (NRC) is concerned that current TS requirements may not be sufficient to ensure that steam generator (SG) tube integrity can be maintained in accordance with current licensing and design basis. The NRC is, therefore, issuing this GL to request that addressees either submit a description of their program for ensuring SG tube integrity for the interval between inspections or adopt alternative TS requirements for ensuring SG tube integrity. Alternative TS requirements that address the staff's concerns with the existing TS were developed by the industry and found acceptable by the staff. Related Generic Communications • NRC Information Notice 2005-09, "Indications in Thermally Treated Alloy 600 Steam Generator Tubes and Tube-to-Tubesheet Welds," April 7, 2005 (ML050530400). • NRC Information Notice 2004-17, "Loose Part Detection and Computerized Eddy Current Data Analysis in Steam Generators," August 25, 2004 (ML042180094). • NRC Information Notice 2004-16, "Tube Leakage due to a Fabrication Flaw in a Replacement Steam Generator," August 3, 2004 (ML041460357). • NRC Information Notice 2004-10, "Loose Parts in Steam Generators," May 4, 2004 (ML041170480). • NRC Generic Letter 2004-01, "Requirements for Steam Generator Tube Inspections,"August 30, 2004 (ML042370766).	Steam generators
GL	2004-02	Potential Impact of Debris Blockage on Emergency Recirculation during Design Basis Accidents	The U.S. Nuclear Regulatory Commission (NRC) is issuing this generic letter to: (1) Request that addressees perform an evaluation of the emergency core cooling system (ECCS) and containment spray system (CSS) recirculation functions in light of the information provided in this letter and, if appropriate, take additional actions to ensure system function. Additionally, addressees are requested to submit the information specified in this letter to the NRC. This request is based on the identified potential susceptibility of pressurized-water reactor (PWR) recirculation sump screens to debris blockage during design basis accidents requiring recirculation operation of ECCS or CSS and on the potential for additional adverse effects due to debris blockage of flowpaths necessary for ECCS and CSS recirculation and containment drainage. (2) Require addressees to provide the NRC a written response in accordance with 10 CFR 50.54(f).	Strainers

Type	No.	Title	Topic	SPC Affected
		at Pressurized -Water Reactors	<u>Discussion</u> Following the resolution of USI A-43 in 1985, several events challenged the conclusion that no new requirements were necessary to prevent the clogging of ECCS strainers at operating BWRs: - On July 28, 1992, at Barseback Unit 2, a Swedish BWR, the spurious opening of a pilot-operated relief valve led to the plugging of two containment vessel spray system suction strainers with mineral wool and required operators to shut down the spray pumps and backflush the strainers. - In 1993, at Perry Unit 1, two events occurred during which ECCS strainers became plugged with debris. On January 16, ECCS strainers were plugged with suppression pool particulate matter, and on April 14, an ECCS strainer was plugged with glass fiber from ventilation filters that had fallen into the suppression pool. On both occasions, the affected ECCS strainers were deformed by excessive differential pressure created by the debris plugging. - On September 11, 1995, at Limerick Unit 1, following a manual scram due to a stuck-open safety/relief valve, operators observed fluctuating flow and pump motor current on the A loop of suppression pool cooling. The licensee later attributed these indications to a thin mat of fiber and sludge which had accumulated on the suction strainer. <u>Related Generic Communications</u> • Bulletin 2003-01, "Potential Impact of Debris Blockage on Emergency Recirculation During Design-Basis Accidents at Pressurized-Water Reactors," June 9, 2003. • Bulletin 96-03, "Potential Plugging of Emergency Core Cooling Suction Strainers by Debris in Boiling-Water Reactors," May 6, 1996. • Bulletin 95-02, "Unexpected Clogging of a Residual Heat Removal (RHR) Pump Strainer While Operating in the Suppression Pool Cooling Mode,"October 17, 1995. • Bulletin 93-02, "Debris Plugging of Emergency Core Cooling Suction Strainers," May 11, 1993. • Bulletin 93-02, Supplement 1, "Debris Plugging of Emergency Core Cooling Suction Strainers," February 18, 1994. • Generic Letter 98-04, "Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System After a Loss-of-Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment,"July 14, 1998. • Generic Letter 97-04, "Assurance of Sufficient Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal Pumps," October 7, 1997. • Generic Letter 85-22, "Potential For Loss of Post-LOCA Recirculation Capability Due to Insulation Debris Blockage," December 3, 1985. • Generic Letter 91-18, Rev. 1, "Information to Licensees Regarding NRC Inspection Manual Section	

Type	No.	Title	Topic	SPC Affected
			on Resolution of Degraded and Nonconforming Conditions," October 8, 1997. • Information Notice 97-13, "Deficient Conditions Associated With Protective Coatings at Nuclear Power Plants," March 24, 1997. • Information Notice 96-59, "Potential Degradation of Post Loss-of-Coolant Recirculation Capability as a Result of Debris," October 30, 1996. • Information Notice 96-55, "Inadequate Net Positive Suction Head of Emergency Core Cooling and Containment Heat Removal Pumps Under Design Basis Accident Conditions," October 22, 1996. • Information Notice 96-27, "Potential Clogging of High Pressure Safety Injection Throttle Valves During Recirculation," May 1, 1996. • Information Notice 96-10, "Potential Blockage by Debris of Safety System Piping Which Is Not Used During Normal Operation or Tested During Surveillances," February 13,1996. • Information Notice 95-47, "Unexpected Opening of a Safety/Relief Valve and Complications Involving Suppression Pool Cooling Strainer Blockage," October 4, 1995. • Information Notice 95-47, Revision 1, "Unexpected Opening of a Safety/Relief Valve and Complications Involving Suppression Pool Cooling Strainer Blockage," November 30,1995. • Information Notice 95-06, "Potential Blockage of Safety-Related Strainers by Material Brought Inside Containment," January 25, 1995. • Information Notice 94-57, "Debris in Containment and the Residual Heat Removal System," August 12, 1994. • Information Notice 93-34, "Potential for Loss of Emergency Cooling Function Due to a Combination of Operational and Post-LOCA Debris in Containment," April 26, 1993. • Information Notice 93-34, Supplement 1, "Potential for Loss of Emergency Cooling Function Due to a Combination of Operational and Post-LOCA Debris in Containment,"May 6, 1993. • Information Notice 92-85, "Potential Failures of Emergency Core Cooling Systems Caused by Foreign Material Blockage," December 23, 1992. • Information Notice 92-71, "Partial Plugging of Suppression Pool Strainers at a Foreign BWR," September 30, 1992. • Information Notice 89-79, "Degraded Coatings and Corrosion of Steel Containment Vessels," December 1, 1989. • Information Notice 89-79, Supplement 1, "Degraded Coatings and Corrosion of Steel Containment Vessels," June 29, 1990. • Information Notice 89-77, "Debris in Containment Emergency Sumps and Incorrect Screen Configurations," November 21, 1989. • Information Notice 88-28, "Potential for Loss of Post-LOCA Recirculation Capability Due to	

Type	No.	Title	Topic	SPC Affected
			Insulation Debris Blockage," May 19, 1988.	
GL	2004-01	Requirements for Steam Generator Tube Inspec	The U.S. Nuclear Regulatory Commission (NRC) is issuing this generic letter to (1) advise addressees that the NRC's interpretation of the technical specification (TS) requirements in conjunction with 10 CFR Part 50, Appendix B, raises questions as to whether certain licensee steam generator (SG) tube inspection practices ensure compliance with these requirements, (2) request that addressees submit a description of the tube inspections performed at their plants, including an assessment of whether these inspections ensure compliance with the TS requirements in conjunction with 10 CFR Part 50, Appendix B, (3) request that addressees who conclude they are not in compliance with the SG tube inspection requirements contained in their TS in conjunction with 10 CFR Part 50, Appendix B, propose plans for coming into compliance with these requirements, and (4) request addressees to submit a tube structural and leakage integrity safety assessment that addresses any differences between their practices and the NRC's position regarding the requirements of the TS in conjunction with 10 CFR Part 50, Appendix B. A safety assessment should be submitted for all areas of the tube required to be inspected by the TS where flaws have the potential to exist and inspection techniques capable of detecting these flaws are not being used. This assessment should include an evaluation of whether the inspection practices rely on an acceptance standard different from the TS acceptance standards and whether the technical basis for these inspection practices constitutes a change to the "method of evaluation" (as defined in 10 CFR 50.59) for establishing the structural and leakage integrity of the tube-to-tubesheet joint. <u>Background:</u> In 2002, the staff learned that several licensees were not fully implementing inspection methods capable of detecting circumferentially oriented cracks at all locations where the potential for such cracks exists and where, based on available evidence, there is reason to believe such cracks may be present. These licensees were performing full-length bobbin probe inspections of the tubes and were performing additional inspections using specialized probes to inspect for axial and circumferential cracks at certain locations, including the tube expansion transitions near the top of the tubesheet. The licensees conducted the specialized probe inspections at the tube expansion transitions in an area that extended from 2 inches above the top of the tubesheet to about 5 inches below the top of the tubesheet. <u>At several facilities, circumferential cracks were identified (specific plants not identified in GL)</u> at tube expansion transitions, as well as below the transitions near the bottom of the zone being inspected. These results indicate a potential for circumferential cracks to exist in the tubing below the zone inspected with the specialized probe. However, each licensee also performed an analysis indicating that circumferential cracks below the zone being inspected with the specialized probe would not be detrimental to tube structural and leakage integrity. These licensees concluded,	Steam Generators

Type	No.	Title	Topic	SPC Affected
			therefore, that additional inspections for circumferential cracks with the specialized probe were unnecessary. These analyses had not been provided to the NRC staff.	
GL	98-04	Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System After a Loss-of-Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment	The U.S. Nuclear Regulatory Commission (NRC) is issuing this generic letter for several reasons. It alerts addressees that foreign material continues to be found inside operating nuclear power plant containments. During a design basis loss-of-coolant accident (DB LOCA), this foreign material could block an emergency core cooling system (ECCS) or safety-related containment spray system (CSS) flow path or damage ECCS or safety-related CSS equipment. In addition, construction deficiencies and problems with the material condition of ECCS systems, structures, and components (SSCs) inside the containment continue to be found. Design deficiencies also have been found which could degrade the ECCS or safety-related CSS. No action or information is requested regarding these issues. The NRC has issued many previous generic communications on this subject, as discussed later in this generic letter, and assumes that addressees have had adequate prior notice to consider possible actions at their facilities to address these concerns. The NRC is also issuing this generic letter to alert the addressees to the problems associated with the material condition of Service Level 1 (see definitions of Service Levels in Attachment 3 of GL) protective coatings inside the containment and to request information under 10 CFR 50.54(f) to evaluate the addressees' programs for ensuring that Service Level 1 protective coatings inside containment do not detach from their substrate during a DB LOCA and interfere with the operation of the ECCS and the safety-related CSS. The NRC intends to use this information to assess whether current regulatory requirements are being correctly implemented and whether they should be revised. <u>Discussion</u> Attachment 2 of the GL presents a tabulation of 57 operational events involving debris in the ECCS recirculation flow paths. This tabulation includes the plant name, the report (e.g., LER, IN, NRC Inspection Report) and a short description of the problem. <u>Related Generic Communications</u> 20 Generic Communications listed related to ECCS and CSS sump and strainer blockage.	ECCS and CSS sump & drainage blockage and Containment protective coating
GL	97-06 (1997)	Degradation of Steam Generator Internals	The U.S. Nuclear Regulatory Commission (NRC) is issuing this generic letter to (1) again alert addressees to the previously communicated findings of damage to steam generator internals, namely, tube support plates and tube bundle wrappers, at <u>foreign PWR facilities</u>; (2) alert addressees to recent findings of damage to steam generator tube support plates at a U.S. PWR facility; (3) emphasize to addressees the importance of performing comprehensive examinations of steam generator internals to	Steam Generators, including those at foreign facilities

Type	No.	Title	Topic	SPC Affected
			ensure steam generator tube structural integrity is maintained in accordance with the requirements of Appendix B to 10 CFR Part 50; and (4) require all addressees to submit information that will enable the NRC staff to verify whether addressees' steam generator internals comply with and conform to the current licensing bases for their respective facilities. Background: Foreign authorities have reported various steam generator tube support plate damage mechanisms. The affected steam generators are similar, but not identical, to Westinghouse Model 51 steam generators. As previously documented in IN 96-09 and IN 96-09, Supplement 1, one damage mechanism involved the wastage of the uppermost support plate caused by the misapplication of a chemical cleaning process. A second damage mechanism involved broken tube support plate ligaments at the uppermost, and sometimes at the next lower, tube support plates. The support plate ligaments broke near a radial seismic restraint and near an antirotation key; the damage apparently dates back to initial startup of the affected plants. According to foreign authorities, the ligaments may have broken because of excessive stress during the final thermal treatment of the monobloc steam generators, which in turn was caused by inadequate clearance for differential thermal expansion between the support plates, wrapper, and seismic restraints. As previously documented in IN 96-09, Supplement 1, a third damage mechanism involved wastage not associated with chemical cleaning and affected tube support plates at various elevations. This damage mechanism is active (progressive) and apparently involves a corrosion or erosion-corrosion mechanism of undetermined origin.	
GL	97-05 (1997)	Steam Generator Tube Inspection Techniques	The U.S. Nuclear Regulatory Commission (NRC) is issuing this generic letter to (1) emphasize to the addressees the importance of performing steam generator tube inservice inspections using qualified techniques in accordance with the requirements of Appendix B to 10 CFR Part 50, and (2) require certain information from addressees to determine whether they are in compliance with the current licensing basis for their respective facilities given their steam generator tube inservice inspection practices. Background: Licensees have traditionally relied upon eddy-current inspection techniques to assess the condition of their steam generator tubes. Although the eddy- current method is a proven technique for detecting tube degradation, the ability to depth size indications is possible only for specific modes of degradation. Specifically, tube degradation from intergranular attack (IGA) and stress corrosion cracking (SCC), major modes of steam generator tube degradation, are difficult to size with eddy-current inspection techniques because of a number of complicating variables. In one recent instance, a	Steam Generators

Type	No.	Title	Topic	SPC Affected
			licensee employed a technique to size the depths of IGA tube degradation based on tube specimens removed from two plants. However, pulled tube data analyzed after the initial application of the technique indicated that the method did not adequately estimate the true depth of the indications consistent with the criteria established for qualifying the sizing technique.	
GL	97-01 (1997)	Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations	The U.S. Nuclear Regulatory Commission (NRC) is issuing this generic letter to (1) request addressees to describe their program for ensuring the timely inspection of PWR control rod drive mechanism (CRDM) and other vessel closure head penetrations and (2) require that all addressees provide to the NRC a written response to the requested information. The information requested is needed by the NRC staff to verify compliance with 10 CFR 50.55a and 10 CFR Part 50, Appendix A, GDC 14, and to determine whether an augmented inspection program, pursuant to 10 CFR 50.55a(g)(6)(ii), is required. <u>Background:</u> Primary Water Stress Corrosion Cracking of Vessel Closure Head Penetrations - Most PWRs have Alloy 600 CRDM nozzle and other vessel head closure penetrations (VHPs) that extend above the reactor pressure vessel head. The stainless steel housing of the CRDM is screwed and seal-welded onto the top of the nozzle penetration. The weld between the nozzle top and bottom pieces is a dissimilar metal weld, which is also called a bimetallic weld. The nozzles protrude below the vessel head, thus exposing the inside surface of the nozzles to reactor coolant. The CRDM nozzle and other VHPs are basically the same for all PWRs worldwide, which use a U.S. design (except in Germany and Russia). The areas of interest for potential cracking are the weld between the nozzle and reactor vessel head, and the portion of the nozzle inside the reactor vessel head above the nozzle-to- vessel weld.	RPV – closure head penetrations
Bulletin (BL)	2004-01	Inspection of Alloy 82/182/600 Materials Used in the Fabrication of Pressurizer Penetrations and Steam	The U.S. Nuclear Regulatory Commission (NRC) is issuing this bulletin to: (1) advise PWR licensees that current methods of inspecting Alloy 82/182/600 materials used in the fabrication of pressurizer penetrations and steam space piping connections may need to be supplemented with additional measures to detect and adequately characterize flaws due to primary water stress corrosion cracking (PWSCC), (2) request PWR addressees to provide the NRC with information related to the materials from which the pressurizer penetrations and steam space piping connections at their facilities were fabricated, (3) request PWR licensees to provide the NRC with information related to the inspections that have been and those that will be performed to ensure that degradation of Alloy 82/182/600 materials used in the fabrication of pressurizer penetrations and steam space piping connections will be identified, adequately characterized, and repaired, and	Pressurizer and steam space piping connections used in PWR primary coolant systems

Type	No.	Title	Topic	SPC Affected
		Space Piping Connections at Pressurized-Water Reactors	(4) require PWR addresses to provide a written response to the NRC in accordance with the provisions of Section 50.54(f) of Title 10 of the Code of Federal Regulations (10 CFR 50.54(f)). Background: Operating experience has demonstrated that Alloy 82/182/600 materials exposed to primary coolant water (or steam) at the normal operating conditions of PWR plants have cracked due to PWSCC. The NRC has previously issued generic communications regarding the emergence of this phenomena, and its consequential effects, in other areas of PWR primary systems. NRC Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles," addressed PWSCC of control rod drive mechanism penetrations and other penetrations in the RPV upper heads of PWRs. NRC Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity," addressed the issue of boric acid corrosion of low alloy steel components as a result of leakage through PWSCC-induced flaws in the reactor coolant pressure boundary (RCPB). NRC Bulletin 2002-02, "Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs," followed up on NRC staff concerns regarding the adequacy of visual examinations as a primary inspection method for the RPV upper head and RPV upper head penetrations. Finally, NRC Bulletin 2003-02, "Leakage From Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity," addressed the potential for PWSCC of RPV bottom mounted instrumentation nozzles. Operating experience, both domestic and foreign, has demonstrated that Alloy 82/182/600 materials connected to a PWR's pressurizer may be particularly susceptible to PWSCC. Since the late 1980's, approximately 50 Alloy 600 pressurizer heater sleeves at Combustion Engineering-designed (CE-designed) facilities in the United States have shown evidence of RCPB leakage which has been attributed to PWSCC. The most recent events of this type occurred at Millstone, Unit 2, and Waterford, Unit 3, in October 2003, and at Palo Verde, Unit 3, in February 2004. All available evidence from finite element modeling studies and limited nondestructive evaluation (NDE) has suggested that these leakage events were the result of axially-oriented PWSCC of the pressure boundary portion of these heater sleeves. However, NDE results from Palo Verde, Unit 2's fall 2003 refueling outage, on heater sleeves which had not shown evidence of leakage have demonstrated that circumferentially-oriented PWSCC can occur in the non-pressure boundary portion (i.e., above the J-groove attachment weld) of these components. Cracking in a TMI-1 diaphragm plate was attributed to PWSCC in the heat affected zone of the seal weld. Boric acid corrosion of the low alloy steel strongback was also observed to have resulted from the leakage. Small diameter Alloy 82/182 instrument line penetrations have also shown evidence of PWSCC at many PWR facilities since the 1980's. For example, in October 2003, the Crystal River, Unit 3,	

