NUREG/CR-5314
EGG-2562
Vol. 5

Insights for Aging Management of Light Water Reactor Components

Metal Containments

Prepared by
V. N. Shah/INEL
S. K. Smith/OEES
U. P. Sinha/INEL

Idaho National Engineering Laboratory
EG&G Idaho, Inc.

Ogden Environmental and Energy Services

Prepared for
U.S. Nuclear Regulatory Commission

AVAILABILITY NOTICE

Availability of Reference Materials Cited in NRC Publications

Most documents cited in NRC publications will be available from one of the following sources:

1. The NRC Public Document Room, 2120 L Street, NW., Lower Level, Washington, DC 20555-0001
2. The Superintendent of Documents, U.S. Government Printing Office, Mail Stop SSOP, Washington, DC 20402-9328
3. The National Technical Information Service, Springfield, VA 22161

Although th listing that follows represents the majority of documents cited in NRC publications, it is not intended to be exhaustive.

Referenced documents available for inspection and copying for a fee from the NRC Public Document Room include NRC correspondence and internal NRC memoranda; NRC bulletins, circulars, information notices, inspection and investigation notices; licensee event reports; vendor reports and correspondence; Commission papers; and applicant and licensee documents and correspondence.

The following documents in the NUREG series are available for purchase from the GPO Sales Program: formal NRC staff and contractor reports, NRC-sponsored conference proceedings, international agreement reports, grant publications, and NRC booklets and brochures. Also available are regulatory guides, NRC regulations in the *Code of Federal Regulations*, and *Nuclear Regulatory Commission Issuances*.

Documents available from the National Technical Information Service include NUREG-series reports and technical reports prepared by other Federal agencies and reports prepared by the Atomic Energy Commission, forerunner agency to the Nuclear Regulatory Commission.

Documents available from public and special technical libraries include all open literature items, such as books, journal articles, and transactions. *Federal Register* notices, Federal and State legislation, and congressional reports can usually be obtained from these libraries.

Documents such as theses, dissertations, foreign reports and translations, and non-NRC conference proceedings are available for purchase from the organization sponsoring the publication cited.

Single copies of NRC draft reports are available free, to the extent of supply, upon written request to the Office of Administration, Distribution and Mail Services Section, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001.

Copies of industry codes and standards used in a substantive manner in the NRC regulatory process are maintained at the NRC Library, 7920 Norfolk Avenue, Bethesda, Maryland, for use by the public. Codes and standards are usually copyrighted and may be purchased from the originating organization or, if they are American National Standards, from the American National Standards Institute, 1430 Broadway, New York, NY 10018.

NUREG/CR-5314
EGG-2562
Vol. 5

Insights for Aging Management of Light Water Reactor Components

Metal Containments

Manuscript Completed: January 1994
Date Published: March 1994

Prepared by
V. N. Shah/INEL, S. K. Smith/OEES, U. P. Sinha/INEL

G. H. Weidenhamer, NRC Project Manager

Idaho National Engineering Laboratory
Managed by the U.S. Department of Energy

EG&G Idaho, Inc.
Idaho Falls, ID 83415

Subcontractor
Ogden Environmental and Energy Services
29200 Southfield
Suite 103
Southfield, MI 48706

Prepared for
Division of Engineering
Office of Nuclear Regulatory Research
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001
NRC FIN A6389
Under DOE Contract No. DE-AC07-76ID01570

ABSTRACT

This report evaluates the available technical information and field experience related to management of aging damage to light water reactor metal containments. A generic aging management approach is suggested for the effective and comprehensive aging management of metal containments to ensure their safe operation. The major concern is corrosion of the embedded portion of the containment vessel and detection of this damage. The electromagnetic acoustic transducer and half-cell potential measurement are potential techniques to detect corrosion damage in the embedded portion of the containment vessel. Other corrosion-related concerns include inspection of corrosion damage on the inaccessible side of BWR Mark I and II containment vessels and corrosion of the BWR Mark I torus and emergency core cooling system piping that penetrates the torus, and transgranular stress corrosion cracking of the penetration bellows. Fatigue-related concerns include reduction in the fatigue life (a) of a vessel caused by roughness of the corroded vessel surface and (b) of bellows because of any physical damage. Maintenance of surface coatings and sealant at the metal-concrete interface is the best protection against corrosion of the vessel.

FIN A6389—Aging—Component and Systems IV

CONTENTS

LIST OF FIGURES

LIST OF TABLES

EXECUTIVE SUMMARY

This report is prepared for the USNRC Nuclear Plant Aging Research Program. Its primary objective is to evaluate aging damage to light water reactor (LWR) metal containments, which are ranked high among the major LWR components for their importance to plant safety, and to suggest a generic, comprehensive approach to assess and manage the damage. The report is based solely on the review of available technical information, field experience, and consultations with experts; no new basic research or development has been carried out in preparing this report. The report focuses on BWR Mark I and PWR cylindrical containments, which represent more than three fourths of the LWR metal containments in the United States.

Aging degradation is defined as a cumulative degradation of a component, system, or structure which, if unmitigated, may result in a loss of function and impairment of safety. Poor design, improper materials selection, or inadequate maintenance practices can accelerate the aging degradation.

The generic assessment approach includes review of plant design and operational data to estimate aging damage specifically caused by corrosion and fatigue, evaluation of inservice inspection techniques to characterize aging damage, prediction of aging damage during the next operating period, and identification of mitigation techniques so that acceptable safety margins are maintained during the next operating period.

Assessment and Mitigation of Corrosion Damage

The carbon steel metal shells of BWR Mark I and PWR cylindrical containments are susceptible to several different corrosion mechanisms: general corrosion, pitting, crevice corrosion, differential aeration, microbially influenced corrosion, aggressive chemical attack, and galvanic corrosion. The major concerns include corrosion of the embedded portion and the inaccessible side of the metal shell, corrosion of the BWR suppression pool below the water line, and loss of corrosion protection because of deteriorated coating on the metal shell and sealant at the concrete-metal interface. If the cracks in the concrete beneath the embedded portion of the containment shell are connected so as to form a path through the basemat, and if the rubber membrane underneath the basement is ruptured, aggressive groundwater (with high chloride, sulfate, and oxygen levels) may reach the uncoated outside surface of the embedded portion, making it susceptible to pitting. A portion of the inaccessible outside surface of the Mark I drywell adjacent to the sand pocket is uncoated and is susceptible to corrosion if there is any leakage of coolant from the refueling pool. The outside surface of the Mark I drywell is also susceptible to crevice corrosion if the compressible filler material is present in the gap between the drywell and secondary shield wall. Moisture may become trapped against the vessel and leach out corrosive constituents, such as magnesium chloride, present in the filler material.

The gradient in the oxygen concentration in the BWR suppression pool coolant makes the region just below the waterline susceptible to corrosion by differential aeration. Such gradients in the moist sand in the sand pocket may cause similar corrosion damage to the adjacent outside surface of the drywell. The suppression pool water and moist sand in the sand pocket may provide an environment to support microbially influenced corrosion. The BWR Mark I emergency core cooling system pipes, which penetrate the suppression pool below the waterline and constitute the containment pressure boundary, are susceptible to pitting. Aggressive chemicals such as borated water in PWRs, sodium pentaborate in BWRs, and decontamination fluids will cause corrosion of the metal shell if in contact. The potential sites for galvanic corrosion in metal containments are in the carbon steel vent and penetration lines near their connections to stainless steel bellows.

Visual and ultrasonic inspection techniques are currently used to detect corrosion of metal containments. Visual inspection is generally used to detect any deterioration of surface coating that may be considered as an indicator of possible corrosion damage to the shell underneath. However, visual inspection cannot detect any damage under an intact coating.

Ultrasonic testing is used to detect and size corrosion damage to the containment shell by measuring its wall thickness, if at least one side of the shell is accessible. Wall thickness can be measured either by a commercially available digital thickness gauge or by a conventional ultrasonic transducer that displays the echo signals on an oscilloscope (A-scan). A digital gauge is not reliable to measure the thickness of a significantly corroded wall because the rough surface scatters the ultrasonic signal, resulting in an incorrect thickness measurement. For example, a typical digital gauge can give a measurement error of 20 to 40% if the surface roughness is 0.2-mm root mean square, which is equivalent to an average pit depth of 0.56 mm (24 mils) with a surface profile assumed to be sinusoidal. A thickness gauge with an oscilloscope circuitry or a conventional ultrasonic transducer will display any signal scattering on the oscilloscope and, thus, warn of incorrect thickness measurement. A focused transducer with a water column for coupling the ultrasound can provide more reliable thickness measurements to a certain higher level of surface roughness; after which, its performance also degrades. Trending of wall thickness measurements may be used to determine the corrosion rate needed for aging management.

Advanced techniques such as the electromagnetic acoustic transducer and half-cell potential measurement are the potential techniques to detect corrosion damage in the embedded portion of the containment vessel, which is not accessible for inspection by conventional inspection techniques. In laboratory tests on a large rectangular plate [4.9-m (16-ft) long, 2.1-m (7-ft) wide, and 25.4-mm (1-in.) thick], electromagnetic acoustic transducers detected large corrosion-like defects. Half-cell potential measurement has been successfully used to detect any corrosion zones in the reinforcing bars before appreciable damage occurs; however, this technique cannot size the damage.

Recently developed underwater techniques can be used to detect corrosion damage to the submerged surface of the pressure suppression pool wall without draining it. These techniques include ultrasonic mapping of critical areas, coating adhesion tests, and measuring the dry film thickness of coating.

Maintenance of coatings and sealants is the best protection against corrosion damage. Zinc-rich primer with a phenolic top coating on the inside and outside surfaces of the containment can provide better corrosion protection than red lead or epoxy coatings. However, several areas such as the outer surface of the Mark I vessels are inaccessible to recoating. Application and maintenance of a sealant at the concrete-metal interface can prevent entry of moisture and, thus, provide protection.

Degradation of Coatings

The stressors responsible for coating degradation are temperature, condensation and immersion, radiation, base metal corrosion, and the activities, such as transportation of an equipment during maintenance, causing physical damage. At high temperatures, coatings disintegrate and stop providing corrosion protection. An epoxy coating disintegrates at 120°C (248°F). The disintegration temperature for zinc-rich coating is higher. If enough radiation is present, a coating will disintegrate by ionization. Once moisture and oxygen penetrate through a coating, local corrosion of the metal surface can result and propagate. Areas where condensation and immersion may degrade coatings are also the most likely sites of accelerated corrosion of the base metal underneath. Thermal effects on coatings include differential thermal expansion between coating and base metal, which may cause cracking in the coating. Physical damage such as gouge marks, cracks, or pinholes can permit moisture to reach the substrate metal through the coating. With time, corrosion of the base metal spreads and lifts the coating, which in turn exposes a larger base metal surface to moisture and accelerates coating deterioration.

Assessment of Fatigue Damage

Metal containment vessels are designed for loads imposed during normal operation; hence, the resulting fatigue damage is small. However, its fatigue life may be significantly reduced if the vessel surface has become significantly rough because of corrosion damage. As pits form on the surface, new sites for fatigue crack initiation become available, and the initiation time may be significantly reduced.

Fatigue is a major design consideration for bellows, which are part of the containment penetrations and the Mark-I vent lines and constitute part of the containment pressure boundary. Fatigue damage, caused by relative thermal movement between the containment vessel and the high-temperature process piping, is not significant provided that the bellows are not physically damaged. Scratches or sharp dents incurred during construction or operation create stress concentrations that can significantly reduce the fatigue life; however, inservice inspection can detect such physical damage and the damaged bellows can then be repaired or replaced.

Current inspection techniques for characterizing fatigue cracks in metal containment shells include visual inspection, liquid penetrant inspection, magnetic-particle testing, eddy-current testing, and magnetography. Visual inspection can detect a fatigue crack in the base metal underneath the coating only if the coating is deteriorated. Other techniques can detect a crack underneath an intact coating. Detection of a flaw by magnetic particle testing through a coated surface depends on the flaw size, shape, depth, orientation and location, and on the thickness of the coating. The sensitivity of eddy-current testing is not as influenced by coating thickness and test position as is magnetic particle testing. Eddy-current testing is an effective complementary technique for use on coated surfaces to detect flaws in the toe of a weld. Magnetography has the advantage that the noise signals from flaws can be suppressed and the output can be displayed on an oscilloscope. This technique can be employed for inspecting underwater surfaces and improperly cleaned weld surfaces.

Field Experience

The Oyster Creek plant experienced corrosion damage on the external, uncoated surface of the drywell adjacent to the sand pocket. Refueling pool coolant leaked at the bellows drain line gasket, and it also leaked through the fatigue cracks in the pool's stainless steel liner into the gap between the drywell and the shield wall during a refueling outage. The corrosive contaminants such as chlorine, bromine and sulfate ions, were largely responsible for corrosion damage. The drywell wall thickness was measured with a conventional ultrasonic transducer (A-scan). As of 1987, the thickness in the worst-affected sand pocket region was reduced to 21.30 mm (0.838 in.) from the as-fabricated thickness of 29.30 mm (1.154 in). As of 1991, the reported upper and lower bound corrosion rates near sand pocket elevations were 0.52 mm/year (20.5 mils/year) and 0.44 mm/year (17.4 mils/year), respectively. At an upper bound corrosion rate of 0.52 mm/year, the drywell shell thickness is projected to be acceptable until January 1994. Such wall thinning, if unchecked, could potentially lead to a through-wall crack and leakage. The cracks in the stainless steel liner were repaired to stop leakage of the coolant; however, the corrosion continues because of contaminants and the small amount of moisture still present in the sand. Cathodic protection was applied to inhibit further corrosion of the outside surface, but proved unsuccessful and it has been discontinued.

Proposed surveillance for this corrosion problem includes checking torus rooms, sand cushion drain lines, and drywell seal bellows drains for the presence of any water during refueling. Borescope inspection of the drains can verify that they are not blocked. Installation of flow alarms on bellows seals can warn of any possible water leakage. Representative carbon steel specimens can be inserted into the sand pocket around the drywell and withdrawn periodically to check for any indication of corrosion.

Recently, a long-term repair to stop the corrosion of the Oyster Creek drywell was completed.

The repair included removal of the sand from the sand pocket, removal of corrosion products, cleaning of the affected surface, inspection of the drywell (which did not reveal any deep pitting), and recoating the drywell surface with epoxy. Twenty-in.-diameter access holes (manways) were drilled through the shield wall about 12-in. away from each of the ten vent lines to reach the affected drywell surface. The sand was not replaced, and the manways were left in place. The structural analysis results confirm that these changes do not jeopardize the structural integrity of the drywell.

The inside surface of the uncoated torus shell of Nine Mile Point Unit 1 experienced corrosion damage immediately below the waterline. The torus wall inside surface had experienced an overall corrosion rate of 0.08 mm/yr (3.2 mil/yr), which is double the expected (design) rate of 0.04 mm/yr (1.6 mil/yr). In addition, the portion of the torus wall below the waterline might have also experienced pitting. Repair of the pitted areas followed by coating of the inside surface will reduce the corrosion damage. Cathodic protection might be used for corrosion protection of the inside surface of the torus.

The outside surface of both Units 1 and 2 of the McGuire and Catawba plants (ice-condenser-type PWR containments) experienced corrosion at the metal-concrete interface. Borated coolant leaking from instrumentation line connections puddled on the floor and caused corrosion. Corrosion damage at the McGuire plants was more severe than that at the Catawba plants. Actions taken to reduce or prevent further corrosion damage included weld repairing and recoating the damaged areas, and sealing the accessible areas between the containment and concrete floor.

The inside surface of the metal containment at McGuire Unit 1 experienced corrosion damage at two locations. The corrosion was located at upper and lower floor levels under the ice condenser. Inspection revealed general surface corrosion on the entire circumference near the elevation of the lower floor level with scattered worst-affected areas above the lower floor level. The inspection also revealed worst-affected areas along a 55-degree arc at the upper floor level. Surface corrosion was also found on the inside surface of the containment between the floors. At each of the floor elevations, cork filler material [61- to 76-cm (24- to 30-in.) in height)] was installed in a 51-mm (2-in.) gap between the steel containment vessel and interior concrete structure. The radial expansion experienced by the containment during heatup and cooldown and the integrated leak tests caused the epoxy surfacing compound to crack at the inside and outside edges of the cork. It is possible that the intrusion of moisture through the cracks caused corrosion. The moisture might have originated from the ice condenser or from other condensation. Action taken to resolve the corrosion problems included developing acceptance criteria for expansion joint material and coating, replacing the cork material, applying new coating to the areas susceptible to corrosion, and preventing water and boric acid from penetrating the expansion joint.

Dresden Unit 2 experienced excessive heating of the drywell because of inadequate maintenance. The filling material in the annular space between the containment and reinforced concrete shield wall caught fire during reactor water cleanup pipe replacement. Hot slag produced while cutting the pipe ran through the sleeve in the shield wall and contacted the filling material in the gap. An estimated temperature increase of 170°C (338°F) attained during the fire resulted in discoloration and flaking of the coating in scattered locations on the inside surface of the drywell. Since the outside surface of the drywell is inaccessible, it is difficult to detect or repair any coating damage on that surface.

Excessive leakage was detected from a drywell ventilation penetration bellows during the Quad Cities Unit 1 containment integrated leak rate test. A metallurgical investigation revealed that transgranular stress corrosion cracking (TGSCC) was the failure mechanism for the leaking bellows and that the crack initiated on the bellows inner surface. The investigation found no evidence that the crack growth was caused by fatigue. TGSCC had also been identified as a failure mechanism for the leakage from four bellows at Quad Cities Units 1 and 2 and Dresden Unit 3. Chlorides, fluorides, and sulfides were identified as the responsible corrosive species. The fracture mechanics evaluation concluded that the damaged bellows would remain capable of performing its design function during the operating cycle. The leaking bellows were removed and the new one were assembled in situ. This replacement method was qualified by fatigue testing and hydrotesting of the facsimile bellows as required by ASME Code Case N-315.

An Aging Management Approach

The aging management approach presented in this report systematically and comprehensively identifies techniques to (a) determine current damage (corrosion and fatigue) to metal containment, (b) estimate additional damage to the metal containment at the end of the next operating period, (c) evaluate the integrity of the containment at the end of the next operating period, and (d) identify options and actions available to manage aging during the next operating period.

Table ES-1 outlines a ten-step approach for plant-specific aging evaluations of LWR metal containments. Steps 1 to 5 suggest review of the documents and records to estimate the current state of damage for a given containment. While some of the documents will be used directly in the assessment, others will be reviewed to provide background and to uncover issues that may impact the aging management. Steps 6 and 7 provide guidelines for estimating damage at the end of the next operating period. The operating period can be as short as one fuel cycle, equal to inspection period or interval as defined in the ASME Section XI inservice inspection program, or equal to any other suitable period. Step 8 provides guidelines for evaluating containment integrity during that period. Step 9 provides guidelines for selecting appropriate mitigative actions to ensure safe operation during the next operating period. Step 10 is related to reevaluation of containment integrity if significant actions are identified in Step 9.

Conclusions

The major conclusions related to susceptibility to and inspection and mitigation of corrosion to BWR Mark I and PWR cylindrical containments are as follows:

- Corrosion damage to the embedded portion of a metal containment is of major concern. Another major concern is the corrosion of the inaccessible outside surface of the Mark I and Mark II drywells.
- The BWR Mark I emergency core cooling system piping that penetrates the torus below the waterline is susceptible to corrosion but is not inspected during inservice inspection.
- Maintenance of the surface coatings and the sealants at the metal-concrete interface is the best protection against corrosion.

Table ES-1. An aging management approach for an LWR metal containment.

Step 1.	Review Design Data
Step 2.	Review Construction/Quality Control Documents
Step 3.	Review Preoperational Test Records
Step 4.	Review Inspection, Test, and Maintenance Records
Step 5.	Review Operating Records
Step 6.	Assess Corrosion Damage at the End of the Next Operating Period
Step 7.	Assess Fatigue and Wear Damage at the End of the Next Operating Period
Step 8.	Evaluate Containment Integrity at the End of the Next Operating Period
Step 9.	Select Mitigative Actions
Step 10.	Reevaluate Containment Integrity at the End of the Next Operating Period if Significant Mitigative Actions are Identified in Step 9.

- Electromagnetic acoustic transducers, if further developed, may be used for inspection of corrosion damage in the embedded portion of the BWR metal containments. This technique has been used in the laboratory to detect corrosion-like damage in steel plates.

- Evaluation of the half-cell potential technique could determine its usefulness in identifying zones of corrosion in the embedded portion of the metal shell before appreciable damage occurs. This technique has the potential to become an effective detection technique because it has been already successfully developed to detect corrosion of reinforcing bars in concrete bridge deck.

- Standard ultrasonic pulse-echo techniques do not reliably size containment corrosion damage if the outside surface has become very rough, which causes scattering of the ultrasonic waves. A focused transducer can be used up to a certain higher level of roughness before its performance also degrades.

- Underwater inspection and local repair of deteriorated coating and the corroded base metal of several BWR suppression pools have been successfully performed.

- Cathodic protection has not worked in mitigating corrosion of the Oyster Creek drywell wall adjacent to the sand pocket region. However, long-term coating repair has been performed to effectively stop the corrosion. The repair included establishment of permanent access to the drywell outside surface, removal of the sand, and recoating the affected surface.

- The penetration line bellows are susceptible to transgranular stress corrosion cracking. Leaking bellows can be replaced with the new ones that are assembled in situ.

Key conclusions related to fatigue are as follows:

- Rough containment surfaces caused by extensive corrosion damage may result in significantly reduced fatigue life.

- Surface damage and flaws can reduce the fatigue life of the bellows.

- Magnetic particle, magnetographic, and eddy-current techniques can detect and size surface fatigue cracks in weld regions underneath 0.4-mm- (15-mils-) thick intact coating. Visual inspection can detect these flaws only if the flaws have caused coating deterioration.

INEL FOREWORD

The United States was one of the first nations to use nuclear power to commercially generate electricity and, therefore, has some of the oldest operating commercial reactors. As U.S. light water reactors (LWRs) have matured, problems associated with time- or use-dependent degradation (aging) mechanisms such as stress corrosion, radiation embrittlement, fatigue, and other effects have occurred and have raised questions about the continued safety and viability of older nuclear plants. Some of the recent aging-related problems include primary water stress corrosion cracking of pressurized water reactor (PWR) pressurizer heater sleeves and instrument nozzles and PWR steam generator tube plugs, steam generator tube ruptures caused by high-cycle fatigue and by a failed tube plug, significant wall-thinning of light water reactor metal containments caused by corrosion, fatigue failure of boiling water reactor (BWR) recirculation pump internals (resulting in potential damage to reactor pressure vessel core and internals), catastrophic failure of a "nonnuclear" portion of a PWR feedwater line caused by erosion-corrosion, and through-wall thermal-fatigue cracks in high-pressure safety injection lines and a residual heat removal line.

Therefore, the potential problems of managing aging in older plants and the resolution of associated technical safety issues have become a major focus for the research sponsored by the U.S. Nuclear Regulatory Commission (USNRC). An important part of the USNRC research effort is the Nuclear Plant Aging Research (NPAR) Program that is being conducted at several national laboratories, including the Idaho National Engineering Laboratory (INEL). One of the NPAR program tasks at the INEL is to identify, develop, and evaluate various aging management techniques for the major PWR and BWR components and structures. These evaluations will help the USNRC identify and resolve safety issues associated with LWR aging degradation and develop policies and guidelines for making operating plant aging management decisions that may safely extend its operation.

Most of the effort for this aging assessment and mitigation task is focused on integrating, evaluating, and updating the technical information relevant to aging from current or completed NRC and industry research programs. A five-step approach is being pursued to accomplish the aging management task: (1) identify and prioritize major components, (2) identify degradation sites, mechanisms and stressors, and potential failure modes for each component, and then evaluate the current inservice inspection (ISI) techniques, (3) assess advanced inspection, surveillance, and monitoring techniques, (4) develop and evaluate aging management approaches for the major LWR components, and (5) support the development of a technical basis useful for aging management considerations.

A brief discussion of each of these steps follows:

1. *Identification and prioritization of major components*: Virtually all major equipment contained within a nuclear plant complex is subject to some aging degradation and need to be evaluated in an aging program. From the USNRC's perspective of ensuring the health and safety of the public, the first step in this assessment task was to identify those major components critical to nuclear power plant safety. Components that help contain the release of fission products during normal, off-normal, or accident conditions were selected. The PWR components (in rough order of importance) include the reactor pressure vessel (RPV), the containment and basemat; reactor primary coolant piping, safe ends, and nozzles; surge and spray lines; charging and safety injection lines; steam generators; reactor coolant pump bodies; pressurizer; control rod drive mechanisms; cables and connectors; emergency diesel generators; RPV internals; RPV supports; and feedwater lines and nozzles. A similar list was developed for BWRs except that the containment was ranked most important. Although

me PWR steam generator and BWR recirculation piping have been replaced, their replacement is a major, time-consuming operation. In addition, steam generator tubes and recirculation piping constitute a part of the primary pressure boundary, and therefore, aging evaluation of these components is included in this task. The lifetime of many of the smaller, less expensive components such as the pumps, valves, sensors, batteries, controls, etc. is often less than the initial license period of 40 years, and these components are usually repaired, refurbished, or replaced relatively frequently. The aging management of these smaller components is being studied in other NPAR tasks that are focusing more on reliability, availability, and maintainability.

2. *Identification of the degradation sites, mechanisms and stressors, and the potential failure modes and evaluation of the current ISI techniques*: Time- or use-dependent damage or aging can be caused by one or several different mechanisms active within a component, structure, or material and, if not recognized and properly managed, may result in some type of failure or impairment of function. The degradation is often the result of interactions between design, materials, operational stressors, and environments. Poor design, improper material selection, severe environments, or inadequate maintenance practices can accelerate the degradation. Therefore, identification and understanding of the design, materials, stressors, environments, and aging mechanisms is essential. This step consists of identifying and qualitatively evaluating the stressors, potential degradation sites and mechanisms, probable failure modes, and current ISI techniques for each of the selected major components. This qualitative analysis of the degradation sites and processes and current ISI techniques is essential to developing a proper understanding of the impact of aging on safe operation of nuclear power plants and identifying and prioritizing the unresolved technical issues relevant to nuclear power plant aging.

3. *Assessment of advanced inspection, surveillance, and monitoring techniques*: Knowledge of the current damage state of the material is essential for a proper assessment of structural integrity of a component or structure. Inservice inspections are performed to measure the current state of damage. However, many of the standard nondestructive examination (NDE) techniques employed to satisfy current ISI were developed for the detection and qualitative assessment of fabrication-related flaws. These techniques are not entirely adequate for effective aging management. Inspections for aging management generally demand greater detection reliability and a more quantitative determination of defects and accumulated damage than provided by traditional ISI. Development of emerging inspection techniques may provide for accurate assessment of, for example, the size, shape, location, orientation, and type of both surface and internal flaws.

4. *Develop and evaluate aging management approaches for the major LWR components:* An important feature of this NPAR task is to identify appropriate aging management approaches for the major, risk-significant LWR components and structures. The main objective of this task is to review the available aging-related technical information, including design and operation of major components, field experience, and consultations with experts. There is no plan to perform any new basic research or development in carrying out this task. Effective aging management approaches for various components and structures may differ considerably. However, a general aging management approach that may work well for many of the reactor primary

system pressure boundary components, the containment, and possibly other major components is as follows: (a) evaluate the present state of the component, (b) estimate the change expected during the planned operating period, (c) identify appropriate design requirements, and (d) compare the estimated condition of the component at the end of the planned operating period with the design requirements.

The component state or condition of interest might be one or more of its material properties, such as fracture toughness, fatigue usage, strength, elasticity, etc., and/or one or more geometry characteristics, such as flaw size, wall thinning from wear, corrosion, and erosion, tolerances, etc. These characteristics can be determined by inspection, destructive examination, analysis, or other techniques. However, note that the use of analysis to estimate key material properties (such as fracture toughness or elasticity) and component geometry changes from wear, corrosion, erosion, flaw growth, etc., generally needs a good knowledge of the initial material condition and tolerances and a very good understanding of the relationships between stressors and states. This understanding needs to be based on appropriate data and physical models.

The changes in the component state or condition during some future planned operating period can be estimated based on conservative extrapolation of previous ISI (for example, wall thickness data) and destructive examination measurements or analysis. Again, the analysis tools need to reflect a good understanding of the physical relationships between the operating stressors and the changes in the component state or condition.

The component or structural design is generally based on traditional engineering analyses (thermal, hydraulic, stress, neutronic, etc., as appropriate) or testing and reflect appropriate margins between the expected loads and the calculated failure loads. The original design analysis may be sufficient for some components. A revised design analysis may be necessary for other components subject to additional cycles, previously unknown stressors, etc. New information may, in some cases, allow a reduction in or revised estimate of the margin.

The final step, comparing the design condition with the expected condition of the component, would be followed, of course, by a decision to replace or repair the component or leave the component as is. The comparison of design condition with a component's expected condition might also influence the planned future operating period and the frequency of future ISI or destructive examination activities.

A somewhat different approach is associated with components subject to environmental qualification (EQ) requirements. These are components that need to function properly during a normal operating period of some given duration and also during selected design basis accidents (DBA). Here three general approaches are cited: (a) compare actual operating environments with the preaging EQ environments, (b) compare estimated mechanical properties at the end of the planned operating period with the preaged EQ sample mechanical properties, and (c) remove samples from the plant, add additional aging (to reflect the expected aging during the planned future operating period), and subject the samples to DBA testing. The first two approaches are based on modeling of the complex relationships between environmental stressors, aging degradation (which are often material property changes), and time. The third approach provides results with more certainty but possibly at the highest cost.

These approaches will have a strong impact on the development of technical criteria for aging management. It is important that the limitations and uncertainties associated with whichever approach is chosen be assessed so that confidence intervals can be calculated and safety margins properly assessed.

5. *Development of technical basis for aging management*: The results of the activities discussed above are being used to identify and resolve technical safety issues related to aging, and to develop guidelines for aging management in operating nuclear power plants of all ages. The use of acceptable aging management approaches could form the quantitative technical basis for regulatory guides if warranted. The project results are being used by the Pacific Northwest Laboratory to develop a NUREG report, *Information Useful for Managing Aging Degradation in Nuclear Power Plants*, NUREG/CR-5562. The project results have contributed to the development of draft Regulatory Guide DG-1009, "Standard Format and Content of Technical Information for Application to Renew Nuclear Power Plant Operating Licenses," and of a NUREG report, *Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants*, NUREG-1299. Project results have also contributed to the reviews of several industry topical reports related to license renewal.

Overall project results to date are as follows. The first two steps have been completed, and results are presented in a two-volume report: *Residual Life Assessment of Major Light Water Reactor Components—Overview*, NUREG/CR-4731. Some progress has been made on Step 3, the assessment of emerging inspection, surveillance, and monitoring techniques. The emerging inspection, monitoring, and materials evaluation techniques are briefly discussed in Volume 1 of NUREG/CR-4731. A report summarizing an assessment of fatigue monitoring has been submitted for review. A report summarizing materials properties evaluation techniques will be submitted in the near future.

This report evaluates the aging management techniques for LWR metal containments. A similar evaluation of the aging management techniques for cast stainless steel components was published in October 1990. Evaluations of the aging management techniques for PWR steam generator tubes and LWR reinforced and prestressed concrete containments have been submitted for review. Aging management techniques for two other major components will be published soon as part of Step 4: PWR reactor pressure vessels and PWR reactor coolant system piping. These evaluations are being published in this multi-volume NUREG report, as indicated below.

PWR Reactor Pressure Vessels—Volume 1

LWR Reinforced and Prestressed Concrete Containments—Volume 2

LWR Cast Stainless Steel Components—Volume 3

PWR Steam Generator Tubes—Volume 4

LWR Metal Containments—Volume 5

PWR Reactor Coolant System Piping—Volume 6

P. F. MacDonald
V. N. Shah
January 1994

ACKNOWLEDGMENTS

The authors of this report acknowledge the significant role that G. H. Weidenhamer of the U.S. Nuclear Regulatory commission has played in providing programmatic guidance and review for this report.

The authors sincerely appreciate the critical review of this report performed by G. Arndt, W. Norris, J. A. Davis, C. P. Tan, and other members of the U.S. Nuclear Regulatory Commission. The authors thank the following persons for their in-depth review: A. B. Johnson, Jr., of Pacific Northwest Laboratory, D. J. Naus of Oak Ridge National Laboratory, F. E. Gregor of Multiple Dynamics Corporation, W. Dirk of Westinghouse Idaho Nuclear Company, and H.L. Magleby, R. L. Miller, and D. F. Glenn of EG&G Idaho. The authors thank D. E. Demart and J. Kelly of Duke Power, J. Pelliccone of GPU Nuclear, L. Goldberg of Sea Test Services, and A. S. Birring of Houston Lighting and Power Company for providing relevant technical information during telephone conversations.

Finally, the authors thank D. R. Pack and D. L. Bramwell for their technical editing and publication coordination, and also thank EG&G Idaho Electronic Publications for timely and professional document composition.