Type	No.	Title	Topic	SPC Affected
			licensee reported RCPB leakage from three pressurizer upper level instrument tap nozzles, which are exposed to the steam space in the pressurizer. The leakage was attributed to PWSCC of Alloy 82/182/600 material from which the connections were constructed. Finally, inspection results from September 2003 at Tsuruga, Unit 2, in Japan are relevant with respect to PWSCC in larger diameter, butt welded lines connected to the steam space of the pressurizer. Evidence of boron deposits on the surface of a pressurizer relief valve nozzle (inside diameter 130 mm, or approximately 5 inches) led to the discovery of five axially-oriented flaws in the nickel-based alloy weld material used in the fabrication of the nozzle-to-safe end weld. Subsequent NDE performed on a safety valve nozzle of similar diameter resulted in the discovery of two additional flaws in its nozzle-to-safe end weld. Fractographic analysis of the flaw surfaces confirmed PWSCC as the mechanism for flaw initiation and growth. This event at Tsuruga, Unit 2 was similar to an event at Palisades in 1993 where leakage was observed and attributed to a circumferentially-oriented PWSCC flaw in a line leading to the unit's power operated relief valves. <u>Related Generic Communications</u> • Bulletin 2003-02, "Leakage From Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity," August 21, 2003 (ADAMS Accession No. ML032320153) • Bulletin 2002-02, "Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle • Inspection Programs," August 9, 2002 (ADAMS Accession No. ML022200494) • Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity," March 18, 2002 (ADAMS Accession No. ML020770497) • Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles," August 3, 2001 (ADAMS Accession No. ML012080284)	
BL	2003-02	Leakage from Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant	The U.S. Nuclear Regulatory Commission (NRC) is issuing this bulletin to: (1) advise PWR addressees that current methods of inspecting the RPV lower heads may need to be supplemented with additional measures (e.g., bare-metal visual inspections) to detect reactor coolant pressure boundary (RCPB) leakage, (2) request PWR addressees to provide the NRC with information related to inspections that have been or will be performed to verify the integrity of the RPV lower head penetrations, and (3) require PWR addresses to provide a written response to the NRC in accordance with the provisions of Section 50.54(f) of Title 10 of the *Code of Federal Regulations* (10 CFR 50.54(f)). <u>Discussion</u> The RPV and its head penetrations are an integral part of the RCPB, and their integrity is important to	RPV – closure head penetrations

Type	No.	Title	Topic	SPC Affected
		Pressure Boundary Integrity	the safe operation of the plant. The recent identification of cracking and leakage from two bottom mounted instrumentation (BMI) penetrations at South Texas Project (STP) Unit 1 raises questions about potential degradation mechanisms which may be active in this area. In addition, licensee responses to the Bulletin 2002-01 followup RAIs raised questions about the adequacy of inspections performed by licensees to detect leakage from RPV lower head penetrations. Related Generic Communications • Regulatory Issue Summary 2003-13, "NRC Review of Responses to Bulletin 2002-01, 'Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity,'July 29, 2003 (ADAMS Accession No. ML032100653) • Information Notice 2003-11 "Leakage Found on Bottom-Mounted Instrumentation Nozzles," August 13, 2003 (ADAMS Accession No. ML032250135) • Bulletin 2002-02, "Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs," August 9, 2002 (ADAMS Accession No. ML022200494) • Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity," March 18, 2002 (ADAMS Accession No. ML020770497) • Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants," March 17, 1988 (ADAMS Accession No. ML031130424)	
BL	2003-01	Potential Impact of Debris Blockage on Emergency Sump Recirculation at Pressurized-Water Reactors	The U.S. Nuclear Regulatory Commission (NRC) is issuing this bulletin to: (1) Inform addressees of the results of NRC-sponsored research identifying the potential susceptibility of pressurized-water reactor (PWR) recirculation sump screens to debris blockage in the event of a high-energy line break (HELB) requiring recirculation operation of the emergency core cooling system (ECCS) or containment spray system (CSS). (2) Inform addressees of the potential for additional adverse effects due to debris blockage of flowpaths necessary for ECCS and CSS recirculation and containment drainage. (3) Request that, in light of these potentially adverse effects, addressees confirm their compliance with 10 CFR 50.46(b)(5) and other existing applicable regulatory requirements, or describe any compensatory measures implemented to reduce the potential risk due to post-accident debris blockage as evaluations to determine compliance proceed. (4) Require addressees to provide the NRC a written response in accordance with 10 CFR 50.54(f). Discussion See discussion in GL 2004-02 above. Related Generic Communications	Strainers

Type	No.	Title	Topic	SPC Affected
			See list in GL 2004-02 above.	
BL	2002-02	Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs	The U.S. Nuclear Regulatory Commission (NRC) is issuing this bulletin to: (1) Advise pressurized-water reactor (PWR) addressees that visual examinations, as a primary inspection method for the reactor pressure vessel (RPV) head and vessel head penetration (VHP) nozzles, may need to be supplemented with additional measures (e.g., volumetric and surface examinations) to demonstrate compliance with applicable regulations. (2) Advise PWR addressees that inspection methods and frequencies to demonstrate compliance with applicable regulations should be demonstrated to be reliable and effective. (3) Request information from all PWR addressees concerning their RPV head and VHP nozzle inspection programs to ensure compliance with applicable regulatory requirements. (4) Require all PWR addressees to provide written responses to this bulletin related to their inspection program plans. <u>Discussion</u> As a result of the circumferential cracking of VHP nozzles at Oconee Nuclear Station 3 and other PWR facilities, the RPV head material degradation at Davis-Besse, and the staff's review of responses to NRC Bulletins 2001-01 and 2002-01, the NRC staff has a number of concerns about the inspection requirements and programs for RPV head and VHP nozzles. Based on the experience and information currently available concerning cracking and degradation, it may be necessary for inspection programs that rely on visual examinations to be supplemented with additional measures (e.g., volumetric and surface examinations) to demonstrate compliance with applicable regulations. The NRC has developed Web pages to keep the public informed of generic activities related to Alloy 600 cracking and RPV head degradation: http://www.nrc.gov/reactors/operating/ops-experience/alloy600.html http://www.nrc.gov/reactors/operating/ops-experience/vessel-head-degradation.html <u>Related Generic Communications</u> See GL 2003-02 above.	RPV head and vessel head penetrations
BL	2002-01	Reactor Pressure Vessel Head	The U.S. Nuclear Regulatory Commission (NRC) is issuing this bulletin to require pressurized-water reactor (PWR) addressees to submit: (1) information related to the integrity of the reactor coolant pressure boundary including the reactor	RPV and reactor coolant pressure

Type	No.	Title	Topic	SPC Affected
		Degradation and Reactor Coolant Pressure Boundary Integrity	pressure vessel head and the extent to which inspections have been undertaken to satisfy applicable regulatory requirements, and (2) the basis for concluding that plants satisfy applicable regulatory requirements related to the structural integrity of the reactor coolant pressure boundary and future inspections will ensure continued compliance with applicable regulatory requirements, and (3) a written response to the NRC in accordance with the provisions of Title 10, Section 50.54(f), of the Code of Federal Regulations (10 CFR 50.54(f)) if they are unable to provide the information or they can not meet the requested completion dates. <u>Discussion</u> The reactor pressure vessel head is an integral part of the reactor coolant pressure boundary, and its integrity is important to the safe operation of the plant. The recent identification of thinning of the reactor pressure vessel head at Davis-Besse raises questions regarding licensees' practices for identifying and resolving degradation of the reactor coolant pressure boundary, including licensees' models for assessing corrosion that is caused by contaminants such as boric acid in the operating environment of the reactor pressure vessel head, or erosion that is caused by flow through a through-wall defect in a vessel head penetration nozzle. Since the NRC issued Information Notice 2002-11, additional information has become available concerning the condition of the reactor pressure vessel head at Davis-Besse. Specifically, the 3/8-inch stainless steel cladding near control rod drive mechanism nozzle 3 was found to be deflected upwards by about 1/8-inch over a 4-inch distance, indicating that the material had yielded. This is significant because the 3/8-inch cladding had essentially become the reactor coolant pressure boundary near the affected nozzle after the base material of the reactor pressure vessel head had degraded. In addition, two areas of less severe thinning have been detected near control rod drive mechanism nozzle 2. <u>Related Generic Communications</u> • Information Notice 2002-11: "Recent Experience with Degradation of Reactor Pressure Vessel Head," March 12, 2002. [ADAMS Accession No. ML020700556] • Bulletin 2001-01: "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles," August 3, 2001. [ADAMS Accession No. ML012080284] • Information Notice 2001-05, "Through-Wall Circumferential Cracking of Reactor Pressure Vessel Head Control Rod Drive Mechanism Penetration Nozzles at Oconee Nuclear Station, Unit 3," April 30, 2001. [ADAMS Accession No. ML011160588] • Generic Letter 97-01, "Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel	boundary

Type	No.	Title	Topic	SPC Affected
			Closure Head Penetrations," April 1, 1997. • Information Notice 96-11, "Ingress of Demineralizer Resins Increases Potential for Stress Corrosion Cracking of Control Rod Drive Mechanism Penetrations," February 14, 1996. • Information Notice 86-108, Supplement 3, "Degradation of Reactor Coolant System Pressure Boundary Resulting from Boric Acid Corrosion," January 5, 1995. • NUREG/CR-6245, "Assessment of Pressurized Water Reactor Control Rod Drive Mechanism Nozzle Cracking," October 1994. • Information Notice 94-63, "Boric Acid Corrosion of Charging Pump Casing Caused by Cladding Cracks," August 30, 1994. • Information Notice 90-10, "Primary Water Stress Corrosion Cracking of INCONEL 600," February 23, 1990. • Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants," March 17, 1988. • Information Notice 86-108, Supplement 2, "Degradation of Reactor Coolant System Pressure Boundary Resulting from Boric Acid Corrosion," November 19, 1987. • Information Notice 86-108, Supplement 1, "Degradation of Reactor Coolant System Pressure Boundary Resulting from Boric Acid Corrosion," April 20, 1987. • Information Notice 86-108, "Degradation of Reactor Coolant System Pressure Boundary Resulting from Boric Acid Corrosion," December 29, 1986. • Bulletin 82-02, "Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants," June 2, 1982. • Information Notice 82-06, "Failure of Steam Generator Primary Side Manway Closure Studs," March 12, 1982. • Information Notice 80-27, "Degradation of Reactor Coolant Pump Studs," June 11, 1980.	
BL	2001-01	Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles	The U.S. Nuclear Regulatory Commission (NRC) is issuing this bulletin to: (1) request that addressees provide information related to the structural integrity of the reactor pressure vessel head penetration (VHP) nozzles for their respective facilities, including the extent of VHP nozzle leakage and cracking that has been found to date, the inspections and repairs that have been undertaken to satisfy applicable regulatory requirements, and the basis for concluding that their plans for future inspections will ensure compliance with applicable regulatory requirements, and (2) require that all addressees provide to the NRC a written response in accordance with the provisions of 10 CFR 50.54(f). <u>Discussion</u>	RPV head penetrations

Type	No.	Title	Topic	SPC Affected
			The recent discoveries of cracked and leaking Alloy 600 VHP nozzles, including control rod drive mechanism (CRDM) and thermocouple nozzles, at four pressurized water reactors (PWRs) have raised concerns about the structural integrity of VHP nozzles throughout the PWR industry. Nozzle cracking at Oconee Nuclear Station Unit 1 (ONS1) in November 2000 and Arkansas Nuclear One Unit 1 (ANO1) in February 2001 was limited to axial cracking, an occurrence deemed to be of limited safety concern in the NRC staff's generic safety evaluation on the cracking of VHP nozzles, dated November 19, 1993. However, the discovery of circumferential cracking at Oconee Nuclear Station Unit 3 (ONS3) in February 2001 and Oconee Nuclear Station Unit 2 (ONS2) in April 2001 - particularly the large circumferential cracking identified in two CRDM nozzles at ONS3 - has raised concerns about the potential safety implications and prevalence of cracking in VHP nozzles in PWRs. <u>Related Generic Communications</u> • Information Notice 2001-05, "Through-Wall Circumferential Cracking of Reactor Pressure Vessel Head Control Rod Drive Mechanism Penetration Nozzles at Oconee Nuclear Station, Unit 3," April 30, 2001. [ADAMS Accession No. ML011160588] • Generic Letter 97-01, "Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations," April 1, 1997. • Information Notice 96-11, "Ingress of Demineralizer Resins Increases Potential for Stress Corrosion Cracking of Control Rod Drive Mechanism Penetrations," February 14, 1996. • Information Notice 90-10, "Primary Water Stress Corrosion Cracking of INCONEL 600," February 23, 1990. • Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants," March 17, 1988. • NUREG/CR-6245, "Assessment of Pressurized Water Reactor Control Rod Drive Mechanism Nozzle Cracking," October 1994.	
Information Notices (IN)	2007-37	Buildup of Deposits in Steam Generator	The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice (IN) to alert addressees to the potential for deposits to accumulate in their steam generators and potentially affect steam generator performance and tube integrity. The NRC expects that recipients of this IN will review the information for applicability to their facilities and consider taking actions, as appropriate, to avoid similar problems. However, suggestions contained in this IN are not NRC requirements; therefore, no specific action or written response is required. <u>Discussion</u> Corrosion products can accumulate in the secondary side of the steam generator as a result of the gradual erosion and corrosion of secondary side components in a pressurized water reactor. This	Steam Generators

Type	No.	Title	Topic	SPC Affected
			accumulation of corrosion products results in the buildup of deposits on the tubes, tubesheets, and other secondary side steam generator structures (including the holes through which the tubes pass). Harmful contaminants can concentrate in these deposits and result in corrosion of the steam generator tubes. In addition, these deposits can affect the thermal performance of the steam generator (i.e., the ability to transfer heat from the primary-to-secondary side of the steam generator) and the thermal hydraulic characteristics of the steam generator (by changing the flow patterns within the steam generator). Between 2004 and 2006, three primary-to-secondary leaks occurred at the Cruas Nuclear Plant, a multi-unit site in France. The last primary-to-secondary leak occurred at Cruas Unit 4 in February 2006 (Autorité de Sûreté Nucléaire 2006 Annual Report, http://annual-report.asn.fr/PDF/nuclear-power-plants-EDF.pdf), and it was detected through the use of nitrogen-16 radiation monitors. The leak rate increased from very low levels to approximately 3 gallons per minute [600 liters per hour] in 12 minutes. In the early 1990s, steam generator water level oscillations were observed at Surry Power Units 1 and 2, near Newport News, Virginia. Due to the severity of these water level oscillations, the units operated at reduced power levels for varying periods of time. The cause of the steam generator water level oscillations was severe deposit buildup in the TSP quatrefoil-shaped holes. The licensee corrected the problem by performing chemical cleaning on all steam generators at both units to reduce the extent of deposits.	
IN	2007-21	Pipe Wear Due to Interaction of Flow-induced Vibration and Reflective Metal Insulation	The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice (IN) to alert addressees that a licensee identified significant wear marks on the outside wall of chemical volume control system (CVCS) stainless steel piping, which was subject to flow-induced vibration conditions. The licensee determined that the wear marks were caused by the interaction between the piping base metal and the properly installed reflective metal insulation (RMI). The NRC expects that addressees will review the information for applicability to their facilities and consider actions, as appropriate, to identify and address similar problems. However, suggestions contained in this IN are not NRC requirements; therefore, no specific action or written response is required. During a Catawba Unit 1 refueling outage conducted in the fall of 2006, the licensee identified multiple wear marks on CVCS field-run stainless steel piping (see Enclosure, Figure 1) that was downstream of the CVCS letdown orifices. The licensee determined that these marks were a result of abrasive wear between the stainless steel RMI end caps and the stainless steel piping. This abrasive wear was most probably caused by the known flow-induced vibration downstream of the letdown	Piping

Type	No.	Title	Topic	SPC Affected
			orifices combined with end cap to piping interaction. RMI is assembled by clipping short segments of insulation together. End caps are found at the intersection of each insulation segment, and these end caps are perpendicular to the pipe wall (see Enclosure, Figure 2). The licensee confirmed that the RMI end caps had been installed properly in accordance with plant procedures and vendor instructions. None of the wear marks around the piping were continuous for 360 degrees and most extended less than 180 degrees of the circumference. The deepest wear mark was one thirty-seconds of an inch. All of the CVCS piping with identified wear marks was located inside containment.	
IN	2006-27	Circumferential Cracking in the Stainless Steel Pressurizer Heater Sleeves of Pressurized Water Reactors	The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice (IN) to describe a recent experience in which a licensee attributed a circumferentially-oriented crack to intergranular stress corrosion cracking (IGSCC) in a stainless steel pressurizer heater sleeve in a PWR reactor coolant environment. The NRC expects that addressees will review the information for applicability to their facilities and consider actions, as appropriate, to identify and address similar problems. However, suggestions contained in this IN are not NRC requirements; therefore, no specific action or written response is required. <u>Discussion</u> During the spring 2006 outage at Braidwood, Unit 1, Exelon Generation Company (the licensee) found boron deposits in the pressurizer surge line area during insulation removal. The licensee determined that the leakage originated from the number 52 pressurizer heater (heater number 52) at the upper weld between the pressure tube and heater coupling. The licensee based this determination on deposit patterns, deposit chemical analysis, and rouging (i.e., rust) found in the convection cover insulation sleeve for heater number 52. Rouging could be caused by steam impingement on the stainless steel material. The licensee visually inspected all 78 pressurizer heaters to determine the extent of the condition and determined that heater number 52 was the only source of boric acid leakage from the pressurizer. The licensee removed leaking coupling for heater number 52 from the system and plugged the tube. The licensee shipped the coupling to a testing facility to determine the cause of the failure. The results of the laboratory examinations to date suggest that the observed cracking in the sleeve occurred due to circumferentially-oriented IGSCC in the heat affected zone.	Pressurizer heater sleeves
IN	2006-17	Recent Operating Experience of Service Water	The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice (IN) to inform addressees of operating experience within the past few years affecting the operability of the service water system at several nuclear power plants. The NRC expects that recipients will review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems. However, suggestions contained in this IN are not NRC requirements; therefore, no specific	Piping – service water systems – plugging/fouling

Type	No.	Title	Topic	SPC Affected
		Systems Due to External Conditions	action or written response is required. Discussion During 2004 through 2005, 15 events occurred related to blockages in service water systems. These events were primarily self-revealing. The various blocking agents included silt, sand, small rocks, grass or weeds, frazil ice, and small aquatic fauna, such as fish. All these events were of low safety significance but illustrate the susceptibility of the safety-significant service water system. For instance, in September 2005, NRC inspectors identified a condition at Fort Calhoun that allowed small rocks to regularly enter the raw water system, contribute to tripping of a pump and strainer motors, and interfere with traveling screen operation (NRC Inspection Report 50-285/2005-11, Agencywide Documents Access and Management System (ADAMS) Accession No. ML052920543). In June 2005, NRC inspectors found a portion of a service water accumulator outlet line at Salem to be nearly full of silt (NRC Inspection Report 50-272/2005-03, ADAMS Accession No. ML052090344). Other occurrences are also described for Watts Bar and Cooper Nuclear nuclear plants.	
IN	2006-08	Secondary Piping Rupture at the Mihama Power Station in Japan	The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice (IN) involving foreign operating experience to alert addressees of the root causes and lessons learned from a secondary piping rupture at the Mihama Power Station, Unit 3 (Mihama 3) in Japan. It is expected that recipients will review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems. However, suggestions contained in this information notice are not NRC requirements; therefore, no specific action or written response is required. Discussion The Mihama 3, is an 826 Megawatts electric, 3-loop Westinghouse type pressurized-water reactor (PWR) owned by Kansai Electric Power Company, Inc., and licensed by the Japanese government. This unit has been in service since 1976. On August 9, 2004, a fire alarm annunciated in the central control room at Mihama 3. Upon investigation, operators discovered the area covered by the alarm was filled with steam. Suspecting that steam or high temperature water was leaking from the secondary piping, the operators began an emergency load reduction. While they were doing this, the reactor tripped automatically based on the steam flow from the 3A steam generator exceeding the feedwater flow to that steam generator. The rupture occurred in a 55.9 centimeter (cm) (22 inch) outside diameter pipe in the 'A' loop condensate system between the fourth feedwater heater and the deaerator, downstream of an orifice for measuring single-phase water flow. At the time of the secondary piping rupture, 105 workers were preparing for the periodic inspections to commence. The	Secondary piping rupture

Type	No.	Title	Topic	SPC Affected
			accident resulted in five deaths and six injuries. A microscopic inspection of the inside surface of the ruptured pipe revealed a fish scale-like pattern over almost the entire inner surface of the pipe downstream of the orifice, except at the bottom of the pipe. The thickness along the bottom of the pipe was found to be the nominal wall thickness. The inside surface of the bottom of the pipe was covered with a thick surface film. These conditions are characteristic of flow-accelerated corrosion (FAC).	
IN	2006-01	Torus Cracking in a BWR Mark I Containment	The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice (IN) to inform the owners of BWR Mark I containments about the occurrence and potential causes of the through-wall cracking of a torus in a BWR Mark I containment. Recipients are expected to review the information for applicability to their facilities and consider appropriate actions to avoid similar problems. However, the measures suggested in this IN are not NRC requirements; therefore, no specific action or written response is required. Discussion On June 27, 2005, with the plant operating at 100-percent power during a licensee inspection of reactor core isolation cooling system torus suction piping, James A. FitzPatrick Nuclear Power Plant (FitzPatrick) personnel discovered a torus leak near a torus support. The plant's torus is a large doughnut-shaped steel structure that is partially filled with water and designed to act as a pressure suppression chamber. The leak was located about 5 feet below the waterline and just below the high-pressure coolant injection (HPCI) turbine exhaust pipe. The leak was characterized as a slight seepage with streaking and a small puddle below the leak. Subsequent nondestructive examination determined that the leakage was from a small through-wall torus crack which was x-shaped with an approximate 4.6 inch maximum length. The FitzPatrick licensee performed a root cause investigation of the event, and after eliminating a number of possible causes, the licensee concluded that the most likely cause for the initiation and propagation of the crack was the hydrodynamic loads of the turbine exhaust pipe during HPCI operation coupled with the highly restrained condition of the torus shell at the torus column support. The licensee concluded that the crack was initiated by cyclic loading due to condensation oscillation during HPCI operation.	Steel Containment - Torus
IN	2004-21	Additional Adverse Effect of	The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice (IN) to inform addressees of potential adverse effects of boric acid leakage that may not have been previously considered and to reemphasize concerns regarding boric acid accumulations on reactor plant	Potential Boric Acid Corrosion on

Type	No.	Title	Topic	SPC Affected
		Boric Acid Leakage: Potential Impact on Post-Accident Coolant pH	equipment inside containment. The primary concern regarding boric acid leakage is corrosion of ferritic steel components. However, if boric acid deposits of sufficient magnitude are present in containment, dissolution of these deposits may also affect the pH of the reactor coolant in the containment sump. The NRC anticipates that recipients will review the information for applicability to their facilities and consider appropriate actions. However, suggestions contained in this IN do not constitute NRC requirements; therefore, no specific action or written response is required. <u>Discussion</u> During refueling outages throughout the 1990s, personnel at the Davis-Besse nuclear power plant performed visual inspections of the reactor pressure vessel (RPV) head surface that was accessible through the service structure weep holes. Visual inspections performed below the RPV head insulation found some accumulation of boric acid deposits on the RPV head. The boric acid buildup was due to leaking control rod drive mechanism flanges and reactor coolant pressure boundary leakage. Many areas of the RPV head were not visible because of persistent boric acid deposits that the licensee did not clean. In addition to the significant buildup of boric acid on the reactor pressure vessel head, a substantial amount of boric acid built up inside the containment at Davis-Besse.	Various Equipment
IN	2004-11	Cracking in Pressurizer Safety and Relief Nozzles and in Surge Line Nozzle	The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice (IN) to alert addressees to cracking and leakage indications found on pressurizer safety and relief nozzles and in a surge line nozzle-to-safe end weld. It is expected that the recipients of this notice will review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems. However, suggestions contained in this information notice are not NRC requirements; therefore, no specific action or written response is required. <u>Discussion</u> During an annual inspection in September of 2003, cracking and leakage were discovered on pressurizer safety and relief nozzles in Tsuruga Power Plant, Unit 2 (Tsuruga 2), in Japan. Tsuruga 2 is a four-loop pressurized water reactor (PWR) unit (similar to the PWRs in the U.S). Tsuruga 2, which started commercial operation in February 1987, was designed and fabricated by Mitsubishi Heavy Industries. Full power for Tsuruga 2 is 1160 MWe. At 100% power, the average primary coolant temperature is 289 ºC (552 ºF) in the cold leg and 322 ºC (612 ºF) in the hot leg. During a refueling outage in October 2003, an indication was detected in a surge line nozzle-to-safe end dissimilar metal weld at Three Mile Island, Unit 1 (TMI-1). TMI-1 is a Babcock and Wilcox pressurized water reactor which started commercial operation in September 1974.	Pressurizer nozzles
IN	2004-09	Corrosion	The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice to alert addressees	Steel

Type	No.	Title	Topic	SPC Affected
		of Steel Containment and Containment Liner	to recent occurrences of corrosion in freestanding metallic containments and in liner plates of reinforced and pre-stressed concrete containments. It is expected that recipients will review this information for applicability to their facilities and consider actions, as appropriate. However, the suggestions in this information notice are not NRC requirements; therefore, no specific action or written response is required. <u>Discussion</u> Inspections of containment at the floor level, as well as at higher elevations, have identified various degrees of corrosion and containment plate thinning. This is a partial listing of such occurrences. <u>Corrosion of freestanding metallic containment</u> • In July of 2002, at the Davis-Besse Nuclear Power Station, the NRC identified corrosion where the containment meets the floor. The licensee subsequently performed ultrasonic examinations to confirm that the freestanding metal containment had not been corroded below the minimum design thickness. The licensee subsequently installed a moisture barrier at the containment-to-floor junction to prevent moisture intrusion (NRC Inspection Report 50-346/02-09, ADAMS Accession No. ML022560237). • In May of 2002, at the Sequoyah Nuclear Plant, Unit 2, the NRC identified areas of the steel containment vessel (SCV) with degraded coatings and rust (NRC Inspection Report 50-328/02-02, ADAMS Accession No. ML022070149). One of the floor drains was clogged in the annulus area (1.5 m [5 feet] wide) between the SCV and the reinforced concrete shield building. Localized water ponding at the clogged drain had come in contact with a section of the SCV, causing deterioration of the SCV coatings and rusting of the SCV. This SCV is restricted for access due to the close proximity between the SCV and the emergency gas treatment system (EGTS) duct work. After reviewing NRC Information Notice 89-79, the licensee had identified the problem in 1990, but the corrective action was inadequate. Since the identification in 2002, additional corrective actions have been implemented by the licensee. These actions consist of the removal of the EGTS duct work on both Unit 1 and Unit 2 to allow the SCV area behind the EGTS duct work to be cleaned and recoated. Also the licensee has identified this SCV area behind the EGTS duct work for periodic visual examination. • In November of 2001, at the Dresden Unit 2 Nuclear Power Station, the licensee identified an area of missing coating and primer encircling the drywell shell adjacent to the basement floor. The area was 5-10 cm (2-4 inches) wide. In this area, the base metal of the drywell shell was found to be corroded. However, based on ultrasonic and visual examinations, the degraded area was found to be within the corrosion allowance for the drywell shell. The shell coating was repaired in this area to prevent	Containment & Liner of Concrete Containment

Type	No.	Title	Topic	SPC Affected
			further degradation (Inservice Inspection Summary Report, Fall 2001 Inspection Period, DAMS Accession No. ML020450608). Corrosion of containment liner plate • In March of 2001, at the D. C. Cook Nuclear Power Plant, the licensee iscovered a hrough-wall hole in the containment liner plate. Surface preparation for further nspection of a weld repair of the liner plate dislodged the repair material, leaving a hole. The hole was repaired. However, further examination of the repair area indicated corrosion of the liner from the embedded side of the liner. The cause of this corrosion was found to be a wire brush handle lodged in the concrete at the interface with the liner. The licensee replaced an area about 30 cm (12 inches) square in the liner plate and performed a local leak rate test as part of the corrective action (AEP:NRC:2612-01: "Response to NRC Request for Additional Information Regarding License Amendment Request for One-Time Extension of Containment Integrated Leakage Rate Test Interval," November 11, 2002, ADAMS Accession No. ML023170524). • In February and March of 1998, at the D. C. Cook Nuclear Power Plant, the licensee identified corrosion (pitting) of the containment liner at the moisture barrier seal areas of both units. At Unit 1, the licensee identified more than 60 areas in which the thickness (1 cm [3/8 inch] nominally) of the steel liner plate had been reduced below the minimum design thickness value of (0.6 cm [0.25 inch]). The licensee subsequently installed a new liner-to-floor moisture barrier seal (Licensee Event Report 50-315/98011-02, NUDOCS Accession No. 9809040123* and NRC Inspection Report 50-315/99026, ADAMS Accession No. ML003677533). • In fall 2003, at the Surry Power Station, Unit 2, NRC inspectors found degraded coatings and rust on the containment liner at the junction of the metal liner and interior concrete floor. The inspectors also discovered that the moisture barrier at the junction between the metal liner plate and interior concrete floor was degraded. Review of the records of previous inspections performed by licensee personnel in 2000, 2002, and 2003 revealed that the licensee had not identified the degraded moisture barrier (caulking), but had identified the degraded coatings. (NRC Inspection Report 50-281/2003-05, ADAMS Accession No. ML040280056). • In October of 1999, at the Palisades Plant, the licensee discovered that a floor-to-liner moisture barrier seal had never been installed and used a thin metal blade as a probe, confirming the presence of moisture in the crevice. Subsequently, the licensee used a borescope to identify areas of liner corrosion. The licensee determined that the corrosion had not yet appreciably degraded the liner in this area and installed a new liner-to-floor moisture barrier seal. • In May of 1999, at the Brunswick Steam Electric Plant, Unit 2, the licensee identified three areas in the drywell liner where corrosion had penetrated the liner. These areas were at the 5.5, 16, and 21 m	

Type	No.	Title	Topic	SPC Affected
			(18, 52, and 70 feet) elevations. At the 16 m elevation, the wall had corroded from the outside to the inside surface. At the 21 m elevation, the wall had corroded from the inside to the outside surface. At the 5.5 m elevation, the direction of the through-wall corrosion could not be determined. The liner corrosion was a result of foreign materials embedded in the concrete containment adjacent to the liner. One hole in the liner was adjacent to a leather work glove found buried in the concrete, while the other two hole locations were adjacent to wood found buried in the concrete (NRC Inspection Report 50-324/99-03, NUDOCS No. 9906170114*). • In December, 1996, at the H.B. Robinson Steam Electric Plant, Unit 2, an NRC inspector identified degraded caulking and insulation sheathing panels during a containment walkdown. The vertical portion of the containment liner at Robinson is protected by Vinylcel insulation, a polyvinyl chloride material, and a metal sheathing material. The licensee determined that a portion of this insulation sheathing material was loose and that some of the caulking between the sheathing panels was deteriorated. After examination during subsequent refueling outages, the licensee determined that the protective coating for the containment liner was degraded and that while some corrosion of the containment liner had occurred, the liner met design requirements. The licensee restored the coating and insulation panels (NRC Inspection Reports 50-261/96-14, NUDOCS Accession No 9702110115* and 50-261/98-02, NUDOCS Accession No. 9805050171*).	
IN	2004-08	Reactor Coolant Pressure Boundary Leakage Attributable to Propagation of Cracking in Reactor Vessel Nozzle Welds	The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice to alert addressees to cracking identified in the nozzle-to-cap weld of control rod drive (CRD) return line penetration N10 at Pilgrim Nuclear Power Station (Pilgrim Station). The NRC expects recipients to review the information in this notice for applicability to their facilities and consider actions, as appropriate, to avoid similar problems. However, suggestions contained in this information notice do not constitute NRC requirements and, therefore, do not require any specific action or written response. <u>Discussion</u> During a planned outage on September 30, 2003, the licensee for Pilgrim Station began performing drywell inspections to identify and make necessary repairs to reduce drywell leakage. On October 1, 2003, the licensee's drywell inspections revealed leakage from the nozzle-to-cap weld area of penetration N10. The licensee concluded that the leakage was a contributor to the unidentified drywell leakage.	RPV nozzle penetrations
IN	2004-05	Spent Fuel Pool Leakage to Onsite	The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice to inform addressees of the recent identification of a longstanding leak to onsite groundwater from the spent fuel pool of an operating pressurized water reactor facility. It is expected that recipients will review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar	Spent fuel pool structure

Type	No.	Title	Topic	SPC Affected
		Groundwater	problems. However, suggestions contained in this information notice are not NRC requirements; therefore, no specific action or written response is required. <u>Discussion</u> On September 18, 2002, the licensee for the Salem Nuclear Generating Station identified evidence of radioactive water leakage through an interior wall located at the 24-meter (78-foot) elevation of the Unit 1 auxiliary building mechanical penetration room, a radiologically controlled area. The Salem Unit 1 fuel handling building (FHB) is a seismically qualified structure that contains the Unit 1 spent fuel pool (SFP). Unit 1 SFP support systems in the Unit 1 auxiliary building pass through adjacent building walls to the Unit 1 FHB. The walls are separated by a Styrofoam-filled 15-cm (6-inch) seismic gap and the support systems traverse the seismic gap. The Unit 1 SFP is a concrete structure with a stainless steel liner. The SFP includes an integral liner leakage detection and collection system, consisting of an extensive network of collection lines running both horizontally and vertically within the narrow gap between the SFP liner and the concrete SFP structure. The collected liner leakage is discharged to a collection trough through 17 drain lines (tell-tale drains). The tell-tale drains provide a means to detect, monitor, and quantify potential leakage from the SFP liner. The collected leakage is subsequently directed to the liquid radioactive waste system for processing. The licensee's reviews discovered that over the years since initial facility startup, materials such as boric acid residue and minerals accumulated within the leak collection and detection system and restricted the normal drainage of liquid. The reviews also found that a modification to the tell-tale drains in 1998 resulted in the inadvertent introduction of sealant into the tell-tale drains, further restricting the free drainage of leakage from the liner. As a result, through-liner leakage accumulated between the SFP liner and the concrete structure of the SFP. The accumulated water, containing tritium, subsequently migrated to other locations through penetrations, concrete construction joints, and cracks. The seismic gap was confirmed to contain water with radionuclides characteristic of Unit 1 SFP water. The water is believed by the licensee to have made its way to the groundwater in the restricted area via the seismic gap. The licensee cleaned the tell-tale drains, improving the drainage of the accumulated water between the liner and spent fuel pool concrete structure and stopping the through-wall and penetration leakage.	
IN	2004-01	Auxiliary Feedwater Pump	The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice to inform addressees of the potential common cause failure of auxiliary feedwater pumps because of fouling of pump recirculation line flow orifices. It is expected that recipients will review the information for	Filter – plugging/fouling