Insights for Aging Management of Major Light Water Reactor Components Volume 5: Metal Containments

1. INTRODUCTION AND BACKGROUND

This report discusses the aging degradation mechanisms that affect light water reactor metal containments (ranked high for their relevance to plant safety) and presents techniques for estimating the remaining useful life of these structures. The report also identifies deficiencies in current life evaluation techniques and identifies topics of further research and development to address those deficiencies.

Aging degradation is defined as a cumulative degradation of a component, system, or structure which, if unmitigated, may result in a loss of function and impairment of safety. Aging degradation mechanisms are often resulted from the interactions between design, materials, operational stressors, and environment, and can cause a loss of fracture toughness, strength, and fatigue resistance. Poor design, improper materials selection, or inadequate maintenance practices can accelerate the aging degradation.

Table 1 lists the operating domestic commercial light water reactors (LWRs) with metal containments in chronological order of their operating license dates, and presents their containment type. The metal containments for boiling water reactors (BWRs) and pressurized water reactors (PWRs) may be divided into six types:

Table 1. Type and year of commercial operation of metal containments (Naus 1986, USNRC 1987a).

Plant	BWR/ PWR	Year of Operating License	Containment Type
Yankee Rowe[a]	PWR	1961	Spherical
Big Rock Point	BWR	1962	Spherical
San Onofre 1[a]	PWR	1967	Spherical
Oyster Creek	BWR	1969	Mark I
Nine Mile Point 1	BWR	1969	Mark I
Dresden 2	BWR	1969	Mark I
Millstone 1	BWR	1970	Mark I
Dresden 3	BWR	1971	Mark I
Monticello	BWR	1970	Mark I
Pilgrim 1	BWR	1972	Mark I
Vermont Yankee	BWR	1973	Mark I
Quad Cities 1	BWR	1971	Mark I
Quad Cities 2	BWR	1972	Mark I
Prairie Island 1	PWR	1973	Cylindrical
Browns Ferry 1	BWR	1973	Mark I

Table 1. (continued).

Plant	BWR/ PWR	Year of Operating License	Containment Type
Kewaunee	PWR	1973	Cylindrical
Peach Bottom 2	BWR	1973	Mark I
Cooper	BWR	1974	Mark I
Peach Bottom 3	BWR	1974	Mark I
Prairie Island 2	PWR	1974	Cylindrical
Browns Ferry 2	BWR	1974	Mark I
Duane Arnold	BWR	1974	Mark I
Fitzpatrick	BWR	1974	Mark I
Hatch 1	BWR	1974	Mark I
St. Lucie 1	PWR	1976	Cylindrical
Browns Ferry 3	BWR	1976	Mark I
Davis-Besse	PWR	1977	Cylindrical
Hatch 2	BWR	1978	Mark I
Sequoyah 1	PWR	1980	Cylindrical, ice condenser
McGuire 1	PWR	1981	Cylindrical, ice condenser
Sequoyah 2	PWR	1981	Cylindrical, ice condenser
McGuire 2	PWR	1983	Cylindrical, ice condenser
St. Lucie 2	PWR	1983	Cylindrical
Washington NP 2	BWR	1983	Mark II
Waterford 3	PWR	1984	Cylindrical
Catawba 1	PWR	1985	Cylindrical, ice condenser
Fermi 2	BWR	1985	Mark I
River Bend	BWR	1985	Mark III
Catawba 2	PWR	1986	Cylindrical, ice condenser
Hope Creek 1	BWR	1986	Mark I
Perry 1	BWR	1986	Mark III

a. This plant is now shut down.

1. **BWR Mark I Containments** (see Figure 1). There are twenty-two Mark I metal containments. The containment consists of a light-bulb-shaped drywell vessel surrounded at the base by a torus-shaped suppression chamber. The two vessels are connected by vent lines spaced around the drywell base. The bottom of the drywell is embedded in a concrete basemat. The suppression chamber is supported by steel columns and saddles.

2. **BWR Mark II Containments** (see Figure 2). There is one Mark II metal containment (Washington Nuclear Project No. 2), similar in principle to Mark I containments, but the vessel's shape and arrangement differ. The drywell and suppression chamber

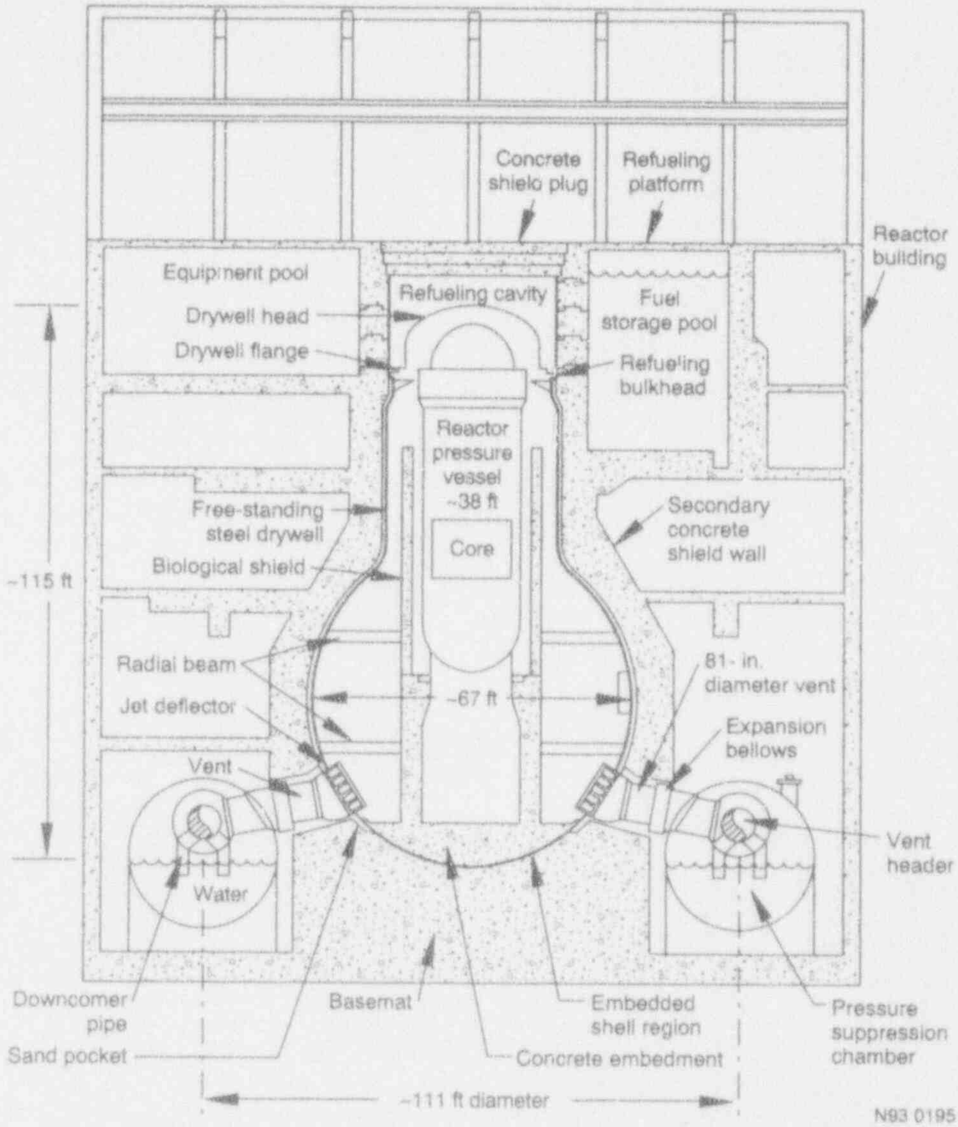

Figure 1. BWR Mark I metal containment.

are one vessel, separated by a diaphragm plate with downcomers. The vessel is supported by a concrete basemat in which the bottom of the vessel is embedded.

3. **BWR Mark III Containments** (see Figure 3). There are two Mark III metal containments (Perry 1 and River Bend). The Mark III vessel is substantially larger than the Mark I or II vessels, housing nearly all of the reactor building components. The drywell is a separate structure within the containment, and the suppression pool is formed between the containment vessel and the drywell wall. The containment vessel is a free standing steel cylinder with an ellipsoidal dome, secured to a reinforced concrete basemat lined with carbon steel. The portion of the carbon steel liner that is exposed to the suppression pool coolant is covered with stainless steel cladding. The annulus concrete extends above the basemat for about 23 ft and provides stiffness to the steel vessel, which is subject to postulated steam relief valve discharge loading.

4. **BWR/PWR Spherical Containments**. There is one BWR plant (Big Rock Point) and two PWR plants (San Onofre and

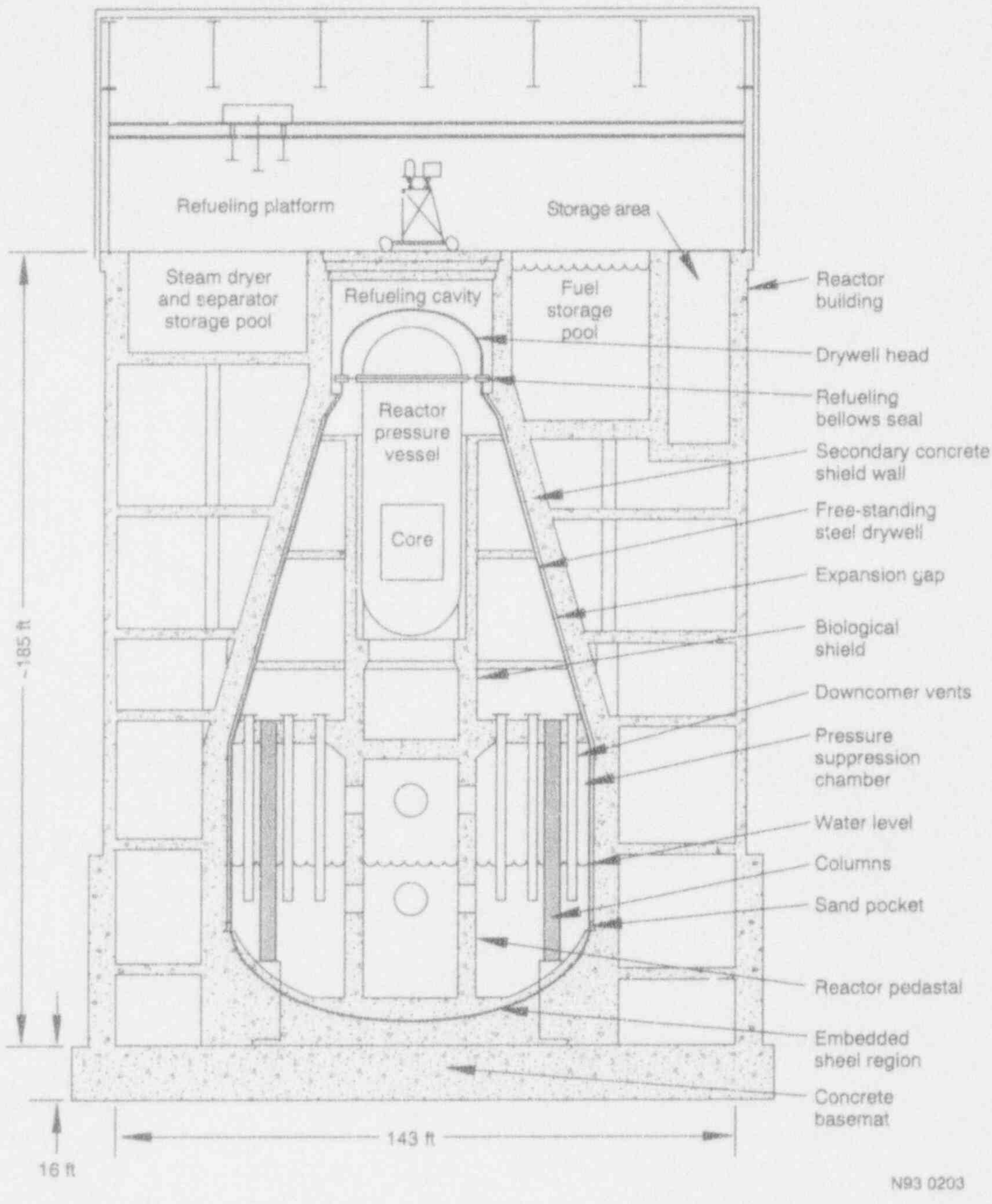

Figure 2. BWR Mark II containment enclosed in a reactor building.

Yankee Rowe, both of which are now shutdown) with spherical containments. These vessels are exposed to the exterior environment, so they have extensive coating systems on the outside surface. The Big Rock Point containment is embedded in concrete for support. The San Onofre 1 and Yankee Rowe containments are supported by external columns. Figure 4 shows the spherical metal containment, also called vapor container, of Yankee Rowe. The reinforced internal concrete structure supports the pressurized equipment. This concrete structure is surrounded by the containment. Eight steel encased concrete columns, which penetrate the spherical containment, support the reinforced internal concrete structure.

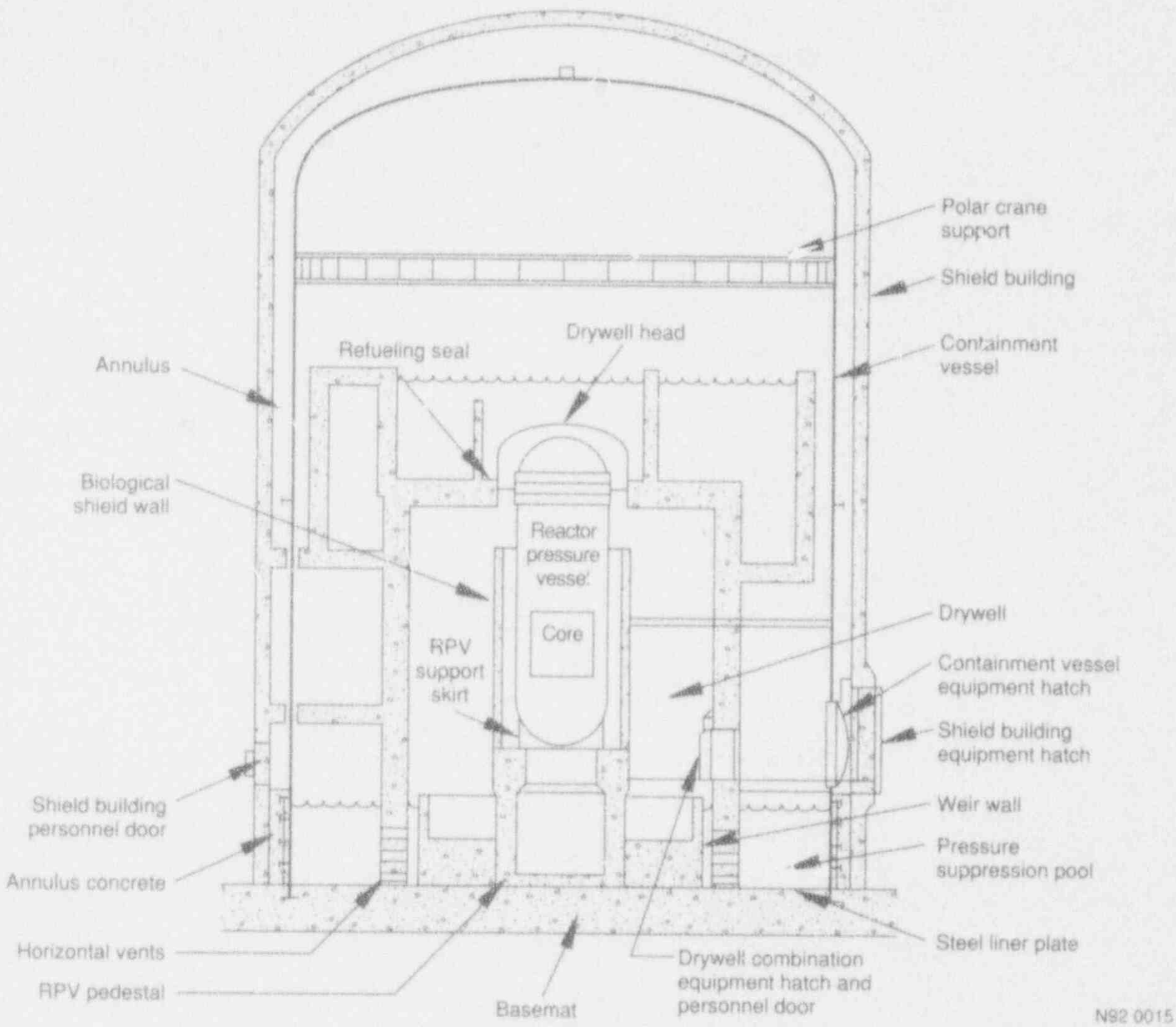

Figure 3. Mark III metal containment enclosed in a concrete shield building.

5. **PWR Cylindrical Containments Without Ice Condensers** (see Figure 5). There are six cylindrical containment vessels without ice condensers. Each consists of a steel cylinder with a hemispherical top and an ellipsoidal base. The base is embedded in a concrete basemat for support. A concrete shield wall (reactor building wall) encloses the steel containment with an annular space of about three to six feet between the two structures.

6. **PWR Cylindrical Containments with Ice Condensers** (see Figure 6). The containment vessel is a freestanding welded steel structure. It consists of a vertical cylinder with a hemispherical dome and a flat base. The base is a 6.35-mm (0.25-in.) steel plate liner that functions as a leak-tight membrane, not as a structural member. This liner plate is encased in the concrete and anchored to the reactor building foundation. The reactor building wall (a concrete shield wall) encloses the steel containment. An annular space of about 1.9 m (6 ft) separates the reactor building wall and the steel containment. A slightly negative pressure in the annular space prevents leakage of radioactive gases to the outside atmosphere in the event of a loss-of-coolant accident. The

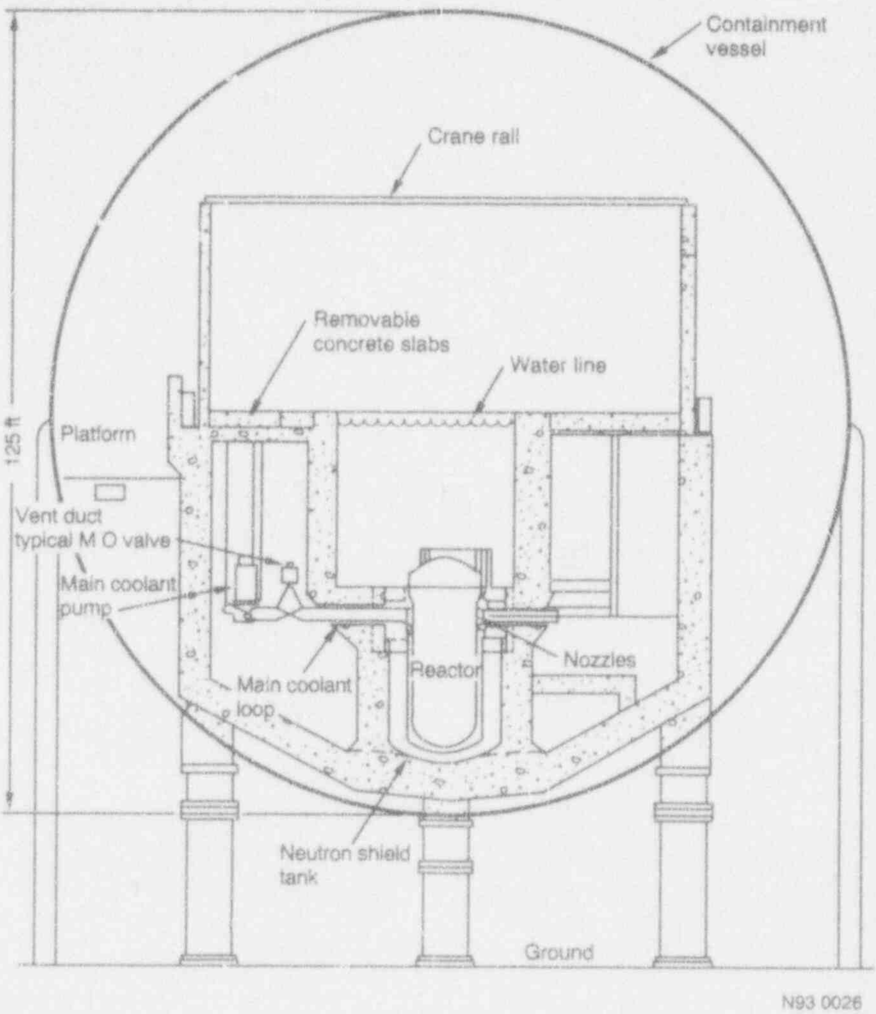

Figure 4. PWR spherical metal containment.

containment has a divider barrier structure that separates the reactor coolant system from the upper compartment. In the event of a loss-of-coolant accident, the divider barrier contains the steam released from the reactor coolant system and channels the steam through vent doors into the ice condenser. The ice condenses the steam, thereby minimizing the energy released into the upper compartment.

Typical design parameters of the different containment types are given in Table 2. Note that all of the metal containments, with the exception of the spherical vessels, are protected from the outdoor environment by a concrete shield building. Aging-related background information on containment designs, environmental conditions (interior and exterior), containment coatings, and containment testing/inspection is presented in Section 1.1. The environment of the shield building is described in Section 1.2.

The metal containment pressure boundary includes the containment vessel(s) and the bellows. In BWR Mark I, a portion of the emergency core cooling system (ECCS) suction intake pipes, which penetrate the bottom of the suppression pool, is also included in the containment pressure boundary. This portion consists of ECCS piping from the suction intake pipe penetrations in the suppression pool to the first check valve on the ECCS header. Because the ECCS piping is made of carbon steel and generally not coated on the inside surface, it is susceptible to corrosion by the suppression pool water.

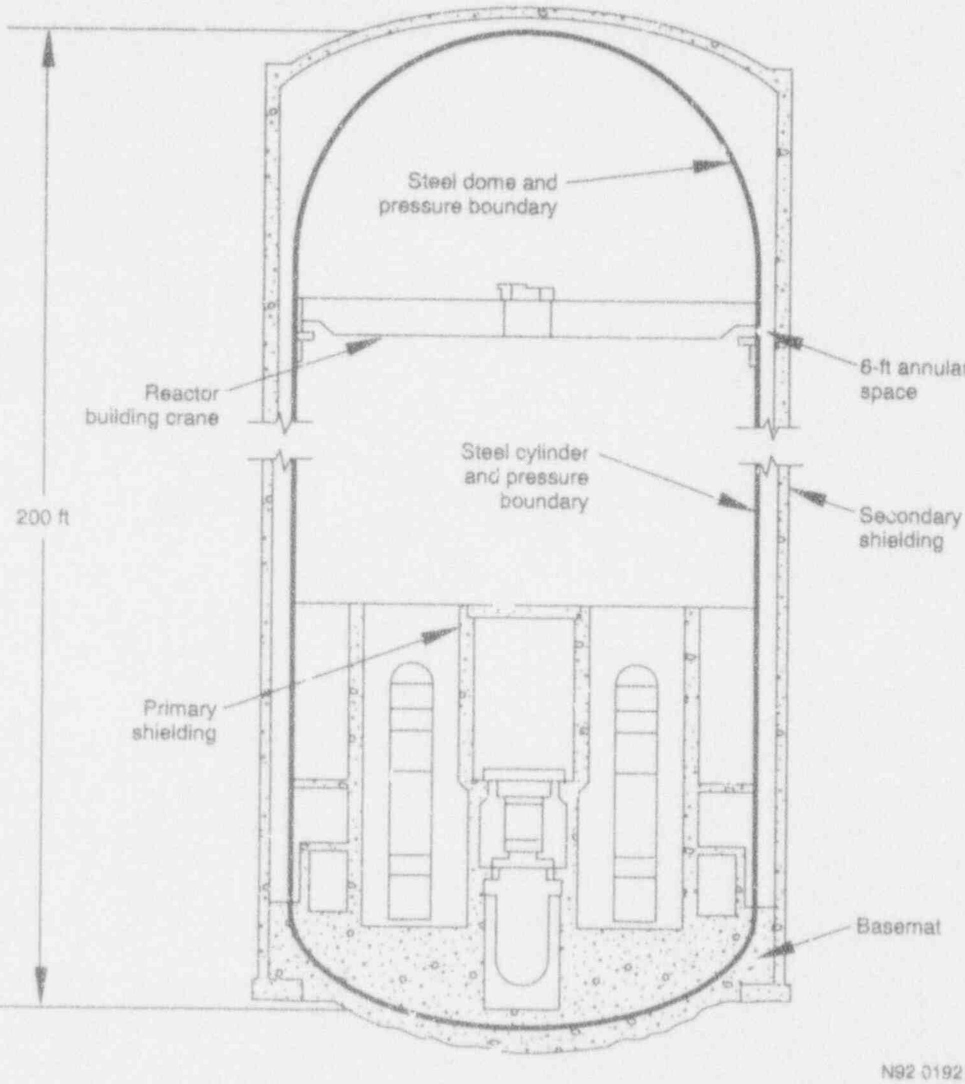

Figure 5. PWR cylindrical steel containment enclosed in a reinforced concrete reactor building.

BWR Mark I and PWR cylindrical containments represent more than three fourths of all light water reactor metal containments (see Table 1). Additionally, these containment types are generally found in the older plants. Therefore, the focus of this report is on these two containment types. The aging management approach suggested here focuses on the metal containment boundary. Items such as gaskets and seals are maintenance items, so they are not a major concern unless their function affects aging of the shell.

1.1 Design and Analysis

All three PWR spherical containments and the first BWR Mark-I containment (see Table 1) were designed according to Section VIII of the American Society of Mechanical Engineers (ASMEb 1965) Boiler and Pressure Vessel Code. Subsequent metal containments were designed as ASME Section III, Class B vessels. The main difference of the 1965 Section III with respect to containment design is the provision for determining whether a fatigue analysis was required and methods to perform such analysis. This provision is not far reaching because critical fatigue locations are those affected by hydrodynamic loading (for example, safety relief valve actuation or condensation and oscillations). These effects apply only to BWR containments with suppression pools (Oyster Creek, the one Section VIII containment with a suppression pool, has

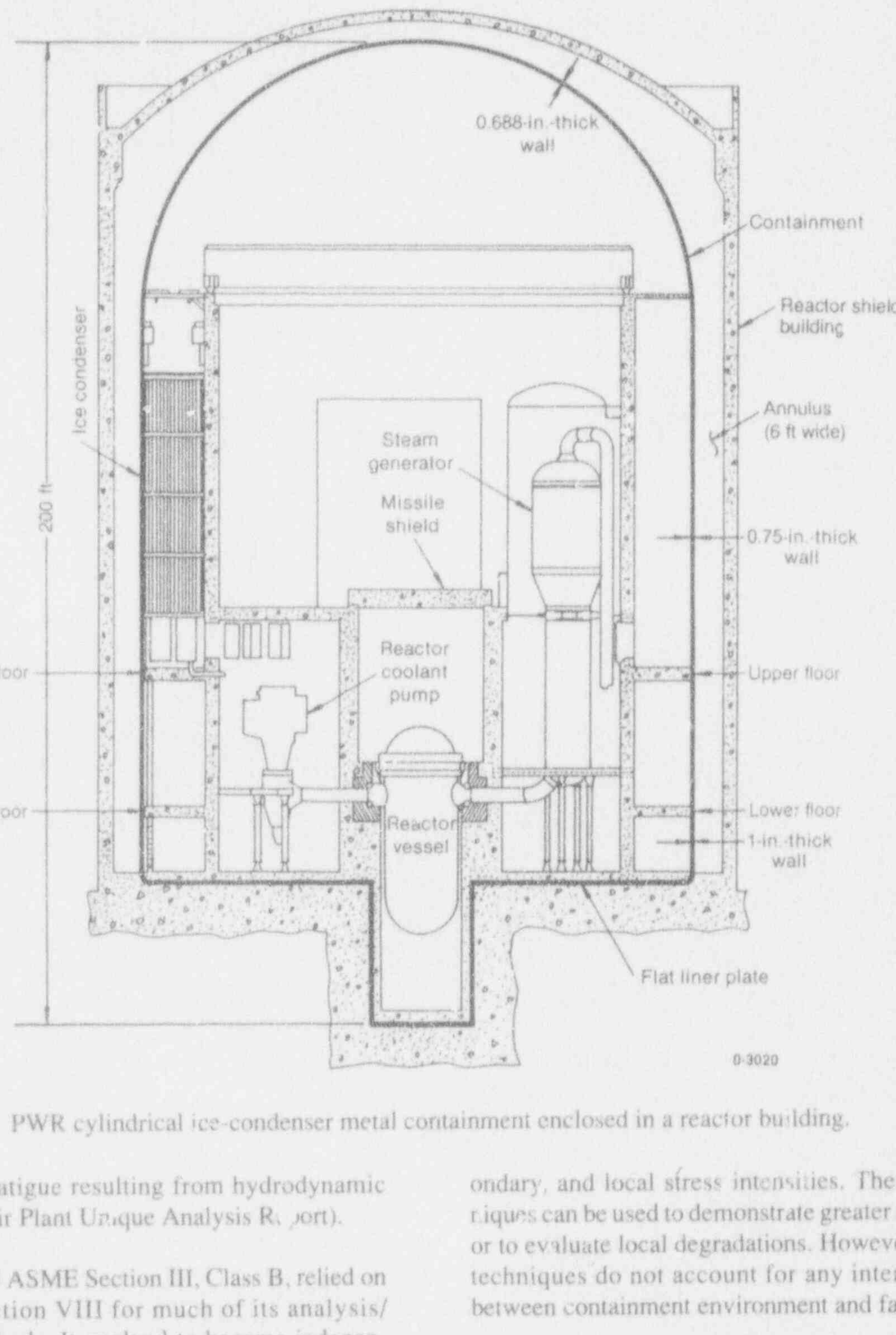

Figure 6. PWR cylindrical ice-condenser metal containment enclosed in a reactor building.

evaluated fatigue resulting from hydrodynamic loads in their Plant Unique Analysis Report).

The 1965 ASME Section III, Class B, relied on ASME Section VIII for much of its analysis/design methods. It evolved to become independent of Section VIII and, later, metal containments received their own category, i.e., ASME Section III, Class MC (ASME 1992a). The most significant change in the code has been to allow higher design stresses and to allow certain sophisticated analytical techniques to determine primary, secondary, and local stress intensities. These techniques can be used to demonstrate greater margins or to evaluate local degradations. However, these techniques do not account for any interactions between containment environment and fatigue.

In general, the design provisions of the ASME provide a reasonable safety margin for postulated load combinations. With respect to degradation, two provisions of the code are pertinent. One provision concerns material thinning caused by corrosion, erosion, abrasion, or other environmental

Table 2. Physical parameters of metal containments [1 MPa = 0.145 ksi; 1 m = 3.28 ft, 1 in. = 25.4 mm; °C = (°F − 32) × 5/9].

Materials[a]

ASTM A-516 Grade 70 or SA-212 Grade B (Shell)

Minimum yield strength	38 ksi
Minimum tensile strength	70 ksi
Nil ductility temperature	−50 to 0°F
Chemical composition (wt%)	0.27 to 0.30 C
	0.80 to 1.25 Mn
	0.035 P, maximum
	0.04 S, maximum
	0.13 to 0.33 Si

ASME SA-299 (Shell)

Minimum yield strength	40 ksi
Minimum tensile strength	75 ksi
Chemical composition (wt%)	0.28 C
	0.84 to 1.62 Mn
	0.035 P, maximum
	0.040 S, maximum
	0.13 to 0.33 Si

Type 304 Stainless Steel (Bellows)

Minimum yield strength	30 ksi
Minimum tensile strength	75 ksi
Chemical composition (wt%)	0.08 C
	2.0 Mn, maximum
	0.045 P, maximum
	0.030 S
	1.00 Si, maximum
	18 to 20 Cr
	8 to 10.5 Ni

Typical Dimensions

BWR Mark I[b]

Drywell

Height	100 to 120 ft
Diameter of sphere	60 to 70 ft
Diameter of cylinder	32 to 45 ft
Embedment	5 to 10 ft
Shell thickness	0.625 to 2.5 in.

Suppression Chamber

Major diameter	95 to 115 ft
Minor diameter	25 to 31 ft
Shell thickness	0.375 to 1 in.

Table 2. (continued).

	BWR Mark II[c]	
Drywell		
Diameter:		
Top		31 ft-8 in.
Bottom		65 ft-9 in.
Height		78 ft-0 in.
Suppression Chamber		
Diameter		65 ft-9 in.
Height		42 ft-0 in.
	Spherical[d]	
Diameter		125 to 130 ft
Embedment (BWR)		27 ft
Shell thickness		0.875 to 1 in.
	BWR Mark III[e]	
Height		200 to 300 ft
Diameter		120 to 130 ft
Embedment depth		5 to 10 ft
Shell thickness		0.75 to 1.75 in.
	PWR Cylindrical (Without Ice Condenser)[f]	
Height		232 ft
Diameter		140 ft
Embedment depth		23 ft
Shell thickness		0.95 to 1.9 in.
	PWR Cylindrical (With Ice Condenser)[g]	
Height		200 ft
Diameter		115 ft
Embedment depth		15 ft
Shell thickness		0.69 to 1.0 in.

a. ASME Boiler and Pressure Vessel Codes, Section III, 1965–present.

b. Northern States Power Company, Monticello Nuclear Generating Plant, *Updated Safety Analysis Report*, Revision 6, June 1988.

c. Niagara Mohawk, Nine Mile Point 2, *Final Safety Analysis Report*, Vol. 14, November 1984.

d. Jim R. Chapman, private communication, Yankee Atomic Electric Company, March 1990.

e. Gulf States Utilities Co., River Bend Station 1, *Final Safety Analysis Report*, Vol. 9, May 1985.

f. Louisiana Power and Light, Waterford 3, *Final Safety Analysis Report*, Vol. 6, September 1983.

g. Duke Power Co., Catawba Nuclear Station, *Final Safety Analysis Report*, Vol. 6, 1986.

conditions (see ASME Boiler and Pressure Vessel Code, Section III, Subsection NE, Paragraph NE-3121). For vessels subject to material thinning, the design needs to provide additional thickness (that is, a corrosion allowance) above that required for structural considerations, to compensate for the expected material thinning. Typical corrosion allowances range from no allowance to one-eighth inch. In the industry generally, no allowance for corrosion is recognized for vessels that are coated and partially embedded in concrete. However, conditions can exist (as discussed later) in which sections of the containment shell are exposed to a corrosion environment. This will be one of the major concerns in determining the residual life of a vessel.

The other ASME Code provision pertinent to this discussion concerns fatigue (see ASME Code, Section III, Subsection NE, Paragraph NE-3221). To determine if a vessel requires a detailed fatigue evaluation, a set of criteria is given [see ASME Code, Section III, Subparagraph NE-3221.5(d)]. The criteria limit the number of service (ambient to normal operating and back to ambient) pressure, temperature, and mechanical load cycles (more details on cyclic loads are provided in ASME Section III). The criteria are based on the ASME S-N curves for metal containment material. For vessels meeting the criteria, one can assume that stress intensity limits as governed by fatigue have been met by compliance with other code provisions. One can also assume that fatigue cracking will be minimal for vessels in this category. If a vessel does not meet the criteria, a fatigue usage factor (based on linear fatigue damage theory) must be calculated and compared with the allowable usage factor of 1.0 [see ASME Code, Section III, Subparagraph NE-3221.5(e)]. A detailed fatigue evaluation was not required at the time of original design for most metal containment vessels. For containment vessels designed in accordance with the 1965 (or earlier) ASME Code, even a cursory fatigue analysis was not required. Although current fatigue damage assessment techniques are based on the ASME Code evaluation, the evaluation might not represent actual degradation and safety margins. This is due, in part, to the lack of developed criteria to account for any synergistic interaction between corrosion and fatigue.

Another aspect of containment analysis relevant to aging and degradation is the development of more sophisticated analytical techniques. These improvements can be seen in both the analysis used to define the accident load values and in the stress analysis of the vessels. During the Mark I Containment Long Term Program, redefinition of hydrodynamic loads resulting from safety relief valve discharge and peak pressure/temperature loads resulting from loss-of-coolant accident established a need for greater strength and required structural modifications to many suppression chambers (USNRC 1980). The use of upgraded thermal-hydraulic codes provided lower peak pressure/temperature loads and structural analysis codes provided, in general, lower stresses; the lower stresses helped in minimizing the required modifications to the suppressions pools. The lower peak pressure loads also established 25 to 30% greater design margins for most drywell vessels, which can allow larger corrosion margin and provide longer fatigue life for drywells.

1.2 Environment

The environment pertaining to the metal containment (interior and exterior atmospheres and suppression pool) is responsible for its degradation by corrosion and corrosion-assisted fatigue. Atmosphere is characterized by pressure, temperature, and humidity. Suppression pool water is characterized by conductivity, pH level, and chemical impurity.

1.2.1 Interior Atmosphere. The containment interior atmosphere is a controlled volume, with the pressure, temperature, and chemical makeup held at nearly constant values during operation. Normal operating pressures vary somewhat for different plants, but are generally in the range of −1 to +2 psig. The pressure is monitored to permit operator action to maintain the desired value. Normal operating temperatures for Mark I containments are in the range of 57 to 66°C (135 to 150°F). PWR containments maintain ambient temperatures at about 49°C (120°F). One area of concern is the containment shell near the high-temperature piping penetrations (see Figure 7). Local shell temperatures can be higher at these locations and are more susceptible to fluctuations. To minimize this effect, most plants insulate the pipe within the penetration. However, the nearby wall temperatures can still fluctuate from the normal operating temperatures given above to about 93°C (200°F). Local drywell shell temperatures near the reactor cavity bulkhead region can be high if the ventilation hatches are inadvertently left closed. High temperature reduces humidity from the environment and makes it less corrosive; however, high temperature also degrades surface coating and reduces corrosion protection to the drywell wall.

The interior atmosphere of all BWR Mark I and Mark II containments is inerted with nitrogen to prevent hydrogen-oxygen recombination. The oxygen content is generally maintained at a level of less than 4% by volume. In BWR Mark III and PWR containments, hydrogen-oxygen recombination is generally prevented by other techniques, so these containments are filled with air. The relative humidity in BWR and PWR ice condenser containments is rather high, generally in the 40 to 60% range, because of the suppression pools and ice condensers, respectively. In other PWRs, the relative humidity is generally in the 15 to 40% range. During shutdown, condensate may form on the interior surfaces and accumulate at the base.

Control of the containment atmospheric parameters is achieved through the containment cooling system. The system provides temperature control and air circulation, and includes monitoring devices. The system is generally not safety-related, but its function is important to containment longevity.

Postulated environmental conditions vary widely among the different types of containments and accident scenarios. The postulated conditions are useful in defining the allowable aging damage, but these conditions do not significantly contribute to aging damage. Therefore, Table 3 summarizes only the accident condition ranges.

1.2.2 Suppression Pool. A special case of BWR containments is the suppression pool. The carbon steel interior surface in Mark I suppression pools becomes passive in the presence of

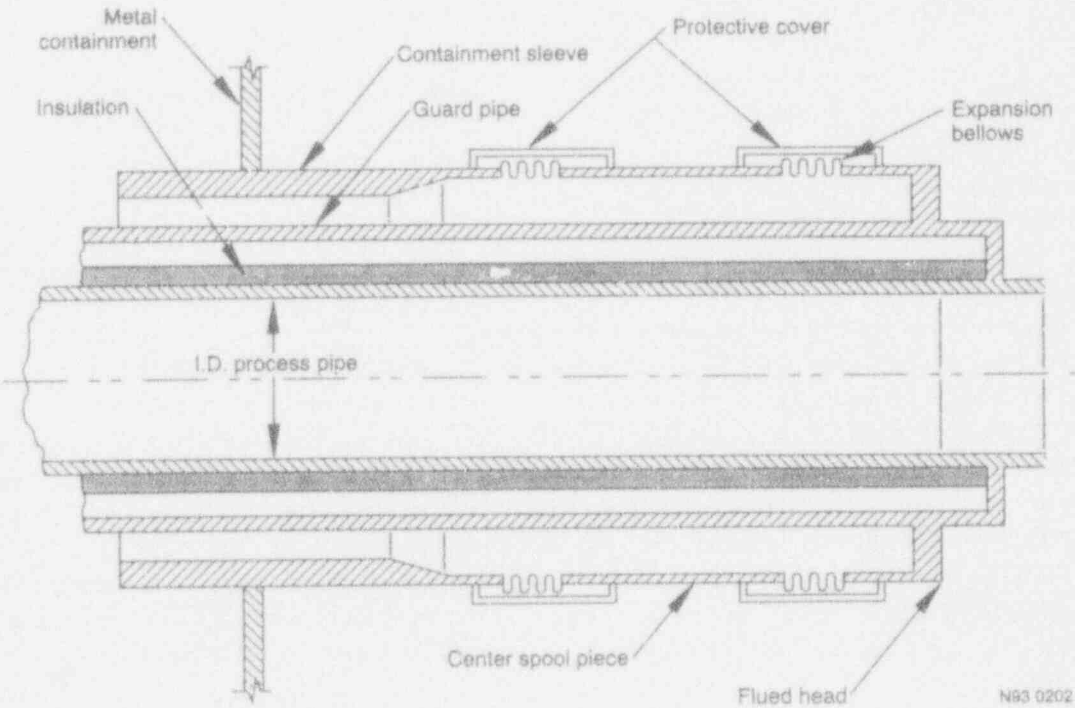

Figure 7. Typical hot penetration assembly.

Table 3. Postulated accident condition ranges [°C = (°F – 32) × 5/9].

BWR Mark I[a]	
Drywell	Range
Pressure	40 to 56 psig
Temperature	280 to 305°F
Humidity	100%
Suppression Chamber	
Pressure	25 to 32.2 psig
Temperature	182°F
Humidity	100%
BWR Mark II[b]	
Drywell	
Pressure	37 to 48 psig
Temperature	280 to 340°F
Humidity	100%
Suppression Chamber	
Pressure	28 psig
Temperature	275°F
Humidity	100%
BWR Mark III[c]	
Pressure	7 to 15 psig
Temperature	140 to 185°F
Humidity	100%
PWR Cylindrical[d]	
Pressure	40 to 50 psig
Temperature	260 to 280°F
Humidity	100%
PWR Spherical[e]	
Pressure	27 psig
Temperature	190°F
Humidity	100%

a. Northern States Power Company, Monticello Nuclear Generating Plant, *Updated Safety Analysis Report*, Revision 6, June 1988.

b. Niagara Mohawk, Nine Mile Point 2, *Final Safety Analysis Report*, Vol. 14, November 1984.

c. Gulf States Utilities Co., River Bend Station 1, *Final Safety Analysis Report*, Vol. 9, May 1985.

d. Louisiana Power and Light, Waterford 3, *Final Safety Analysis*, Vol. 6, September 1983.

e. Jim R. Chapman, private communication, Yankee Atomic Electric Company, March 1990.

chromated water, which was used earlier (Uhlig and Revie 1985). However, in the event of a loss-of-coolant accident, the water in the suppression chamber is also a primary source of water for the emergency core cooling system. Therefore, chromated water, being toxic, is no longer used in suppression pools (except possibly in one or two plants), thus avoiding its circulation through the reactor core during emergency core cooling and avoiding the problem of discharging the toxic water when the torus is drained. The presence of nonchromated water can increase the susceptibility of the suppression vessel to corrosion. The increased susceptibility can be mitigated by maintaining the surface coating and by maintaining a strict control on the water quality.

Table 4 lists the suggested values for the parameters of suppression pool water quality for a typical Mark I containment (NSP 1988). These values are considered adequate for combating shell degradation, though a concentration of chlorine near the upper end of the range (300 to 500 ppb) would provide the best protection against microbially influenced corrosion (Pope 1986). One parameter not specified or monitored but important to metal degradation is oxygen content. Typical oxygen concentrations are in the range of 3000 to 5000 ppb. High dissolved-oxygen levels facilitate corrosion in areas of the containment shell exposed as the result of coating failure. Torus shell corrosion resulting from degraded coatings is discussed in Section 2.

1.2.3 Exterior Atmosphere. The exterior surface of the containment shell is exposed to a different environment than is the interior surface.

Table 4. Suggested guidelines for suppression pool water quality.

Parameter	Value
Conductivity	5 micromhos/cm maximum
pH	6.5 to 8.5
Millipore crud	500 ppb maximum
Chlorides	1 to 500 ppb

With the exception of the three spherical containments for older plants (see Table 1), all the metal containments are enclosed by a reactor building or shield building. Thus, only the exterior surface of the spherical containments is directly exposed to the outside weather. The enclosed containments have openings to the reactor building such that the atmosphere (temperature, humidity, and pressure) between the steel containment and the inside wall of the reactor building is controlled. The exterior environment of the metal containment is significantly influenced by the proximity of the shield or secondary containment wall that surrounds the containment shell. From an aging viewpoint, the exterior environment is harsher than the interior environment in many cases. Temperatures and humidity levels can be significantly different outside containment, and variations in conditions are more frequent and larger in magnitude.

During construction, compressible material was placed on the drywell shell of Mark I and Mark II containments to maintain proper spacing, a small gap of 51 to 76 mm (2 to 3 in.), between the shell and shield wall, as shown in Figure 8. This gap allows for thermal and pressure expansion and contraction during normal operation and during design-basis accidents. In some plants, the compressible material was removed after construction was complete, while in others it was left in place. The material is soft enough to collapse and allow for thermal expansion of the vessel during operation. A sand pocket is located at the bottom of the gap, as shown in Figure 8. The purpose of the sand cushion is to reduce the stress concentration at the point of embedment of the shell in concrete when the shell is subjected to loss-of-coolant accident (pressure and thermal loading) and seismic loadings. Moisture may be trapped in the filler material or may collect in the sand pocket and cause corrosion of the drywell. However, in some Mark I containments, a galvanized steel plate covers the sand pocket and prevents moisture from entering; drains remove the moisture that may collect on the top of this plate. Table 5 shows the status of the gap between the metal containment and the concrete shield in Mark I containment vessels, and the type of material originally used to fill the gap (USNRC 1987b). Because of the small size of the gap,

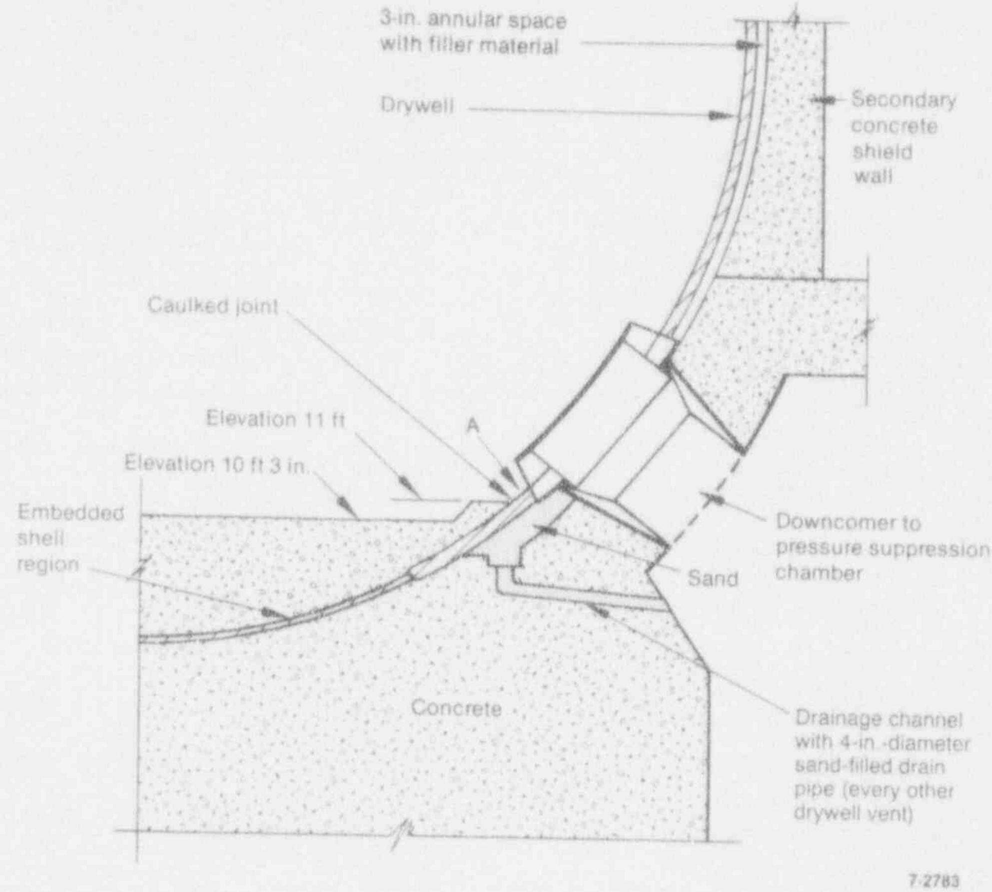

Figure 8. BWR Mark I drywell base, concrete shield wall, and sand pocket.

the exterior surface of the containment is extremely difficult to access for inspection or recoating, if warranted. It was also common to apply only one coat of shop paint to the exterior surface of these vessels. Shop paint is a low cost, lead-based coating. Its dry film thickness and chemical characteristics are not conducive to a long service life (SSPC 1985).

To compound the situation, the environmental conditions of the gap are often favorable to corrosion damage. The upper regions of most drywells are flooded during refueling, which subjects this area to cycles of wet and dry. In addition, leaks through the bellows at the drywell-to-cavity seal or through deteriorated gaskets can lead to corrosion of the exterior surface of the containment (USNRC 1986a). Similarly, leaks from the failed penetrations of control rod drive insert/withdraw lines can lead to corrosion of the exterior and interior surfaces of the drywell (Duane Arnold Energy Center 1990). A sand pocket is located at the base of the gap in a Mark I containment. Once the sand becomes moist, it is capable of supporting microorganisms, which can potentially lead to microbially influenced corrosion.

Compressible fill material in the gap can trap moisture against the shell and create opportunity for crevice corrosion to occur. Additionally, if the fill material degrades, chemicals in the material can create an aggressive environment for the metal by leaching out and concentrating in certain spots. Analysis of one plant's fill material, Firebar-D, showed high contents of Na, K, Ca, Mg, SO_4, and Cl (Wilson 1987). Several of these elements are aggressive to steel surfaces. Removing the fill material would reduce the threat of crevice corrosion, but the residual material particles would still likely create an aggressive environment. And removing the material is not considered feasible because access is constrained.

Table 5. BWR Mark I fill materials.

Nuclear Units	Fill Material	Fill Material Removed as of January 6, 1987	Comments
Oyster Creek	Firebar D and fiberglass	No	Gap not sealed
Nine Mile Pt 1	Fiberglass foam	—	Gap sealed, drain provided
Dresden 2	Polyurethane foam	No	—
Monticello	Polyurethane strips	Yes	Gap sealed, drain provided
Millstone 1	—	Yes	No thinning noted. Gap not sealed
Dresden 3	Polyurethane foam (burned up)	No	Gap not sealed
Quad Cities 1	Polyurethane foam	No	Gap not sealed
Quad Cities 2	Polyurethane foam	No	Gap not sealed
Pilgrim 1	Ethafoam	Yes	Gap sealed, drain provided
Vermont Yankee	Styrofoam	No	Probably not sealed
Peach Bottom 2	Polyethylene strips	No	Gap sealed, drain provided
Browns Ferry 1	Polyurethane	No	Gap not sealed
Cooper	Urethane foam	Yes	Gap sealed, drain provided
Duane Arnold	Polyurethane foam	Yes	Gap sealed, drain provided
Peach Bottom 3	Polyethylene strips	No	Gap sealed, drain provided
Browns Ferry 2	Polyurethane	No	Gap not sealed
Hatch 1	Ethafoam	Yes	Gaps sealed, drain provided
Fitzpatrick	Ethafoam	Yes	Gaps sealed, drain provided
Brunswick 2	NA	NA	Reinforced concrete containments
Browns Ferry 3	Polyurethane	No	Gap not sealed
Brunswick 1	NA	NA	Reinforced concrete containment
Hatch 2	Ethafoam	Yes	Gap sealed, drain provided
Fermi 2	Foam	No	Gap not sealed
Hope Creek 1	Fiberglass	No	—

NA = Not Applicable.

The BWR Mark III and PWR cylindrical containments have a larger annular space, instead of a small gap, between the metal shell and containment shield building. The space permits inspection and recoating of the exterior surface without severe difficulty. Drains are located on the floor beneath the annular space.

An important consideration regarding exterior environment is the potential damage that may be caused by ground water. If the cracks in the concrete under the embedded portion of the containment are connected such as to form a path through the basemat, and if the rubber membrane underneath the basemet is ruptured, ground water might reach the outside surface of the embedded portion of the containment and corrode it.

Another important consideration regarding the exterior environment of metal containments is the damage caused during plant construction. During construction, the shell can be exposed to rain, snow, sun, etc. Plants with long construction periods and that are exposed to aggressive environments (for example, salt air or acid rain) can significantly degrade a containment prior to initial startup. Three spherical containments do not have a secondary containment wall. Therefore, the exterior surface of the metal shells in the spherical containments are exposed to a harsh environment not only during plant construction but throughout operation. However, the exterior surface of the spherical containments is coated and is accessible for inspection and recoating.

1.3 Protective Coatings

The interior surfaces of light water reactor containment vessels are coated to provide corrosion protection and to facilitate decontamination of the containment shell and surrounding concrete structures. Since construction of the earlier plants, qualification criteria for containment interior surface coatings have been developed. Current requirements and guidelines can be found in ANSI Standards N5.9 (1967), N101.2 (1972a), and N101.4 (1972b) and in Regulatory Guide 1.54 (USNRC 1973a). The requirements focus on environmental qualification for normal and accident temperatures and humidities; qualification is achieved through vendor tests performed under simulated conditions of design-basis accidents and artificial aging.

Prior to current requirements, coatings were selected on the basis of experience with coatings in similar environments and on manufacturers' recommendations. Coating vendors specify the minimum and maximum dry film-thickness that can be applied with specific coatings. Qualification tests on coatings used in the early containments, performed after the fact, indicate that the coatings were acceptable for use in containment environments and under design-basis accident conditions. Based on the generally positive experience of the systems in the older plants, newer containments use the same or similar coating systems.

Containment coating systems, in general, consist of a minimum of one coat of primer with additional top coats. The interior surface of the suppression chamber in some plants is not coated above the waterline. The exterior surfaces of the containment and the suppression chamber in some plants have one coat of lead-based coating with a typical dry film-thickness of 0.05 mm (2 mil). The interior surfaces of the containment and the suppression chamber in some plants have a primer coating of inorganic zinc and intermediate and finish coatings of polyamide epoxy, with a dry film-thickness of 0.15 to 0.23 mm (6 to 9 mil). Some plants have used phenolic epoxy enamel as primer, intermediate, and finish coatings on the interior immersion steel surfaces, with a typical dry film-thickness of 0.23 mm (9 mil). The typical dry film-thickness range on the drywell interior surface is 0.20 to 0.25 mm (8 to 10 mil), and that on the torus wall interior surface is 0.25 to 0.50 mm (10 to 20 mil) (Sea Test Service 1988). The interior surface of the lines such as an ECCS line that penetrate the containment wall is not coated.

A critical feature of a coating application is surface preparation. The object of the preparation is to provide a surface profile conducive to coating adhesion. Surface preparation may involve solvent-cleaning and various degrees of blast cleaning to remove dirt, oil, and grease and to prepare the surface for proper adhesion. For the zinc-rich primer, commercial blast cleaning (SSPC 1985, SSPC-SP6) is recommended for nonimmersion service and white metal blast cleaning (SSPC 1985, SSPC-SP5) for immersion service, that is, for the BWR suppression chamber interior surfaces. The white metal blast cleaning process prepares a suitable surface for stronger adhesion and more uniform thickness of coating on the metal surface than is achieved by a commercial blast cleaning process. These processes remove sharp edges and provide a 0.03- to 0.08-mm (1- to 3-mil) blast profile. Note that blast cleaning the vessel for coating application reduces the containment vessel wall thickness slightly, 0.03 to 0.13 mm (1 to 5 mil).

Maintenance of the coating is important to reduce corrosion damage to the containment shell. The key parameters associated with coating maintenance are inspection to identify degraded areas, removal of degraded coatings, surface preparation, and selection of a compatible coating material. Inspection can include a visual survey and dry film-thickness measurements, where necessary. Dry film-thickness measurements can be taken easily with commercially available magnetic gauges. Removal of degraded coatings and surface preparation can be performed using the blast cleaning techniques described above. However, as a typical containment coating lasts for about 7–10 yrs, coating maintenance may be required several times over the course of plant life, and the reduction of vessel material by blast cleaning can be too extensive. Additionally, blast cleaning of relatively small areas is difficult. Several products are now available to prepare small areas for recoating. The products (SSPC 1985, SSPC-SP-11-87T) use woven or coated sanding discs or small-diameter needle guns. Surface loss is generally less than 0.03 mm (1 mil). Selection of compatible recoating materials is based on the adhesion of new coatings to old coatings. Manufacturers' literature on coatings generally specifies compatibility to other coating types.

1.4 Preoperational Testing

A number of tests are typically performed to confirm containment integrity prior to operation of a light water reactor. The tests fall into four categories:

1. Material properties. Tests for mechanical properties and chemical content, as specified in Section II of the ASME Boiler and Pressure Vessel Code (ASME 1992c)

2. Weld inspection. Nondestructive testing, generally radiography, on pressure retaining welds, according to criteria of Section III of the Code

3. Leakage rate tests. Tests performed to check leakage rates at design pressure or at reduced test pressure

4. Overpressure test. The 1965 ASME Code required a pneumatic pressure test at 120 to 125% of design pressure. This is the code that many of the early containment vessels were constructed to. Since that time, the code has been revised to require the test at 110% of design pressure.

Preoperational test results can provide initial or baseline properties, such as material yield and tensile strengths, needed for aging management. These data can often provide justification for a smaller minimum wall thickness or, conversely, a larger corrosion allowance. However, use of actual material properties is not endorsed by the ASME Code, and approval from the USNRC would be required. It is unlikely that any U.S. utility has yet used the actual material properties for determining the minimum wall thickness.

In addition, a review of the results of all preoperational tests may provide information relevant to aging management. Of particular interest are the radiographic examination results, which may indicate potential lamination (separation of metal grain boundaries) flaws. Although such indications were originally acceptable by ASME

Code standards, they may have either grown or may indicate weak locations in the vessel, and may, therefore, require more detailed analysis. Components that required repairs or modifications to meet test requirements are also potential areas for further analysis.

1.5 Inservice Tests and Inspections

Continued assurance of containment integrity is obtained by periodic inservice tests and inspections. The following paragraphs describe the current tests and inspections and their effects on aging of metal containment vessels.

1.5.1 Leakage Rate Tests. A program of leakage testing of the primary containment is required by 10 CFR 50, Appendix J (1986), in order to ensure leaktight integrity. Allowable leakage rates are specified in plant-specific technical specifications and are based on containment design, plant-unique mitigation features, such as a filtration system, and offsite dose projections calculated in accordance with 10 CFR 100 (1991) for various design-basis accident conditions. Appendix J requires three types of leakage tests: Type A, Type B, and Type C. Type A tests are designed to measure the integrated leakage of the entire primary containment system. They are conducted three times during each 10-year service period. The Type A test includes pressurizing the entire containment to a pressure based on the peak design-basis pressure and then monitoring any leakage. Technical specifications of a plant define the pressure used for the Type A test. Prior to the Type A test, a visual inspection of the containment is required to determine if there are any obvious containment integrity problems.

Current regulation allows a reduced pressure, not less than half the peak design-basis pressure, for Type A tests, provided a reliable correlation between the leakage rates at full and at reduced pressure tests is established. Review of leakage rate data for the reduced and full-pressure tests performed at several U.S. PWRs with concrete containments did not reveal any correlation (Koegh 1984). There are two main reasons for this lack of correlation. Leakage through valves and steam generator manways may not vary with pressure in any particular pattern. The second reason is that the internal concrete structures absorb or release gas during the pressure tests. Most of the US nuclear power plants perform Type A tests at the peak pressure; only six or so older plants perform the tests at the reduced pressure.

Type B tests are designed to measure any local leakage through the containment penetrations. They are performed by local pneumatic pressurization of the penetration bellows. These local leakage tests are conducted every operating cycle at test pressures equal to the calculated maximum pressure caused by a design-basis accident.

Type A and B tests can result in local stress intensities of 1.5 S_a [199 MPa (28,875 psi for SA-516 Grade 70)], where S_a = allowable stress intensity. Type C tests are designed to measure any containment isolation valve leakage. Type C tests are not relevant to containment aging because they do not induce stresses in the containment.

1.5.2 Inspection and Surveillance. Section XI, Subsection IWE, of the ASME Code provides a reasonable and systematic basis for ensuring the continued integrity of the containment vessel during its service lifetime. The Subsection was originally developed with the objective of ensuring that the critical areas of the containment such as pressure-retaining accessible welds, seals, gaskets, and hatch bolts maintain their integrity throughout the plant lifetime. The preservice condition of the finished containment welds as painted or coated and the preservice condition of other pressure-retaining components may be visually examined and documented to provide a reference baseline. This baseline is then compared with the condition determined by visual examination at each subsequent inservice inspection. Removal of the surface coating or paint is not required for routine examinations of containment welds. Visual examinations that detect surface indications may be supplemented by either surface or volumetric examination techniques. The coating or paint is removed to facilitate the supplemental inspection.

Subsection IWE was recently revised to emphasize the inservice inspections of both containment vessel base metal and welds instead of only welds (ASME 1992b). This revision is based on the operating experience at several nuclear power plants, which has shown that the base metal is more susceptible to degradation by corrosion, for example, than the welds. The revised Subsection IWE is not yet endorsed by 10 CFR 50.55(a), but it is being reviewed by the NRC. The revision includes a visual examination of the accessible surface areas on the containment pressure boundary during each inspection interval. These accessible areas include the outside surface of the penetration and vent line bellows. In addition, the revision includes an augmented examination of surface areas that are susceptible to accelerated degradation by corrosion, or wear, and that have minimal or no corrosion allowance or have experienced repeated loss of protective coating. Examples of such areas include the surface areas exposed to standing water, persistent leakage, substantial traffic, or water jets from safety relief valve discharges. The augmented examination requires visual inspection if the susceptible surface area is accessible from both sides, or ultrasonic thickness measurement if the susceptible area is accessible only from one side. For ultrasonic measurement, use of a 1-ft grid is recommended. Ultrasonic measurements are made at a minimum-wall-thickness location in each grid during each inspection period. If an area inspected remains unchanged for three consecutive inspection periods, an augmented inspection for that area is no longer required.

In addition to the above requirements, each plant has a unique set of operating and surveillance requirements published in plant-specific technical specifications. Typical operational limits for containments specify the following parameters:

- Maximum and minimum temperatures
- Maximum and minimum pressures
- Maximum differential pressure (drywell/torus and primary/secondary containment)
- Suppression chamber water level and maximum temperature.

Additionally, the technical specifications require implementation of leakage rate testing and any plant-unique surveillance, such as coating inspections or condition assessment walkdowns.

The remainder of this report is in five sections. Section 2 describes assessment of corrosion damage and degradation of the surface coating of carbon steel metal shells. Section 3 describes assessment of fatigue damage to the carbon steel metal shell and fatigue and stress corrosion cracking of stainless bellows. Section 4 describes the most significant events of corrosion damage to metal containments. Section 5 describes a generic approach for performing comprehensive aging management of a metal containment. Section 6 summarizes the key conclusions, maintenance activities, and future work based on the technical issues related to corrosion and fatigue damage to metal containments.

2. ASSESSMENT AND MITIGATION OF CORROSION DAMAGE

Corrosion is the potentially life-limiting degradation mechanism for metal containments. Various corrosion mechanisms affecting the carbon steel metal shell are described in this section, as are the available data on the degradation rates, techniques for detecting or monitoring the aging damage, techniques for preventing or mitigating damage, and degradation of surface coatings.

2.1 Corrosion of Containment Vessels

Corrosion of the carbon steel metal shell is probably the most damaging mechanism affecting metal containments. Corrosion damage to a metal usually occurs by an electrochemical process if the metal is not protected by coating and is in contact with an electrolyte (water, salt solution, acid, or alkali). Corrosion damage has been detected at several plants, and at least three plants have experienced extensive damage. The major concern related to corrosion damage is that some sites susceptible to corrosion are not accessible for inspection or recoating.

Corrosion of the metal shell reduces the structural strength of the containment by wall thinning and has the potential to develop a leak path for the interior environment of the containment. In addition, a rough corroded surface can act as a stress raiser and reduce the fatigue life of the containment shell.

2.1.1 Description of Mechanisms. The tendency for metal corrosion, according to the modern theory of corrosion, is measured by the change in a thermodynamic function called Gibbs' free energy, G (Uhlig and Revie 1985). The change in Gibbs' free energy, ΔG, is a direct measure of the maximum electric energy available from a system. If the change in free energy is positive, there is no tendency for corrosion. For example, the value of ΔG for the reaction of gold with oxygenated water is positive, indicating that gold will not corrode and form hydroxides. If the change in free energy is negative, there is a tendency for corrosion. For example, the value of ΔG for the reaction of iron with oxygenated water is negative, indicating that iron is susceptible to corrosion. The more negative the value of ΔG, the greater is the tendency for corrosion. However, the more negative value is not necessarily associated with a higher corrosion rate, i.e., thermodynamics does not predict kinetics. Therefore, the concept of change in Gibbs' free energy is generally not used in studying the corrosion phenomena.

This section describes the different corrosion mechanisms using a simpler, classical corrosion theory based on the concept of local anodes and cathodes. This concept is not in conflict with the modern theory of corrosion based on thermodynamics, but represents a different approach to the problem of understanding the electrochemical aspects of corrosion reactions (Fontana 1986).