Type	No.	Title	Topic	SPC Affected
		Recirculation Line Orifice Fouling - Potential Common Cause Failure	applicability to their facilities and consider actions, as appropriate, to avoid similar problems. However, suggestions in this information notice are not NRC requirements; therefore no specific action or written response is required. Discussion Point Beach Nuclear Plant (PBNP) is a two unit site. Each unit has a turbine-driven AFW pump (pumps 1P29 and 2P29) which can supply water to both steam generators. Additionally, the plant has two motor-driven AFW pumps (pumps P38A and P38B) each of which can be aligned to a steam generator in each unit. Each pump has a recirculation line back to the condensate storage tanks (CSTs) to ensure minimum flow to prevent hydraulic instabilities and dissipate pump heat. The recirculation line contained a pressure reducing, flow restricting orifice. The RO used a multi-stage, anti-cavitation trim package installed in the body of a globe valve to limit flow. This style of orifice or flow restrictor was installed in the AFW recirculation lines at PBNP in the past few years to eliminate cavitation caused by the old orifices. This type of flow restrictor used very small channels and holes in each stage combined with a tortuous path to limit flow and prevent cavitation. After removal of the orifice internals, partial blockage was observed in 24 of the 54 holes in the outermost sleeve. No particles were found on any of the inner sleeves. Samples of the particles removed from the orifice were retained for analysis. A boroscope inspection of the recirculation piping at the orifice location revealed no evidence of debris. Following cleaning and reassembly, the orifice was reinstalled and the P38A AFW pump was successfully retested.	
IN	2003-13	Steam Generator Tube Degradation at Diablo Canyon	The U.S. Nuclear Regulatory Commission is issuing this information notice to inform addressees about findings from a recent steam generator tube inspection at the Diablo Canyon Power Plant, Unit 2 (DCPP-2). The NRC anticipates that recipients will review the information for applicability to their facilities and consider taking actions, as appropriate, to avoid similar problems. However, no specific action or written response is required. Discussion DCPP-2 has four Westinghouse model 51 steam generators (SGs), with 7/8 inch outside diameter (OD), mill-annealed Alloy 600 tubing and drilled hole carbon steel tube support plates. The model 51 steam generator has 45 rows of tubes, with row 1 having the smallest bend radii in the U-bend area. During Operating Cycle 11, a small steam generator tube leak (less than or equal to approximately 6.5 gallons per day) was present at DCPP-2. During the 2003 refueling outage, Pacific Gas & Electric	Steam generators

Type	No.	Title	Topic	SPC Affected
			(PG&E), the licensee for DCPP-2, performed SG secondary side pressure tests to locate the source of the SG leakage. Several potentially leaking SG tubes were identified and subsequent eddy current testing identified two contributing degradation modes: circumferential primary water stress corrosion cracking (PWSCC) in the U-bend region and axial outside diameter stress corrosion cracking (ODSCC) at the tube-to-tube support plate intersections. <u>Related Generic Communications</u> The following documents describe other recent reactor operating experience with steam generator tubes: • IN 2003-05, "Failure to Detect Freespan Cracks in PWR Steam Generator Tubes," dated June 5, 2003 • IN 2002-02 and IN 2002-02 supplement 1, "Recent Experience With Plugged Steam Generator Tubes" dated January 8, 2002 and July, 17, 2002 • IN 2002-21, "Axial Outside-Diameter Cracking Affecting Thermally Treated Alloy 600 Steam Generator Tubing" dated June 25, 2002 • IN 2001-16, "Recent Foreign and Domestic Experience with Degradation of Steam Generator Tubes and Internals," dated October 31, 2001 • NRC Generic Letter 97-05, "Steam Generator Tube Inspection Techniques," dated December 17, 1997 • Inspection Report 50-323/03-09, "Diablo Canyon Power Plant - NRC Special Team Inspection Report" dated May 8, 2003 (Adams ML031290198)	
IN	2003-11s1 and original 2003-11	Leakage Found on Bottom-Mounted Instrumentation Nozzles	The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice (IN) to alert addressees to indications of leakage in the form of boron deposits discovered on bottom mounted instrumentation (BMI) nozzles at South Texas Project Unit 1 (STP Unit 1). This supplement specifically provides additional information regarding the STP Unit 1 licensee's root cause analyses, as discussed in licensee's final licensee event report on this topic, dated October 15, 2003 (ADAMS Accession No. ML032950483). It is expected that the recipients of this IN will review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems. However, suggestions contained in this IN are not NRC requirements; therefore, no specific action or written response is required. <u>Discussion</u> An extensive description of the STP Unit 1 BMI penetration leakage event was given in IN 2003-11, "Leakage Found on Bottom-Mounted Instrumentation Nozzles," dated August 13, 2003. The relevant pre-August 2003 information is summarized herein. In April 2003, the STP Unit 1 licensee identified	RPV – instrumentation nozzles

Type	No.	Title	Topic	SPC Affected
			small boron deposits around two of the 58 STP Unit 1 BMI penetrations (penetrations 1 and 46), the only evidence of BMI nozzle penetration leakage reported by a U.S. facility to date. The STP Unit 1 BMI penetrations were constructed from an drilled Inconel 600 bar stock connected to the reactor vessel lower head by an Inconel 82/182 J-groove weld. The licensee's subsequent nondestructive examination (NDE) campaign, which included ultrasonic test (UT), visual, and eddy current testing, resulted in the identification of three axially oriented cracklike indications in the penetration 1 nozzle wall and two axially oriented cracklike indications in the penetration 46 nozzle wall.	
IN	2003-08	Potential Flooding Through Unsealed Concrete Floor Cracks	The Nuclear Regulatory Commission (NRC) is issuing this information notice to inform addressees of observed flooding in a room containing safety-related panels and equipment as a result of fire water seepage through unsealed concrete floor cracks. It is expected that recipients will review the information for applicability to their facilities and consider actions as appropriate to avoid similar problems. However, suggestions contained in this NRC information notice are not NRC requirements; therefore, no specific action or written response is required. Discussion On May 3, 2002, at Energy Northwest's Columbia Generating Station, 15 to 20 gallons of water spilled from a firewater drain line onto the floor of the radwaste building 484' elevation cable spreading room. A small amount of this water leaked down into the remote shutdown room and the Division II switchgear room, which is located below the cable spreading room floor. The licensee determined that the pathway for the leakage was through cracks in the concrete floor.	Concrete – floor - cracks
IN	2003-05	Failure to Detect Freespan Cracks in PWR Steam Generator Tubes	This information notice (IN) is being provided to inform licensees of a recent problem experienced at Comanche Peak Unit 1 concerning the detection of freespan outside diameter stress corrosion cracking (ODSCC) in steam generator (SG) tubes. This has led to tube integrity performance criteria not being met as defined in Nuclear Energy Institute (NEI) 97-06, "Steam Generator Program Guidelines." The NRC anticipates that recipients will review the information for applicability to their facilities and consider taking appropriate actions. However, suggestions contained in this IN do not constitute NRC requirements; therefore, no specific action or written response is required. Discussion Comanche Peak Unit 1 is a four-loop Westinghouse PWR with four Westinghouse Model D4 recirculating SGs (1, 2, 3, 4). Each SG contains 4578 mill- annealed Alloy 600 tubes, which are nominally 0.750 inch in diameter and have a nominal wall thickness of 0.043 inch. The tubes are supported by a number of carbon steel tube support plates with circular holes and by V-shaped chrome-plated Alloy 600 anti-vibration bars (AVBs). Comanche Peak Unit 1 was shut down approximately 1 week prior to its scheduled refueling outage as a result of a primary-to-secondary	Steam Generators

Type	No.	Title	Topic	SPC Affected
			leak. A 5- to 15-gallon-per-day (gpd) leak was first observed in SG 2 on September 26, 2002. Over the next 2 days, the leakage spiked to higher values several times. On September 28, 2002, after a leakage spike to 52 gpd, the licensee elected to shut down the plant and to commence refueling (1RF09). After shutting down the plant, the licensee began inspecting the SG tubes with eddy current testing techniques.	
IIN	2003-02	Recent Experience With Reactor Coolant System Leakage And Boric Acid Corrosion	The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice to inform addressees of recently observed reactor coolant leakage at two pressurized water reactor facilities, one of which resulted in the subsequent degradation of the reactor pressure vessel head. It is expected that recipients will review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems. However, suggestions in this information notice are not NRC requirements; therefore no specific action or written response is required. <u>Discussion</u> A number of mechanical and welded connections exist above the reactor pressure vessel head that, historically, have leaked at a number of plants. This leakage of borated water may lead to degradation of the low alloy steel reactor vessel head by boric acid corrosion. At Sequoyah Unit 2 (December 26, 2002), the leakage resulted in relatively minor degradation of the reactor vessel head. At Comanche Peak Unit 1 (November 30, 2002), the leakage resulted in no apparent degradation of the RCS pressure boundary. In the Sequoyah Unit 2 and Comanche Peak Unit 1 events, the unidentified reactor coolant leakage had not shown a discernible increase from the very low levels that typically occur at a PWR facility.	RPV – head connection/penetration
IN	2002-26 s1, s2, & original 2002-26	Additional Flow-Induced Vibration Failures after a Recent Power Uprate	The U.S. Nuclear Regulatory Commission (NRC) is issuing this supplement to a previously issued information notice (IN) to alert addressees to the failure of the steam dryer and other plant components at Quad Cities Nuclear Power Station, Unit 1 (QC-1), a boiling water reactor (BWR), during operations following a power uprate. The NRC expects that the recipients will review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems. However, suggestions contained in this information notice are not NRC requirements. Therefore, no specific action or written response is required. <u>Discussion</u> As discussed in IN 2002-26, “Failure of Steam Dryer Cover Plate After a Recent Power Uprate” (ML022530291), a cover plate on the outside of the steam dryer at Quad Cities Nuclear Power Station, Unit 2 (QC-2), broke loose in June 2002 and caused pieces of the dryer to be swept down the main steamline. Before the unit was shut down in 2002, steam dryer degradation was indicated by an increase in moisture carryover and minor perturbations in reactor pressure, water level, and steam	RPV – steam dryer cover plate, hood, & other areas – fatigue

Type	No.	Title	Topic	SPC Affected
			flow. The licensee evaluated the cause of the steam dryer cover plate failure and determined that the failure of the plate was due to high-cycle fatigue. The second failure of the steam dryer in May 2003 at QC-2 was discussed in IN 2002-26, Supplement 1, "Additional Failure of Steam Dryer After a Recent Power Uprate" (ML031980434). Inspection of the dryer revealed (1) through-all cracks (about 90 inches long) in the vertical and horizontal portions of the outer bank hood, 90-degree side, (2) one vertical and two diagonal internal braces detached from the outer bank hood, 90-degree side, (3) one severed vertical internal brace on the outer bank hood, 270-degree side, and (4) three cracked tie bars on top of the dryer. The licensee believes the most probable cause of the failure of the steam dryer in QC-2 is low-frequency, high-cycle fatigue driven by flow induced vibrations associated with the higher steam flows present during EPU operating conditions. In late October 2003 at QC-1, the licensee observed changes in main steamline flows, steamline pressure drop, and increasing moisture carryover measurements. On November 12, the licensee shut down QC-1 to inspect the steam dryer and identified significant damage to several areas.	
IN	2002-02 s1	Recent Experience With Plugged Steam Generator Tubes	The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice (IN) to inform addressees of findings from recent inspections and examinations of steam generator tubes at Oconee Nuclear Station Unit 1 (ONS-1). The NRC anticipates that recipients will review the information for applicability to their facilities and consider taking actions, as appropriate, to avoid similar problems. However, suggestions contained in this information notice do not constitute NRC requirements; therefore, no specific action or written response is required. <u>Discussion</u> Potential severance of plugged steam generator tubes was discussed in IN 2002-02, "Recent Experience With Plugged Steam Generator Tubes," (ML013480327) as a result of inspection findings at Three Mile Island Unit 1 (TMI-1) during the fall 2001 refueling outage. At TMI-1, a plugged tube, located on the periphery of the tube bundle, severed near the secondary side of the upper tubesheet and damaged four adjacent in-service (i.e., nonplugged) tubes. The preliminary laboratory investigation of the severed tube found signs of high cycle fatigue, ductile failure, and outside-diameter-initiated intergranular attack (IGA). In addition, the tube diameter was greater than the nominal tube diameter, indicating that the severed tube had swollen. The licensee determined that the most likely cause of failure was fatigue caused by flow-induced vibration of the swollen and restrained tube. On March 25, 2002, ONS-1 was shut down for a refueling outage. In addition to the standard steam	Steam Generators

Type	No.	Title	Topic	SPC Affected
			generator tube inspections, the licensee performed supplemental inspections of plugged tubes in both steam generators. These supplemental inspections were performed to address the TMI-1 plugged tube severance event (discussed in Information Notice 2002-02). While inspecting two tubes in the B steam generator, the licensee identified signs of wear on the outside tube surface near the secondary face of the lower tubesheet. The circumferential location of the wear on these two tubes indicated that the wear was most likely due to impact from an adjacent tube. Subsequent visual inspection from the secondary side of the steam generator indicated that tube one of the tubes was completely severed at the secondary side (i.e., top) of the lower tubesheet.	
IN	2002-21, s1 & original 02-21	Axial Outside-Diameter Cracking Affecting Thermally Treated Alloy 600 Steam Generator Tubing	The U.S. Nuclear Regulatory Commission (NRC) is issuing this supplement to IN 2002-21 to inform addressees of the root cause assessment for the axially oriented outside-diameter crack indications in the thermally treated Alloy 600 steam generator (SG) tubing at Seabrook. It is expected that recipients will review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems. However, suggestions contained in this information notice are not NRC requirements; therefore, no specific action or written response is required. <u>Discussion</u> During the eighth refueling outage, 42 eddy current indications in 15 “low row” tubes (tubes in rows 1 through 10) were identified and classified as potential axially oriented outside diameter stress corrosion cracks (ODSCC). All indications were in one steam generator and all indications were located in the region where the tube passes through a TSP (i.e., tube-to-tubesupport-plate intersection). Both hot and cold leg tubes were affected. No indications were observed at the top of the tubesheet. This issue was discussed in NRC IN 2002-21, “Axial Outside-Diameter Cracking Affecting Thermally Treated Alloy 600 Steam Generator Tubing”, issued June 25, 2002 (ADAMS Accession No. ML021770094).	Steam Generators
IIN	2002-13	Possible Indicators of Ongoing Reactor Pressure Vessel Head Degradation	The U.S. Nuclear Regulatory Commission is issuing this information notice on recent Davis-Besse experience to alert addressees to possible indicators of reactor coolant pressure boundary degradation including degradation of the reactor pressure vessel (RPV) head material. The NRC anticipates that recipients will review this information for applicability to their facilities and consider taking appropriate actions. However, the suggestions contained in this information notice do not constitute NRC requirements and, therefore, no specific action or written response is required. <u>Discussion</u> The Davis-Besse nuclear power plant recently discovered a significant cavity in the RPV head on the downhill side of control rod drive nozzle number 3 and some head wastage behind nozzle number 2. In response, the NRC issued Information Notice 2002-11, "Recent Experience With Degradation of	RPV head

Type	No.	Title	Topic	SPC Affected
			Reactor Pressure Vessel Head," on March 12, 2002, and Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity," on March 18, 2002. NRC also sent an Augmented Inspection Team (AIT) to the plant to investigate the circumstances of the degradation of the RPV head material. Through the AIT, several possible indicators of reactor coolant pressure boundary degradation such as was observed at Davis-Besse were identified. These indicators include unidentified reactor coolant system (RCS) leakage and containment air cooler (CAC) and radiation element (RE) filter fouling. RCS leakage, boron deposits, and corrosion products like ferric oxide in CACs and RE filters may indicate degradation of the reactor coolant pressure boundary materials. These indicators do not provide clear evidence of the degradation; however, they may provide an opportunity for licensees to suspect that degradation is ongoing. The NRC understands that the indications at Davis-Besse were sometimes complicated by other events (e.g., flange leaks). Nonetheless, in combination with other indicators, they may provide insights into whether degradation of the reactor coolant pressure boundary materials is occurring.	
IN	2002-11	Recent Experience with Degradation of Reactor Pressure Vessel Head	The U.S. Nuclear Regulatory Commission is issuing this information notice to inform addressees about findings from recent inspections and examinations of the reactor pressure vessel (RPV) head at Davis-Besse Nuclear Power Station. It is expected that recipients will review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems. However, suggestions contained in this information notice are not NRC requirements; therefore, no specific action or written response is required. <u>Discussion</u> On February 16, 2002, the Davis-Besse facility began a refueling outage that included inspection of the vessel head penetration (VHP) nozzles, which focused on the inspection of control rod drive mechanism (CRDM) nozzles, in accordance with the licensee's commitments to NRC Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles," which was issued on August 3, 2001. These inspections identified axial indications in three CRDM nozzles, which had resulted in pressure boundary leakage. Specifically, these indications were identified in CRDM nozzles 1, 2, and 3, which are located near the center of the RPV head. These findings were reported to the NRC on February 27, 2002, and supplemented on March 5 and March 9, 2002. The licensee decided to repair these three nozzles, as well as two other nozzles that had indications but had not resulted in pressure boundary leakage. <u>Related Generic Communications</u>	RPV head

Type	No.	Title	Topic	SPC Affected
			• Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles," August 3, 2001. • Bulletin 82-02, "Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants," June 2, 1982. • Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants," March 17, 1988. • Generic Letter 97-01, "Degradation of Control Rod Drive Mechanism Nozzles and Other Vessel Closure Head Penetrations," April 1, 1997. • Information Notice 80-27, "Degradation of Reactor Coolant Pump Studs," June 11, 1980. • Information Notice 82-06, "Failure of Steam Generator Primary Side Manway Closure Studs," March 12, 1982. • Information Notice 86-108, "Degradation of Reactor Coolant System Pressure Boundary Resulting from Boric Acid Corrosion," December 29, 1986. • Information Notice 86-108, Supplement 1, "Degradation of Reactor Coolant System Pressure Boundary Resulting from Boric Acid Corrosion," April 20, 1987. • Information Notice 86-108, Supplement 2, "Degradation of Reactor Coolant System Pressure Boundary Resulting from Boric Acid Corrosion," November 19, 1987. • Information Notice 86-108, Supplement 3, "Degradation of Reactor Coolant System Pressure Boundary Resulting from Boric Acid Corrosion," January 5, 1995. • Information Notice 90-10, "Primary Water Stress Corrosion Cracking of INCONEL 600," February 23, 1990. • Information Notice 94-63, "Boric Acid Corrosion of Charging Pump Casing Caused by Cladding Cracks," August 30, 1994. • Information Notice 96-11, "Ingress of Demineralizer Resins Increases Potential for Stress Corrosion Cracking of Control Rod Drive Mechanism Penetrations," February 14, 1996. Information Notice 2001-05, "Through-Wall Circumferential Cracking of Reactor Pressure Vessel Head Control Rod Drive Mechanism Penetration Nozzles at Oconee Nuclear Station, Unit 3," April 30, 2001.	
IN	2002-02	Recent Experience with Plugged Steam Generator	The U.S. Nuclear Regulatory Commission is issuing this information notice to inform addressees about findings from recent inspections and examinations of steam generator tubes at Three Mile Island Unit 1 (TMI-1). The NRC anticipates that recipients will review the information for applicability to their facilities and consider taking actions, as appropriate, to avoid similar problems. However, suggestions contained in this information notice do not constitute NRC requirements; therefore, no specific action or written response is required.	Steam Generators