On metal surfaces, there exist different regions of varying composition and, hence, different electrode potentials. For example, manganese sulfide (MnS) inclusions are present on the carbon steel surface. The different electrode potential forms, on a microscopic scale, anodic and cathodic sites on the metal surface, which constitute corrosion cells in the presence of an electrolyte. Electric current flows from the cathodic to the anodic site along the metal surface and flows in the opposite direction in the electrolyte. This corrosion cell, which is of very small dimension (e.g., < 0.1 mm), is called a local-action cell, and the current is called local-action current (Wranglen 1985). Figure 9 is an enlarged schematic arrangement of local-action cells. The anodic and cathodic sites in the cell may occupy the same location or may be separated. The local-action cells often lead to local attack such as pitting or stress corrosion cracking.

In general, two important types of corrosion cells, on a macroscopic scale, take part in the corrosion of metal: concentration cells and dissimilar electrode cells (Uhlig and Revie 1985). For example, a difference in oxygen concentration between two surfaces or two sites on the same

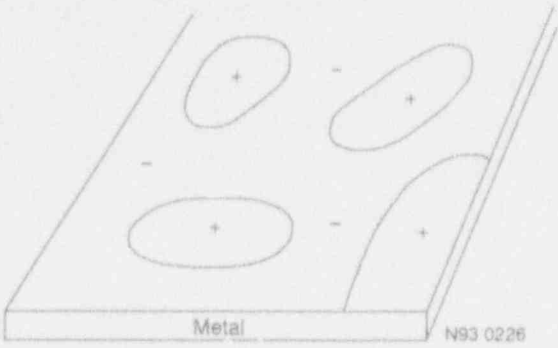

Figure 9. Local-action cells on a metal surface.

surface produces an oxygen concentration cell in the presence of water or an aqueous electrolyte (salt solution, acid, or alkali). Dissimilar electrode cells are formed when any of the following conditions exist: (a) two dissimilar metals are placed in contact with each other, (b) both cold-worked and annealed states exist in the same metal, or (c) the composition of the grain-boundary is different from the material within the grain (in carbon steel, inclusions such as sulfide at the grain-boundary make the composition at the grain boundary different from that of the material within the grain) (Uhlig and Revie 1985). When the metal containment is exposed to aqueous electrolytes, local-action current flowing in concentration or dissimilar electrode cells will corrode the metal shell. In practice, cells responsible for corrosion may be a combination of these two types. The carbon steel shell of the metal containment is susceptible to the following seven mechanisms of corrosion, differing from each other in appearance of corroded metal or in environment causing corrosion damage (Fontana 1986):

1. General corrosion
2. Pitting
3. Crevice corrosion
4. Differential aeration
5. Microbially influenced corrosion (MIC)
6. Aggressive chemical attack
7. Galvanic or dissimilar-metal corrosion.

Some of these mechanisms, for example, pitting and crevice corrosion, are closely related; however, they warrant separate consideration because the environments causing corrosion damage and the susceptible sites can be different. The relationships between these mechanisms are identified in the following discussions. The similarities and differences between pitting and crevice corrosion are discussed in Section 2.1.1.3. The corrosion mechanisms listed above are not in any particular order of importance.

The first mechanism is based on the local-action cell concept. The next five mechanisms are based on the concentration cell concept, and the last one is based on the dissimilar electrode cell concept. More than one mechanism may act at the same site. Table 6 summarizes the potential metal containment sites for each type of corrosion.

2.1.1.1 General Corrosion. Whenever corrosion causes a more or less uniform loss of metal over a large surface of the metal shell, it is called general corrosion or uniform corrosion. General corrosion is an electrochemical process. The anodic reaction is the oxidation of iron in carbon steel to ferrous ion. Under an aerated, near neutral environment (pH=6–8), the cathodic reaction consists of oxygen reduction. Under an acidic environment, hydrogen evolution will [illegible] one of the cathodic reactions. The final product of the overall reaction is films of rust, which normally consist of two layers of iron oxides, i.e., Fe_2O_3 and Fe_3O_4. The metal oxide layer formed on anodic areas is less permeable to oxygen and may retard further corrosion.

The general corrosion of carbon steel can be explained using the local-action cell concept. In general corrosion, the individual local-action cells are of such small dimensions that they cannot be distinguished even under a microscope, or the anodic and cathodic surfaces fluctuate over the metal surface in a statistical disorder way so that the anodic and cathodic reactions take place simultaneously, and the attack will be more uniform (Wranglen 1985). In the case of pitting and crevice corrosion, discussed in the following sections, the local-action cells have larger dimensions, and the anodic and cathodic surfaces are separated.

Table 6. Summary of potential corrosion sites.

Type	Site
General corrosion	Mark I and II exterior drywell surface; any uncoated carbon steel surface, interior/exterior surfaces of LWR containment vessel, BWR emergency core cooling system pipes.
Pitting	Torus wall (if coating has deteriorated); section of high-pressure injection pipe between torus and check valve; outer surface of Mark I containment near sand pocket; containment vessel wall near concrete-metal interface (if sealant is not intact or not applied).
Crevice corrosion	Under hatch gaskets and bolts (if coating has deteriorated); concrete embedment region; Mark I and II drywell exterior surface (if compressible material was left in place).
Differential aeration	Near waterline of suppression pool (if coating has deteriorated).
Microbially induced corrosion	Mark I drywell sand pocket region; suppression pool region; containment sump regions where cracks in the concrete allow water to come in contact with metal; areas where standing water accumulates; sump line penetrations.
Aggressive chemical attack	Embedded shell region; low areas in penetration sleeves; refueling seal region; sand pocket region (Mark I); outside surface of PWR cylindrical containment.
Galvanic corrosion	Near vent line bellows (dissimilar-metal welds between stainless and carbon steels); any equipment attached to the containment through different metal connections (supports, ducts, grounding wires, etc.).

At containment operating temperatures, dissolved oxygen in neutral or near-neutral water is necessary for appreciable corrosion of the carbon steel shell to occur, and then only if the surface is uncoated or the coating has deteriorated. In air-saturated water, such as the coolant in the torus near the waterline, the corrosion rate may initially be high, but it decreases over a period of days as the iron oxide (rust) layers form and act as a barrier to oxygen diffusion. In the pH range of 4 to 10, carbon steel corrosion is controlled by oxygen diffusion, which depends upon oxygen concentration, temperature, and diffusivity. The steady-state corrosion rate increases with oxygen concentration. In the absence of dissolved oxygen, the corrosion rate for the metal shell is negligible.

General corrosion can occur on both interior and exterior surfaces of the drywell and torus. In BWR plants, the portions of the emergency core cooling system pipes between the containment and check valves, which are typically made of carbon steel and penetrate the torus below the waterline, are susceptible to corrosion. The rate of corrosion can be accurately predicted and can be accounted for in the design. Historical data indicate general long-term environmental corrosion rates in the range of 0.003 to 0.03 mm/year (0.1 to 1.0 mil) (ASM 1978). Figure 10 shows the data resulting from a long-term corrosion experiment performed by Larrabee and Coburn (ASM 1978). Figure 11 shows the results of atmospheric corrosion experiments performed by several electric utilities on uncoated carbon steel plates (Multiple Dynamics 1987). The conclusions drawn from Figures 10 and 11 are that the initial corrosion rates are relatively high, and then reduce to long-term rates over the next two- to seven-year period. All of these tests were performed in an outdoor environment, which is different than the containment environment, and the results might not be directly applicable in the containment applications. Outdoor environments are subject to greater temperature swings, and to moisture in the form of rain, condensation, or snow.

General corrosion is manageable because it can easily be detected and mitigated if the surface is accessible. Visual examination can identify the evidence of any flaking, blistering, peeling, and discoloration and any other signs of damage to the accessible metal shell surface coating. A borescope can be used to detect such damage in the inaccessible areas near the containment penetration. These areas are generally 0.9 to 1.2 m (3 to 4 ft) from the containment penetrations. Periodic recoating of the degraded steel surface may be used to prevent the corrosion damage of the metal shell.

2.1.1.2 Pitting. Corrosion that produces small holes in the metal surface is called pitting. The surface diameter of a pit may be about the same or less than its depth. Pits may occur within a pit, and, frequently, they are so close together that the surface is merely irregular.

Pitting usually occurs when the passive oxide film on a metallic surface, formed during fabrication or produced by reaction with the environment, breaks down locally by the action of the surrounding corrosive media having free access to the surface. Pitting initiates at the weak spots in the oxide film, for example, where the sulfide inclusions appear on the surface. Pitting of carbon steel most often occurs in chloride solutions;

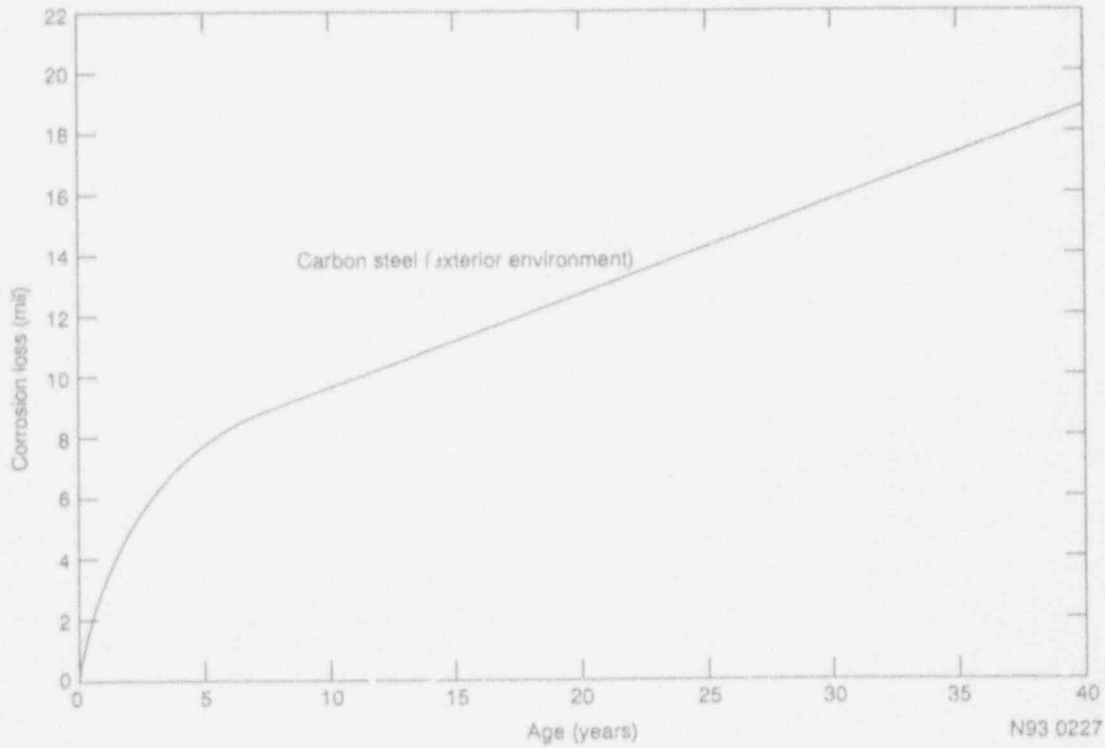

Figure 10. Long-term corrosion test results for carbon steel exposed to an exterior environment (ASM 1978). Copyright American Society for Materials; reprinted with permission.

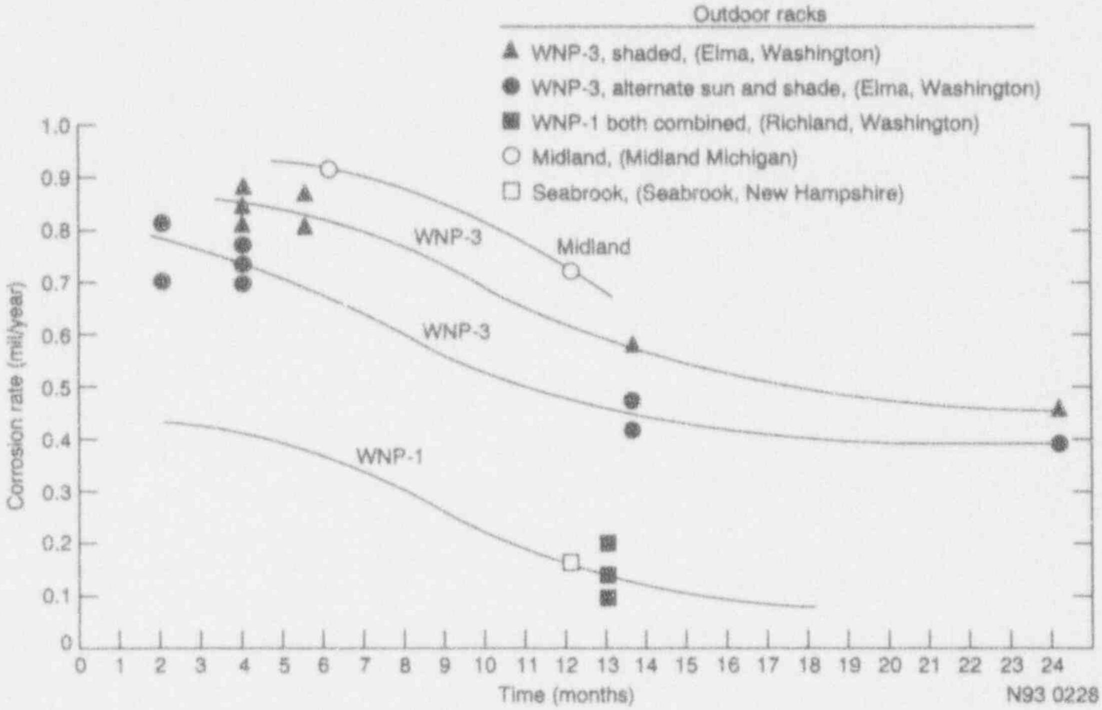

Figure 11. Results of carbon steel corrosion tests performed by utilities (Multiple Dynamics 1987). Copyright Electric Power Research Institute; reprinted with permission.

however, under certain conditions, it can occur in the presence of sulfate ions in aqueous solution at room temperature (Szklarska-Smialowska 1986). The critical potential at which the passive oxide film begins to break down is called critical pitting potential.

Pitting takes place at isolated sites when the chloride concentration is moderate. Chloride ions break down the passive film locally at a small isolated site where the film is weak, and a pit forms at such a site. The site acts as an anode, where dissolution of iron takes place; this produces an excess of positively charged metallic ions in the pit solution. To balance the excess charge, the chloride ions migrate into the pit, producing a high concentration of ferric chloride. The metal chlorides hydrolyze and produce chloride and hydrogen ions (free hydrochloric acid) that accelerates metal dissolution in the pit, which further increases the migration of chloride ions. Thus, the pitting process is self propagating. The large area of the metal surface surrounding the pit acts as a cathode where oxygen reduction takes place, forming hydroxyl ions. Acid produced at the anode shifts the pH at the anode to lower values. Hydroxide produced at the cathode shifts the pH at the cathode to higher values. Another factor contributing to these pH shifts is the high current densities at the anode (Arup 1983). Because the solubility of oxygen in the concentrated and acidic iron chloride solution in the pit is low and environment is highly oxidizing, little oxygen reduction takes place within the pit. Oxygen reduction takes place in the large area surrounding the pit, which protects the area from corrosion and prevents formation of new pits in the neighborhood of the pit, unless low oxygen concentrations or high chloride concentrations are established. The corrosion products within the anodic pit react with the hydroxyl ions produced at the cathode sites adjacent to the pit to form hydroxides. After further oxidation, these hydroxides form iron oxides, which can form tubercles, as frequently seen in iron corrosion (Miller 1977).

Pitting can be considered as an intermediate stage between complete corrosion resistance and general overall corrosion. At high chloride concentrations, a large number of closely spaced pits are formed and, as a result, anodic and cathodic reactions take place everywhere on the surface. As a result, the environment at the pits is neutral or alkaline; oxygen has access in such an environment. The corrosion takes place uniformly over the surface and the resulting products are iron oxides. Thus, a high chloride concentration will lead to general corrosion, whereas moderate concentration will lead to isolated pits (Fontana 1986, Arup 1983).

Sites Susceptible to Pitting—Pitting has been reported in the BWR Mark I containments on the submerged surface of suppression pools and the outside surface of a drywell adjacent to the sand pocket region (Stuart 1993, Gordon and Gordon 1987). Pitting has also been reported in the PWR cylindrical containments with ice-condensers on the outside surface at the interface of the containment wall and concrete floor and on the inside surface at the upper and lower floor levels.

Pitting can occur at locations where the surface coating has failed prematurely. The locations include, for example, areas having surface discontinuities that where not detected and repaired when the original coating was applied and areas where roughly welded seams were not sealed. Pits can initiate at a discontinuity (pore or gap) in the coating where an electrolyte containing dissolved oxygen and sufficient concentration of chlorine ions penetrates the coating, breaks the oxide film, and comes in contact with base metal.

The other potential sites for pitting damage are the outside surface of the Mark I and II drywells, the embedded portion of the metal containments, and the inside surface of the piping connected to the submerged portion of the suppression pool. Leakage of water at the drywell bellows drain line gaskets during refueling may create a pool of stagnant water (a corrosive environment) at the junction of Mark I and II drywell wall and the concrete floor. Leaching of chlorides from fill material, if present between the drywell and the secondary concrete shield wall, can aggravate the corrosive environment. This environment can damage an uncoated metal surface, while having minimal effect on a coated surface.

The inside surface of the embedded portion of metal containments is susceptible to pitting if the sealant at the metal-concrete interface is deteriorated. The interior concrete acts as a coating to the embedded portion of the shell and protects it from corrosion. However, during startup and shutdown, differences in the thermal expansion of the concrete and metal containment may cause the sealant to deteriorate and create a gap or crevice between the containment and the concrete. Any moisture trapped in this gap will have access to an uncoated steel surface, creating a potential site for pitting. Application and maintenance of a sealant at the accessible concrete-metal interfaces can prevent entry of moisture and protect against pitting damage.

If there are cracks in the concrete beneath the embedded portion of the containment shell that are connected such as to form a path through the basemat, and if the waterproof membrane underneath the basemat is ruptured, groundwater might reach the uncoated outside surface of the embedded shell and make it susceptible to corrosion. Similarly, water from inside the containment, for example, from the BWR Mark II pressure suppression pool, might reach the inside surface of the embedded shell and make it susceptible to corrosion. For example, a pit may form on a small area and penetrate the embedded steel, thus compromising the leak tightness integrity of the containment.

The emergency core cooling system suction intake pipes are connected to the Mark I torus below the waterline. A portion of these pipes between the torus and first check valve contains stagnant water that might damage the inside surface of the pipes (which are uncoated) by pitting.

Because pitting is a form of local corrosion, total metal loss is very small. However, the amount of metal loss is not as important as the possibility that an individual pit may develop into a through-wall penetration. The average pit depth is a poor way to estimate pit damage, because the deepest pit can develop a sudden leak path.

Pitting is generally identified by the presence of tubercles or nodules, which can be visually detected if the affected surface is accessible. Visual inspection can also detect a degraded coating on the interior surface of BWR Mark I and II containments and on the interior and exterior surfaces of Mark III and PWR cylindrical containments provided that the access to these surfaces is not obstructed.

Pits on the submerged surface of Mark I and II suppression pool walls can be inspected and repaired under water (Stuart 1993). There is no longer any need for draining the pool and inspecting it in a dry condition. Prior to inspection and repair, desludging is performed to reduce radiological exposure and improve visibility in the suppression pool. The inspection includes visual detection and counting the number of pits in a given area, measuring the pit depths, and determining the areas where coating is not intact. The underwater repair includes cleaning the damaged metal surface by grinding and coating it with underwater epoxy and allowing it to cure. The epoxy cures in 24 to 36 hours, depending on the temperature. The underwater inspection and repair method has been successfully applied at 18 operating BWRs in the United States.

2.1.1.3 Crevice Corrosion. Crevice corrosion is a form of local corrosion that occurs in the crevices or cracks, generally in the presence of chloride solution. Similar to pitting, metals and alloys whose corrosion resistance depends on passive oxide film are susceptible to crevice corrosion. Crevice corrosion occurs at shielded areas on metal where moisture can be trapped and become stagnant. A critical opening wherein crevice corrosion occurs is a few thousandths of an inch wide or less. It rarely occurs within a crevice with a wide opening, for example, a 3-mm- (0.125-in.-) wide groove or slot.

The basic mechanism of crevice corrosion can be explained as follows. Initially, these reactions occur uniformly over the entire surface, including both the interior and exterior of the crevice. Both oxygen reduction and metal dissolution take place in the crevice. After a short time, the oxygen within the crevice becomes depleted because of restricted mass transfer and no further reduction of oxygen within the crevice takes place, but the oxygen reduction continues outside the crevice. As the area within the crevice is much smaller than the area external to the crevice, the corrosion process continues despite the oxygen depletion, and the system begins to operate as a differential aeration cell. The dissolution of the metal within crevice continues, which produces an excess of the positively charged metallic ions in the crevice solution. To balance the excess charge, the chloride ions migrate into the crevice, producing a high concentration of metal chlorides. The metal chlorides hydrolyze and produce chloride and hydrogen ions in the crevice, which accelerate the metal dissolution in the crevice. This, in turn, increases the migration of Cl^- ions into the crevice and the environment within the crevice becomes highly acidic. When the acidity attains a critical value, passivity breaks down and initiation of crevice corrosion takes place. Propagation of crevice corrosion follows the same mechanism as pitting. The corrosion rate within the crevice increases as the crevice width diminishes. The crevice corrosion rate can be as high as 1.30 mm/yr (50 mil/yr). As corrosion within the crevice increases, the rate of oxygen reduction on the adjacent surface also increases. This, in turn, cathodically protects the external surfaces. Thus, as in the case of pitting, the metal within the crevice corrodes while the metal surface surrounding the crevice undergoes little or no corrosion damage (Fontana 1986, Szklarska-Smialowska 1986).

The preceding discussions reveal several similarities and differences between crevice corrosion and pitting of metal in chloride solution. Some researchers believe that pitting is a special form of crevice corrosion because micropits formed on the metal surface act similar to crevices where highly acidic environment develops. These researchers also assume that crevice corrosion initiates from pits formed inside the crevice where passivity initially breaks down. Also, from an electrochemistry point of view, both crevice corrosion and pitting are identical, except crevice corrosion is associated with a longer diffusion path (Szklarska-Smialowska 1986).

However, there are sufficient differences between crevice corrosion and pitting that each warrants separate consideration. The three main differences are as follows: (a) crevice corrosion can occur only in the presence of stagnant fluid in the gap, whereas pitting can occur when the metal surface is in contact with stagnant or mobile fluid; (b) crevice corrosion occurs in narrow gaps, whereas pitting can occur on the surface having small variations caused by nonmetallic inclusions, grain boundary, etc.; and (c) crevice corrosion initiates more rapidly than pitting because the change in the composition of solution in a narrow crevice takes place at a faster rate than in an uncovered pit. Therefore, crevice corrosion is more detrimental than pitting in practice.

Sites Susceptible to Crevice Corrosion—Locations under hatch gaskets and bolts (if coating has deteriorated), concrete embedment regions, cork joint/steel containment vessel interfaces, and Mark I drywell outside surfaces (if compressible material was left in place) are vulnerable to the presence of aqueous solutions. Proper maintenance of coatings and sealants at these locations can minimize crevice corrosion.

The potential for this form of corrosion exists at the base of the vessel where the shell is embedded in concrete. The interior and exterior concrete acts as a coating to resist corrosion of the embedded shell. However, during startup and shutdown, differences in thermal expansion rates may deteriorate the sealant and create a gap between the shell and the concrete. Any moisture trapped in this gap will have access to an uncoated steel surface, creating a potential corrosion site. The embedded section of the vessel is considered a fixed support in the resistance of lateral loads (that is, seismic, design-basis accident pressure, and thermal expansion loads), and, therefore, is subjected to large stresses during lateral loading conditions. Thus, corrosion of this shell region can have a severe negative impact on a vessel's structural capacity.

As discussed in Section 1.2, some Mark I and II containments have compressible material in the gap between the drywell vessel and shield wall. Moisture in this gap can become trapped against the vessel and accelerate the corrosion rate. A relatively large surface area can be affected by this phenomenon, so it is considered an area of high susceptibility to corrosion.

2.1.1.4 Differential Aeration. Differential aeration is similar to crevice corrosion in that the corrosion rate is accelerated by a difference in the concentration of dissolved gases. Differential aeration occurs on the metal surface where two adjacent sites are exposed to two different concentrations of oxygen (Fontana 1986). Because BWR containments have suppression pools, the area near the waterline is a potential site for differential aeration. The metal walls of the Mark I and II suppression pools are partially submerged in water. The dissolved oxygen content in the pool water at the waterline is higher than that below the waterline. This condition forms a local oxygen concentration cell, and the metal surface at the waterline becomes a cathode, while the metal surface somewhat below the waterline becomes an anode and results in local corrosion. Other areas where standing water can cause corrosion because of differential aeration are the low points in vent systems, sump drain lines, refueling seals and skirts, the sand pocket area, and penetration sleeves.

Recently, corrosion of an uncoated torus wall was reported at Nine Mile Point Nuclear Station Unit I. The utility (Niagara Mohawk) estimated the corrosion rate to be 0.08 mm/yr (3.2 mil/yr), which is more than twice the corrosion rate assumed in the design. The high corrosion rate is likely a product of differential aeration (USNRC 1988b).

Visual detection of coating damage on the interior wet surface of the torus is difficult. Maintenance of a coating in good condition and recoating of degraded wet areas can protect the metal against corrosion. Stainless steel cladding on the submerged metal surface in Mark III containments makes the surfaces nonsusceptible to corrosion.

2.1.1.5 Microbially Influenced Corrosion. The problem of microbially influenced corrosion in the nuclear industry is receiving increased attention. A number of cases have been found since its recognition. Microbially influenced corrosion of metal can take place in the presence or absence of oxygen in the environment and most metal alloys are susceptible to this degradation mechanism (Pope 1986).

Microbially influenced corrosion often occurs in conjunction with or subsequent to crevice corrosion and differential aeration (Pope 1986). Microbially influenced corrosion occurs in sites where moisture, which is capable of supporting microorganisms, is permitted to stand (and stagnate) in contact with metal. Microorganisms are small, varying from less than 0.20 μm in length to several hundred micrometers in length and by up to 2 to 3 μm (0.08 to 0.11 mil) in width. Because of their small size, microorganisms can penetrate into crevices (Pope 1986). The microorganisms can live in a wide range of temperatures [−10 to 99°C (14 to 210°F)], pH levels (0 to 10.5), oxygen concentrations (0 to 100%), and pressures [0.1 MPa (atmospheric pressure) to 100 MPa (15 ksi)] (Fontana 1986). A typical corrosion rate of carbon steel in environments conducive to microbially influenced corrosion is 0.25 to 0.76 mm/yr (10 to 30 mil/yr) (Wolfram et al. 1988).

Microorganisms are of two types, aerobic and anaerobic. Aerobic microorganisms use oxygen in their metabolic processes, while anaerobic microorganisms grow most favorably in environments containing little or no oxygen (Fontana 1986). The process by which the microorganism degrades the metal depends on the type of microorganism (Pope 1986). Some degrade the metal by creating a local environment conducive to corrosion. The microorganisms alter the environment by intake of certain chemicals (a food source) and production of waste product. The waste products can be highly acidic and, thus, accelerate corrosion. Other types of microorganisms feed on chemicals in the coatings on the metal shell and leave the metal susceptible to corrosion. Still others are capable of oxidizing or reducing metal ions directly. Microbially influenced corrosion products form in discrete deposits (nodules) in the pits on the surface of metal or alloy. The size of the pits is smaller than the overlaying microbially influenced corrosion deposits. Significant amounts of iron and manganese are found in the deposits, regardless of the type of material. Silicon, sulfur, chloride, and phosphorus are also found in the deposits.

Degradation of the systems susceptible to microbially influenced corrosion occurs especially during construction and during outages. If the systems are not treated by chlorination during outages, as they are during operation, then the propensity for this corrosion increases. Any place where water is allowed to stand (and stagnate) in contact with the containment metal shell is a potential location for microbially influenced corrosion. The most obvious site for standing water is the suppression pool in BWRs. Both aerobic and anaerobic microorganisms are most likely to exist in the suppression pool. Aerobic microorganisms readily grow in such environments containing atmospheric oxygen, whereas anaerobic microorganisms develop most favorably in environments in which the concentration of dissolved oxygen approaches zero (Uhlig 1958). Aerobic microorganisms have been found at the beginning of the fuel cycle when there is enough dissolved oxygen in the normally stagnant coolant in the Mark I pressure suppression chamber, whereas anaerobic microorganisms have been found at the end of the fuel cycle when most of the oxygen present in the coolant has been consumed.[a] Anaerobic microorganisms consume hydrogen absorbed on the metal surface, and iron atoms ionized in this process dissolve into aqueous solution (Uhlig and Revie 1985). Microbially influenced corrosion can be minimized by maintaining both an intact surface coating and high quality water; water is most often treated with biocides to control microbial infestation (EPRI 1990).

Another potential corrosion location in Mark I containments is in the sand pocket region of the drywell. The sand pocket is the lowest location where any moisture or condensation on the drywell exterior surface can collect. Both aerobic and

a. J. Wolfram, private communication, EG&G Idaho, December 1987.

anaerobic microorganisms can exist in the sand pocket environment. Anaerobic microorganisms have been found in wet sand, whereas aerobic microorganisms have been found in dry sand.[a] The sand pockets in Mark I containments with an unsealed gap between the drywell and shield wall may contain a large amount of moisture resulting from any water leakage during refueling (Mathur 1987). Wall thinning caused by corrosion in this region was found at the Oyster Creek Nuclear plant. Chemical analysis of a sample of sand from the pocket indicated the presence of microbes. However, no substantive evidence was found to link microbially influenced corrosion with the corrosion in this instance. But, the occurrence does show the variable nature of microbially influenced corrosion and its potential (Wilson 1987).

Other potential sites for microbially influenced corrosion depend on operating occurrences and plant-unique geometries. Any spills, leaks, condensate, or plugged drains may create stagnant water. Additionally, those containment low points identified as susceptible to the differential aeration mechanism are potentially susceptible to standing water and, thus, microbially influenced corrosion.

2.1.1.6 Aggressive Chemical Attack. A number of chemicals present within containments are capable of degrading carbon steel if they come in contact with it. The aggressive chemicals that can potentially come in contact with the containment vessels are borated water in PWRs, sodium pentaborate in BWRs, decontamination fluids, and groundwater containing high levels of chlorides or sulfates. These chemicals can cause a marked increase in the local corrosion rate. The reactor coolant water in PWRs typically has a boric acid content of 0.2 to 0.4%. The containment vessel can be exposed to this water from valve stem leakage, pipe leaks or breaks, and spillage from refueling operations. In cases where the leaking coolant reaches an accessible surface, boric acid crystals or rust staining may be noticed. Such observations are cause for concern.

The coated regions of the vessel are afforded a certain amount of protection assuming the coatings are maintained and the spills are cleaned as soon as possible (zinc-rich coatings are rated well for mild acidic environments; phenolic coatings are rated average to below average). However, if the spill seeps through cracked concrete or deteriorated sealant to the embedded region, the borated water will be in direct contact with the steel. Similarly, undetected leakage from sumps and embedded piping could propagate through shrinkage cracks in the concrete toward the embedded shell portions. On the exterior of the embedded region, the vessel can be exposed to groundwater if the basemat develops cracks that are connected and form a path, and the waterproof membrane has ruptured. Groundwater with high chloride, sulfate, and oxygen levels can accelerate the corrosion in this region. Although the operating stresses in the embedded sections are low, the threat of potential leakage exists. Because the metal is embedded in concrete, it is difficult to detect the onset of corrosion and to repair any damage.

Another potential source for aggressive chemical degradation is the gap filler material used by some Mark I plants. As discussed in Section 1.2, this material can degrade and collect in the sand pocket. Aggressive chemicals in this material, such as chlorides and sulfates, can significantly accelerate corrosion rates.

2.1.1.7 Galvanic or Dissimilar-Metal Corrosion. Galvanic corrosion occurs because of a potential difference that exists between two dissimilar metals in contact with water or electrolyte. If two metals are placed in direct contact or are in contact through an electrically conductive material, the potential difference creates a flow of electrons between them. The less resistant metal forms the anodic site and is susceptible to corrosion, while the other metal forms the cathodic site and is protected (Fontana 1986). An intact surface coating does not prevent galvanic corrosion.

A potential site for galvanic corrosion in metal containments is in the vent or penetration lines near the bellows locations. The bellows material is stainless steel, whereas the rest of the vent lines and pipe sleeves material is carbon steel. The sites on carbon steel pipe sleeves and vent lines adjacent to dissimilar welds become anodic with respect to the adjacent sites on stainless steel bellows and are susceptible to corrosion. In many cases, these sites are difficult to inspect or recoat. Therefore, this type of corrosion could have a significant impact on the integrity of the vent lines or penetration assemblies.

It is not possible to determine all potential sites for galvanic corrosion because the materials used in contact with the containment shell are plant-specific. Some feedwater, main steam, and control rod drive penetrations have dissimilar metal welds; Mark III containments have stainless steel cladding in the suppression chamber; and refueling and drywell seal bellows have dissimilar attachment welds to the containment.

2.1.2 Current and Emerging Inspection Techniques. Inspection techniques currently used to detect corrosion damage include visual inspection and ultrasonic examination (UT). The UT may include the use of a commercially available ultrasonic thickness gauge or an electromagnetic acoustic transducer for the inspection of the embedded portion of the metal containment.

2.1.2.1 Visual Inspection. The most common inspection technique is visual inspection of all accessible surfaces. Section XI of ASME Code, Subsection IWE, requires visual examination of the accessible surfaces of the pressure-retaining boundary prior to each 10 CFR Appendix J, Type A, leakage rate test. Visual examination can identify any flaking, blistering, peeling, discoloration, and other signs of damage to the accessible surface coatings. Inspection sites at higher elevations may be accessed using scaffolding or ladders. Visual inspection includes periodic inspection of all areas of the containment, supplemented by remote inspection. Techniques for remote visual inspection employ periscopes, still cameras, stereo video cameras, and laser scanning cameras. The lower portion of the containment embedded in concrete is not accessible to visual inspections.

The inspection of the outside surface of a Mark I drywell is difficult because the narrow annular space between the drywell and concrete shield wall makes the surface inaccessible. Therefore, visual inspection is limited to borescopic inspection through a piping penetration annulus to examine the area directly surrounding the penetration. The inspection of the outside surface of a PWR ice-condenser steel containment is much easier because of the wider annular space between the containment and the reactor building wall. The shell outside surface, in general, can be inspected and, if necessary, recoated. However, heating, ventilation, and air conditioning duct lines present in the annular space obstruct inspection of some portion of the outside shell surface. Assuming that the inside and outside surface coatings are maintained properly, general corrosion of the metal shell can be expected to be minimal in PWR cylindrical containments.

Because crevice corrosion is possible near hatches, under gaskets, and under bolt heads or nuts, maintenance at these locations with grease and lubricants can be effective in controlling the corrosion. Periodic (5- to 10-year intervals) visual inspection of hatches and flanged connections not opened routinely will help to ensure that any degraded areas receive attention. Also, inspection and repair of the suppression pool's coating, though partially submerged, is not likely to be difficult.

2.1.2.2 Ultrasonic Inspection. Ultrasonic testing is commonly used to monitor wall thinning and can be used to detect and monitor corrosion on the inaccessible side of the containment if the other side is accessible. The Subgroup on Containment has revised Subsection IWE of ASME Section XI, as discussed in Section 1.5.2 of this report, to incorporate the requirements of ultrasonic thickness measurement at susceptible areas that are accessible only from one side. Some foreign codes also have provisions for periodic ultrasonic thickness measurements of containment vessels (Canadian Standards 1987). Metal thickness is measured by the ultrasonic pulse-echo technique; that is, an ultrasonic transducer transmits waves toward the metal surfaces, signals are reflected from the front and back surfaces, and the difference between the arrival times of these two signals is used to determine the thickness. Metal loss is then calculated from the measurement of metal thickness. Thickness can be measured either by a commercially available ultrasonic thickness gauge that produces a digital readout of the thickness or by an ultrasonic device that can display the echo signals (A scan) on an oscilloscope. The advantage of this device over the gauge is that signal scattering caused by rough surfaces (Figure 12a) is evident on the display (Figure 12b).

Commercially available ultrasonic thickness gauges, also called digital gauges, are successfully used to measure thickness of a wall having smooth surfaces, as is the case either when an original smooth surface has remained undamaged during service or has been damaged uniformly by general corrosion. However, use of digital gauges is not reliable to detect and size any significant corrosion damage on the outside surface of a Mark I drywell. Significant corrosion makes the surface extremely rough, which scatters the ultrasonic signal and results in an incorrect thickness measurement. The digital gauges do not provide any indication of such erroneous readings. A surface is defined extremely rough if the depth of a pit is greater than 2 mm (79 mil) (Birring et al. 1985, Beissner and Birring 1988).

Figure 13 shows the accuracy of five different commercial thickness gauges for measuring the average thickness of steel with varying degrees of surface roughness caused by various levels of corrosion (Birring et al. 1985, Beissner and Birring 1988). The percent error in thickness measurement is defined by

$$\%\ \text{error} = \frac{|t_a - t_m| + 2\sigma}{t_a} \times 100$$

where

t_a = actual thickness

t_m = average of a large set of measured thicknesses

σ = standard deviation of measured thickness.[b]

The term $|t_a - t_m|$ represents a systematic difference between the actual thickness and the measurements by a particular thickness gauge, whereas the term 2σ represents the precision of a given thickness gauge (ASTM 1990).

b. A. S. Birring, private communication, The Light Company, Houston, December 1991.

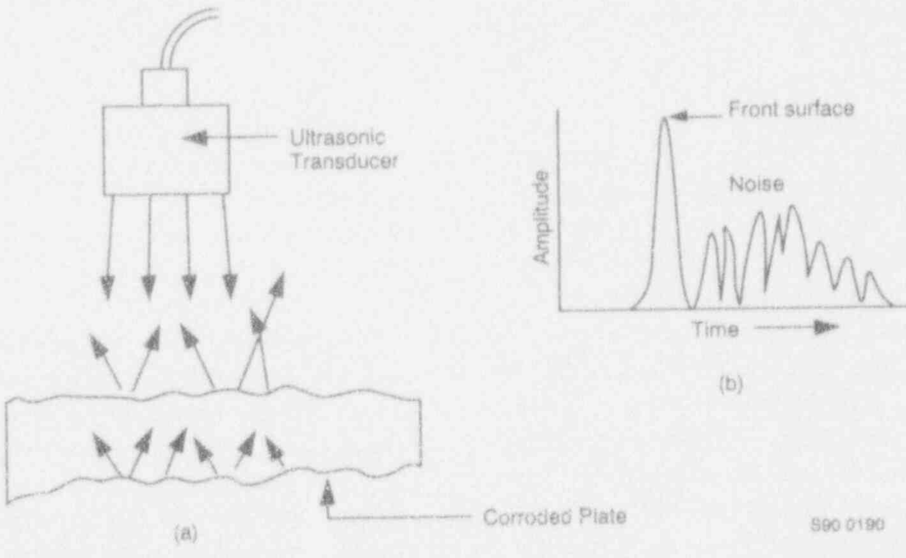

Figure 12. Thickness measurement of corroded plate, using conventional ultrasonic thickness gauge. (a) Scattering is caused by the corroded surface. (b) The back-surface signal cannot be resolved in scattering-generated noise (Beissner and Birring 1988). Copyright Nondestructive Testing Information Analysis Center; reprinted with permission.

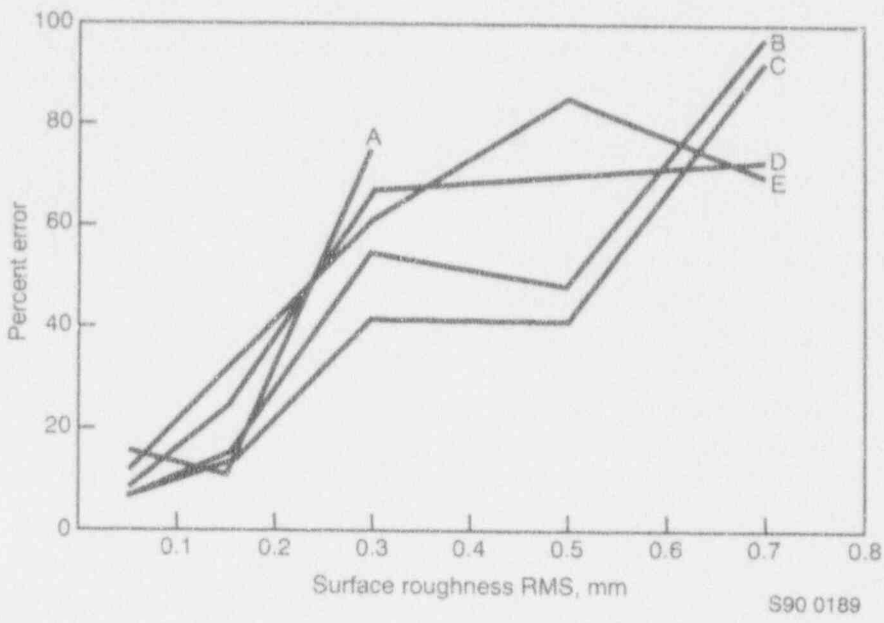

Figure 13. Accuracy of thickness gauges. None of the gauges was acceptable to cover all surface roughness (Beissner and Birring 1988). Copyright Nondestructive Testing Information Analysis Center; reprinted with permission.

The comparison shown in Figure 13 indicates that because of measurement error none of the gauges is suitable for thickness measurements over the entire range of surface roughness. The Gauges B and C are preferred for use within a surface roughness range of 0- to 0.2-mm root mean square (RMS), whereas the Gauge A is preferred for use only within a surface roughness range of 0.1 to 0.2-m RMS. [A surface roughness of 0.1-mm RMS is equivalent to an average pit depth of 0.28 mm (12 mil) if surface profile variation is sinusoidal.] None of the five gauges is preferred for measuring the surface roughness greater than 0.2-mm RMS because of the large measurement errors. The different accuracies of these gauges result from their design differences.

Some types of digital gauges have circuitry for display on an oscilloscope. Such a gauge when connected to oscilloscopes can reveal any UT scattering caused by rough, corroded surfaces (Figure 12b)[c] and, thus, provide warning about incorrect thickness measurements. In such a case, use of a focused transducer and bubbler with a water column would provide more accurate thickness measurements.

The external surfaces of Mark I and Mark II metal containments are also susceptible to corrosion damage, but their surfaces are inaccessible. Standard ultrasonic testing techniques are used to measure wall thinning at selected locations to determine corrosion damage (General Public Utilities 1987); however, for severe damage the results may not be reliable because of the ultrasonic scattering discussed earlier.

BWR Mark III and PWR steel containments, because of their larger annular space, are at a significant advantage. The shell exterior can be inspected and, if necessary, recoated. Assuming that the interior and exterior coatings are maintained properly, general shell corrosion can be expected to be minimal in these containment types.

Inspection of the submerged surface of the torus wall involves draining the suppression chamber or employing underwater examination techniques. Draining the suppression chamber results in a large pressure reduction that may cause additional blistering or popping of existing blisters in the coating. Recently developed underwater

c. A. S. Birring, private communication, The Light Company, Houston, November 1990.

techniques can be used to detect corrosion. These techniques include dislodging, ultrasonic mapping of critical areas, coating adhesion tests, and measurement of dry film thickness. (USNRC 1988a, 1989a, Beissner and Birring 1988).

As discussed in Section 1, a portion of the emergency core cooling system piping in BWR Mark I plants constitute a part of the containment pressure boundary. This portion of the piping is susceptible to corrosion because it is made of carbon steel and contains stagnant suppression pool water. Ultrasonic inspection can detect thinning of piping caused by corrosion.

The lower portion of the outer surface of the wall in Mark I containments is in contact with sand, gravel, and, possibly, ground water (see Figure 8). In addition, in some Mark I containments, the lower portion of the inner surface of the wall adjacent to the sand pocket is covered by a concrete floor and is not accessible to the standard through-wall, pulse-echo type ultrasonic examination technique for the detection of wall thinning. Therefore, it is difficult to assess the integrity of these containments.

2.1.2.3 Inspection of Embedded Portion of Containment Vessel. The embedded portion of metal containments may have a potential for corrosion if the rubber membrane underneath the basemat, which is provided in some plants, is ruptured and cracks in the concrete underneath the containment shell are connected such that the aggressive groundwater comes in contact with the shell surface. The groundwater would break down the protective alkaline environment of the concrete by reducing the pH to <11.5 and corrode the shell. Electromagnetic acoustic transducers and half-cell potential (corrosion potential) measurement techniques are a potential means of corrosion detection in the embedded portion of the metal containments. Laboratory tests have shown that the electromagnetic acoustic transducers can detect simulated corrosion-like defects in steel plate, but cannot locate or size it. The half-cell potential measurement technique has been used both in the laboratory and field to detect corrosion damage in reinforcing steel bars in concrete.

The electromagnetic acoustic transducers consist of transmitter and receiver, both of which contain a permanent magnet or electromagnet and a coil. The transmitter coil is excited by high radiofrequency current (approximately 1 MHz) to induce an eddy current in the surface of the metal. The eddy current interacts with the magnetic field, generated by the transmitter coil to produce Lorentz force in the metal. The force produces guided plate waves in the metal. When receiving ultrasonic energy, the vibrating specimen can be regarded as a moving conductor or a magnetic field, which generates current in the receiver coil. The generated current is processed by the instruments in the circuit to display the signals.

There are several advantages of using electromagnetic acoustic transducers for the detection of corrosion damage. A couplant is not needed between the transducer and metal surface because the ultrasound is generated directly in the metal rather than in the transducer. A typical distance between transducer and metal surface may be up to 1.5 mm (59 mils). Generated ultrasound plate waves have high energy, which enables them to travel long distances parallel to the surface of the plate. The wave velocity is independent of plate thickness because the polarized waves can travel parallel to the metal surface. Finally, ultrasound can be generated through a surface coating that can be as thick as 1.5 mm (59 mils); the maximum thickness of containment coating is about 0.48 mm (16 mils).[d]

The electromagnetic acoustic transducers are used in the laboratory to detect simulated corrosion-like defects in a large [4.9-m- (16-ft-) long, 2.1-m- (7-ft-) wide, and 25.4-mm- (1-in.-) thick] steel plate. The electromagnetic acoustic transducers may be used in two different modes to detect deeply penetrated corrosion-like defects: pulse-echo mode and through-transmission mode. In the pulse-echo mode, the transmitter generates ultrasound in the plate parallel to its surface. A signal scattered by a corrosion-like defect is picked up by a receiver placed near the transmitter. In the pulse-echo mode, a flaw at least half-way through

d. B. W. Maxfield, private communication, Innovative Sciences, Inc., February 1992.

the plate thickness and as far as 4.6 m (15 ft) from the transducer can be detected. In the second mode, the through-transmission mode, the transducer transmits ultrasound from above the plate at one side of plate, which travels through the plate parallel to its surface, and is received by the transducer at the other side. Deep corrosion damage (more than 75% of the wall thickness) at a distance of 15.24 m (50 ft) from the transmitter can be detected, but its location cannot be determined (Maxfield and Kuramoto 1988).

The electromagnetic acoustic transducer can be further developed to detect corrosion in the embedded portion of the containment. For example, in the pulse-echo mode, the transmitter can send ultrasound along the embedded drywell wall of the containment from above the concrete floor where the inner surface is accessible (such as point A in Figure 8). Signals scattered by the corrosion damage area can be picked up by a receiver placed near the transmitter. In the through-transmission mode, the transducer transmits ultrasound from above the concrete floor on one side of the drywell shell through the embedded portion of the shell for about 30.5 m (100 ft) to a point above the floor on the diametrically opposite side, where a receiver picks up the signal. This mode is not sensitive to small amounts of corrosion, but may detect deeply penetrated corrosion damage. Further work may make this a reliable inspection technique for the embedded portion of a metal containment.

Electromagnetic acoustic transducers have also been used in other industries. Examples of these applications include detection of fatigue cracks in wheels on freight cars of U.S. design, flaws in heat exchanger tubes, and flaws in metals (in steel mills) moving at high speed [61 km/hr (200 ft/min)] (Schramm and Clark, Jr., 1988, Krautkramer and Krautkramer 1990, Alers and Burns 1987).

The *half-cell potential measurement technique* has been used to detect corrosion of reinforcing steel in concrete bridge decks and can be used possibly in the embedded portion of a metal containment vessel. The technique consists of an electrochemical cell in which a copper electrode immersed in water saturated with copper sulfate acts as a reference electrode, and the reinforcing bar acts as another electrode of the cell, as shown in Figure 14. The reference electrode is called a half cell,[e] and the technique using such electrode is called the half-cell potential measurement technique (ASTM 1991, Malhotra and Carino 1991).

e. The rate of copper dissolution and deposition are the same in the half cell; there is no net change in the reference electrode system.

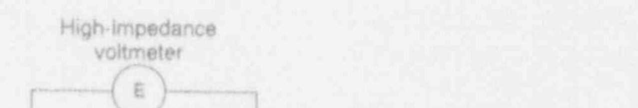

Figure 14. Schematic of half-cell potential measurement technique for reinforcing bar.

The application of the half-cell potential measurement technique to reinforcing bars is as follows. The surface of the concrete being investigated is usually divided into a grid, and measurements are made at each grid point. The reference electrode is electrically connected to a reinforcing bar at a convenient location. A wet sponge provides electrical continuity between the reference electrode and the concrete and moisture in the concrete completes the circuit. The potential difference between the reference electrode and reinforcing bar can then be measured at any desired location by moving the reference electrode over the concrete surface.

A grid size of about 1.2 m (4 ft) has been found satisfactory for evaluation of the corrosion of reinforcing steel in bridge decks (Malhotra and Carino 1991). The measured potential is used to estimate the likelihood of corrosion. ASTM has recommended specific values indicative of corroding and noncorroding conditions (ASTM 1991). For example, if the measured potentials over an area are more negative than –0.35 V, there is a greater than 90% probability that reinforcing steel corrosion is occurring in that area. Positive measurements, if obtained, generally indicate a poor connection with the steel, insufficient moisture in the concrete, or the presence of stray current and would not be considered valid.

2.1.3 Statistical Determination of Corrosion Rates. One way of estimating containment shell corrosion rates is to perform periodic ultrasonic testing for thickness measurements at a number of points on the vessel surface. The change in wall thickness during a given time interval divided by the time interval gives the average corrosion rate for a given point.

$$r_{1,2,3,\ldots,n} = \frac{t_j - t_i}{T_j - T_i} \quad \ldots.\ i,\ j$$

$$= 1, 2, 3, \ldots n \qquad (1)$$

where

t_j = current wall thickness

t_i = wall thickness at the preceding measurement

T_j = time of current measurement

T_i = time of preceding measurement.

Since different regions of the vessel shell often have different design thicknesses, measurements need to be taken in each region. For each region, the inspection includes measurements at a number of test points; these points can be marked on the vessel to ensure that the measurements at the end of successive time intervals are taken at the same location. The number of test points (inspection sample size) for each thickness region can be determined statistically to ensure that the error range is acceptable. The number of test points, n, for a given thickness region can be calculated by the following equation (Miller and Freund 1965):

$$n = \frac{K\sigma^2}{E} \qquad (2)$$

where

K = factor based on confidence level (K = 1.96 and 2.575 for 95% and 99% confidence level, respectively)

E = maximum error

= $\overline{X} - \mu$

$\overline{X}$ = mean value of measured thicknesses

= sample mean

μ = mean value of actual thickness

= population mean

σ = population standard deviation.

The population standard deviation can be calculated from the baseline measurements or it can be estimated with the sample standard deviation. The maximum error, E, for a given region needs to be less than the corrosion margin of that region on the vessel. A vessel with a large corrosion margin (actual wall thickness minus the minimum required wall thickness) could tolerate a larger error, so in that case a smaller number of test points may be employed. However, the number of test points in a given region needs to be greater than or equal to 30, otherwise Equation (2) is not valid (Miller and Freund 1965). The projected wall thickness at the end of next inspection period needs to exceed the minimum required wall thickness by the value of the acceptable error.

After determining the number of test points for each thickness region, the periodic thickness measurements are performed in the field. The measurements are nondestructive and can be performed quickly on sites that are easily accessible. Inspection sites that are inaccessible from platforms may be accessed from scaffolding or ladders. Personnel dose within containment is a concern at most plants, so work is done during an outage.

For each test point, the corrosion rate can be determined from Equation (1). The upper bound for the corrosion rate to be used in the aging assessment for each region is given by the following equation (Miller and Freund 1965):

$$r = r_m + K \frac{\sigma_r}{n} \qquad (3)$$

where

r = corrosion rate to be used in the aging assessment (in./yr)

r_m = the mean of corrosion rates r_1, r_2, $r_3 ... r_n$ (in./yr)

σ_r = standard deviation of corrosion rates.

For 30 test points, n = 30, the upper bound for the corrosion rate is given by

r = $r_m + 0.36\ \sigma_r$ (95% confidence internal)

= $r_m + 0.47\ \sigma_r$ (99% confidence internal).

2.1.4 Mitigation/Prevention. The types of steel (ASTM A-516 Grade 70 or ASTM A-212 Grade B) used for fabrication of containments are susceptible to corrosion. Prevention of corrosion of metal containments is mainly achieved with protective coatings. The typical containment coating systems, discussed in Section 1.3, are considered good corrosion-resistant systems for the conditions of the containment interior space. Some surfaces, however, are often left uncoated, such as penetration sleeves, air locks, vent systems, leak chase channels, and the embedded base region. These surfaces can be highly susceptible to corrosion.

Inspecting the metal shell embedded in concrete is difficult (requiring removal of the concrete) and has the potential to damage the metal shell. Several plants installed a flexible sealant (caulk) at the time of construction to mitigate shell corrosion. Applying and maintaining these special sealants and bonding agents can reduce moisture and oxygen intrusion into the gap, thereby isolating the metal in its natural alkaline environment and minimizing any corrosion in the region. Experience with these sealants or caulks has shown a useful life cycle from 2 to 10 years, depending on type, application, and environment. When sealants age, they become brittle and crack or separate from the surfaces and thereby allow moisture and oxygen to intrude into the gap.

Prevention of microbially influenced corrosion is much more effective than its treatment. Once the problem of microbially influenced corrosion initiates, it can often only be controlled, rather than solved. Many microorganisms are capable of rapid multiplication and can become resistant to chemicals used to treat them, such as antibiotics and disinfectants. Oxygen starvation and chlorine treatment are largely unsuccessful, whereas application of heat 104 to 135°C (220 to 275°F) seems to be one potential remedy (Pope 1986).

In most cases, plants are using protective coatings to minimize the effects of corrosion on the containment shell. However, as discussed earlier, areas such as the outer surfaces of the Mark I and Mark II vessels are inaccessible for coating maintenance. When the coating deteriorates, no corrosion protection exists. Another portion of the shell, the embedded section, is not coated. Situations where this part of the shell is susceptible to corrosion have been discussed in previous sections. The remainder of this section discusses two potential approaches for mitigating corrosion in these areas.

2.1.4.1 Cathodic Protection. Cathodic protection is the technique of using electrochemical reactions to mitigate corrosion of metal components, primarily the carbon steel components. Prior to the application of cathodic protection, most corroding structure surfaces have both cathodic and anodic areas adjacent to each other; corrosion occurs at the anodic areas in the presence of an electrolyte (NACE 1984, Uhlig 1948). This corrosion can be stopped if all the anodic areas on the corroding structure surface can be converted to cathodic areas; this is what an effective cathodic protection system accomplishes.

Types of Cathodic Protection Systems. Two types of cathodic protection have been widely used: sacrificial (galvanic) anode systems and impressed-current anode systems. Sacrificial anode systems are generally limited to smaller components (or areas of components) requiring small voltage difference (1v or less) between a sacrificial anode and cathode, i.e., the cathodically protected component. An example of a sacrificial anode system is the use of a buried magnesium anode electrically connected to a buried coated steel pipeline. In as much as the magnesium anode has a lower potential than the steel pipeline, this anode system protects the steel at the expense of the magnesium. The sacrificial anode system does not use any external power source for its operation. It is designed to discharge the necessary cathodic protection current for a reasonably long time, and when it is consumed, it may be replaced without interrupting the normal function of the metal component.

Impressed-current systems are used for cathodic protection of larger components (or areas of components), in which the component is connected to the negative terminal of an external direct current power supply and the anode is connected to the positive terminal. Some impressed-current anodes, unlike the sacrificial anodes, are made of nonconsumable electrode materials, which act as anodes because of their connection to the direct current source. Examples of the anode materials include platinum, titanium, niobium, and graphite.

Coating on the metal surface greatly reduces the amount of current necessary to obtain cathodic protection. The coated surface takes lower currents because the only areas requiring protection are defects or "holidays" in the protective layer (Fontana 1986). The reduction may run from as much as 99.8% (for an extremely good coating, i.e., a coating with good bonding on the metal surface) to as low as 50% (for a damaged coating) (NACE 1984). Typical current values for cathodic protection of coated steel in soil are 0.003 to 1.0 mA/m^2 (0.0003 to 0.1 mA/ft^2), as compared to 10 to 500 mA/m^2 (1 to 50 mA/ft^2) for uncoated steel. The magnitude of the impressed-current should be such that the cathodic protection criterion (the −0.85 volt criterion), which is discussed later in this subsection, is satisfied.

There are several differences between impressed-current systems and sacrificial anode systems (Heidersbach 1987). Impressed-current systems are more complex than sacrificial anode systems and require more maintenance. However, the use of a large sacrificial anode system requires higher capital investment. The voltage difference between anode and cathode in an impressed-current system can be much larger than that in a sacrificial anode system, where it is limited to 1 volt or less. The use of the larger voltage difference available with the impressed current has two specific advantages: it allows the use of the impressed-current system in a low-conductivity environment such as concrete, and it also allows remote anode locations, which produces more efficient current distribution over the surface of a component to be cathodically protected.

Overprotection of a component with a large voltage difference or with too much external current has several disadvantages (Heidersbach 1987). The overprotection can damage the components being protected; it can cause blistering or disbonding of the coating on the surface of the steel containment shell and hydrogen embrittlement of high-strength steels such as tendons in prestressed concrete containments. The overprotection can also cause stray current corrosion of adjacent metal components.

Figures 15 and 16 are simple schematics that illustrate the basic principle of the impressed-current anode system. Figure 15 shows corroding

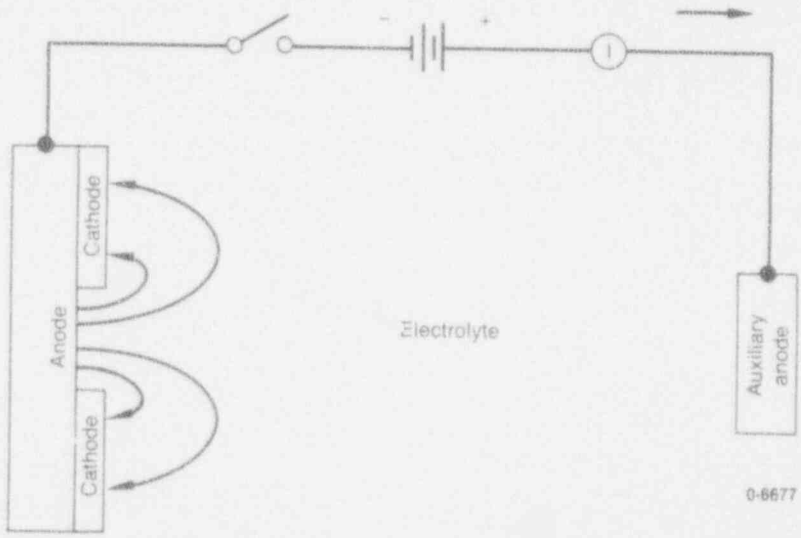

Figure 15. Flow of local-action current in open-circuit cond... .n (Uhlig 1948). Copyright John Wiley & Sons; reprinted with permission.

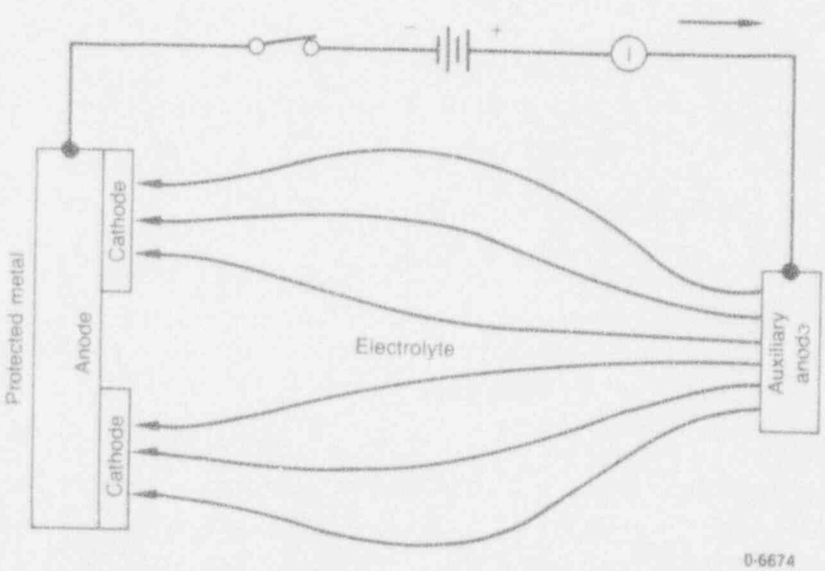

Figure 16. Superposition of impressed current on local-action current in a closed-circuit condition (vector sum of current in and out of anode on protected metal is zero) (Uhlig 1948). Copyright John Wiley & Sons; reprinted with permission.

metal surface surrounded by an electrolyte. The metal is connected to the cathodic protection system with no external current passing through the system. The metal surface is idealized by representing all anodes on the metal surface by one placed symmetrically between two cathodes. The schematic shows the flow of local-action current passing from a local anodic area, for example, a pit, into the electrolyte, and then to the local cathodic area covered with oxide film. As there is no external current in the system, a cathodic protection system does not provide any protection to the corroding metal.

Figure 16 shows the cathodic protection system with a battery supplying direct external current (impressed current) to protect the corroding metal. The direct current flows from an external source to the impressed-current anode, also called auxiliary anode, and then through the electrolyte to the surface of the structure and vectorially cancels the current flowing out from the local anodic area. The amount of external current needed depends on the requirement to support a cathodic reaction over the whole of the metal surface to be protected. (If the negative terminal of the battery is erroneously connected to the auxiliary anode so that the external current flows in the opposite direction, it will actively support the corrosion of the metal.) There is a certain minimum current density that needs to be exceeded to prevent corrosion of the metal surface. The presence of a depolarizer, such as oxygen or chloride, increases current requirements for metal protection.

Criteria for Cathodic Protection. A number of criteria for cathodic protection have been developed for ensuring that the structure is adequately protected. The criteria are based on the voltage of the protected metal surface instead of on the magnitude of applied current, because the voltage can be more easily measured with the use of a reference electrode such as a saturated copper/copper sulfate electrode.

The National Association of Corrosion Engineers has developed five criteria for cathodic protection of buried steel pipelines. The most common and widely used criterion is that the voltage between the cathodically protected metal surface and the saturated copper/copper sulfate reference electrode should be at least –0.85 volts. Determination of this voltage is to be made while the protective external current is applied. Davis and Kellner (1989) examined the theoretical basis of the five criteria and concluded that only one criterion, the -0.85 volts criterion, is valid based on thermodynamics principles.

Cathodic Protection of Mark I Drywell. Oyster Creek employed an impressed-current cathodic protection system to mitigate corrosion of the containment shell near sand pocket elevations (Gordon 1988). The system, designed to protect the uncoated embedded metal shell, includes an auxiliary anode, a rectifier (a source of low voltage dc power), and a reference electrode (General Public Utilities 1987). The auxiliary anode has an outside diameter of 3.18 mm (0.125 in.) and is constructed from co-extruded metals consisting of an external, 200-μin. layer of plated platinum, a middle layer of niobium, and an inner core of copper for conductivity. The reference electrode, made of silver and silver chloride, is placed in the sand close to the metal shell to monitor the potential of the shell. The electrode provides feedback to an automatic potential control rectifier circuit to maintain a specific potential on the metal shell within a preselected range. Placing the reference electrode close to the metal shell minimizes the voltage drop through the electrolyte.

Figure 17 shows the configuration of the cathodic protection system for the Oyster Creek drywell. The applied voltage need only be sufficient to supply an adequate current density to all parts of the drywell. The current density is based on the total area (both anodic and cathodic) of the metal shell that is in contact with sand. The impressed-current density necessary to protect the metal shell increases whenever its corrosion rate increases. The cathodic current for a metal shell depends on the conductivity of the soil, the physical location of the shell, and the condition of coating, which vary from place to place. Any change in the conditions of sand alters its resistance; for example, leakage of water into dry sand decreases its resistance and increases its

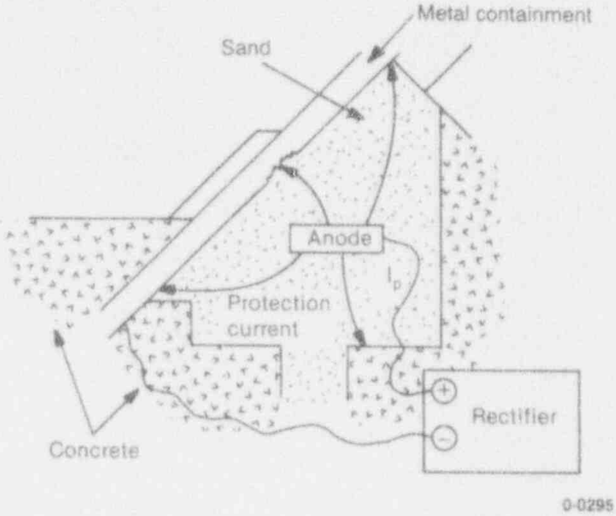

Figure 17. The cathodic protection system for the Oyster Creek drywell.

conductivity. Necessary current densities for different locations of the metal shell are different; hence, fifteen separate rectifiers, contained in the rectifier enclosure, supply current to fifteen independent anodes. The potential criteria were developed by mock test to achieve adequate cathodic protection, because it was not practical to produce and monitor a uniform current distribution on the large surface area of the steel shell. A potential difference on the order of −1.0 V or more negative is maintained between the metal shell and the reference electrode for complete cathodic protection. When the platinum is consumed, niobium protects the anode by creating a passive film on its surface, halting the discharge of current to the sand. At this point, the shell is no longer protected by cathodic protection. The auxiliary anode needs to be replaced for continued protection of the shell.