Type	No.	Title	Topic	SPC Affected
		Tubes	<u>Discussion</u> On October 8, 2001, TMI-1 was shut down for a refueling outage. While inspecting the tubes in the B Steam Generator, the licensee (AmerGen Energy Company, LLC) identified signs of wear near the upper tubesheet on the outer surface of four tubes on the periphery of the tube bundle. These wear indications did not appear to have been present during the prior steam generator tube inspections, which were performed approximately 2 years earlier. Given the pattern and location of the wear signs, the licensee suspected that a neighboring plugged tube had caused the wear. The licensee removed the upper plug in the suspected tube and performed a video inspection. The video inspection revealed that the tube was severed near the secondary face of the upper tubesheet and in physical contact with the drilled hole where the tube passed through the 15^{th} support plate. Neighboring tubes were not in contact with the drilled holes at the point where they passed through the 15^{th} support plate.	
IN	2001-16	Recent Foreign and Domestic Experience with Degradation of Steam Generator Tubes and Internals	The U.S. Nuclear Regulatory Commission is issuing this information notice to inform addressees about findings from recent inspections of steam generator tubes and secondary-side internal components and structures. It is expected that recipients will review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems. However, suggestions contained in this information notice are not NRC requirements; therefore, no specific action or written response is required. <u>Discussion</u> Foreign Sludge Lancing Experience In 1998, a foreign reactor was shut down for a refueling outage. At the time of the shutdown, there was no evidence of primary-to-secondary leakage. During the outage, sludge lancing was performed followed by a bobbin coil probe inspection of 100% of the tubes in all four steam generators. The tube inspections revealed only minor wall thinning. However, during plant startup following the outage, a very small primary-to-secondary leak was observed, and the reactor was shut down to investigate its source. Subsequent inspections identified several degraded steam generator tubes in the second and third rows of the steam generator tube lane. The degradation consisted of localized loss of the outer surface of the tubes just above the top of the tubesheet. Extensive wall loss in one of these tubes resulted in a pinhole-sized perforation of the tube wall. Degradation of the Calvert Cliffs Unit 2 Tube Support	Steam Generators

Type	No.	Title	Topic	SPC Affected
			During the performance of a steam generator secondary-side visual inspection in 1999, Baltimore Gas and Electric Company (BGE) identified degradation at the periphery of the eggcrate tube supports in both steam generators at Calvert Cliffs Nuclear Power Plant Unit 2. In the #21 steam generator, BGE found minor degradation of the eggcrate supports on the hot-leg side at the sixth, seventh, and eighth support elevations. In the #22 steam generator, BGE found more extensive degradation of the eggcrate supports on the hot-leg side at the seventh and eighth support elevations, as well as on the cold-leg side at the sixth support elevation. On the basis of the location and nature of the degradation, BGE concluded that it was caused by erosion-corrosion, similar to, but much less extensive than, that observed at San Onofre Unit 3. (The San Onofre experience is discussed in GL 97-06). Possible Degradation in Thermally Treated Alloy 600 Tubes The steam generators at Turkey Point Units 3 and 4 were replaced in 1982 and 1983, respectively, with steam generators of an improved design. The tubes of the replacement steam generators were made of a more corrosion-resistant material, thermally treated Alloy 600, and were hydraulically expanded (and therefore, subjected to less stress). The quatrefoil tube supports were also more resistant to corrosion, being made of stainless steel. During a steam generator tube examination in the spring of 2000, the licensee for Turkey Point Unit 3 detected 69 tubes which required plugging. Of the 69 plugged tubes, 41 had volumetric pit-like indications, 15 had inside-diameter-initiated circumferential indications, eight had outside-diameter-initiated circumferential indications, and five had wear indications. Related Generic Communications • IN 96-38, "Results of Steam Generator Tube Examinations" • IN 97-26, "Degradation in Small-Radius U-Bend Regions of Steam Generator Tubes"; IN 97-49, "B&W Once-Through Steam Generator Tube Inspection Findings" • IN 97-88, "Experiences During Recent Steam Generator Inspections" • Regulatory Issue Summary 2000-22, "Issues Stemming From NRC Staff Review of Recent Difficulties Experienced in Maintaining Steam Generator Tube Integrity." • IN 96-09, "Damage in Foreign Steam Generator Internals" • IN 96-09 Supplement 1, "Damage in Foreign Steam Generator Internals" • GL 97-06, "Degradation of Steam Generator Internals."	
IN	2001-09	Main	The U.S. Nuclear Regulatory Commission is issuing this information notice (IN) to alert addressees to	Piping

Type	No.	Title	Topic	SPC Affected
		Feedwater System Degradation in Safety-Related ASME Code Class 2 Piping Inside the Containment of a Pressurized Water Reactor	the discovery of main feedwater (MFW) system wall thinning to below allowable limits in turbine building components and in risk-important, safety-related portions of American Society of Mechanical Engineers (ASME) Code Class 2 piping inside the reactor containment building (containment) at the Callaway Plant. <u>Discussion</u> During a refueling outage that began on April 7, 2001, the Callaway Plant licensee conducted scheduled inspections to assess the effects of erosion/corrosion on steel piping exposed to flowing water (single-phase fluids) and water-steam mixtures (two-phase fluids). These effects are commonly referred to as flow-accelerated corrosion (FAC). Inspections identified several instances of localized MFW system piping wall thinning to below the minimum thickness required by ASME Boiler and Pressure Vessel Code, Section III, for safety-related piping, and to below the minimum thickness specified by American National Standards Institute (ANSI) B31.1, "Power Piping," for non-safety-related portions of the MFW system. The wall thicknesses in the degraded areas had not been previously measured. The licensee had expanded and upgraded its FAC program following an August 11, 1999, event in which an 8-inch moisture separator reheater drain line experienced a double-ended guillotine break causing operators to manually trip the reactor. The upgraded and expanded FAC program, utilizing CHECWORKS™ Rev. F software, predicted wall thinning in the MFW system. However, without wall thickness trending data, the software was not able to accurately predict the extent of degradation. After performing an inspection during the current outage, the licensee found the MFW degradation to be more extensive than anticipated. Based on the licensee's initial findings and on additional industry information, FAC inspections were expanded to include portions of the condensate system, auxiliary feedwater (AFW) system, feedwater heaters, and other areas. Additional degradation was found in piping for the feedwater heaters. <u>Summary of Previously Identified Pipe Wall Thinning Issues and Events</u> • 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	

Type	No.	Title	Topic	SPC Affected
			• 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 • 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, Bulletin 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 Through-wall pinhole leaks due to erosion were discovered in a 45-	

Type	No.	Title	Topic	SPC Affected
			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 • September 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 • 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	

Type	No.	Title	Topic	SPC Affected
			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 • 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	
IN	2005-01	Through-Wall Circumfere	The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice to alert addressees to the recent detection of through-wall circumferential cracks in two of the control rod drive mechanism (CRDM) penetration nozzles and weldments at the Oconee Nuclear Station, Unit 3	RPB head CRD penetration

Type	No.	Title	Topic	SPC Affected
		ntial Cracking of Reactor Pressure Vessel Head Control Rod Drive Mechanism Penetration Nozzles at Oconee Nuclear Station, Unit 3	(ONS3). It is expected that recipients will review the information for applicability to their facilities and consider actions, as appropriate. However, suggestions contained in this information notice are not NRC requirements; IN 2001-05 <u>Discussion</u> On February 18, 2001, with ONS3 in Mode 5, Duke Energy Corporation (the licensee) performed a visual examination (VT-2) of the outer surface of the unit's reactor pressure vessel (RPV) head to inspect for indications of borated water leakage. This RPV head inspection was performed as part of a normal surveillance during a planned maintenance outage. The VT-2 revealed the presence of small amounts of boric acid residue in the vicinity of nine of the 69 CRDM penetration nozzles (Figures 1 and 2). Subsequent nondestructive examinations (NDEs) identified 47 recordable crack indications in these nine degraded CRDM penetration nozzles. The licensee initially characterized these flaws as either axial or below-the-weld circumferential indications, and initiated repairs of the degraded areas. NDEs of nine additional CRDM penetration nozzles from the same heat of material were conducted for "extent of condition" purposes, but did not detect recordable indications	nozzles
IN	200-17 s2, s1 and Original 2000-17	Crack in Weld Area of Reactor Coolant System Hot Leg Piping at V. C. Summer	The U.S. Nuclear Regulatory Commission is issuing this information notice (IN) supplement to provide updated information about the crack found in a weld in the A loop hot leg pipe in the reactor coolant system (RCS) at the V. C. Summer Nuclear Station. It is expected that recipients will review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems. However, no specific action or written response is required. <u>Discussion</u> On October 7, 2000, during a containment inspection after entering a refueling outage, the licensee identified a large quantity of boron on the floor and protruding from the air boot around the "A" loop RCS hot leg pipe. Ultrasonic testing (UT) and eddy current testing (ET) identified an axial crack-like indication approximately 2.7 inches long located approximately 7 degrees counterclockwise from top dead center of the first weld between the reactor vessel nozzle and the "A" loop hot leg piping approximately 3 feet from the reactor vessel. Based on the UT data, the axial crack-like indication began at the inner diameter and shows evidence of complete through-wall extension. Visual examination from the outer diameter identified a small "weep hole" in the center of the weld at approximately the same circumferential location as the UT and ET indications.	Piping
IN	2000-09	Steam Generator Tube Failure at	The U.S. Nuclear Regulatory Commission is issuing this information notice to inform addressees of a steam generator tube failure at Indian Point Unit 2. NRC investigations of the licensee's steam generator inspection program are ongoing and any potentially generic issues identified will be communicated in a separate generic communication. However, the investigations to date re-emphasize	Steam Generator

Type	No.	Title	Topic	SPC Affected
		Indian Point Unit 2	the importance of licensee involvement with ongoing industry efforts to understand and detect steam generator degradation. It is expected that recipients will review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems. However, suggestions contained in this information notice are not NRC requirements; therefore, no specific action or written response is required. <u>Discussion</u> On February 15, 2000, at 7:17 p.m., the Indian Point Unit 2 nuclear plant experienced a steam generator tube failure, which required the declaration of an Alert at 7:29 p.m., and a manual reactor trip at 7:30 p.m. The operators identified that the #24 steam generator was the source of the leak and completed isolation of the #24 steam generator by 8:31 p.m.	
IN	99-10, Rev. 1, and 99-10	Degradation of Prestressing Tendon Systems in Prestressed Concrete Containments	The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice to alert addressees to the degradation of prestressing systems components of prestressed concrete containments (PCCs). The following specific items are addressed: (1) breakage of prestressing tendon wires, (2) effects of high temperature on the prestressing forces in tendons, and (3) trend analysis of prestressing forces. It is expected that recipients will review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems. However, suggestions contained in this information notice are not NRC requirements; therefore, no specific action or written response is required. <u>Discussion</u> On April 13, 1999, the staff issued Information Notice 99-10 to describe the degradation associated with the tendon prestressing system of prestressed concrete containments (PCCs). The staff received a letter from Duke Energy on May 6, 1999, which indicated that Attachment 3 to IN 99-10, "Comparison and Trending of Prestressing Forces," misrepresented the Oconee experience. This revision corrects the observations made by the staff concerning the sixth tendon surveillance performed at Oconee Unit 3 in the summer of 1995 and provides other editorial and clarifying changes. Inspections of PCCs and PCC tendons have identified a number of concerns related to the degradation of prestressing tendon systems in PCCs. Findings relevant to these concerns are: Breakage of Prestressing Tendon Wires, Effects of High Temperature on the Prestressing Forces in Tendons, Comparison and Trending of Prestressing Forces	Prestressing tendons
IN	98-45	Cavitation Erosion of	The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice to alert addressees to potential problems caused by cavitation erosion of letdown line orifices in the chemical and volume	Piping

Type	No.	Title	Topic	SPC Affected
		Letdown Line Orifices Resulting in Fatigue Cracking of Pipe Welds	control system (CVCS). Such erosion has contributed to failures in pipe welds downstream of the letdown line orifices. It is expected that recipients will review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems. However, suggestions contained in this information notice are not NRC requirements; therefore, no specific action or written response is required. <u>Discussion</u> On September 11, 1996, Surry Power Station, Unit 2, experienced its fourth socket weld failure in 12 months. The failed welds were located on the low-pressure portion of the CVCS letdown line, just downstream of the pressure-reducing orifice isolation valves. The licensee determined that the most likely cause of the weld failure was flow-induced vibration. The licensee performed a microscopic examination of the Unit 2 letdown line orifices and concluded that two of the orifices exhibited cone-shaped patterns, wider at the discharge of the orifice and tapering toward the inlet of the orifice. In addition, the orifice exhibited very rough and irregular surface profiles. The damage to the letdown line orifices is indicative of cavitation erosion and is believed to have contributed to flow-induced vibration of the letdown line and to the socket weld failures. On March 15, 1997, the licensee performed radiographic examinations on the Surry Unit 1 letdown line orifices to check for an erosion condition similar to that previously seen in the Unit 2 letdown line orifices. The licensee concluded that erosion was present in all three orifices and that the most extensive deterioration was present in the 45-gpm orifice. Socket welds have also failed at Diablo Canyon Nuclear Power Plant, Unit 2. From June 1989 through December 1990, four socket welds failed on two of three reactor coolant system (RCS) pressure letdown lines in the CVCS. All four failed welds were located on the piping downstream of the RCS letdown orifice isolation valves. On March 19, 1991, Diablo Canyon Unit 2 experienced the fifth letdown leak since June 1989. During the repair effort, the licensee determined that the cause of the failures was flow-induced vibration due to a damaged letdown orifice upstream of the weld failure.	
IN	98-27	Steam Generator Tube End Cracking	The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice to inform licensees of instances of steam generator tube-end cracking. It is expected that recipients will review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems. However, suggestions contained in this information notice are not NRC requirements; therefore, no specific action or written response in required. <u>Discussion</u>	Steam Generators

Type	No.	Title	Topic	SPC Affected
			Entergy, the licensee for Arkansas Nuclear One, Unit 1 (ANO-1), conducted leak testing on each once-through steam generator (OTSG) during the spring 1998 refueling outage to identify the source of primary-to-secondary leakage measured during the previous operating cycle. The leak testing revealed a small leak in one tube of each OTSG. The leak in each tube was in flaws in the tube hardroll just below the upper tubesheet seal weld. Subsequent eddy current inspections identified primary-water stress-corrosion cracking (PWSCC) in each of the two tubes. The through-wall flaws in the tubes were oriented both axially and circumferentially in the tubes. Examinations of all upper tubesheet seal weld areas in both OTSGs revealed possible flaws in 1896 additional tubes. Eddy current inspections completed at Davis-Besse Nuclear Power Station in April 1998 identified five tubes with "tube end anomalies" believed to be related to the flaws identified at ANO-1. Duke Power Co. recently completed an assessment to determine if its Babcock and Wilcox-designed, operating units, Oconee Nuclear Station, Units 1 and 3, were affected by tube-end cracking. The licensee concluded that 372 indications in the Unit 1 OTSGs and 61 indications in the Unit 3 OTSGs exceeded the repair criteria in the Oconee Technical Specifications. Tube-end cracking has also been reported for the steam generators at Prairie Island Nuclear Generating Plant.	
IN	98-26	Settlement Monitoring and Inspection of Plant Structures Affected by Degradation of Porous Concrete Subfoundations	The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice (IN) to inform addressees who own and operate facilities with plant sites that include structures with porous concrete subfoundations of the possibility of degradation of these subfoundations. Such degradation could have deleterious effects on structures, systems, and components (SSCs). It is expected that recipients will review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems. However, suggestions contained in this information notice are not NRC requirements; therefore, no specific action or written response is required. <u>Discussion</u> The containment structure at Millstone Nuclear Power Station, Unit 3 (MNPS-3), has a 3.05-meter (10-foot) thick reinforced-concrete basemat founded on rock. Between the foundation rock surface and the underside of the basemat are several layers of different materials. In the upper porous concrete layer, 15-cm (6-inch) diameter porous concrete pipes are installed to collect and drain ground water, which may seep down along the periphery of the containment wall. The collected water drains into two sumps inside the engineered safety features (ESF) building. The MNPS-3 licensee, Northeast Nuclear Energy Company, identified the issue of cement erosion from the porous concrete drainage system in 1987 upon examination of the accumulated white residue	Concrete – porous concrete subfoundation

Type	No.	Title	Topic	SPC Affected
			in the two lower drain sumps in the ESF building. IN 97-11, "Cement Erosion From Containment Subfoundations at Nuclear Power Plants," was issued on March 21, 1997, to alert addressees to the potential for erosion of cement from porous concrete subfoundations.	
IN	98-11	Cracking of Reactor Vessel Internal Baffle Former Bolts in Foreign Plants	The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice to alert addressees to the cracking of reactor vessel internal baffle former bolts found at several foreign PWRs and to inform addressees of actions taken and planned by domestic PWR owners groups in response to this experience. It is expected that the recipients will review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems. However, suggestions contained in this information notice are not NRC requirements; IN 98-11 Discussion European plants identified the cracking of baffle former bolts as early as 1988 and this problem continues to occur. Although this cracking is not fully understood, testing of cracked bolts suggests an age-related intergranular stress-corrosion cracking process influenced by bolt material, fluence, stress, and temperature. The reported cracking occurred in 316 cold-worked stainless steel bolts. Most of the cracking reported has been in four French 900-MWe (megawatt electric) PWRs.	RPV reactor internals – internal baffle bolts
Bulletin (BL)	2004-01	Inspection of Alloy 82/182/600 Materials Used in the Fabrication of Pressurizer Penetrations and Steam Space Piping Connections at Pressurized-Water Reactors	The U.S. Nuclear Regulatory Commission (NRC) is issuing this bulletin to: (1) advise PWR licensees that current methods of inspecting Alloy 82/182/600 materials used in the fabrication of pressurizer penetrations and steam space piping connections may need to be supplemented with additional measures to detect and adequately characterize flaws due to primary water stress corrosion cracking (PWSCC), (2) request PWR addressees to provide the NRC with information related to the materials from which the pressurizer penetrations and steam space piping connections at their facilities were fabricated, (3) request PWR licensees to provide the NRC with information related to the inspections that have been and those that will be performed to ensure that degradation of Alloy 82/182/600 materials used in the fabrication of pressurizer penetrations and steam space piping connections will be identified, adequately characterized, and repaired, and (4) require PWR addresses to provide a written response to the NRC in accordance with the provisions of Section 50.54(f) of Title 10 of the Code of Federal Regulations (10 CFR 50.54(f)). Operating experience, both domestic and foreign, has demonstrated that Alloy 82/182/600 materials connected to a PWR's pressurizer may be particularly susceptible to PWSCC. Since the late 1980's, approximately 50 Alloy 600 pressurizer heater sleeves at Combustion Engineering-designed (CE-designed) facilities in the United States have shown evidence of RCPB leakage which has been attributed to PWSCC. The most recent events of this type	Pressurizer and Piping

Type	No.	Title	Topic	SPC Affected
			occurred at Millstone, Unit 2, and Waterford, Unit 3, in October 2003, and at Palo Verde, Unit 3, in February 2004. All available evidence from finite element modeling studies and limited nondestructive evaluation (NDE) has suggested that these leakage events were the result of axially-oriented PWSCC of the pressure boundary portion of these heater sleeves. However, NDE results from Palo Verde, Unit 2's fall 2003 refueling outage, on heater sleeves which had not shown evidence of leakage have demonstrated that circumferentially-oriented PWSCC can occur in the non-pressure boundary portion (i.e., above the J-groove attachment weld) of these components. Cracking in a TMI-1 diaphragm plate was attributed to PWSCC in the heat affected zone of the seal weld. Boric acid corrosion of the low alloy steel strongback was also observed to have resulted from the leakage. Related Generic Communications • Bulletin 2003-02, “Leakage From Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity,” August 21, 2003 (ADAMS Accession No. ML032320153) BL 2004-01 • Bulletin 2002-02, “Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs,” August 9, 2002 (ADAMS Accession No. ML022200494) • Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity,” March 18, 2002 (ADAMS Accession No. ML020770497) • Bulletin 2001-01, “Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles,” August 3, 2001 (ADAMS Accession No. ML012080284)	
BL	2003-02	Leakage from Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity	The U.S. Nuclear Regulatory Commission (NRC) is issuing this bulletin to: (1) advise PWR addressees that current methods of inspecting the RPV lower heads may need to be supplemented with additional measures (e.g., bare-metal visual inspections) to detect reactor coolant pressure boundary (RCPB) leakage, (2) request PWR addressees to provide the NRC with information related to inspections that have been or will be performed to verify the integrity of the RPV lower head penetrations, and (3) require PWR addresses to provide a written response to the NRC in accordance with the provisions of Section 50.54(f) of Title 10 of the Code of Federal Regulations (10 CFR 50.54(f)). The RPV and its head penetrations are an integral part of the RCPB, and their integrity is important to the safe operation of the plant. The recent identification of cracking and leakage from two BMI penetrations at South Texas Project Unit 1 (STP Unit 1) raises questions about potential	RPV head penetrations

Type	No.	Title	Topic	SPC Affected
			degradation mechanisms which may be active in this area. In addition, licensee responses to the Bulletin 2002-01 followup RAIs raised questions about the adequacy of inspections performed by licensees to detect leakage from RPV lower head penetrations. Related Generic Communications • Regulatory Issue Summary 2003-13, “NRC Review of Responses to Bulletin 2002-01, ‘Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity,’ July 29, 2003 (ADAMS Accession No. ML032100653) • Information Notice 2003-11 “Leakage Found on Bottom-Mounted Instrumentation Nozzles,” August 13, 2003 (ADAMS Accession No. ML032250135) • Bulletin 2002-02, “Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs,” August 9, 2002 (ADAMS Accession No. ML022200494) • Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity,” March 18, 2002 (ADAMS Accession No. ML020770497) • Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary • Components in PWR Plants," March 17, 1988 (ADAMS Accession No. ML031130424)	
BL	2003-01	Potential Impact of Debris Blockage on Emergency Sump Recirculation at Pressurized-Water Reactors	The U.S. Nuclear Regulatory Commission (NRC) is issuing this bulletin to: (1) Inform addressees of the results of NRC-sponsored research identifying the potential susceptibility of pressurized-water reactor (PWR) recirculation sump screens to debris blockage in the event of a high-energy line break (HELB) requiring recirculation operation of the emergency core cooling system (ECCS) or containment spray system (CSS). (2) Inform addressees of the potential for additional adverse effects due to debris blockage of flowpaths necessary for ECCS and CSS recirculation and containment drainage. (3) Request that, in light of these potentially adverse effects, addressees confirm their compliance with 10 CFR 50.46(b)(5) and other existing applicable regulatory requirements, or describe any compensatory measures implemented to reduce the potential risk due to post-accident debris blockage as evaluations to determine compliance proceed. (4) Require addressees to provide the NRC a written response in accordance with 10 CFR 50.54(f). In the event of a HELB within the containment of a PWR, energetic pressure waves and fluid jets would impinge upon materials in the vicinity of the break, such as thermal insulation, coatings, and concrete, causing damage and generating debris. Debris could also be	ECCS and CSS sump & drainage blockage

Type	No.	Title	Topic	SPC Affected
			generated through secondary mechanisms, such as severe post-accident temperature and humidity conditions, flooding of the lower containment, and the impact of containment spray droplets. To assess the likelihood of the ECCS and CSS pumps at domestic PWRs experiencing a debris-induced loss of NPSH margin during sump recirculation, the NRC sponsored a GSI-191 research program, which culminated in a parametric study. The parametric study mechanistically treated phenomena associated with debris blockage using analytical models of domestic PWRs that were generated with a combination of generic and plant-specific data. As documented in Volume 1 of NUREG/CR-6762, "GSI-191 Technical Assessment: Parametric Evaluations for Pressurized Water Reactor Recirculation Sump Performance," dated August 2002, the GSI-191 parametric study concludes that recirculation sump clogging is a credible concern for the population of domestic PWRs. The NRC's GSI-191 research identified the holdup or diversion of recirculation sump inventory as an important and potentially credible concern, and a number of LERs associated with this concern have also been generated, which further confirms both its credibility and potential significance. These LERs include: • LER 50-369/90-012, "Loose Material Was Located in Upper Containment During Unit Operation Because of an Inappropriate Action," McGuire Unit 1, submitted August 30, 1990. • LER 50-266/97-006, "Potential Refueling Cavity Drain Failure Could Affect Accident Mitigation," Point Beach Unit 1, submitted February 19, 1997. • LER 50-455/97-001, "Unit 2 Containment Drain System Clogged Due to Debris," Byron Unit 2, submitted April 17, 1997. • LER 50-269/97-010, "Inadequate Analysis of ECCS Sump Inventory Due to Inadequate Design Analysis," Oconee Unit 1, submitted January 8, 1998. • LER 50-315/98-017, "Debris Recovered from Ice Condenser Represents Unanalyzed Condition," D.C. Cook Unit 1, submitted July 1, 1998. Other cases included in the BL: • On December 11, 2002, the licensee for Davis-Besse Unit 1 submitted LER 50-346/02-005-01, "Potential Clogging of the Emergency Sump Due to Debris in Containment." • On May 5, 2003, the Davis-Besse licensee submitted LER 50-346/03-002-00, which stated that the HPI pumps had been declared inoperable as a result of the potential for debris to damage the pump internals during the recirculation phase of certain postulated LOCAs when the HPI pumps are required to take suction from the containment recirculation sump.	

Type	No.	Title	Topic	SPC Affected
			<u>Related Generic Communications</u> 24 Generic Communications listed related to ECCS and CSS sump and strainer blockage.	
BL	2002-02	Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs	The U.S. Nuclear Regulatory Commission (NRC) is issuing this bulletin to: (1) Advise pressurized-water reactor (PWR) addressees that visual examinations, as a primary inspection method for the reactor pressure vessel (RPV) head and vessel head penetration (VHP) nozzles, may need to be supplemented with additional measures (e.g., volumetric and surface examinations) to demonstrate compliance with applicable regulations. (2) Advise PWR addressees that inspection methods and frequencies to demonstrate compliance with applicable regulations should be demonstrated to be reliable and effective. (3) Request information from all PWR addressees concerning their RPV head and VHP nozzle inspection programs to ensure compliance with applicable regulatory requirements. (4) Require all PWR addressees to provide written responses to this bulletin related to their inspection program plans. <u>Discussion</u> Primary water stress corrosion cracking (PWSCC) in PWR control rod drive mechanism (CRDM) nozzles and other vessel head penetration nozzles fabricated from Alloy 600 is not a new issue; axial cracking in the CRDM nozzles has been identified since the late 1980s. In addition, numerous small-bore Alloy 600 nozzles and pressurizer heater sleeves have experienced leaks attributable to PWSCC. The area of interest for potential cracking of RPV head penetrations is the pressure-retaining boundary, which includes the J-groove weld between the nozzle and reactor vessel head and the portion of the nozzle inside the head. Inspections of the reactor nozzles at Oconee Nuclear Stations 2 and 3 in early 2001 identified circumferential cracking of the nozzles above the J-groove weld. In early March 2002, while conducting VHP nozzle inspections that were prompted by NRC Bulletin 2001-01, Davis-Besse Nuclear Power Station identified a large cavity in the RPV head near the top of the dome. The cavity was adjacent to a nozzle which was leaking as a result of through-wall axial cracking, and was located in an area of the RPV head that the licensee had left covered with boric acid deposits for a number of years.	RPV head & nozzle penetrations

Type	No.	Title	Topic	SPC Affected
			Related Generic Communications • Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity," March 18, 2002. [ADAMS Accession No. ML020770497] • Information Notice 2002-11, "Recent Experience with Degradation of Reactor Pressure Vessel Head," March 12, 2002. [ADAMS Accession No. ML020700556] • Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles," August 3, 2001. [ADAMS Accession No. ML012080284] • Information Notice 2001-05, "Through-Wall Circumferential Cracking of Reactor Pressure Vessel Head Control Rod Drive Mechanism Penetration Nozzles at Oconee Nuclear Station, Unit 3," April 30, 2001. [ADAMS Accession No. ML011160588] • Generic Letter 97-01, "Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations," April 1, 1997. • Information Notice 96-11, "Ingress of Demineralizer Resins Increases Potential for Stress Corrosion Cracking of Control Rod Drive Mechanism Penetrations," February 14, 1996. • Information Notice 90-10, "Primary Water Stress Corrosion Cracking of INCONEL 600," February 23, 1990. • Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants," March 17, 1988. • NUREG/CR-6245, "Assessment of Pressurized Water Reactor Control Rod Drive Mechanism Nozzle Cracking," October 1994.	
BL	2002-01	Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity	The U.S. Nuclear Regulatory Commission (NRC) is issuing this bulletin to require pressurized-water reactor (PWR) addressees to submit: (1) information related to the integrity of the reactor coolant pressure boundary including the reactor pressure vessel head and the extent to which inspections have been undertaken to satisfy applicable regulatory requirements, and (2) the basis for concluding that plants satisfy applicable regulatory requirements related to the structural integrity of the reactor coolant pressure boundary and future inspections will ensure continued compliance with applicable regulatory requirements, and (3) a written response to the NRC in accordance with the provisions of Title 10, Section 50.54(f), of the Code of Federal Regulations (10 CFR 50.54(f)) if they are unable to provide the information or they can not meet the requested completion dates. Discussion	RPV head & nozzle penetrations

Type	No.	Title	Topic	SPC Affected
			On August 3, 2001, the NRC issued Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles" (ADAMS Accession Number ML012080284). That bulletin described instances of cracked and leaking Alloy 600 reactor pressure vessel head penetration nozzles, including control rod drive mechanism and thermocouple nozzles. In response to that bulletin, pressurized-water reactor licensees provided their plans for inspecting their reactor pressure vessel head penetrations and/or the outside surface of the reactor pressure vessel head to determine whether the nozzles were leaking. Some plants have completed these inspections. In conducting these inspections at the Davis-Besse Nuclear Power Station in February and March 2002, the licensee identified three control rod drive mechanism nozzles with indications of axial cracking that resulted in reactor coolant pressure boundary leakage. <u>Related Generic Communications</u> 16 Generic Communications listed related to this issue.	
BL	2001-01	Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles	The U.S. Nuclear Regulatory Commission (NRC) is issuing this bulletin to: (1) request that addressees provide information related to the structural integrity of the reactor pressure vessel head penetration (VHP) nozzles for their respective facilities, including the extent of VHP nozzle leakage and cracking that has been found to date, the inspections and repairs that have been undertaken to satisfy applicable regulatory requirements, and the basis for concluding that their plans for future inspections will ensure compliance with applicable regulatory requirements, and (2) require that all addressees provide to the NRC a written response in accordance with the provisions of 10 CFR 50.54(f). <u>Discussion</u> The recent discoveries of cracked and leaking Alloy 600 VHP nozzles, including control rod drive mechanism (CRDM) and thermocouple nozzles, at four pressurized water reactors (PWRs) have raised concerns about the structural integrity of VHP nozzles throughout the PWR industry. Nozzle cracking at Oconee Nuclear Station Unit 1 (ONS1) in November 2000 and Arkansas Nuclear One Unit 1 (ANO1) in February 2001 was limited to axial cracking, an occurrence deemed to be of limited safety concern in the NRC staff's generic safety evaluation on the cracking of VHP nozzles, dated November 19, 1993. However, the discovery of circumferential cracking at Oconee Nuclear Station Unit 3 (ONS3) in February 2001 and Oconee Nuclear Station Unit 2 (ONS2) in April 2001 - particularly the large circumferential cracking identified in two CRDM nozzles at ONS3 - has raised concerns about the potential safety implications and prevalence of cracking in VHP nozzles in PWRs. <u>Related Generic Communications</u>	RPV head penetrations

Type	No.	Title	Topic	SPC Affected
			Same as BL 2002-02.	

Table 4-2 Summary of Degradation Information by Generic Communications

Generic Correspondence	Component / Subcomponent	Number of Generic Correspondences on this Component
Generic Letter	Steam Generators	4
	Strainer – Sump Pump Screens	2
	RPV – CRD nozzles & other penetrations	1
		Subtotal = 7
Bulletin	RPV – head penetrations, & coolant boundary	4
	Strainer – Sump Pump Screens	1
	Pressurizer & steam space piping connection	1
		Subtotal = 6
Information Notice	Steam Generators	9
	RPV - nozzles	8
	Piping	7
	Containment	3
	Concrete	2
	Pressurizer	2
	Spent fuel pool – liner	1
	Equipment – boric acide leakage onto	1
		Subtotal = 33
		Total = 46

Table 4-3 Summary of Degradation by Components

Component	Number of Generic Correspondences
Steam Generators	13
RPV	13
Piping	7
Strainer – Sump Pump Screens	3
Pressurizer	3
Containment	3
Concrete	2
Spent Fuel Pool	1
Equipment – boric acide leakage onto	1
	Total = 46

Table 4-4 License Renewal Applications for Information Related to Aging Degradation – Palisades Nuclear Power Plant

[Available on the NRC Website]

Aging Management Program	Description of Aging Management Program (AMP)	Operating Experience
Alloy 600 Program	This is an existing program that manages aging due to PWSCC of the Primary Coolant System (PCS) pressure boundary Alloy 600 components, including Inconel 82/182 weld joints, reactor vessel head penetrations, etc.	Industry: Instances of degradation of material have occurred as a result of PWSCC Plant Specific: • Pressurizer Temperature Element Penetration • Pressurizer Safe End • CRD Nozzle penetration indications (2)
ASME Section XI IWB, IWC, IWD, IWF Inservice Inspection Program	This is an existing program that facilitates inspections to identify and correct degradation in Class 1, 2, and 3 piping, components, their supports and integral attachments. The program includes periodic visual, surface and/or volumetric examinations and leakage tests of all Class 1, 2 and 3 pressure-retaining components, their supports and integral attachments, including welds, pump casings, valve bodies, pressure-retaining bolting, piping/component supports, and reactor head closure studs.	Industry: Numerous instances of degradation of components, component supports, and bolting have occurred. Plant Specific: • Control Rod Drive Housings • Piping Welds • Component Supports • Bolting • Temperature Element Penetration • Reactor Coolant Pressurizer Safe End • Engineered Safeguards Systems Check Valve
Bolting Integrity Program	This is an existing program that manages the aging effects associated with bolting through the performance of periodic inspections. The program also includes repair/replacement controls for ASME Section XI related bolting and generic guidance regarding material selection, thread lubrication and assembly of bolted joints.	Industry: Numerous instances of degradation of bolting have occurred. Plant Specific: • Piping Flange Bolts (1) • Pump Studs (2) • Tank Flange Bolts (1) • Pipe Support Bolting (1) • ESS Equipment Bolting (1)
Boric Acid Corrosion	This is an existing program that monitors component degradation due to boric acid leakage through the	Industry: • Boric acid wastage of reactor coolant system piping and nozzles

Aging Management Program	Description of Aging Management Program (AMP)	Operating Experience
Program	performance of periodic inspections. It implements the recommendations of NRC Generic Letter 88-05. The program requires periodic visual inspection of all systems within the scope of license renewal that contain borated water for evidence of leakage, accumulations of dried boric acid, or boric acid wastage. The program also provides for visual inspections and early discovery of borated water leaks such that structures, electrical and mechanical components that may be contacted by leaking borated water will not be adversely affected such that their intended functions are impaired.	• Boric acid corrosion of reactor vessel head and closure studs from leaking borated water • Failure of valve packing gland bolts due to boric acid wastage • Failure of valve body to bonnet studs/nuts due to boric acid wastage • Boric acid wastage of reactor coolant pump closure flange studs • Boric acid corrosion of steam generator manway closure studs • Boric acid corrosion of high pressure safety injection pump casing <u>Plant Specific:</u> • Boric acid leaks in the containment spray header in containment at flanges with carbon steel bolting and a threaded spray nozzle connection • Boric acid wastage of primary coolant pump studs • Boric acid wastage of manual valve body-to-bonnet bolts • Corrosion of flanges for primary coolant pump component cooling water connections due to external boric acid leakage
Buried Services Corrosion Monitoring Program	This is a new program that manages aging effects on the external surfaces of carbon steel, low-alloy steel, and stainless steel components that are buried in soil or sand. This program includes (a) visual inspections of external surfaces of buried components for evidence of coating damage and substrate degradation to manage the effects of aging, (b) visual inspection of the external surfaces of buried stainless steel components for evidence of crevice corrosion, pitting, and MIC. The periodicity of these inspections for carbon, low-alloy, and stainless steel will be based on opportunities for inspection such as scheduled maintenance work.	<u>Industry:</u> Issues related to Diesel fuel line leakage from the absence of required coating leading to corrosion. <u>Plant Specific:</u> • Through wall leak in buried steam line. • Generic program deficiencies from internal Engineering Programs audit. • See the Fire Protection Program for OE related to buried fire main ruptures. None of the plant operating issues or instances resulted from normal aging, or reflect significant program deficiencies.
Closed Cycle Cooling Water Program	This is an existing program that manages aging effects in closed cycle cooling water systems that are not subject to significant sources of contamination, in which water chemistry is controlled and heat is not directly rejected to the ultimate heat sink. The program includes (a) maintenance of system	<u>Industry:</u> • SCC in reactor coolant pump oil cooler discharge piping. • Corroded solder connections in diesel lube oil cooler due to inadequate corrosion inhibitor • Inoperable check valves (stuck open) due to corrosion product buildup • Cracks in Component Cooling Water piping

Aging Management Program	Description of Aging Management Program (AMP)	Operating Experience
	corrosion inhibitor concentrations to minimize degradation, and (b) periodic or one-time testing and inspections to assess SSC aging.	• Fouling of diesel cooling water heat exchangers Plant Specific: • Tube blockage and fouling in Component Cooling Heat Exchanger • Fuel Pool Heat Exchanger tube breakage due to high Component Cooling Water flow • Through wall flaw in Spent Fuel Pool Cooling pipe
Containment Inservice Inspection Program	This is an existing program that is designed to ensure that containment shell concrete, the post-tensioning system and steel pressure retaining elements continue to provide an acceptable level of structural integrity. In addition, it is designed to ensure that the liner (with associated moisture barriers), other leakage limiting steel barriers and pressure retaining bolted connections have not degraded.	Industry: Instances have occurred with containments. Plant Specific: • Liner plate corrosion • Unacceptable tendon liftoff value • Tendon gallery corrosion • Tendon grease leakage • Moisture barrier not in place • Tendon sheath water intrusion
Diesel Fuel Monitoring and Storage Program	This is an existing program that assures the continued availability and quality of fuel oil to be used in diesel generators and diesel fire pumps. The program includes (a) monitoring and trending of fuel oil chemistry to maintain fuel oil quality and mitigate corrosion, (b) periodic draining, cleaning, and internal inspection of fuel oil storage tanks, and (c) verification of program effectiveness by a one-time measurement of fuel oil storage tank bottom thickness confirming the absence of an aging effect.	Industry: • Fuel contamination leading to corrosion of fuel oil system components. • Improper zinc coating curing and epoxy application by the manufacturer leads to zinc-fuel reaction creating adverse corrosion. • Fuel oil leak caused by improper outer coating application. Plant Specific: No aging issues were identified.
Fire Protection Program	This is an existing program that includes (a) fire barrier inspections, (b) electric and diesel-driven fire pump tests, and (c) periodic maintenance, testing, and inspection of water-based fire protection systems. Periodic visual inspections of fire barrier penetration seals, fire dampers, fire barrier walls,	Industry: • Fire water system piping corrosion and ruptures • Fire retardant coatings and materials • Fouling of components in contact with raw water • Problems with fire barriers.