The reference electrode, which is equipped with a water sensor, detects the presence of any moisture in the sand and sends a signal to the rectifier (Oyster Creek 1989). In turn, the rectifier adjusts the potential difference between the metal shell and the auxiliary anode within the limits to maintain adequate cathodic protection. Theoretically, the embedded portion of the metal shell in the drywell is not expected to corrode under these conditions as long as the appropriate external direct current is maintained. However, the application of cathodic protection to the Oyster Creek Drywell was not successful because the sand in the region immediately surrounding the anodes had become dry and the needed external direct current could not be maintained because of high electric resistance. The corrosion of the Oyster Creek drywell is discussed in Section 4.1.1.

2.1.4.2 Inerting the Gap Atmosphere. Another potential technique for mitigating exterior surface corrosion on containments with inaccessible gaps is to inert the atmosphere of the gap. Removal of oxygen from the atmosphere prevents oxidation of the metal surface. However, the oxygen concentration needs to be reduced to well below 1% by volume for this practice to be effective. To accomplish this, the gap is be sealed at the drain and shield wall penetration locations. Nitrogen (or another suitable gas) is then pumped in at one location, with venting for release of the air in the gap. However, controlling the oxygen content of air to the low levels required is difficult when nitrogen is present.

There are several other drawbacks to this technique. It has not been implemented at any plant, so it is unproven in the field. Additionally, not all containments with small gaps are candidates for the technique. Fill material in the gap may make inerting unfeasible. Also, gaps with construction material (for example, Ethafoam) at the concrete lift heights would need additional nitrogen monitoring instrumentation or equipment, or both, to ensure that each region is inerted. Further evaluation of this technique would determine its feasibility.

2.2 Degradation of Coatings

Coatings protect the structure and components from corrosion caused by all the mechanisms discussed in Section 2.1. Coatings also facilitate decontamination. Most operating LWRs have similar types of coatings. These coatings have been applied according to manufacturers' recommendations, and the available industry standards were used as guidelines for selection of the original coatings. However, both interior and exterior environments may cause degradation of containment coatings. This section describes five major stressors that cause coating degradation, discusses techniques of maintaining the coatings, and presents data on containment coating life.

2.2.1 Stressors. The five major stressors causing degradation of coatings are described as follows:

1. **Temperature**. Temperature can cause failure of a containment coating in that the coating dries and hardens, causing shrinkage and cracking. At high temperatures, coatings will disintegrate and stop providing corrosion protection. For example, an epoxy coating will disintegrate at 120°C (248°F) (Stoller 1987). The corresponding temperature for zinc-rich coating is higher. Once moisture and oxygen penetrate the coating, local corrosion of the metal surface can result and propagate, lifting the coating in the form of blisters, peels, and flakes. This process is detectable by visual inspection and manifests itself through irregular coating surfaces, rust staining, and, ultimately, coating delamination. Temperature can also cause differential thermal expansion, causing stresses between different layers of the coating (especially in relatively thick coatings), and between the coating and base metal (Munger 1984). Potential areas of concern include containment areas adjacent to main steam lines and upper drywell surfaces.

2. **Condensation and Immersion**. High humidity, condensation, and immersion can degrade containment coatings. Areas where condensation and immersion may degrade coatings are also the most likely sites of accelerated corrosion of metal substrates. In the normal metal containment atmosphere, condensation occurs at cool surfaces (for example, near coolers and uninsulated piping). Those metal containment components whose protective coatings are subject to continual or periodic immersion are the suppression chamber, vent system, drywell components above the drywell bellows, and the drywell sump. If piping penetrations are misaligned, water can collect in the sleeves and degrade coatings.

3. **Radiation**. Radiation can cause failure of a containment coating in the form of embrittlement. The coating dries and hardens resulting in shrinkage and cracking. Radiation degrades coating materials by ionization. If enough radiation is present, the molecular bonds of the surface treatment will break, and the material will begin to disintegrate. Organics are more prone to embrittlement degradation by ionizing radiation than inorganics. Maximum allowable radiation doses for epoxy-polyamide and inorganic zinc coatings on steel are 1×10^{10} and 2.2×10^{10} rads, respectively (Munger 1984).

4. **Stressor Causing Physical Damage**. Physical damage is most prevalent in areas where plant personnel or equipment interaction with the coated surfaces is greatest. Chipping, gouging, and wear can occur when equipment is transported during maintenance activities. Mechanical wear or abrasion by equipment close to the containment may also occur. High traffic areas, areas of mechanical activity, and locations where spills or component replacements

occur can be inspected to detect any damage, allowing repair work to be performed.

5. **Damage Caused by Corrosion of Base Metal**. The presence of a light surface rust on the base metal may tend to flake or chip the coating. This form of degradation may have only local effect for a properly coated substrate. Gouge marks, cracks, or pinholes are the typical stressors on the coated surface. These stressors permit moisture to reach the substrate metal surface through the coating. With time, the substrate corrosion spreads and lifts the coating, which in turn exposes a larger base metal surface to the moisture and accelerates coating delamination. The damage rate of containments for a zinc-rich coating will be smaller than that for epoxy and red lead coatings because zinc is more anodic to carbon steel. Use of proper coating techniques and application of several coats to ensure surface sealing can protect the containment against this form of degradation.

2.2.2 Coating Life. The aging effects of qualified metal containment coatings have not been quantified (EPRI 1986). It is expected that combined thermal, humidity, and radiation aging effects will result in local degradation and consequent maintenance activities during the life of a containment. Mark I suppression chambers are routinely inspected internally (7- to 15-year intervals), and most plants have performed local repairs. USNRC Information Notice 88-82 alerts BWR plants of torus shell corrosion and coating degradation (USNRC 1988a). Brunswick and Dresden 2 have reported coating problems in the submerged regions of the torus. The inside surface of Mark I drywells is also routinely inspected, and several plants have performed local repairs. The Notice reinforces the need for inspection and maintenance for continued coating life of a metal containment. When the local repairs become excessive, recoating of the entire surface is the most cost-effective solution. To date, no plant has completed an entire recoating of its containment surfaces. However, at least three U.S. plants have completely recoated the entire inside surface of the torus, and one other plant is considering the use of aluminum oxide metal spray to coat the inside surface. At least one U.S. plant (about 15 to 20 years old) is planning to recoat the entire inside surface of both the drywell and torus.

Data on containment coating life is based on the age of existing plants, some of which exceed 20 years (see Table 1 in Section 1). The coating life for wet or submerged service ranges from a minimum of 7 years to an upper limit of 15 or more years, depending on how the coating is applied and which coating products are used. It is expected that in a relatively dry environment coatings on interior containment surfaces will last a minimum of 40 years if sufficient maintenance is performed. Many of the degradation modes described above highly depend on the quality of initial coating application. Failures resulting from poor application are generally apparent in the first few years of operation. Once this period is exceeded, coating life depends on maintenance. The economic life of the coating is determined by comparing maintenance costs with recoating costs. Based on the high cost of recoating (including surface preparation, application, cleanup, and personnel dose costs) and the cost associated with the outage time needed for recoating, maintenance can be extensive before its costs exceed those associated with recoating.

3. ASSESSMENT AND MITIGATION OF DAMAGE CAUSED BY FATIGUE, STRESS CORROSION CRACKING, WEAR, AND SETTLEMENT

Several mechanisms other than corrosion mechanisms may limit life of entire metal containment for plants with unusual conditions or of individual containment components, but these are not expected to be of generic concern. These plant-specific mechanisms are effectively evaluated only on a case-by-case basis. These mechanisms include

- Fatigue of a carbon steel metal shell
- Fatigue and stress corrosion cracking of stainless steel bellows
- Mechanical wear
- Settlement.

Radiation embrittlement of the metal shell or bellows is not a concern because the end-of-life fluence experienced by these components is quite small.

3.1 Fatigue of Containment Vessels

A containment shell is subjected to thermal and mechanical fatigue loads during operation, but fatigue damage to a metal shell is likely to be small. However, fatigue damage may be large if the shell surface has become very rough because of significant corrosion damage. The cumulative fatigue damage to the shell may become of greater concern as the containment ages.

Fatigue cracks generally initiate on the shell surface at a structural discontinuity, such as an opening, or at a flaw in the welds, because stresses are concentrated there. In the containment design, reinforcing materials (additional thickness) are included at the sites of structural discontinuity to reduce stress concentration. The flaws are most likely to be in the toe of welds, that is, at the junction between the face of a weld and the base metal. Repeated stressing at the tip of a flaw will generate plastic strain, causing the flaw to grow into a crack and eventually into a through-wall crack, if repeated stressing is allowed to continue indefinitely. However, if a flaw is rounded so that the concentration of local stresses is low, a very large number of cycles will be necessary for the flaw to grow into a crack.

An important factor affecting fatigue life is surface roughness. Initially, the surface of a metal shell is smooth, but becomes rough once it is corroded in service. Rough surfaces may cause as much as a 40% reduction in fatigue life (Shigley 1983). As pits and crevices are formed on the surface, new sites for fatigue crack initiation are available, and fatigue crack initiation time may be significantly reduced. Crack initiation time can be reduced by as much as a factor of three in the presence of pitting (Munger 1984). This effect of corrosion damage on fatigue life is not considered by the current ASME Code.

A number of research programs are analyzing components subjected to concurrent corrosion and fatigue. As an example, research at the University of Maryland has demonstrated that uncoated structures exposed to atmospheric environments can have fatigue lives significantly less (10 to 35%) than those predicted by some design codes (Crooker and Leis 1981). However, these results might not be applicable to fatigue analysis of the containment vessels because the atmospheric environment considered in the Maryland research is different than the environment the containments are exposed to. A program at the U.S. Steel Corporation is developing an analytical technique for determining crack initiation life for components subject to corrosion (Crooker and Leis 1981). Research sponsored by the National Association of Corrosion Engineers and the American Institute of Metallurgical Engineers has resulted in the development of S-N curves for specific environments (Hoepner 1971). Figure 18 presents a qualitative view of an S-N curve and the influence

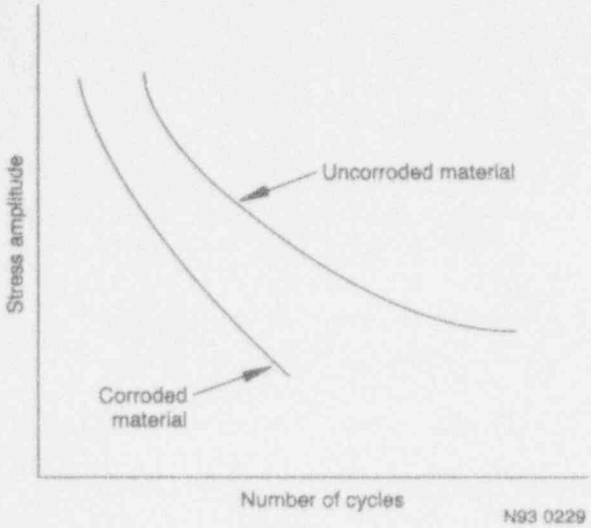

Figure 18. Material S-N curves, showing reduction in fatigue life because of corrosion.

of the environment, showing that the corroded sample fails in fewer cycles for the same level of stress. Furthermore, an endurance limit (lower bound) is not readily apparent for the corroded material. This illustrates the impact that corrosion has on fatigue life. At this time, however, analysis of fatigue is not being performed for nuclear containments having rough corroded surfaces.

Another factor affecting the fatigue life is applied and residual stress. The stress range determines the material damage for each load cycle. Thus, larger stress ranges produce more damage during each cycle. This concept is depicted by the ASME Section III fatigue design curve applicable to containment vessel material, as shown in Figure 19; the vertical axis is the cyclic stress amplitude with mean equal to zero and the horizontal axis is the number of cycles. The curve is applicable for the base metal, weld metal, and heat-affected zone, though the values are based on base metal tests.

Field welding introduces high residual stresses in heavy weldments such as a penetration weldment; however, these weldments are stress relieved. The transition knuckle in Mark I containments and top head flanges are also field stress relieved in accordance with ASME Code. Therefore, the residual stresses at these sites are low. In addition, any increase in the mean stress because of residual stresses has little effect on the low-cycle fatigue life of the contaminate shell (Langer 1962, Burgreen 1975). This is so because the yielding that might occur during operation reduces the effective magnitude of the mean stress.

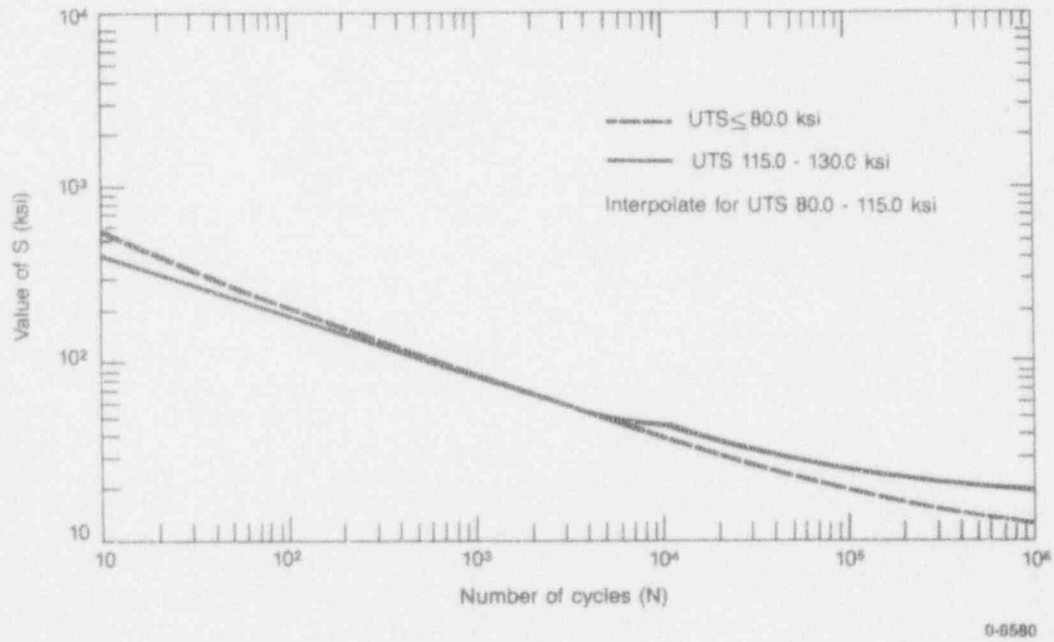

Figure 19. S-N curve for carbon, low alloy, and high-strength steels. (Note: $E = 30 \times 10^6$ psi). Copyright American Society of Mechanical Engineers; reprinted with permission.

The cyclic loads that a containment vessel is subjected to are as follows:

- Startup/shutdown cycles (temperature transients)
- Pipe reactions (at penetrations)
- Crane loads (for BWR Mark IIIs and PWRs)
- Leakage rate test pressures
- Safety relief valve discharge tests (includes steam condensation loads) (BWRs)[f]
- Refueling loads (BWRs)
- Any vessel loads incurred during replacement of internal components (these are not generally considered in the original design)
- Seismic loads.

These cyclic loads are not expected to cause any significant fatigue damage to the metal containments because the containment are designed with sufficient margin to allow for these loads. However, if the surface of the containment vessel becomes rough because of corrosion or wear, significant fatigue damage might take place.

The primary technique for mitigating fatigue is to reduce the number and level of load cycles acting on the containment vessel. Potentially, the number of cycles could be decreased by reducing scrams and by evenly distributing the discharge testing of the safety relief valves in BWRs.

Fatigue data for metal containment material with a smooth surface consist primarily of S-N curves, such as those shown in Figure 19. The curves relate the number of service cycles to stress intensities. S-N diagrams are established for a given material by completing a number of tests aimed at determining how the fatigue strength of the material varies with the number of load cycles applied to the material. For steels, there is a cyclic stress amplitude below which fatigue failure will not occur, no matter how many load cycles are applied. This stress amplitude is known as the endurance limit or fatigue limit (at approximately 10^6). To use these S-N diagrams for fatigue assessment of metal containments, compare the current number of cycles the containment has endured at a certain design stress level with the corresponding number of cycles on the S-N curve.

Development of fatigue curves for the containment vessel, taking into account the corrosive influence of its environment, would facilitate more effective aging management of the vessels. Current engineering research on fatigue of corroded surfaces may be monitored to facilitate future life evaluations of containment components not protected by coatings and subject to fatigue cycling. Additional research and development, if performed for specific containment conditions, would establish applicable S-N curves.

3.1.1 Assessment of Fatigue Damage. If the number of load cycles a vessel is expected to experience by the end of its licensed life does not exceed that specified by the criteria given in the ASME Code, Section III (see Subsection NE, Paragraph NE-3221), fatigue damage will be small. However, the criteria given in the ASME Code do not account for surface roughness and the metal shell is susceptible to significant corrosion damage. If the fatigue damage is expected to be significant, a detailed assessment of fatigue damage can be performed. The assessment, based on cumulative damage theory, will determine the acceptable number of cycles for each load type.

The first step of the fatigue assessment is to define the cyclic loads to which the containment vessel is subjected. The typical cyclic loads are listed earlier in Section 3.1. However, plant-unique conditions may create variations in the list. A review of the vessel design calculations provides specific information on the vessel loads.

Once the cyclic loads are defined, it is necessary to estimate the rate at which the loads will

f. Earlier, these tests were conducted in the field with the valves in place, but this practice has been discontinued, having been replaced with the bench tests.

occur. Generally, information is needed on the historical rate at which the loads have occurred. This information is generally available from the plant operating records. A simple technique to calculate the rate at which the loads will occur is given by the following equation:

$$l_r = \frac{n}{T_j - T_i} \quad (4)$$

where

l_r = rate of cyclic load occurrence (cycles/yr)

n = cyclic load occurrences to date

T_j = current time

T_i = initial time.

Equation (4) makes possible a linear extrapolation for the future rate of cyclic load occurrences. The extrapolation, in turn, provides a linear equation for the occurrence of cyclic loads, as follows:

$$n_i = n_{i,o} + l_{r,i}\,(\Delta T) \quad (5)$$

where

n_i = the number of load cycles at the end of time increment ΔT for the i^{th} load type

$n_{i,o}$ = the actual number of load cycles of the i^{th} load type to date

$l_{r,i}$ = rate of occurrences for the ith load type

ΔT = time increment (yr).

In linear cumulative fatigue damage theory, the total fatigue damage resulting from all cyclic load types is equal to the sum of the damage from the individual load types. In equation form, this can be written as follows (from the ASME Code):

$$\frac{n_1}{N_1} + \frac{n_2}{N_2} + \frac{n_3}{N_3} + \ldots + \frac{n_k}{N_k} \leq 1.0 \quad (6)$$

where

n_i = actual number of load cycles for the i^{th} load type

N_i = acceptable number of load cycles for the i^{th} load type as if that were the only load type applied

i = 1,2, ... k

(n_i/N_i) = the fatigue usage resulting from the i^{th} load type.

For each load type (as listed in Section 3.1), the stress amplitude needs to be determined. The amplitude values can be found by the vessel stress analysis or may be calculated by conventional stress analysis techniques. Wall thinning caused by corrosion and stress concentration resulting from the rough corroded surface can be accounted for in determining the stress amplitudes. The value of N for each load type can be read from Figure 19.

Additionally, the vessel must be capable, at any point in its life, of withstanding the load cycles resulting from a design-basis accident and safe shutdown earthquake. Thus, Equation (6) becomes

$$\frac{n_1}{N_1} + \frac{n_2}{N_2} + \frac{n_3}{N_3} + \ldots + \frac{n_k}{N_k} = 1 - (n/N)_{EOL} \quad (7)$$

where

$(n/N)_{EOL}$ = the available fatigue life needed at the end of the vessel's life.

3.1.2 Current and Emerging Inspection Techniques. Current inspection techniques for characterizing fatigue flaws in metal containment shells consist of visual inspection, liquid penetrant inspection, magnetic-particle testing, and eddy-current testing. These inspection techniques can detect the flaws, nicks, and gouges in the metal containment that can create stress concentrations, so that monitoring or repairs can be performed. Surface cracks are more likely to be in the toe of welds (Sea Test Service 1988).

The ASME Code Section XI, Subsection IWE, requires visual inspection of coated welds in metal containment structures. If a flaw is detected in the painted surface during inspection, the code requires removal of the coating, followed by flaw evaluation using supplemental techniques and replacement of the coating. Liquid penetrant inspection can nondestructively find discontinuities such as surface cracks, gaps, porosity, and shrinkage areas. Liquid penetrant inspection is also used for testing of stainless steel bellows.

Magnetic-particle testing is used for locating surface and subsurface flaws in ferromagnetic materials. When the material being tested is magnetized, magnetic discontinuity that lies in a direction generally transverse to the direction of the magnetic field will cause a leakage field to form at and above the surface of the material. The presence of this leakage field, and therefore the presence of a flaw, is detected by the use of fine ferromagnetic particles applied over the surface, with some of the particles being gathered and held by the leakage field. This magnetically held collection of particles forms an outline of the flaw and generally indicates its location, size, and shape. Magnetic particles are applied over a surface as dry particles or as wet particles in a liquid carrier such as oil or water. Magnetic-particle testing may be used for inspecting a containment wall without removing paint or protective coatings.

Detection of a flaw by magnetic-particle testing through a coated surface depends on the flaw size, shape, depth, orientation, and location, and on the thickness of the coating. Laboratory tests have shown that magnetic particle testing can be reliably applied to satisfy the Subsection IWE requirements for verification of a suspect visual inspection. A surface flaw 12.7-mm long and 0.02-mm wide (0.5-in. long and 0.001-in. wide) present underneath an intact coating up to 16-mil thick can be reliably detected (Sea Test Service 1988). It is generally agreed that magnetic particle testing is more sensitive than other test techniques for the characterization of flaws longer than 6.3 mm (0.25 in.) (Sea Test Service 1988). However, the measured length and width of a small tight flaw underneath the coating are significantly different from the actual length and width. The measured length of a flaw underneath a 10-mil-thick coating is 20% shorter than its actual length. For example, a 6.35-mm- (0.25-in.-) long flaw on the base metal is measured as a 5.0-mm- (0.20-in.-) long flaw. Also, the measured width of a flaw a 10-mil-thick coating is 83% wider than its actual width. For example, a 0.30-mm- (0.012-in.-) wide flaw on the base metal is measured as a 0.56-mm- (0.022-in.-) wide flaw (Cook, Holm, and Lassahn 1988). Magnetic particle testing is sensitive to liftoff (distance from the flaw to the test surface), with the indications becoming weaker as liftoff increases. Working overhead, where coatings are typically greater than 0.25 mm (0.010 in.) thick, is difficult with the magnetic particle testing technique.

Another technique, called magnetography, is potentially less sensitive to liftoff because the magnetic field strength (on which this technique depends) falls off more slowly with distance than in the magnetic particle technique (Burkhardt and Fisher 1990). Therefore, for a given value of liftoff, the magnetographic technique is expected to have a higher degree of sensitivity to smaller flaws than the magnetic particle technique. In other words, for a given value of liftoff, the magnetography technique can detect smaller flaws than the magnetic particle technique (Burkhart and Fisher 1990). A special magnetic tape is pressed on the metal surface during magnetization. The tape is then removed for processing and analysis of indications. The noise in signals from indications can be suppressed, and the output can be displayed on an oscilloscope. Typical tape thickness is 0.5 mm (20 mil). The tape can be used on underwater surfaces or even on an improperly cleaned weld surface.

Eddy-current inspection is an effective complementary technique for use on coated surfaces to detect flaws in the toe of a weld. An advantage of eddy-current testing is that sensitivity is not as influenced by coating thickness and test position as is magnetic particle testing. However, a flaw less than 6.35 mm (0.25 in.) in length present in the toe of the weld cannot be detected by the eddy-current technique.[g] Development of ASME Code rules for eddy-current testing as a surface inspection technique can be useful.

3.2 Fatigue and Stress Corrosion Cracking of Stainless Steel Bellows

The containment penetrations for high-temperature piping and Mark I vent lines are equipped with stainless steel bellows to permit thermal expansion without inducing stresses in the shell. The bellows constitute the primary containment pressure boundary. The containment bellows are generally of a two-ply design with a U-shaped cross section. The thickness of each ply ranges from 0.63 to 0.9 mm (0.025 to 0.035 in.). The bellows are cold-rolled from seamless tubing, which produces substantial residual stresses. These stresses remain in the bellows because they are normally neither stress relieved nor annealed after cold-rolling.

The major operating stresses in the bellows result from pressure and from large relative deflections in axial and lateral directions. Pressure produces meridional membrane stresses, whereas the deflections produce meridional bending stresses. Both these stresses are added to obtain the total stresses. The deflection stresses, which are normally greater than the pressure stresses, are generally above the yield stress of the material (EJMA 1980). These stresses are generally calculated assuming elastic behavior.

The containment bellows are susceptible to low-cycle fatigue and stress corrosion cracking damage during normal operation. The relative deflections during normal operation, including heatups and cooldowns and pressure loads during leak rate tests, cause fatigue damage. The high residual stresses, susceptible material, and containment interior environment cause transgranular or intergranular stress corrosion cracking damage.

3.2.1 Low-Cycle Fatigue. Fatigue is a major design consideration because of the number and magnitude of deflection cycles to which the bellows are subjected. Relative thermal movements of the containment vessel and the process piping produce the maximum deflections of the bellows in the 13- to 50-mm (0.5- to 2.0-in.) range, but leakage rate testing (both integrated and local) and seismic movement also produce deflection and need to be considered. Fatigue analysis of the bellows is performed in accordance with the ASME Code (Section III, Subsection NE) and the Standards of the Expansion Joint Manufacturers Association (EJMA 1980). The analysis can be based on test results of replicate bellows or on an analytical approach using pseudo-elastic theory.

In practice, design specifications for bellows have generally specified a conservative number of design cycles; about 5,000 or more for the penetration bellows and about 500 to 1,000 cycles for vent line bellows (NUTECH 1982a, 1982b). However, two conditions not typically considered in the design can impact the service life of bellows: physical damage and misalignment during installation. Because each ply of bellows is very thin, scratches or sharp dents incurred during construction or operation create significant stress concentrations, which can reduce the fatigue life. Limited space and a buildup of tolerances between the containment vessel and the process piping can produce a large construction tolerance, which results in significant misalignment in the bellows assembly. Such misalignment induces additional stresses in the bellows, which can reduce the fatigue life. However, fatigue evaluations of some penetration bellows in a BWR Mark I containment concluded that axial and lateral misalignment up to one inch would not result in any significant increase in the calculated fatigue usage factor (NSP 1989).

Studies of these two conditions indicate that surface flaws have a much greater impact on the bellows' fatigue life than misalignment (NSP 1989). A misalignment of up to 50% of design

g. L. Goldberg, private communication, Sea Test Services, March 1990.

movement, axial or lateral, has relatively little impact on the number of allowable deflection cycles. However, a flaw size equal to 50% of the ply thickness can significantly reduce the number of allowable cycles (less than 100 cycles, in certain cases).

The bellows' residual life is assessed through examination and analysis. A dimensional examination of the bellows typically needs to be performed to determine the movement and any misalignment in the hot or cold position. In addition, an examination of the convolutions of the bellows is necessary to detect and measure any flaws. The examination uses equipment capable of accurately measuring the depth of the flaw. Eddy-current testing, though not perfectly suited to examination of the bellows, can be acceptably accurate.

A fatigue analysis of the bellows considers the as-installed geometry and accounts for the fatigue strength reduction factors. Note that the analysis is based on pseudo-elastic techniques. The stresses calculated by these techniques are often well above the yield or ultimate strength of the material. These stresses are not actual stresses, but their values are correlated to the S-N curve for bellows, as shown in Figure 20 (EJMA 1980). Therefore, the usable range of stresses on the curve, 830 to 2070 MPa (120,000 to 300,000 psi), is reasonable for the bellows analysis techniques. The analysis will yield an allowable number of load cycles that the bellows can endure. As in the containment shell fatigue analysis, the projected number of actual cycles will have to be correlated to operation time to estimate the fatigue damage.

3.2.2 Transgranular Stress Corrosion Cracking. The cold-worked Type 304 stainless steel is susceptible to transgranular stress corrosion cracking (TGSCC) when exposed to corrosive species such as chlorides and fluorides (Logan 1966). Kuniya et al. (1988) have detected TGSCC in cold-worked nonsensitized austenitic stainless steel. Several two-ply bellows in the BWR Mark I containments have experienced TGSCC damage and have been replaced (Stols 1991).

Transgranular stress corrosion cracking is normally characterized by the long incubation period and slow crack propagation. As the tensile stresses acting on the specimen increases, the incubation period decreases and the propagation rate increases. High residual and tensile stresses in the bellows and water containing a sufficient amount of chlorides collected on the interior portion of the bellows create the necessary condition for TGSCC initiation on the bellows inner surface. Eventually, TGSCC is likely to cause a leakage before causing a catastrophic failure of the bellows.

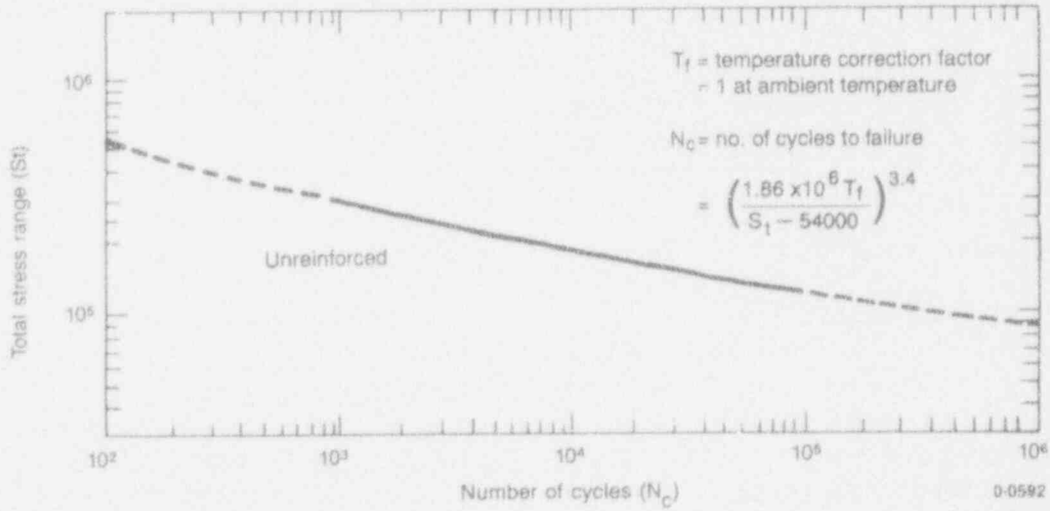

Figure 20. S-N curve for austenitic stainless steel bellows. The solid line represents the valid portion of the curve. The dashed lines, which represent the low- and high-cycle regions of the curve, are based on insufficient data points (1 MPa = 145 psi). Copyright EJMA; reprinted with permission.

3.2.3 Intergranular Stress Corrosion Cracking. Intergranular stress corrosion cracking (IGSCC) of a stainless steel bellows has never been observed. However, there is a potential for such damage to occur. Intergranular stress corrosion cracking (IGSCC) in austenitic stainless steel results from the simultaneous presence of three contributing factors, a sensitized microstructure, a tensile stress above the at-temperature yield stress, and a chemically aggressive environment that will support the occurrence of IGSCC. The sensitization of the microstructure of austenitic stainless steel occurs when the material is exposed to temperatures between about 550 and 850°C (1020 and 1560°F) for certain minimum periods of time. This leads to precipitation of chromium carbide particles near the grain boundaries and a depletion of local chromium content. If the dissolved chromium content in the neighborhood of the grain boundaries falls below about 12%, the material becomes susceptible to IGSCC (Uhlig and Revie 1985).

The field welding of the stainless steel bellows to the carbon steel penetration and vent line sleeves introduces sensitization and high residual stresses to the heat-affected zones. These residual stresses, together with the stresses imposed by the operating loads, contribute to the total tensile stress experienced by the bellows during operation. The interior and exterior environments, particularly of the BWR containment, have high humidity and might contain oxygen and chlorides. The geometry of the bellows also facilitates accumulation of water in the bottom of convolutions, creating a potential concentration of corrosive elements. Thus, all three factors necessary for occurrence of IGSCC can be present at the bellows.