Aging Management Program	Description of Aging Management Program (AMP)	Operating Experience
	ceilings and floors, and periodic visual inspections and functional tests of fire-rated doors are performed to ensure that functionality and operability is maintained.	Plant Specific: • Blockage of Fire Protection piping with corrosion products • Deluge valve trim piping failures due to corrosion • Underground fire main rupture due to cyclic loadings • Water tight fire door seal degradation
Flow Accelerated Corrosion Program	This is an existing program that manages aging effects due to flow-accelerated corrosion (FAC) on the internal surfaces of carbon or low alloy steel piping, elbows, reducers, expanders, and valve bodies which contain high energy fluids (both single phase and two phase).	Industry: • Feedwater heater shell degradation and ruptures • Feedwater and Condensate line ruptures • Pipe wall thinning downstream of control valves and flow restricting devices • Valve body erosion • Extraction steam line ruptures • Moisture Separator Reheater Drain Tank drain line ruptures • Steam Generator Feedwater distribution piping and J-tube damage • Erosion of carbon steel ribs and tube supports in Steam Generators Plant Specific: • FAC on 2 inch main steam line elbows • Higher than expected wear rates on 8 inch steam pipes and elbows on the outlet of Moisture Separator Reheater • Main Condenser tube leaks caused by FAC • Higher than expected wear rates on high pressure extraction steam piping to high pressure feedwater heater • FAC on end-bell of low pressure feedwater heater • Valve body FAC on control valves and check valves • FAC of feedwater heater shell side capped drains • FAC damage to low pressure turbine extraction sleeves • FAC damage to extraction steam lines to high pressure feedwater heaters • FAC damage to Moisture Separator Reheater vent line • FAC of feedwater piping • FAC of reducer downstream of control valve • Through wall steam leak on steam generator flash tank
One-Time Inspection Program	This is a new program that addresses potentially long incubation periods for certain aging effects, including various corrosion mechanisms, cracking,	Industry: Not discussed

Aging Management Program	Description of Aging Management Program (AMP)	Operating Experience
	and selective leaching, and provides a means of verifying that an aging effect is either not occurring or progressing so slowly as to have negligible effect on the intended function of the structure or component.	Plant Specific: Not discussed
Open Cycle Cooling Water Program	This is an existing program that manages aging effects such as loss of material due to general, pitting, and crevice corrosion, erosion, MIC, and loss of heat transfer due to biological/corrosion product fouling (e.g., sedimentation, silting) caused by exposure of internal surfaces of metallic components to raw, untreated (e.g., service) water. The program scope includes activities to manage aging in the Service Water System (SWS) and Circulating Water system (CWS).	Industry: • Accumulations of silt and corrosion products in service water piping, valves, and heat exchangers • Accumulation of biological growth (mussels, clams, and shells) in service water piping, valves and heat exchangers • MIC causing pitting attack of carbon steel and stainless steel service water piping, pump casings, and 90/10 Cu/Ni heat exchanger tubes Plant Specific: • Defective tubes in the Main Condenser that required plugging due to MIC • Control Room Condensing Unit Condenser Drain Plug severely corroded due to MIC • Large Zebra Mussel accumulation near traveling screens and inside intake piping • Blockage of heat exchanger and cooler tubing • Corroded service water piping at threaded connections • Pinhole leaks in service water piping due to MIC • Switch failure due to sediment and corrosion (galvanic) blocking sensing line • Tubercles growing in carbon steel service water piping • Erosion of pipes, cooling coils, and heat exchanger tubes causing service water leaks
Reactor Vessel Integrity Surveillance Program	This is an existing program that manages the aging effect reduction of fracture toughness due to neutron embrittlement of the low alloy steel reactor vessel.	Industry & Plant Specific: GL 92-01, Revision 1, “Reactor Vessel Structural Integrity,” and Supplement 1 to GL 92-01, Revision 1, “Reactor Vessel Structural Integrity.” Palisades' response to these documents has been incorporated into the Reactor Vessel Integrity Surveillance Program. A review of NRC Inspection Reports, QA Audit/Surveillance Reports, and Self Assessments since 1999 revealed no issues or findings that could impact the effectiveness of the Reactor Vessel Surveillance Program.
Reactor	The Reactor Vessel Internals Inspection Program is	Industry:

Aging Management Program	Description of Aging Management Program (AMP)	Operating Experience
Vessel Internals Inspection Program	an existing program that manages the aging effects for reactor vessel internals.	Several instances were revealed where degradation has occurred within the reactor vessel internals. Plant Specific: Degradation was discovered in the core barrel and the control rod drive mechanism (CRDM) seal housings
Steam Generator Tube Integrity Program	This is an existing program that manages the aging effects of steam generator tubes and tube repairs. The Program also manages the aging effects of accessible steam generator secondary side internal components and incorporates the guidance of NEI 97-06.	Industry: Instances of degradation have occurred within the steam generators. Plant Specific: • Top of tubesheet • Within the tubesheet • U-bends • Mechanical wear at eggcrate supports, vertical straps, and diagonal bars
Structural Monitoring Program	This is an existing program that is designed to ensure that age related (as well as other) deterioration of plant structures (including masonry walls) and components within its scope is appropriately managed to ensure that each such structure or component retains the ability to perform its intended function.	Industry: • Corrosion of steel ice condenser containment vessels caused by boric acid and condensation • Cracks in concrete floors caused by flexing and shrinkage Plant Specific: • Settling of air compressor foundations • Watertight barrier degradation • Spalled concrete and exposed anchor bolts • Intake crib damage due to ice and to wave action • Cracking of concrete beams in the Auxiliary Building • Corrosion of condenser rock anchors caused by standing water and debris • Degradation of snubber anchor support structure concrete and grout • Deterioration of floor plugs due to leaking water • Moisture Separator Reheater foundation cracking • Cracks in concrete duct bank • Cracks in West ESS room west wall • Spalled concrete on wall of 1-2 Diesel Generator Exhaust Plenum • Groundwater leaks in Auxiliary Feedwater Pump room floor
System	This is an existing plant-specific program that	Industry:

Aging Management Program	Description of Aging Management Program (AMP)	Operating Experience
Monitoring Program	manages aging effects for normally accessible, external surfaces of piping, tanks, and other components and equipment within the scope of License Renewal. These aging effects are managed through visual inspection and monitoring of external surfaces for leakage and evidence of material degradation.	• Service Water Pump flange welds and bolting found excess rusting leading to leakage (Inadequate/infrequent system walkdowns were cited). <u>Plant Specific:</u> • Various pump and valve flange welds and bolting (carbon steel) were found having significant material loss due to high moisture environment or boric acid accumulations. • Floor-mounted pipe supports were discovered with excessive corrosion of bolts. (Concrete failure may have contributed from vibration and/or concrete boric acid contamination)
Water Chemistry Program	This is an existing program that is credited for managing aging effects such as loss-of-material due to general, pitting and crevice corrosion; cracking due to SCC; and steam generator tube degradation caused by denting, intergranular attack (IGA) and outer diameter stress corrosion cracking (ODSCC), by controlling the environment to which internal surfaces of systems and components are exposed. The aging effects are minimized by controlling the chemical species that cause the underlying mechanisms that result in these aging effects.	<u>Industry:</u> • Cracking in steam generator welds • Cracking and pitting of steam generator tubes and components • Alloy 600 cracking • Thinning of pipe and components due to erosion/corrosion • Cracking in safety injection accumulator nozzles • High wear of Reactor Coolant Pump Aluminum Oxide coated seals • Cracking of Control Rod Drive Housings • Cracking of pressurizer instrument tap nozzles • Cracking of safety injection piping • Cracking in feedwater piping • Chemical impurity intrusions into primary and secondary systems • Resin intrusions into the primary coolant systems <u>Plant Specific:</u> • Defective tubes in the Main Condenser due to steam impingement wear and Microbiologically Influenced Corrosion (MIC) pitting • Exceeding Action Level 3 Limits for Steam Generator Cation Conductivity

Table 4-5 License Renewal Applications for Information Related to Aging Degradation – Point Beach Nuclear Power Plant Units 1 & 2

[Available on the NRC Website]

Aging Management Program	Description of Aging Management Program (AMP)	Operating Experience
ASME Section XI, Subsections IWE & IWL Inservice Inspection Program	This AMP manages aging of (a) steel liners of concrete containments and their integral attachments; containment hatches and airlocks; seals, gaskets and moisture barriers; and pressure retaining bolting, and (b) reinforced concrete containments and unbonded post-tensioning systems.	Industry: Industry operating experience and NRC information notices have documented areas of concern regarding containment liner plate, concrete, and tendon degradation. Plant Specific: Plant specific operating experience has shown that degradation has occurred. For example: failed tendon wires, missing or broken components found in the tendon hardware, degraded concrete in containment structure, corroded containment liner, and corrosion of penetrations inside of containment. ▪ Degradation has occurred in the Unit 1 and 2 containment liners at the 8 foot elevation due to poor condition of the moisture barriers. The degradation consisted of general corrosion and pitting. ▪ Several mechanical penetrations inside the Unit 1 and 2 containments have shown indications of general corrosion and/or peeling paint. ▪ Corrosion was also found in the Unit 1 and 2 Containment Sump A at the interface between the containment liner plates and containment floor slabs. ▪ Inspections performed on the containment tendons have discovered the following degradations: Broken wires, Wires with 2% to 4% less than expected pre-stress, Presence of nitrates in grease, Cracked button-head, missing button-heads, Tendon void of 9.7% of grease volume, More grease added than removed in some instances.
ASME Section XI, Subsection IWF Inservice Inspection Program	This AMP manages aging effects for Class 1, 2, and 3 component supports.	Industry: NRC Information Notice 80-36 notified utilities of the potential for stress corrosion cracking (SCC) of high strength component support bolts. Plant Specific: The most common relevant condition discovered by this AMP has been loose

Aging Management Program	Description of Aging Management Program (AMP)	Operating Experience
		fasteners in supports. Loose fasteners are a maintenance issue, rather than a sign of age-related degradation.
Bolting Integrity Program	This AMP manages the aging effects associated with bolting through the performance of periodic inspections. The program also includes repair/replacement controls for ASME Section XI related bolting and generic guidance regarding material selection, thread lubrication and assembly of bolted joints.	Industry: Numerous instances of primary pressure boundary degradation. There have been various NRC communications including information notices, bulletins, and generic letters on bolting degradation. Most instances of degradation fall into two categories: boric acid corrosion caused by leakage at mechanical joints; and degradation of high strength bolting caused by stress corrosion cracking. General corrosion of bolting and fasteners has also occurred for structural bolting located in a humid environment. Plant Specific: Boric acid wastage on one body/bonnet check valve stud. General corrosion was also found on structural steel bolting. There were also a few instances of improper bolting material and torque values being used. There were no incidents of loss of intended function of a component or system due to fastener degradation.
Boraflex Monitoring Program	The Boraflex Monitoring Program manages aging effects for the Boraflex material in the spent fuel racks.	Industry: NRC Information Notice IN 87-43 addresses the problems of development of tears and gaps in Boraflex sheets due to gamma radiation-induced shrinkage of the material. NRC IN 93-70, NRC IN 95-38 and NRC GL 96-04 address several cases of significant degradation of Boraflex test coupons due to accelerated dissolution of Boraflex caused by spent fuel pool water flow through panel enclosures and high accumulated gamma dose. Plant Specific: The latest inspection of the SFP Boraflex panels was conducted in August 2001. The results of the Blackness Test (neutron attenuation measurements) indicated that for the first time since the Boraflex panels have been inspected, gaps have been found in 27 panels ranging from 0.8 inches to 3.4 inches.
Boric Acid Corrosion Program	This AMP manages aging effects for structures and components as a result of borated water leakage. The program requires periodic visual inspection of systems that contain borated water for evidence of leakage or accumulations of dried boric acid.	Industry: Boric acid solution leaking from the Reactor Coolant System can cause significant corrosion damage to carbon steel reactor coolant pressure boundary components. Severe corrosion damage to the RPV head at Davis-Besse and observed cracking and leakage on the RPV bottom head penetrations at South Texas have resulted in much industry attention to ensuring the implementation of an effective boric acid corrosion

Aging Management Program	Description of Aging Management Program (AMP)	Operating Experience
		program. <u>Plant Specific:</u> Numerous Work Orders, Condition Reports/Action Requests, and several Licensee Event Reports have been issued as a result of this AMP discovering boric acid leaks and corrosion of components due to borated water leakage. A large percentage of these described finding dried boric acid crystal deposits either on the component from which it leaked or on the floor below the leaking component. Occasionally, dried boric acid crystals were found on components located below the leaking component.
Buried Services Monitoring Program	This AMP manages aging effects on the external surfaces of carbon steel, low-alloy steel, and cast iron components (e.g., tanks, piping) that are buried in soil or sand.	<u>Industry:</u> Carbon steel, low alloy steel, or cast iron buried components have experienced corrosion and selective leaching degradation. The critical areas appear to be at the interface where the component transitions from above ground to below ground. This is also the area where coatings and wrappings will most likely be missing or damaged. <u>Plant Specific:</u> No degraded conditions discussed.
Closed-Cycle Cooling Water System Surveillance Program	This AMP manages aging effects in closed cycle cooling water systems that are not subject to significant sources of contamination, in which water chemistry is controlled and heat is not directly rejected to the ultimate heat sink.	<u>Industry:</u> Not discussed <u>Plant Specific:</u> The closed-cycle (CC) System performance has been very good. PBNP has not experienced degradation of its CC System due to corrosion product build up or cracking. Tube vibration in the CC Heat Exchangers has been documented. The vibration has been attributed to increased clearances in the tube to tube support plate interface. The CC Heat Exchangers were re-tubed with SeaCure tube material, which creates the potential for galvanic corrosion of the carbon steel tube support plates. Galvanic corrosion of the tube support plates is believed to be the reason for the increased clearances and subsequent tube vibration at high CC flows. Trending of nitrite and microbiological levels in the engine coolant of G01 and G02 EDGs has revealed slight in-leakage of service water into the engine coolant.
Fire Protection	This AMP includes (a) fire barrier inspections, (b)	<u>Industry:</u>

Aging Management Program	Description of Aging Management Program (AMP)	Operating Experience
Program	electric and diesel-driven fire pump tests, (c) periodic inspection and testing of the halon fire suppression system, and (d) periodic maintenance, testing, and inspection of water-based fire protection systems.	Not discussed <u>Plant Specific:</u> Some cases of small pipe threaded connection leaks, small pipe external corrosion leaks, spray nozzles for the transformer deluge system plugged due to rust scale build-up, and cracked piping and fittings. Pinhole leaks have also been found on the 10 inch fire water supply header and sprinkler heads have been found to leak. Inspections performed on the fire hydrants did reveal that three hydrants were found to be stuck shut over a ten year inspection period. None have been found stuck during the last few inspections. Plant-specific operating experience has indicated that below grade fire system piping leaks are very rare. The sandy soil condition is such that it is not conducive to high rates of corrosion and the Lake Michigan water used for the fire protection system is not aggressive to the internal surfaces of the piping. Fire doors are occasionally found in need of repair. Some of the electrical penetration fire seals in containment were also found in need of repair.
Flow-Accelerated Corrosion Program	This AMP manages aging effects due to flow-accelerated corrosion (FAC) on the internal surfaces of carbon or low alloy steel piping, elbows, reducers, expanders, and valve bodies which contain high energy fluids (both single phase and two phase). The program implements the EPRI guidelines in NSAC-202L-R2 for an effective FAC program and includes (a) an analysis using a predictive code such as CHECWORKS to determine critical locations, (b) baseline inspections to determine the extent of thinning at these locations, (c) follow-up inspections to confirm the predictions, and (d) repairing or replacing components, as necessary. The FAC Program has been an ongoing program at PBNP since 1987 in response to NRC IEB 87-01.	<u>Industry:</u> There are many instances where components have failed in service due to component wall thinning and rupturing due to erosion. A large number of these failures occurred in two phase systems (saturated steam) where a change in geometry exists. Operating experience has also shown failures occurring in single phase systems mostly where a change in geometry exists. <u>Plant Specific:</u> In 1999, Unit 1 experienced a plant shutdown due to steam leaking from feedwater heater 4B. Wall thinning due to steam impingement and FAC had occurred in the heater shell causing the leak. Inspection of similar Unit 1 feedwater heaters indicated that they required repairs due to wall thinning. Inspection of the Unit 2 feedwater heaters revealed no comparable wall thinning. Root cause analysis of the event also discovered that the materials of construction for the Unit 1 feedwater heaters did not contain a sufficient amount of chromium or molybdenum to help mitigate FAC effects. The original design did not specify for chromium or molybdenum content. Unit 2 feedwater heater materials contain an adequate amount of chromium and molybdenum to mitigate the effects of FAC.