3.3 Mechanical Wear

In a few locations of the containment vessel, mechanical wear or abrasion may limit component life locally. Such wear may occur at locations where surfaces are forced to slide against or impinge on each other: (a) personnel air lock doors and frame interfaces, (b) drywell head and flange interfaces (BWR), (c) lubrite baseplates of interior platform connections (see Figure 21) and Mark I suppression chamber support columns, and (d) pin joints.

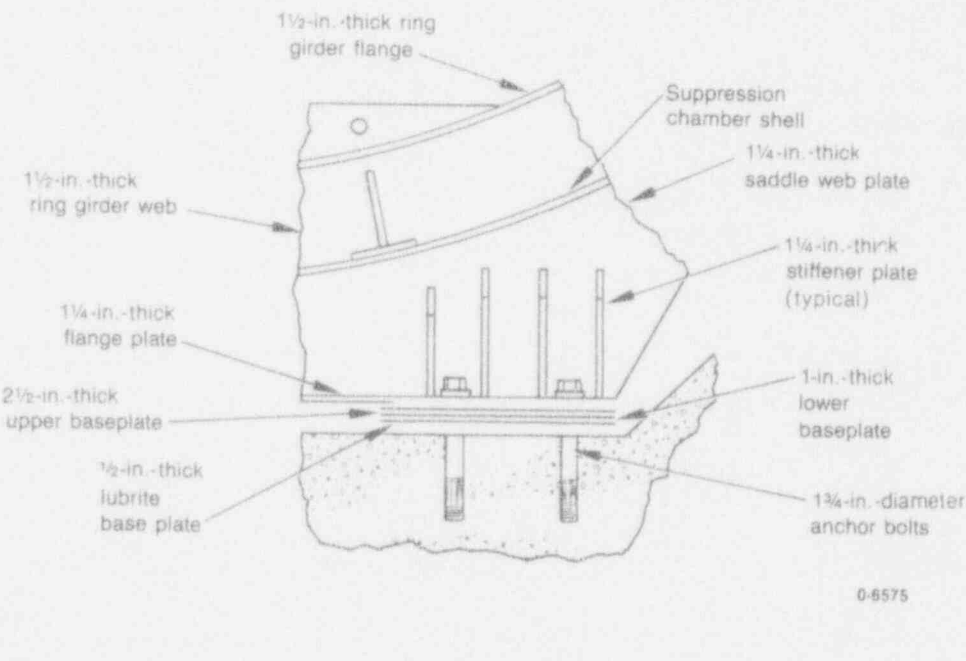

Figure 21. Elevation view of a typical suppression chamber saddle support, showing lubrite base plate.

At the personnel air lock and drywell head flange, surface wear results in excessive leakage. This has been reported at a number of plants, especially for air locks. It is typically repaired by adding or replacing gasket material. At some time, however, these areas may have to be repaired by replacing or resurfacing the material.

Flange systems are subject to physical abuse when bolted and unbolted and when handled by cranes. The surfaces may suffer small nicks, scratches, or impressions that, over time, facilitate leakage between flange and gasket.

The lubrite baseplates of the Mark I suppression chamber support (see Figure 21) permit thermal expansion of the suppression chamber vessel by providing a low friction interface for lateral plate sliding. Mechanical wear and aging can cause these plates to seize in place and restrict sliding. This increases the cyclic thermal stresses in the vessels and, thus, increases fatigue damage. Replacement of these plates, based on an assessment of motion restraint, is a relatively inexpensive way of minimizing the fatigue.

Pin joints, such as those provided on vent header columns or seismic restraint pins, can be periodically inspected to ensure that rotations are not restrained by corrosion or wear of the contacting surfaces.

3.4 Settlement

Settlement is not an issue for plants built on bedrock. Plants that are not built on bedrock and have soil conducive to settlement usually have provisions in their technical specifications or final safety analysis reports to monitor settlement. At these plants, if settlement has occurred, it has taken place within the first 5 to 6 years; the monitoring is generally discontinued after that time.

The original design of containment and building of these plants has taken into account both uniform and differential settlement (ACI 1983). If uniform settlement occurs over time, it does not create stress in the containment vessel. However, if differential settlement occurs over time, it can introduce stresses in the containment vessel. The calculation of the increased stresses is complex, but it has been accomplished at plants with settlement problems. For example, settlement was discovered at the Midland Nuclear Plant before construction was discontinued. A reanalysis of the plant's structures was completed considering stresses induced by settlement.

Currently, few plants are monitoring differential settlement, particularly for interior components. Any major settlement, if present, can be visually detected by examining concrete cracks and apparent differences in surface elevation. If significant differential settlement is discovered, the following steps can be taken with respect to aging management: (a) determine the relative magnitude of the settlement, (b) investigate the cause of the settlement in order to project the rate and extent of future settlement, (c) calculate the additional stresses to the containment vessel caused by the projected settlement, and (d) determine if, or at what point, the additional stress will cause any part of the vessel to be overstressed.

4. OPERATING HISTORY AND MAINTENANCE ACTIVITIES

Review of operating history and maintenance activities helps to identify the design features, stressors, and repair activities that have caused significant damage to metal containments. The review identifies the stressors that were not accounted for in the original design. In addition, the review identifies the weaknesses of the current maintenance activities in mitigating the aging damage. This section describes several aging-related events and presents current and supplementary maintenance practices.

4.1 Operating History

The BWR Mark I containments and PWR cylindrical containments are the oldest and the most numerous LWR metal containments. Most of the aging-related historical operating experience is associated with these containments. The metal containment vessels are made of low carbon steel, which is susceptible to corrosion during operation if the surface coating has deteriorated. This section describes the most significant events of corrosion damage to the metal containments, including BWR Mark I containments of Oyster Creek, Nine Mile Point Unit I, Fitzpatrick, and Dresden Unit 3, and PWR cylindrical containments (ice-condenser-type) of Units I and II of McGuire and Catawba. For each event, the information related to relevant design features of the containment, event description, corrosion rate estimation, identification of corrosion mechanisms, and mitigation of corrosion damage is presented. Sections 4.1.1 to 4.1.4 describe field experience of corrosion incidences. Sections 4.1.5 and 4.1.6 describe overheating incidences that degraded the protective coating. Section 4.1.7 describes transgranular stress corrosion cracking of penetration bellows at several BWR Mark I containments.

4.1.1 Corrosion of Drywell at Oyster Creek

4.1.1.1 Drywell Design. The Oyster Creek plant has a Mark I type drywell containment (made of ASTM A 212 Grade B carbon steel plate) with an annular space of approximately 76 mm (3 in.) between the drywell shell and the concrete shield wall (Figure 8). This gap is filled with compressible material, Firebar D (a composite of foam, fibers, and concrete), which was applied to the metal shell as a spray coat [approximately 70-mm (2.75-in.) thick]. This material was selected because it is firm enough to resist crushing by pressure induced by the head of the uncured concrete during construction, but soft enough to allow for thermal expansion of the metal shell during operation. The material was left in place after construction was complete. The material lacks resistance to weathering and is readily attacked by water, which leaches out magnesium chloride (a constituent of Firebar D); the leached chloride is highly corrosive. The constituents of this material with sulfate can also serve as a food for microorganisms causing microbially influenced corrosion.

The lower 3.17-m (10-ft 3-in.) portion of the drywell interior is filled with concrete, which provides structural support to the drywell and holds it vertical (see Figure 8). A concrete curb follows the contour of the vessel up to elevation 3.35 m (11 ft). The sand pocket is located at the base of the gap. The drywell was coated with one coat of carboline Carbo-Zinc II on the inside surface above the concrete floor and with one coat of red lead on the outside surface [from elevation 2.76 m to 29.10 m (8 ft-11.25 in. to 94 ft)], including the regions in contact with the sand in the sand pocket. The portion of the drywell embedded in concrete was not coated on either the outside or the inside surface. The sand pocket is connected to drains that allow drainage of any water that might enter the sand. It is within this area, where the sand cushion contacts the drywell shell, that corrosion was identified.

4.1.1.2 Event Description. Water was observed around two of the penetrations at elevations 26.6 m (86 ft) and 14.5 m (47 ft) and running down the wall during the 1980 refueling outage. Water on the torus room floor originating from leak drains was also observed following construction in 1969 and during the 1980 refueling outage (Wilson 1987). The probable sources of water were the equipment storage pool, the refueling cavity, or the fuel pool. It was further concluded that leakage occurred only during refueling when the refueling cavity, the equipment storage pool, and the fuel pool were flooded. When water was again found leaking from the sand bed drains during the refueling outage in 1983, it was suspected that corrosion of the drywell shell could be a concern. Measurements of drywell wall thickness during 1986 refueling outage revealed significant corrosion of the drywell shell adjacent to the sand pocket region.

A radiological analysis of the leaking water samples indicated that the leakage water had the same radioactivity as water within the reactor, and the leak path was believed to have been from the refueling cavity located immediately above the drywell (see Figure 22). Initial investigations revealed that the leak was at the bellows drain line gasket. Later on, leaks were also found through the several through-wall fatigue cracks in the stainless steel liner of the refueling cavity (Gordon 1988). Two factors appear to be responsible for this cracking: (1) the thickness of the stainless steel liner was much smaller than the design thickness [6.25 mm (0.25 in.)], (2) the periodic filling of the refueling cavity and equipment pool during refueling exerted cyclic water

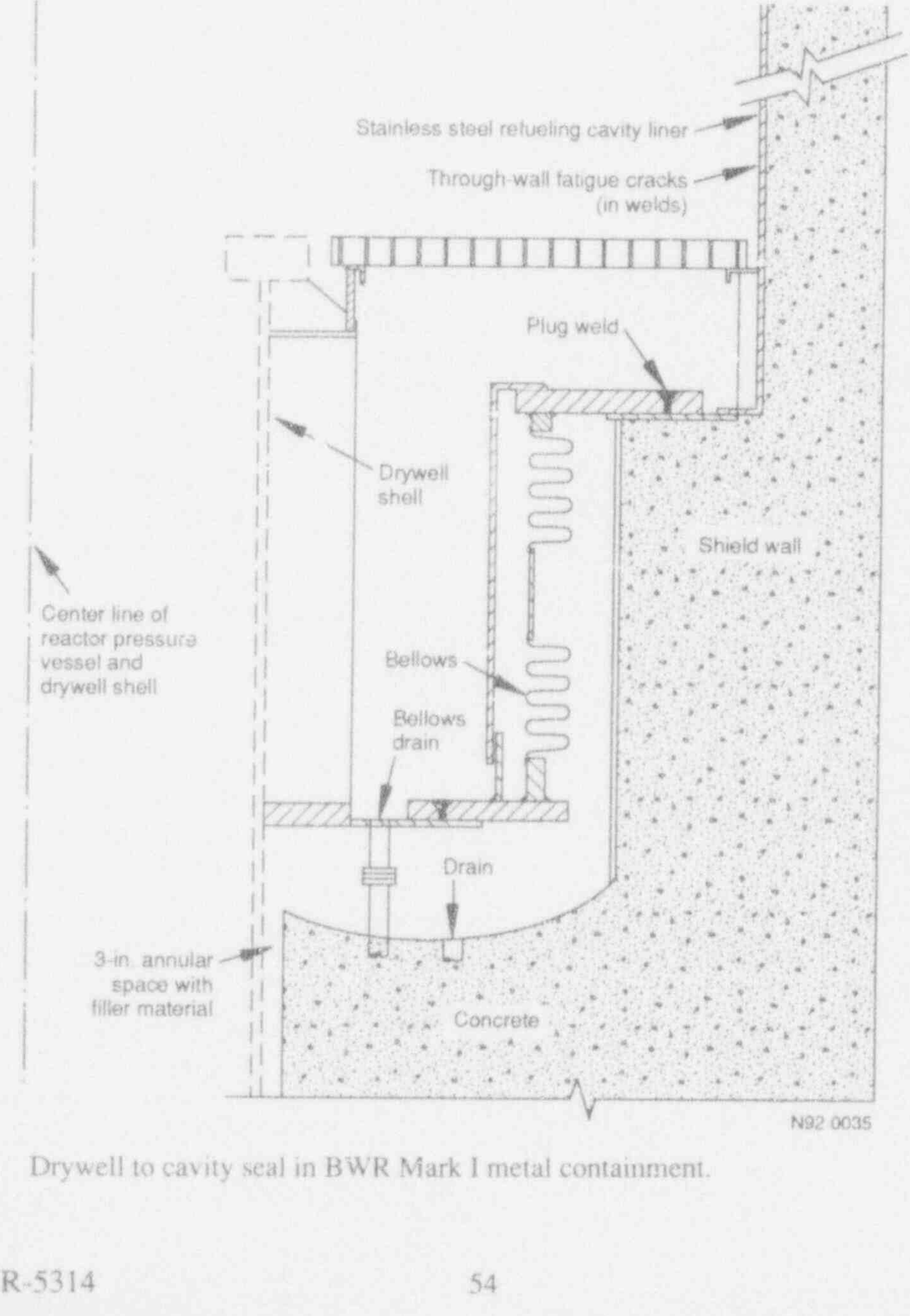

Figure 22. Drywell to cavity seal in BWR Mark I metal containment.

pressure loads on the liner. The cracks were along the perimeter of the liner plates where these plates were welded to the embedded channels (USNRC 1991a). The leaking coolant could have passed along the concrete side of the liner to the 3-in. annular space and eventually into the sand pocket region.

Initially, it was believed that leaks from the cavity into the gap between the shield wall and drywell combined with possible condensation in the gap between the fill material (Firebar D) and the drywell shell, wetted the Firebar D, and leached corrosive magnesium chloride from the Firebar D. The accumulation of magnesium chloride in the sand pocket was originally thought to be the key factor in the drywell corrosion observed at Oyster Creek. However, chemical analysis of samples of water, sand, and corrosion products provided evidence of a high concentration of corrosive contaminants such as chlorine, bromine, and sulfate ions, which are more typical of a marine environment (seawater) than Firebar D (Gordon and Gordon 1987). The chlorine and sulfate ions play a major role in the breakdown of any passive film on the carbon steel, and their presence increases the conductivity of the electrolyte in the moist sand. Based on the observed corrosion rates of the carbon steel drywell shell, the marine environment is likely to be the key factor causing corrosion.

4.1.1.3 Corrosion Rate Estimation. Initial UT thickness measurements (using a UT thickness gauge device called a D-meter) made from the inside of the drywell at a 3.5-m (11-ft 3 in.) elevation near the sand cushion region and at a 15.8-m (51-ft) elevation indicated drywell thinning caused by corrosion. A trench was excavated through the concrete curb in areas where the extent of thinning at the floor level was the most severe. Additional thickness measurements were performed to determine the vertical profile of thinning. The measurements indicate that thinning below the floor level was not as severe and was even less severe at the lower portion of the sand cushion. Several additional measurements were made with a conventional UT transducer displaying a signal on an oscilloscope (A scan).

Seven core samples were removed from various regions in the drywell shell below the concrete floor adjacent to the sand pocket regions to evaluate the validity of the UT measurements. Regions with a wall thickness less than half the 29.3-mm (1.154-in.) nominal wall thickness were designated "pitted/ inclusion" areas. Regions that had UT indications of thinning were designated as "wastage" areas. Regions above the wastage area and within the sand pocket region that appeared to have no thinning or pitting were also selected as candidate core samples sites.

The portion of the drywell shell in contact with the sand pocket experienced significant wall thinning [6.4 to 8.9 mm (0.25 to 0.35 in.)] only within elevations 3.17 m to 3.64 m (10 ft 3 in. to 11 ft 9 in.) (Wilson 1987). The initial UT examination of the core sample from the worst-affected areas (pitted areas) of the drywell below the concrete floor near the sand pocket region indicated a minimum through-wall thickness of 12.5 mm (0.49 in.) (Wilson 1987). However, the average measured thickness (by micrometer) of this core sample was 29.72 mm (1.17 in.). Further destructive metallurgical examination of this sample revealed the presence of a band of aluminide stringers at the core midplane. These inclusions produced a reflection of ultrasound. Thus, the highly local UT indication was caused by an inclusion, not by pitting. The measured depth [12.5 mm (0.49 in.)] of these inclusions correlated with the depth determined by the initial UT. The thickness of two core samples measured by UT was 0 to 4% less than the micrometer measurements. Core samples taken from the drywell shell where adjacent sand was dry did not reveal any corrosion.

The corrosion rate was estimated by establishing a period in which the drywell was exposed to water and comparing this period to metal loss. The region above the 3.64-m (11-ft 9-in.) elevation showed little or no wall loss. The region from 3.17 to 3.64 m (10 ft 3 in. to 11 ft 9 in.) in contact with the sand bed showed the greatest wall loss, followed by the region below 3.17 m (10 ft 3 in.), which showed significantly less wall loss. The conservative estimate of the mean value of the effective drywell thickness near the sand pocket regions was 22.1 mm (0.87 in.). For the initial thickness of approximately 29.21 mm (1.15 in.) (near the sand pocket region), the typical loss in thickness was 7.11 mm (0.28 in.). If it is assumed that the corrosion initiated in 1969 resulting from the intrusion of water in the sand pocket region, the average estimated corrosion rate (between 1969 and 1986) is approximately 0.51 mm/year (17 mil/year) (Wilson 1987, Gordon and Gordon 1987). If it is assumed that all corrosion initiated 6 years before the investigation (in 1980, a year of documented evidence of water leakage in the sand bed), then the estimated corrosion rate (between 1980 and 1986) increases to approximately 1.44 mm/year (48 mil/year) (Wilson 1987). Further assessment of drywell corrosion was performed by the UT measurements in 1991. The reported lower and upper bound corrosion rates near the sand pocket elevations were 0.52 mm/year (17.4 mil/year) and 0.62 mm/year (20.5 mil/year), respectively (USNRC 1991b). However, based on recent trending of thickness measurements, it appears that the corrosion was continuing at a peak rate of 0.89 mm/year (35 mil/year) at the worst areas; the thickness measurements were as low as 20.3 mm (0.80 in.) (Lipford and Flynn 1993).

4.1.1.4 Identification of the Corrosion Mechanism. Several types of corrosion mechanisms have been identified as the potential cause. Water, corrosion products, sand, and core samples were analyzed to evaluate the corrosion mechanisms of the drywell shell near the sand cushion. Factors that affected the corrosion of the metal shell include contaminant levels, moisture level, electrolyte conductivity, bacteria, and acidity/alkalinity.

Cultures of sand samples initially revealed the presence of microbial activity. However, further examination of corrosion products revealed that microbial activity did not have a major influence on corrosion (Mathur 1987). This conclusion regarding microbially influenced corrosion was based on the facts that no deep pitting was observed and no sulfide or substantial concentration of manganese was detected in the corrosion products, both of which are typical evidence of microbially influenced corrosion.

An environment suitable for aqueous corrosion (general corrosion, pitting, and differential aeration) of the drywell shell was present at the sand pocket elevations. Analyses of samples of drain water, sanu, and the corrosion products provided typical evidence of aqueous corrosion. The conductivity of the water samples from various drain lines (680 to 1100 μS/cm) was three orders of magnitude higher than that of pure water at a similar temperature (Gordon and Gordon 1987). Such a high conductivity leads to a high amount of corrosion. The moisture content of the sand samples ranged from 1.1 to 12.6% (Gordon and Gordon 1987). The core samples from areas with adjacent dry sand did not show any significant corrosion. Hence, the wet sand/water environment was sufficiently conducive to establish a viable electrolyte for aqueous corrosion. The source of moisture includes a known leakage of water from the refueling cavity. Other sources of moisture include installation of moist sand during construction, water "squeezed" out of the Firebar D slurry during pressure testing of the drywell, and condensation. The sand, corrosion products, and drain water had a high level of corrosive contaminants (such as Cl^-, Br^-, $SO_4^=$). The presence of these contaminants would be expected to increase the corrosion of carbon steel. In particular, high levels of detrimental chloride and sulfate were noted in virtually all the samples analyzed. Analysis of the characteristics of corrosion products formed on core sample surfaces revealed that the of water leaking from the refueling cavity, not Firebar D, might have been the main source of contaminants in the sand pocket (Gordon and Gordon 1987, Kawaller 1987) and largely responsible for corrosion.

Differential aeration might have contributed to corrosion of the drywell shell. The lower region of the sand cushion near the drain line and upper region near the gap are rich in oxygen and act as cathodes, whereas the region in the middle is depleted in oxygen and acts as anode; the drywell shell adjacent to the anodic region will experience corrosion (see Figure 23), which appears to be

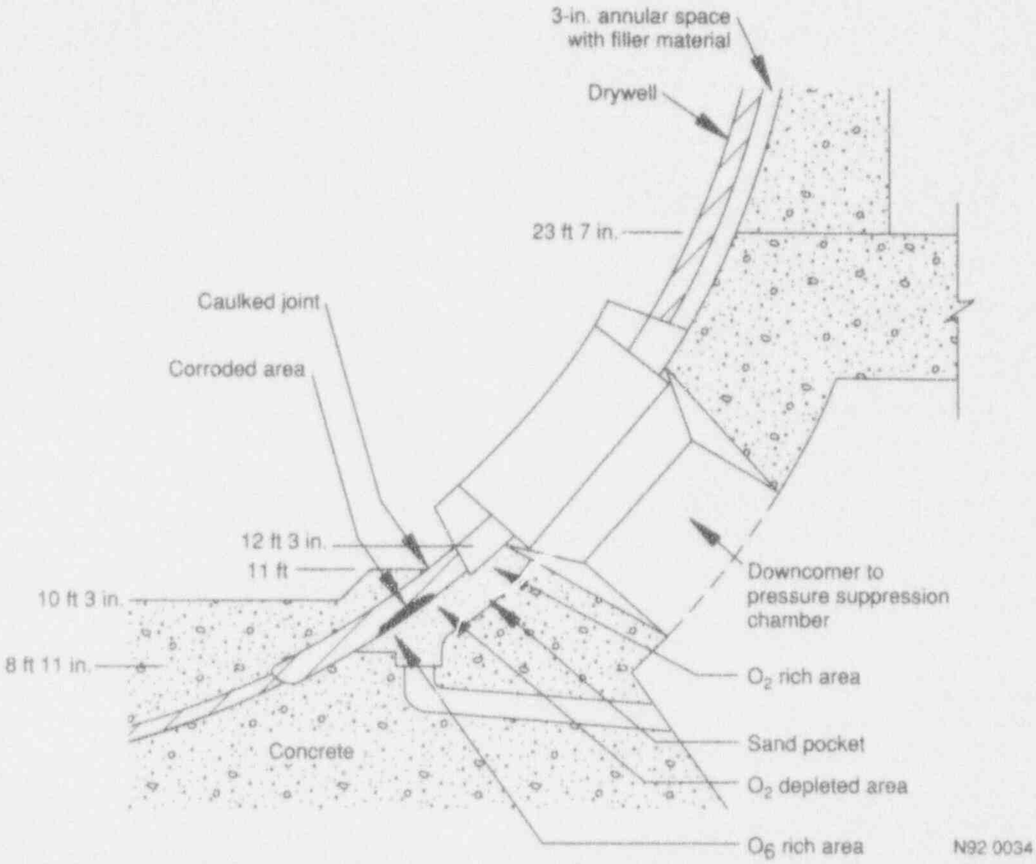

Figure 23. BWR Mark I drywell base, showing corroded area on outside surface near sand pocket region (Gordon 1988). Copyright American Nuclear Society; reprinted with permission (modified).

qualitatively verified by the UT measurements (Gordon 1988).

The red-lead coating applied to the outside surface of the Oyster Creek drywell does not provide adequate corrosion protection to carbon steel subjected to dilute acidic water conditions. The lead in the red-lead coating is cathodic to the carbon steel in dilute acidic water conditions, and, therefore, the steel is sacrificial with respect to the lead (Fontana 1986, USNRC 1986a).

4.1.1.5 Corrosion Mitigation. This section describes the utilities' efforts to reduce the corrosion damage. These efforts include unsuccessful use of cathodic protection, proposed surveillance activities, and eventual repair of the drywell coating. It also summarizes the recommendations presented in the proposed USNRC Generic Letter. Cathodic protection installed to inhibit further corrosion of the outside surface of the embedded portion of the containment has not been successful (USNRC 1991a).[h] This mitigative technique was designed with a fixed potential difference between the drywell and the reference electrode.[h,i] The resistance of the sand in the sand pocket region increased with time as the moisture in the sand immediately surrounding the anodes decreased. The increased electric resistance in the sand caused a decrease in the impressed current density to a level below an optimum level for cathodic protection. However, sufficient moisture present in the sand in contact with the drywell shell allowed continuous corrosion of the shell by the contaminants present both on the outside surface of the metal shell and in the sand.

h. J. Pelliccone, private communication, Oyster Creek Nuclear Plant, November 1990.

i. S. Nikolakakos, private communication, Ebasco Corporation, November 1990.

The proposed surveillance included checking the torus rooms and sand cushion drain lines for water during refueling (Oyster Creek 1987). Sand cushion drains (Figure 23) and drywell seal bellows drains (Figure 22) may be periodically monitored during refueling. Borescope inspection of drains will indicate whether they are blocked. Installation of flow alarms for bellows seal failure will indicate, in advance, any possible water leakage. Removal of the insulation and gap filler material from the drywell gap was also being evaluated (USNRC 1991a).

Recently, a long-term repair of the coating to stop the corrosion of the drywell was completed (Lipford and Flynn 1993). The drywell shell was not repaired because the minimum measured thickness [20.3 mm (0.80 in.)] of the drywell was larger than the minimum required thickness [18.80 mm (0.74 in.)]. The repair included removal of sand from the sand pocket, removal of corrosion products, cleaning of the affected surface, inspection of the drywell (which did not reveal any deep pitting), and recoating the drywell surface with epoxy. Twenty-in.-diameter access holes (manways) were drilled through the shield wall about 12 in. away from each of the 10 vent lines to reach the affected drywell surface.

Two unexpected problems encountered during repair caused some delay. First, water was still leaking out of the refuelling cavity. Special dams and drains were built to isolate the water away from the work area. Second, the concrete floor under the sand cushion had never been poured. The sand pocket's drain pipes were stubbed off about 3 to 4 in. above the rough floor and so would not have functioned even if they had not been blocked, because standing water would have accumulated below the top of drain lines. A new epoxy floor was poured so that the finished floor is flush with the top of the drain pipes.

The sand was not replaced after the repair was completed, and the manways were left in place. The structural analysis results confirm that these changes do not jeopardize the structural integrity of the drywell. The manways will facilitate periodic maintenance of the coating and inspection of the drywell and, thus, mitigate any corrosion damage in the future.

A proposed USNRC Generic Letter has made several recommendations to monitor and mitigate corrosion of BWR Mark I drywell (*Federal Register* 1992). These recommendations include representative carbon steel specimens to be inserted into the sand pocket around the drywell and withdrawn every six months to check for any indication of corrosion. The recommendations also include inspection of the drain lines discussed in the preceding paragraph. If water is found in the sand pocket or the carbon steel specimens are corroded, the proposed Generic Letter recommends UT thickness measurement of the lower portion of the drywell shell near the sand pocket and of the upper portion of the shell, if filler material is present in the gap. Some modification to the construction of the concrete floor inside the drywell might be necessary to allow access for a UT transducer for thickness measurement. The inspection frequency may be determined from the thickness measurements and from the corrosion rates for the steel specimens. These recommendations are also applied to the BWR Mark II drywell because it is susceptible to corrosion damage similar to that of the Mark I drywell.

4.1.2 Corrosion of Torus at Nine Mile Point Unit 1. Nine Mile Point Unit 1, which started commercial operation in 1969, has a Mark I metal containment. The inside surface of the torus shell was designed and constructed as uncoated. Corrosion on the inside surface of the torus shell was detected during an inservice inspection in October 1988. UT measurements were made to determine the wall thinning. According to the measurements, the torus wall inside surface had experienced an overall corrosion rate of 0.08 mm/year (3.2 mil/year), which is double the expected (design) rate of 0.04 mm/year (1.6 mil/year) (*Nucleonics Week* 1988). The differential aeration mechanism probably contributed to the damage of the inside surface of the torus immediately below the waterline. In addition, the submerged portion of the torus inside wall surface might also have experienced pitting corrosion. [New York Power Authority's Fitzpatrick plant has also experienced various degrees of local corrosion

[0.08 to 0.23 mm (3 to 9 mil)] because of degradation of the torus inside wall coatings (*Nucleonics Week* 1988).]

It is necessary to perform periodic visual inspection of the suppression pool steel shells in accordance with their technical specifications. Inspections of torus areas both above the waterline and below it will reveal the presence of any areas damaged by corrosion. Local corrosion such as pitting can be detected most effectively if the torus is drained and inspected under dry conditions (USNRC 1988a). However, the resulting large pressure reduction may cause additional blistering or popping of existing blisters in the coating. Recently developed underwater inspection techniques include dislodging, mapping of critical areas, testing of coating adhesion, measurement of dry film thickness, and spot repair of degraded areas (USNRC 1988a). Potential advantages from the techniques appear to be reduced radiation exposure to personnel and elimination of the need for draining the suppression pool. Ultrasonic inspection of the section of high-pressure injection pipe between its penetration into the torus and the first check valve can reveal any possible corrosion damage to the pipe inside surface, because that section of pipe generally contains stagnant water, and its inside surface is uncoated.

The proposed USNRC Generic Letter also recommends that representative sample specimens, which are of the same material (coating and steel base metal) as those of torus, be placed at the waterline at least one in each bay (*Federal Register* 1992). If visual inspection of the torus or the specimens detects any indication of coating degradation or base metal corrosion, UT thickness measurement of torus wall is recommended. The frequency of these measurements should be based on the highest corrosion rate measured. The thickness measurement needs to be performed at a statistically significant number of points, as discussed in Section 2.1.3. These recommendations are also applied to the BWR Mark II pressure suppression pool because it is susceptible to corrosion damage similar to that of the Mark I torus.

Maintenance of the surface coating is the best protection against corrosion. Repair of the pitted areas followed by recoating will protect the inside surface. Epoxy coatings applied to corrosion-damaged areas will be more durable than red-lead coatings (Munger 1984). Cathodic protection, which has been successfully used to protect inside wetted surfaces of large water tanks, might be used to protect the inside surface of the torus from corrosion damage (Doughty 1981). Use of non-toxic corrosion inhibitors, e.g. phosphates, would require further evaluation of their effectiveness and acceptability.

4.1.3 Corrosion of the Outside Surface of the Cylindrical Containment at McGuire and Catawba. The steel containment vessel at McGuire Unit 2 has a vertical cylinder, a hemispherical dome, and a flat base. The containment metal shell is anchored to the reactor building foundation by anchor bolts around the circumference of the cylinder. A steel plate, encased in concrete and anchored to the reactor building, serves as the base of the containment and also as a leaktight membrane. The vertical cylinder and hemispherical dome were constructed from carbon steel plate of ASME specification SA 516 Grade 60. The cylindrical vessel is surrounded by a reinforced concrete reactor building with an annular space of 1.8 (6 ft) between them. Some areas in the annular space adjacent to the outside surface of the containment are inaccessible because of the ductwork (Figure 24). No sealant was installed at the concrete-metal interface during construction.

A significant amount of water in the annular space of the concrete floor between azimuth 240 and 253 degrees (Figure 24), along with significant coating damage and base metal corrosion on the outer surface of the metal shell, was observed on August 24, 1989 (USNRC 1990, McGuire 1989). This discovery was made during a preliminary inspection of the steel containment vessel prior to leak rate testing. A general visual inspection of the Unit 2 containment performed in May 1986 did not reveal any coating damage, so it can be assumed that the damage occurred between May 1986 and August 1989.

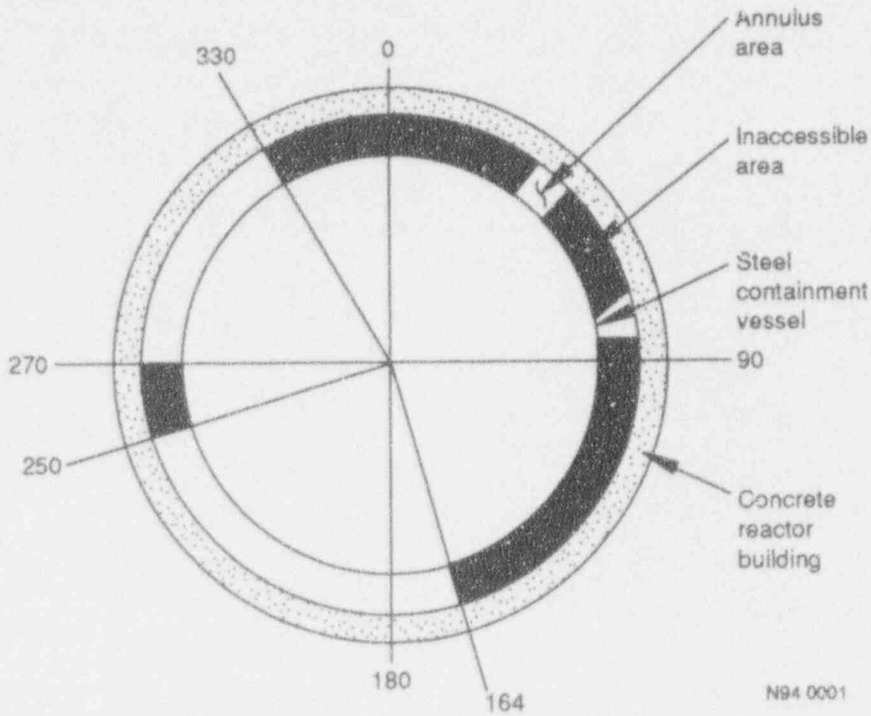

Figure 24. Horizontal cross section of McGuire Unit 2 steel containment vessel, showing the accessible and inaccessible areas in the space region between the containment and reactor building.