Aging Management Program	Description of Aging Management Program (AMP)	Operating Experience
Fuel Oil Chemistry Control Program	This AMP mitigates and manages aging effects on the internal surfaces of fuel oil storage tanks and associated components in systems that contain fuel oil. The program includes (a) surveillance and monitoring procedures for maintaining fuel oil quality by controlling contaminants in accordance with applicable ASTM Standards, (b) periodic draining of water from fuel oil tanks, (c) periodic or conditional visual inspection of internal surfaces or wall thickness measurements (e.g., by UT) from external surfaces of fuel oil tanks, and (d) one-time inspections of a representative sample of components in systems that contain fuel oil.	<u>Industry:</u> The operating experience of some plants has included identification of water in the fuel, particulate contamination, and biological fouling. <u>Plant Specific:</u> The internals of the above ground fuel oil tanks and the underground emergency fuel tank were inspected in August of 2000 and no significant rust deposits, corrosion, or other obvious defects were found. Thickness measurements of the underground emergency fuel tank and the bottom of the above ground fuel oil tanks were performed and indicated no significant loss of material.
One-Time Inspection Program	This AMP addresses potentially long incubation periods for certain aging effects and provides a means of verifying that an aging effect is either not occurring or progressing so slowly as to have negligible effect on the intended function of the structure or component.	<u>Industry:</u> NA <u>Plant Specific:</u> Not applicable because this is a new program to be implemented before the current operating license expires.
Open-Cycle Cooling (Service) Water System Surveillance Program	This AMP manages aging effects caused by exposure of internal surfaces of metallic components in water systems (e.g., piping, valves, heat exchangers) to raw, untreated (e.g., service) water.	<u>Industry:</u> Heat exchangers have experienced erosion/corrosion of end bells, biofouling build-up, and silt accumulation. Erosion/corrosion has also been experienced at or near throttled valves. Zebra mussels have been found. Piping systems have experienced corrosion, pitting, MIC, and sedimentation build-up especially in low flow areas and stagnant dead legs off the main flow stream. <u>Plant Specific:</u> Descriptions of some of the typical deficiencies found in Service Water System components are: • Component Cooling Water heat exchangers experienced corrosion in the wall and nozzle area of the outlet channel head. • Localized pitting was found in the Service Water piping supply to the old Spent Fuel Pool heat exchanger. UT examination revealed that 68% wall thinning had occurred

Aging Management Program	Description of Aging Management Program (AMP)	Operating Experience
		and silt was found in the pipe. • Leakage was found in the Component Cooling Water heat exchanger blowdown lines. • Deep pitting due to MIC was found on the G01 Diesel Generator heat exchangers. The pitting occurred beneath deposits formed by iron oxidizing bacteria. • Radiography of the K-3A Service Water Air Compressor After Cooler heat exchanger showed significant wall thinning due to internal corrosion. The heat exchanger also exhibited blockage due to nodule buildup. • The G01 Diesel Generator heat exchangers (HX-55A-2 and HX -55A-1) were found to have significant erosion/corrosion at the south end bells. • Spent Fuel Pool heat exchanger HX-13A outlet valve body was found to be severely pitted and eroded.
Periodic Surveillance and Preventive Maintenance Program	This AMP is an existing plant-specific program that manages aging effects for certain SSCs within the scope of license renewal. The program provides for inspection, examination, or testing of selected structures and components, including fasteners, for evidence of age-related degradation on a specified frequency based on operating experience or other requirements (e.g., Technical Specification or code requirements). Additionally, the program provides for replacement of certain components on a specified frequency based on operating experience. This AMP is also used to verify the effectiveness of other aging management programs.	<u>Industry:</u> NA <u>Plant Specific:</u> Not discussed
Reactor Coolant System Alloy 600 Inspection Program	This AMP manages crack initiation and growth due to primary water stress corrosion cracking (PWSCC) of RCS pressure boundary nickel-based alloy components (e.g., Alloy 600/690 reactor vessel/head penetration nozzles, Inconel 82/182, 82/152, and 52/152 weld joints).	<u>Industry:</u> Numerous occurrences of cracks and leaks of Alloy 600 nozzles and penetrations with partial penetration welds. Most of the cracks of Alloy 600 penetrations caused by PWSCC have initiated on the inner diameter of the penetration near the elevation of the J-groove weld and have been short and axially oriented. Recently, a few PWRs have experienced circumferential cracking, outer diameter initiated cracking, and cracking initiating in the J-groove weld, in CRDM penetrations. A PWR has experienced a throughwall PWSCC crack in an Inconel 82/182 piping butt weld, one PWR has experienced severe degradation of the RPV head due to boric acid corrosion

Aging Management Program	Description of Aging Management Program (AMP)	Operating Experience
		resulting from a VHP leak and another PWR has detected axial cracking in reactor vessel BMI penetrations. <u>Plant Specific:</u> No plant specific aging related cases identified.
Reactor Vessel Internals Program	This AMP manages the aging effects for reactor vessel internals (RVI).	<u>Industry:</u> Most of the industry operating experience reviewed has involved cracking of austenitic stainless steel baffle-former bolts, or SCC of high-strength internals bolting. SCC of guide tube split pins has also been reported. <u>Plant Specific:</u> An augmented examination via UT was conducted on the baffle-former bolts of PBNP-2. The UT examination identified a number of bolts with indications indicative of crack like flaws.
Reactor Vessel Surveillance Program	The Reactor Vessel Surveillance Program manages the aging effect reduction of fracture toughness due to neutron embrittlement of the low alloy steel reactor vessels.	<u>Industry:</u> Industry operating experience related to this AMP includes GL 92-01, Revision 1, "Reactor Vessel Structural Integrity," and Supplement 1 to GL 92-01, Revision 1, "Reactor Vessel Structural Integrity." <u>Plant Specific:</u> PBNP-1 and PBNP-2 have generally operated successfully within their licensed Pressure-Temperature (P-T) limits. The current P-T curves for PBNP-1 and PBNP-2 are valid until 34.0 Effective Full Power Years (EFPY). New PT curves are developed and issued, as required.
Steam Generator Integrity Program	This AMP incorporates the guidance of NEI 97-06 and maintains the integrity of the steam generators (SG), including tubes, tube plugs or other tube repairs, and various secondary-side internal components.	<u>Industry:</u> Supplement 1 of NRC Information Notice (IN) 2002-21 discusses Outside Diameter SCC (ODSCC) found in Alloy 600 SG tubes at Seabrook. The ODSCC at Seabrook was caused by high residual stresses resulting from non-optimal tube processing and could generically affect mill-annealed Alloy 600, thermally treated Alloy 600, or thermally treated Alloy 690 SG tubes. <u>Plant Specific:</u> The most recent Unit 1 and 2 SG inspection results indicate that they are in very good condition. For Unit 1 only 10 of the 6,428 heat transfer tubes have been plugged. For

Aging Management Program	Description of Aging Management Program (AMP)	Operating Experience
		Unit 2 only 4 of the 6,998 heat transfer tubes have been plugged. No tubes have been plugged because of corrosion type degradation, which is consistent with the experience of all other SGs with thermally treated Alloy 600 heat transfer tubes. Secondary-side inspections of the current SGs to date have revealed no degradation of the swirl vane, moisture separator, feed ring areas, J-Tubes, or tube support plates. There has been no evidence of wrapper drop on any of the SGs.
Structures Monitoring Program	This AMP manages the aging effects associated with steel (including fasteners), concrete (including masonry block and grout), earthen berms, and elastomers. The environments include below grade and fluid exposed material, outdoor weather, and indoor air. The program includes all safety related buildings, structures within the containment, other buildings within the scope of license renewal, crane bridge and trolley structures, and component supports (including HELB structures, panels, etc.) within the scope of license renewal.	<u>Industry:</u> Industry operating experience has shown that degradation occurs in structural steel and concrete components. <u>Plant Specific:</u> The inspections performed at PBNP as part of the Structures Monitoring Program have revealed that degradation has occurred in both concrete and structural steel components. Cracks in masonry walls have been found primarily at the mortar joints and these findings have been documented and resolved. Concrete structure inspections have been and continue to be a large part of this AMP as described in plant procedures. Cracks, erosion, corrosion of embedded steel, and concrete spalling have been observed. Periodic inspections of the circulating water pumphouse have been an ongoing program. Divers perform inspections during refueling outages. Minor degradation of these concrete structures has been found and recorded. Zebra mussels are periodically removed from the forebay areas.
Systems Monitoring Program	This AMP manages aging effects for normally accessible, external surfaces of piping, tanks, and other components and equipment within the scope of license renewal.	<u>Industry:</u> Not discussed <u>Plant Specific:</u> A PBNP review of documentation for seven systems within the scope of license renewal indicated that these walkdowns usually result in the initiation of corrective Work Orders for the repair of minor leaks from both flanged connections and valve stem packing, degraded grout under pumps, or pipe supports.
Tank Internal	This AMP is a new plant-specific program that	<u>Industry:</u>

Aging Management Program	Description of Aging Management Program (AMP)	Operating Experience
Inspection Program	manages aging effects on the (a) internal surfaces of carbon steel tanks, and (b) inaccessible external surfaces of carbon steel tanks (i.e., tank bottoms) where wall thickness measurements may be taken from inside the tank to detect external degradation (e.g., using ultrasonic techniques).	A coated carbon steel Refueling Water Storage Tank (RWST) was found to have coating degradation. <u>Plant Specific:</u> The south Condensate Storage Tank was internally inspected in January 2000 with minor surface rust observed on the floor of the tank and corrosion through the tank coating observed on the lower 6 to 8 inches of the tank wall. Inspection of the north Condensate Storage Tank revealed minor surface rust similar to that found in the other tank.
Thimble Tube Inspection Program	This AMP is an existing plant-specific program that manages aging effects for incore instrument thimble tubes. This program requires periodic eddy current testing of thimble tubes and contains criteria for determining sample size, inspection frequency, flaw evaluation, and corrective action, in accordance with NRC Bulletin 88-09.	<u>Industry:</u> NRC Bulletin 88-09 was issued in response to the thinning of thimble tubes experienced at several Westinghouse pressurized water reactors. <u>Plant Specific:</u> 5 tubes on Unit 1 have been replaced due to wear since 1985. One of these 5 tubes had been capped, one other showed significant wear and would require repositioning or capping prior to the next inspection, while the other 3 were replaced since they indicated the most wear when compared to the remaining tubes.
Water Chemistry Control Program	This AMP manages aging effects by controlling the internal environment of systems and components. Primary, borated and secondary water systems are included in the scope of the program. The program conforms to the guidelines in EPRI TR-105714 and TR-102134.	<u>Industry:</u> Not discussed <u>Plant Specific:</u> Review of plant-specific operating experience indicates that the chemistry program is performing its function of mitigating aging effects. No reports were found that attributed water chemistry as the cause of component deterioration, showing signs of aging effects, or failing to perform its function.

5 CONCLUSIONS

This report describes the research effort performed for the Year 1 scope of work under a collaboration effort between BNL and KAERI. This research focused on collecting and reviewing degradation occurrences in US NPPs and identifying important aging characteristics needed for the seismic capability evaluations that will be performed in the subsequent evaluations in the years that follow. The report presents the results of statistical and trending analyses of this data and compares the results to prior aging studies. In addition, this report provides a description of current regulatory requirements, regulatory guidance documents, generic communications, industry standards and guidance, and past research related to aging degradation of SSCs. This section of the report presents the conclusions reached from this research effort, which includes a summary of the findings from the identification and evaluation effort of degradation occurrences, an assessment of the degradation trending results, and insights into the important aging characteristics that should be considered in the tasks to be performed in the Year 2 through 5 research efforts.

A survey of degradation occurrences for structures and passive components (SPCs) was conducted using recent licensee event reports (LERs) and recent generic letters, bulletins, information notices, and license renewal applications. The study also included trending analysis of the degradation occurrence records (DORs) obtained from LERs, in combination with data reported in NUREG/CR-6679. The goal of this study was to identify any new degradation trends and to determine whether the findings reported in NUREG/CR-6679 still hold. The ultimate goal of this study is to assist in identifying those degraded SPCs that are significant to plant safety for use in the development of seismic capability evaluation technology for degraded structures and components.

Past studies on aging-related degradation were critically evaluated; part of the evaluation presented in this report included a summary of the relevant information presented in NUREG/CR-6679. A description of regulatory requirements, NRC regulatory guidance, NRC programs, industry programs, and international research efforts were presented. Also included in this report is a brief discussion of the NRC sponsored multi-year research program on aging-related degradation, which was performed by BNL recently. This information provides an extensive literature overview that is beneficial to the current BNL-KAERI collaborative effort.

After a thorough examination of possible approaches for performing the review of 4,323 LERs from 1999 to April 16, 2008, software tools were developed to assist the review process of the LERs. These tools assisted in downloading all LERs automatically and in speeding up the review process significantly. The completion of this study benefited greatly from the development of these tools.

Ten component categories were identified for this study which consist of anchorage, concrete, containment, exchanger, filter, piping system, reactor pressure vessel (RPV), structural steel, tank, and vessel. A total of 223 DORs were identified for the ten component categories, and the relevant information is summarized in the primary information table and the secondary information table presented in Section 3 of this report. The results of this study demonstrated that piping systems have the most degradation occurrences reported in LERs, about 36% of the total DORs. Exchangers and RPVs have the next two largest numbers of degradation occurrences, representing about 22% and 17% of the total DORs, respectively. The other seven component categories represent less than 25% of the total DORs. It should be noted that part of the explanation for these results is related to the number of components that are found at a NPP. For example, there are many piping systems and many of these systems are quite long, as compared to a more limited number of other components such as containments and tanks. Also, the environment for certain components such as RPVs is much harsher, and therefore, leads to a greater number of degradation occurrences. It was also found that LERs do not report a significant number of structural type components, such as containments, structural steel, concrete, and anchorages. The number of structural DORs reported in LERs was judged to be lower than the actual structural degradations. However, this does not indicate in any way that structural degradations are of less significance to plant safety. The lower number of structural degradations may be partially attributed to the fact that they may be difficult to identify and the degradations may not have been judged to reach a level that would require a formal submittal of an LER to the NRC.

Taking into consideration that the number of DORs for the piping system was limited during the LER review in NUREG/CR-6679, the current study concluded that exchangers, piping system, and RPVs were found to be the first three categories with the greatest number of DORs. The distribution of DORs over time was somewhat cyclic, which is judged to be partially influenced by inspection intervals that often are scheduled at refueling or are required by special NRC mandatory inspection requirements. Distribution of the average DORs by plant age at event (PAAE) showed that the average number of DORs per plant increase as the plant gets older, with a slightly higher rate for older plants as shown by the steeper slope using the LER 1999-2007 results. The slightly higher degradation rate using more recent LERs reflects the fact that older plants show in general more degradation occurrences. Omitting other factors that may affect the accuracy of the trending analysis, the older plants have about 3 times higher average DORs/year than the younger plants, although the absolute value of the average DORs is considered to be very small (1~1.8 occurrences/plant/year for those plants which have degradation occurrences).

Using the NUREG/CR-6679 (1985 to 1997) results for all sources of degradation occurrences, the NUREG/CR-6679 results based only on LER data, and the current LER study (1999-2008) results, cracking was found to be the most predominant aging effect. Stress corrosion cracking (SCC) was the most significant aging mechanism for all three data series. Primary water stress corrosion cracking (PWSCC) was found to be the major contributor to SCC based on the LER results and intergranular SCC (IGSCC) was the major contributor if the entire NUREG/CR-6679 data was used. The LER 1999-2008 data series also showed that fatigue was the second significant aging mechanism, indicating the possibility that some components might be approaching their fatigue life as NPPs got older. Moisture, organisms, chemical attack, and foreign object were shown to be less important mechanisms using the LER 1998-2008 series. The system that was most vulnerable to degradation is the reactor coolant systems (RCS), as expected because the RCS includes many subcomponents that are constantly subjected to harsh environments such as high temperature, high pressure, high fluid velocity, boron acid, radiation, etc. Also, the RCS receives close scrutiny in terms of inspections and examination in view of the safety importance of the system.

Review of recent generic communications (generic letters, bulletins, and information notices) indicated that exchangers, RPVs, and piping systems are the top three components that generic correspondences address. Generic communications discuss more structural type components than the LERs do. Documents related to LRAs are also useful because they identify applicable aging effects, discuss industry and plant specific operating experience, and describe instances of aging degradation of structures and components at their plants. Two recent representative LRAs, Palisades and Point Beach Units 1 & 2, were chosen for review. Regarding aging-degradations, the information presented in LRAs is not as detailed as in the LERs. These reviews did not yield adequate data for a direct comparison to those found using LERs. However, these reviews confirmed qualitatively the findings using LERs, because in many cases the plant-specific information in the LRAs, for the more significant degradation occurrences, was already in the LERs for that plant.

Utilizing the trending analysis from previous DORs reported in NUREG/CR-6679, DORs from the review of LERs described in this report, and from the general observations obtained from the review of recent representative generic letters, bulletins, information notices, and license renewal applications, it is concluded that the patterns of degradation occurrences have not significantly changed from past studies, although signs of a slight increase in the number of DORs have been observed. Although the LERs do not report many structural degradations based on the reporting requirements governed by 10 CFR 50.73, structural degradations are expected to be a factor as plants age, and are important to plant safety when extreme environmental demands such as large earthquakes are considered. It can be further stated that the conclusions reached from the NUREG/CR-6679 study, regarding the list of components whose age-related degradation is significant to plant safety and the characteristics of aging degradation, are still valid for the collaborative research being performed by BNL and KAERI.

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