The examination of the accessible annulus area included removing containment exterior surface coatings above the concrete floor to a height of 225 mm (9 in.) and removing the concrete floor adjacent to the containment to a depth of 200 mm (8 in.). A depth gauge and a vernier caliper were used to characterize isolated pits, which measured as much as 3.7-mm (123-mil) deep, as shown in Figure 25. The calculated worst-case corrosion rate was 1.15 mm/yr (38.5 mil/yr).

Both the annulus area and the exterior containment surface were coated to Service Level II requirements, which permit surface imperfections in the coatings and are not intended for immersion conditions. Standing water wicked its way between the coating and the metal surface and caused corrosion damage. Severe corrosion occurred in the areas where boric acid deposits were deposited from leaking instrumentation line connections. The absence of sealant at the joint between the containment and concrete floor permitted the intrusion of the corrosive environment, causing corrosion of the metal shell below the concrete floor.

The drains located in the concrete floor failed to function. The concrete floor in the annulus area was designed to circumferentially slope toward four equally spaced drains located at azimuths 45, 135, 225, and 315 degrees. Three possible causes are assigned to the functional failure of the drain system: (a) the drains were capped off or were stubbed off inches above the floor (not cut back to floor level after the floor was poured), (b) the isolation valves were closed, (c) the demineralized water makeup to the drain line loop seal overflowed to the annulus area.

Inspection of McGuire Unit 1 revealed containment degradation similar to that discovered at Unit 2.

Two Catawba containments, ice-condenser-type containments similar to those of McGuire, also experienced coating damage and base metal corrosion on the outer surfaces of steel shells at the intersection of the steel shell and the concrete floor. The corrosion damage to the Catawba containments was not as extensive and severe as the damage to the McGuire containments. The corroded areas covered about 4.6 m (15 ft) of the

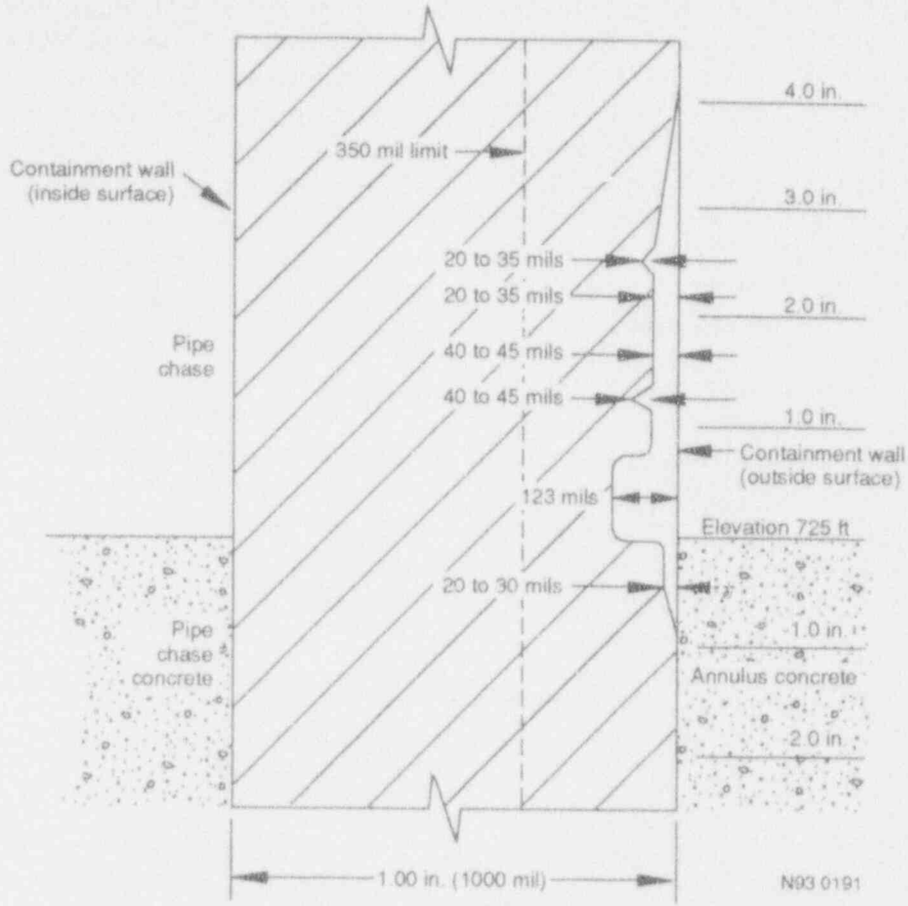

Figure 25. Cross section of McGuire Unit 2 steel containment vessel at azimuth 240 to 243 degrees, showing corrosion damage near the metal-concrete interface.

circumferential section of the steel shell, to a height of 25 mm (1.0 in) above the annulus floor. The average corrosion depth was 0.76 mm (30 mil) (USNRC 1989b, Catawba 1990). The number of occasions and lengths of time the water stood in the annulus area are unknown, so the corrosion rate cannot be estimated. The probable cause of degradation was similar to that for the McGuire containment.

Several actions were taken to reduce or prevent further corrosion damage. Damaged areas were weld-repaired and recoated. Accessible areas between the containment and the concrete floor were sealed. Paint and sealant of immersion-level standards were used. Weekly surveillance of the annulus area was initiated to identify and remove any standing water or boric acid deposits.

4.1.4 Corrosion of the Inside Surface of the Cylindrical Containment at McGuire Unit 1. Corrosion on the inside surface of the coated containment shell was discovered during a refueling outage at McGuire Unit 1 on April 18, 1990 (USNRC 1990, McGuire 1990). The corrosion was located at upper and lower floor levels under the ice condenser. Inspection revealed general surface corrosion for the entire circumference, with scattered worst-affected areas near the lower floor level. The inspection also revealed worst-affected areas along a 55-degree arc at the upper floor level. Within the worst-affected areas at both elevations, a large number of closely spaced pits up to 6.35 mm (0.25 in.) in diameter and less than 0.5 mm (20 mil) in depth can be observed. Significant pitting of various widths and lengths to a depth of up to 1.14 mm (45 mil) was observed at isolated locations. General corrosion was also found on the inside surface of the containment between the floors. At these elevations, cork filler material [610 to 760 mm (24 to 30 in.) in height] is installed in a 51-mm (2-in.) gap between the steel containment vessel and interior concrete floor (Figure 26). Cork is selected for its flexibility to accommodate the anticipated relative movement of the containment vessel. During construction, an epoxy surfacing compound was applied to the concrete floor and cork.

Ultrasonic testing was used from the outside surface to estimate corrosion depth at general surface corrosion areas and the worst pitted areas on the inside surface. The signal was transmitted through a coating and steel to a rough inside surface and then back through the steel and coating. These tests showed that the depth of corrosion was approximately 0.2 mm (8 mil) for general corrosion areas and 1 mm (38 mil) for the worst pitted areas. The results could not be accepted as exact because the signal scatter caused by medium changes and by the rough surface was not within procedural guidelines. However, the results did provide credibility to the estimates of the loss of metal. Corrosion rates were established based on measured metal loss, assuming corrosion activity since the previous Unit 1 inspection before an integrated leak rate test. The preliminary inspection of the Unit 1 containment found a minimum measured thickness of 18 mm (0.705 in.), which is well above the required 16-mm (0.62-in.) minimum wall thickness. The projected worst corrosion rate is 0.33 mm/yr (12.9 mil/yr) (McGuire 1990). A

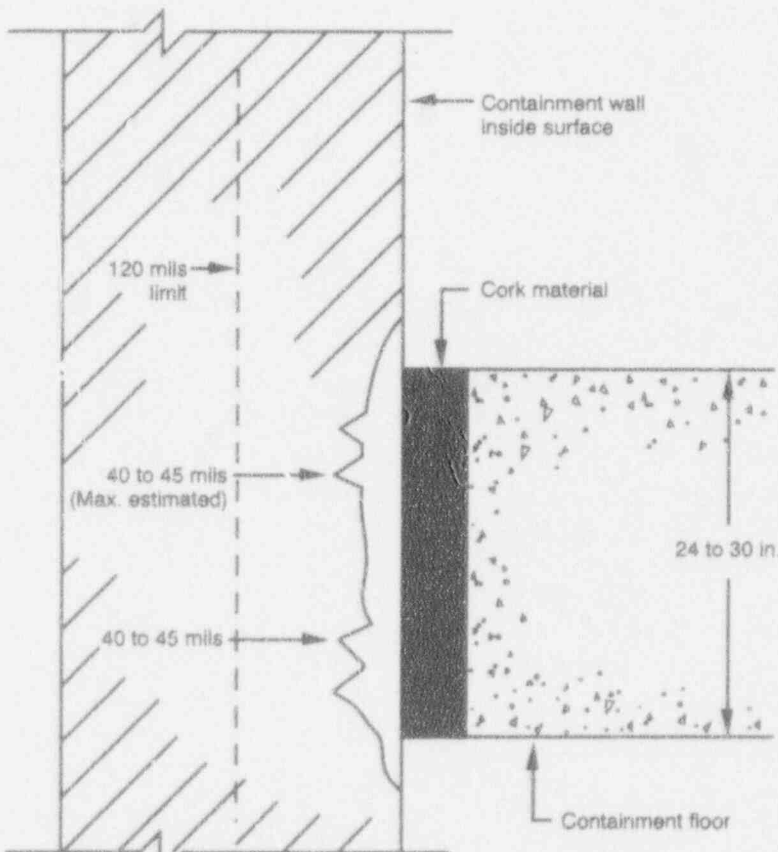

Figure 26. Cross section of McGuire Unit 1 steel containment vessel at 247 to 302 degrees, showing worst-affected areas at elevations 225 m (738 ft-3 in.) and 233.7 m (766 ft-8 in.).

preliminary inspection of the Unit 2 containment indicated corrosion of a lesser magnitude.

An attempt was made to determine the cause of the corrosion. The epoxy surfacing compound on the cork filler material has hardened and become rigid. The radial growth experienced by the containment during integrated leak rate tests caused the epoxy surfacing compound to crack at the inside and outside edges of the cork. This resulted in a flow path for moisture to access and penetrate the cork. It is possible that the corrosion was caused by moisture following this flow path. The moisture might have originated from the ice condenser and from any other condensation.

Actions taken to resolve the corrosion problems included developing acceptance criteria for expansion joint material and coating, replacing the cork material and failed coatings, applying new coating to the containment shell area susceptible to corrosion, and preventing water and boric acid solution from penetrating the expansion joint.

4.1.5 Accidental Fire in Fill Material at Dresden Unit 3. The filling material (polyurethane) in the annular space between the Mark I drywell and concrete shield wall caught fire on January 20, 1986 (USNRC 1986c). (This material was used to facilitate the pouring of the shielding concrete during initial construction.) The resulting high temperatures caused degradation of the drywell shell surface coating. The events leading to the fire are as follows. The plant was in a scheduled refueling outage. The containment was deinerted, with all fuel removed from the reactor vessel and the equipment hatch open. A contractor began removing the reactor water cleanup pipe as a part of the Unit 3 recirculation pipe replacement project. A pipe that penetrates the concrete shield wall was being removed for replacement. An arc-air cutting technique was being used for cutting the pipe. The sleeve in the shield wall through which the pipe passes slopes downward from the outside; hot slag from the pipe cutting ran through the sleeve and contacted the polyurethane foam in the gap. The fire was first detected by the presence of smoke in the reactor water cleanup pipeway and was extinguished shortly thereafter (in less than a day). Water was applied through the penetrations near where the fire apparently started and through adjacent penetrations.

The peak temperature attained during the fire was determined to be about 260°C (500°F), which is likely to damage coating. The coating on the inside surface was discolored and/or flaked in scattered locations in the fire-affected areas of the steel containment. Similarly, the coating on the outside surface was likely to be deteriorated.

Sample tests on the water solution of the burnt foam residues revealed that no significant concentrations of chemicals corrosive to steel were present (Commonwealth Edison 1986). If acids had formed, they would have been highly diluted by the quantity of water used to extinguish the fire. This conclusion was supported by the results of chemical analysis of water samples collected from the sand pocket drain lines. The corrosion of the containment steel by the diluted acidic water is considered to be minimal. However, the burning polyurethane materials produced corrosive and toxic gases, such as nitrogen oxides and possibly other corrosive gases that might have been harmful to the metal.

To prevent the recurrence of such fires, earby gap areas may be stuffed with fire retardant sheeting before any cutting or welding of pipes.

4.1.6 Overheating of the Drywell at Dresden Unit 2. Excessive heating of the drywell at Dresden Unit 2 occurred because of inadequate maintenance. On November 14, 1988, while Unit 2 was shutdown for a scheduled refueling outage, it was determined that the drywell wall at high elevations (near the reactor bulkhead area) had experienced excessive temperatures during the previous operating cycle (Dresden 1988). One of the conditions indicative of high temperatures included peeling and discoloration of the coatings on the inside surface of the drywell. Four of the six ventilation hatches, which were supposed to be open, were closed at the end of the previous refueling outage. The closed hatches prevented forced ventilation near the reactor bulkhead area, resulting in an estimated maximum temperature increase of 170°C (338°F). Adequate maintenance would prevent the occurrence of such incidents. If a drywell temperature monitoring system is installed, it can detect such excessive temperature rise, and the damage to the containment coating may be prevented.

4.1.7 Transgranular Stress Corrosion Cracking at Quad Cities Units 1 and 2 and Dresden Unit 3. Excessive leakage was detected from a drywell ventilation penetration bellows during the Quad Cities Unit 1 containment integrated leak rate test (Stols 1991). Application of soap solution to the bellows surface while the containment was at pressure showed one large crack and over a hundred small indications. A metallurgical investigation revealed that TGSCC was the failure mechanism for the leaking bellows and that the crack initiated on the bellows inner surface. The investigation found no evidence that the crack growth was caused by fatigue. TGSCC had also been identified as a failure mechanism for the leakage from four bellows at Quad Cities Units 1 and 2 and Dresden Unit 3; the cracks were also initiated on the inner surface. Chlorides, fluorides, and sulfides were identified as the responsible corrosive species. These species might have accumulated during fabrication, original construction, or operation. A review of the bellows size, configuration, and design movements at all penetrations of the Quad Cities Unit 1 containment revealed that the ventilation penetration bellows was among the most highly stressed bellows in the plant. The greater-than-expected leakage rate from the ventilation bellows likely resulted from some of the maintenance activities that took place prior to the leak rate test, which might have caused the TGSCC cracks to open.

The fracture mechanics evaluation concluded that TGSCC and fatigue should not cause catastrophic failure of the leaking ventilation bellows during the then current operating cycle (Stols 1991). The evaluation also concluded that the bellows would remain capable of performing its design function during the operating cycle.

Five leaking bellows have been replaced at the Quad Cities and Dresden plants since 1984. The original leaking bellows were removed and the new ones were assembled in situ, thus avoiding the need for removing the process pipe. This replacement method was qualified by fatigue testing and hydrotesting of the facsimile bellows as required by ASME Code Case N-315 (ASME 1989). One proven procedure for bellows replacement is as follows. After removal of the damaged bellows, the new bellows, split in half by longitudinal cuts, is reassembled around the penetration and then the longitudinal seam welds are made. This is followed by the circumferential welds, attaching the bellows to the penetration assembly (Merrick et al. 1984).

4.2 Maintenance Activities

This section describes the current practices of preventive maintenance and corrective actions (repair) for managing aging of metal containments. Based on the review of operating history and aging assessment, supplementary maintenance activities are described in this section.

4.2.1 Current Maintenance Activities. Maintenance programs at most plants encompass inservice inspection, preventive maintenance, and corrective action. Inservice inspection is discussed in Sections 1.5, 2.1.2, and 3.1.2. Preventive maintenance and corrective action are discussed in this section.

Preventive maintenance for containment vessels generally refers to technique of protecting the shell from corrosion. Several plants have programs for inspecting the interior coating at the end of each operating cycle. Several plants also have programs for underwater inspection of suppression pool coating and base metal (Stuart 1993). The exterior coating is inspected less frequently than the interior coating, and in Mark I and Mark II containments, it is not inspected because the exterior surface is not accessible. The inspections identify areas of deteriorated or blistered coating for repair. Such programs have a mitigative effect on containment aging.

To perform coating repair or recoatings, the old coating is removed and the surface prepared for the new coating, generally by sandblasting. The amount of base metal removed during blasting is a concern, since the wastage can be in the range of 0.12 to 0.25 mm (5 to 10 mil) per occurrence. Depending on the type of coating and the location in the vessel, coatings are likely to be replaced in about 10- to 40-year intervals. Locations such as the suppression chamber are likely to be at the lower end of the range, because of the environment.

Corrective action on containment vessels is performed in accordance with ASME Code, Section XI. Typical repairs include removal of defects, arc strikes, or gouges resulting from work done near the vessel shell. Recently developed techniques for BWR suppression pool include underwater repair of deteriorated coating and corroded base metal. In general, precaution is taken to grind the damaged area and blend the shell thickness with that of the surrounding area. This minimizes the stress concentration in the repaired zone, but does not eliminate it. Additionally, the grinding reduces the shell thickness and, therefore, reduces the corrosion allowance in this zone. However, these repair techniques apply only to relatively small areas of the shell. Should large-scale corrosion damage occur, the damaged area can be weld repaired.

Bellows in the vent and penetration lines, in addition to the containment vessel, constitute the containment pressure boundary, and their integrity needs to be maintained. Typical damage to the bellows discovered in the field includes holes, dents, or gouge marks. ASME Section III, Division I, Code Case N-315 limits the size of defects to 4 square inches. Welded repairs have been accomplished on single-ply bellows and on the outer ply of a two-ply bellows. Typical holes 25 mm (1.0 in.) in diameter have been effectively repaired with both insert plug patches and lapped patches. Slots 0.8-mm (0.031-in.) wide by 12.7-mm (0.5-in.) long have been sealed by groove welding (Merrick et al. 1984). Severe dents can be repaired, when access permits, by pushing a small contour anvil into the position inside a dented or mashed convolution to force the damaged surface to return essentially to its original shape. Attendant external cosmetic work is usually done while the anvil is in place. When bellows are found damaged with dents or gouges that are not deemed critically severe, the stress intensifying characteristics of the abrupt change in contour can be lessened by surface blending. If some surface metal was removed when damage occurred, the loss is appraised with respect to the specified pressure. It is desirable that little or no additional metal be removed at the deepest point during blending. The Code Case requires that the effect of the repair on the bellows be evaluated by fatigue testing and hydrotesting of the facsimile bellows (ASME 1989).

Defective bellows can be replaced when they cannot be repaired. Some of the replacement options are replacement of entire penetration assembly, which is an expensive option and generally not preferred, replacement of bellows element only, or installation of new enveloping bellows (Merrick et al. 1984). The selected replacement option also needs to be qualified by fatigue testing and hydrotesting of the facsimile bellows.

4.2.2 Supplementary Maintenance Activities. Additional maintenance activities may be appropriate to enhance the residual life of the containment vessel. Such activities can be identified in periodic walkdowns of all areas of the containment. This is currently being done informally in many plants, but the walkdowns would be more effective if they were formal and documented to ensure that all items are covered and to stress their importance.

Typical items to consider in the walkdowns are the following:

1. Inspect the coating to ensure all blisters or deteriorated areas are repaired

2. Inspect uncoated surfaces for evidence of corrosion

3. Inspect the steel/concrete interfaces, including the sealant, to determine if the embedded steel has been exposed to the atmosphere

4. Ensure that all spills or leaks are cleaned thoroughly and the vessel dried

5. Ensure that all concrete floor cracks are repaired or sealed to prevent water seepage to the embedded region of the shell

6. Ensure that floor drains are not blocked

7. Inspect penetrations for water, corrosion, and debris

8. Inspect/observe motions of the bellows and surface conditions

9. Observe sliding and rotating joints for free motion

10 Maintain an operating log on load cycles, containment environment, including temperature and humidity, and abnormal occurrences.

5. AN AGING MANAGEMENT APPROACH

The metal containment has been identified as one of the high ranking major component in the nuclear power plant with respect to aging (Shah and MacDonald 1993). Therefore, proper management of aging of the metal containment vessel, basemat, and bellows is considered important to preserve the overall safety of the plant. This section presents a generic approach for performing a comprehensive aging assessment of metal containments. The approach is based on the review of the available aging-related technical information, including design and operation of major components, field experience, and consultations with experts. No new basic research or development was carried out in developing the approach. The approach focuses on gathering relevant information, maintaining records, estimating aging degradation mainly caused by corrosion and fatigue, evaluating the integrity of the containment pressure boundary, and determining the actions needed to manage aging. As the containment design varies from plant to plant, a plant-specific aging management approach can be derived from the generic approach presented here.

Table 7 lists the ten steps of the approach for plant-specific aging evaluations of LWR metal containments. The ten steps constitute three parts. Steps 1 to 5 have to do with reviewing documents and records to estimate the current state of damage for a given containment. While some of the documents will be used directly in the assessment, others will be reviewed to provide background and to uncover issues that may impact the aging management. Steps 6, 7, and 8 provide guidelines for estimating damage at the end of the next operating period and for evaluating containment integrity during that period. The operating period can be as short as one fuel cycle, or equal to the inspection period or interval as defined in the ASME Section XI inservice inspection program, or any other suitable period. Steps 9 and 10, respectively, provide guidelines for establishing mitigative actions and making tangible decisions regarding continuous operation during the next operating period.

Table 7. An aging management approach for an LWR metal containment.

Step 1.	Review Design Data
Step 2.	Review Construction/Quality Control Documents
Step 3.	Review Preoperational Test Records
Step 4.	Review Inspection, Test, and Maintenance Records
Step 5.	Review Operating Records
Step 6.	Assess Corrosion Damage at the End of the Next Operating Period
Step 7.	Assess Fatigue and Wear Damage at the End of the Next Operating Period
Step 8.	Evaluate Containment Integrity at the End of the Next Operating Period
Step 9.	Select Mitigative Actions
Step 10.	Reevaluate Containment Integrity at the End of the Next Operating Period if Significant Mitigative Actions are Identified in Step 9

In order to assess the residual life of a metal containment accurately, it is first necessary to establish the baseline by which the containment was designed and built. Table 8 provides guidelines for reviewing the preoperational records for a plant, which includes the first three steps. Step 1 identifies design documents that describe the information used to originally license the plant. The design drawings, material specifications (including coating specifications), stress analysis, and special analyses provide direct input to management of aging caused by both corrosion and fatigue. These documents list the specific design requirements, including loads, materials, and initial stress margins used in developing the corrosion allowance and the allowable fatigue cycles. The other design documents can provide information on specific locations that can be used for local degradation investigations.

The NRC's Standard Review Plan (USNRC 1981) defines the loads to be considered in containment design, and Regulatory Guide 1.57 (USNRC 1973b) provides the guidelines to combine these loads. Early containment designs were categorized as ASME Section VIII or Section III, Class B vessels. After ASME revised the categorization system, metal containments received their own category, Class MC. As discussed in Section 1.1, it is important to know whether a given containment is of ASME Section VIII design or Section III design. The most

Table 8. Review of preoperational records (Steps 1 through 3).

Step 1. Review Design Data

1.1 Design drawings
1.2 Detail drawings
1.3 Design calculation/stress analysis
1.4 Design changes
1.5 Design specifications
1.6 Coating specifications
1.7 Containment special analyses (loss-of-coolant accident, hydrogen recombination, etc.)

Step 2. Review Construction/Quality Control Documents

2.1 Material test records
2.2 Quality Control inspection records (weld examinations, construction deviations, etc.)
2.3 Work progress records
2.4 Coating application
2.5 Actual plate thicknesses used
2.6 Fill material used (Mark I)
2.7 As-built drawings

Step 3. Review Preoperational Test Records

3.1 Overpressure test records
3.2 Leakage test records
3.3 Polar crane load test records (where the crane is supported by the vessel)

important design and construction details are the final as-built dimensions, exact location of welds, basic design assumptions (e.g., transients, fatigue model, and temperature), and fabrication verification records (e.g., heat treatments, material forming, and welding techniques).

Step 2 covers the review of materials and approach used in the construction of the metal containment. The materials include carbon steel for containment vessels, stainless steel for bellows, coating materials, fill materials (Mark I containments), and the materials used for the penetration piping that constitutes the containment pressure boundary. The materials information may be scattered among several sources. The material test records provide information on the mechanical properties and chemical composition of the construction materials. The material chemical analysis provides the content of sulfur, manganese, and phosphorus, as well as the presence of any inclusion. Details on the weld wires, flux types, as-deposited welds, weld techniques, and weld examinations can be reviewed. Data on actual plate thicknesses used to fabricate the containment vessel shell provide information on original margins for corrosion damage.

The construction history of the component, if available, may be reviewed. Incidents that occurred during the construction period may have an impact on the containment life and can be assessed. A review of special construction activities may be conducted to identify possible difficulties. Dispositions of significant process deviations (e.g., welding and heat treatment) and out-of-tolerance dimensions can be reviewed. The number and locations of repair welds may be investigated as potential future concerns. Review of detailed information on vendor specifications, materials performance ratings, and other pertinent data would help in evaluating design adequacy. Test results and supplier data applicable to the performance and design life of the containment may be reviewed, especially the test results not available when the design was originally performed. The quality control records identify flaws or indications that could act as stress raisers and potentially impact the fatigue damage assessment. The other construction documents may be reviewed for anomalies or unusual occurrences that indicate need for further investigation.

Step 3 covers a review of the preoperational test records to identify the number of load cycles the vessel was subjected to before operation. The records can also be reviewed to determine if any repairs were necessary as a result of test failures. These repaired locations could be weak points in the containment structure and may indicate a need for further investigation.

Steps 4 and 5 complete the information gathering (Table 9) by investigating the operative history of the reactor. Step 4 calls for a review of inservice maintenance and inspection. The leakage rate tests provide cyclic loads needed for fatigue assessment. Shell thickness readings are a direct input to the corrosion assessment. Proper documentation and maintenance of detailed records of all aspects of deteriorated coatings and corroded base metal, flaws discovered under coatings, and their disposition would help in estimating corrosion rate and in repair of affected base metal and coating. Enhanced plans for supplemental inspection may be considered and instituted as early in life as possible to provide the maximum amount of information for future aging assessment.

The results of inservice inspections can be used to identify trends in repairs, if any, to the pressure boundary. Increased operational cycles are reconciled with growth rate predictions. Review of the repairs of the containment vessels and their causes would help in estimating the probability of recurrence and acceptability of future repairs. Such repairs might have been necessary because of corrosion damage or because of redefinition of hydrodynamic loads acting on the Mark I suppression pools. The other records may be reviewed for needed repairs and other anomalies. Inservice inspection programs are currently documented through ASME Code and NRC reporting requirements. However, an integrated package of the details and many of the specifics not directly requested by NRC may be developed and

Table 9. Review of operating history records (Steps 4 and 5).

Step 4.	**Review Inspection, Test, and Maintenance Records**	
	4.1	Weld inspections
	4.2	Gasket/seal inspections
	4.3	Shell thickness readings
	4.4	Leakage tests (Types A and B)
	4.5	Hatch bolt tension/torque tests
	4.6	Repair records
	4.7	Coating maintenance records
Step 5.	**Review Operating Records**	
	5.1	Licensee event reports (for the specific plant and similar plants)
	5.2	Temperature readings
	5.3	Pressure readings
	5.4	Humidity readings
	5.5	Startup/shutdown records
	5.6	Safety relief valve actuation records
	5.7	Seismic/ground acceleration measurements

maintained; this package would include information on any additional inspections or enhancements performed that were not required by the ASME Code or NRC.

Step 5 reviews the operating records, which provide much information for the aging management. This involves the consolidation of details on all operating transients that have occurred over the life of the plant. This review is a crucial step in effective aging management of containment because some of the design assumptions might have been violated during actual plant operation. The transients that violate the plant technical specifications for leakage rate limits can be evaluated following the guidance given by the ASME Code, Section XI, for metal containment. The most important parameter is wall thinning (below the specified design limit) caused by corrosion damage, because reduced wall thickness relates directly to the integrity of the containment. Specific information on any corrosion damage and repairs may be reviewed and documented in a form useful for future aging assessment purposes. This step also involves consolidation of information on changes in normal, abnormal, and emergency operating procedures. Many of the readings are input to the cyclic load rate calculation. The environmental readings can be useful for determination of corrosion rates.

Step 6 (Table 10) provides guidelines for assessment of local and general corrosion to metal containment components: containment vessel, vent lines, and portions of lines that constitute the containment pressure boundary and penetrate the BWR pressure suppression pool. Corrosion rate data for susceptible sites may be estimated from the review of historical events and from the review of past inservice inspection, test, and maintenance records for the same plant or for the other plants with similar containment design.

Table 10. Corrosion damage assessment of LWR metal containments (Step 6).

Step 6. Assess Corrosion Damage at the End of the Next Operating Period

6.1 Review past inservice inspection, tests, and maintenance records to estimate corrosion damage at the end of the next operating period

6.1.1 Identify locations that have experienced significant corrosion damage and those that are susceptible to corrosion damage based on the review of operation and maintenance records for plants with similar design.

6.1.2 Estimate corrosion damage.

6.1.3 Estimate corrosion rates

6.1.4 Evaluate potential deterioration of surface coating

6.1.5 Evaluate potential deterioration of sealant at concrete-metal interface

6.2 Review any corrosion rate data from plants with similar containment design and environmental condition

6.3 Estimate corrosion damage (wall thinning) and minimum wall thickness of containment vessel wall at the vulnerable sites at the end of the next operating period

6.3.1 Vessel wall near concrete embedments

6.3.2 Vessel wall contacting sand pocket in Mark I containments

6.3.3 Vessel wall near penetrations

6.3.4 Submerged pressure suppression pool wall in BWR plants

6.3.5 Pressure suppression pool wall near waterline

6.3.6 Other plant specific sites

6.4 Estimate corrosion damage and minimum wall thickness of emergency core cooling system piping, penetrating into BWR Mark I pressure suppression pool, at the end of the next operating period

6.5 Estimate (based on past experience) extent of deterioration of surface coating and sealant at concrete-metal interface at the end of the next operating period.

6.6 Estimate any stress corrosion cracking damage to the bellows at the end of the next operating period.

Characterization of corrosion damage is important for two reasons: extensive corrosion damage, including pitting, (a) may adversely influence fatigue damage and (b) may indicate need for enhanced inservice inspection to detect corrosion damage and determine its extent. It is also important to estimate deterioration of surface coatings and sealants so that the potential of corrosion damage can be determined.

Step 7 (Table 11) outlines an assessment of fatigue and wear damage during the next operating period, which includes estimating fatigue crack initiation, growth of known flaws, and estimating total wear damage. If extensive corrosion damage such as rough surface and pits is present, fatigue life would be significantly reduced and needs to be accounted for in the assessment. If extensive surface damage (such as dents or flaws)

Table 11. Fatigue and wear damage assessment of LWR metal containments (Step 7).

Step 7. Assess Fatigue and Wear Damage at the End of the Next Operating Period

7.1 Identify size and locations of existing flaws from ISI records

7.2 Estimate the load cycles from the review of operation records

7.3 Perform stress analysis of containment vessel and bellows

- 7.3.1 Identify regions of highest stress
- 7.3.2 Estimate stress history at the flaws
- 7.3.3 Estimate flaw growth rates

7.4 Revise the stress analysis of vessel if significant corrosion is present

- 7.4.1 Identify sites susceptible to damage by pitting corrosion
- 7.4.2 Identify rough surface areas caused by general corrosion

7.5 Revise stress analysis of bellows if significant surface damage is present

7.6 Update ASME Section III cumulative fatigue usage factors if

- 7.6.1 Design basis is violated
- 7.6.2 Significant corrosion damage to containment vessel surface
- 7.6.3 Significant damage to bellows surface

7.7 Compute growth of known flaws in containment vessel during next operating period

7.8 Identify the sites that have experienced wear damage from review of inspection, test, and maintenance records

7.9 Estimate the wear damage at the sites identified in Step 7.

is present on the bellows surface, or if extensive repair is present, fatigue life of the bellows would be significantly reduced and needs to be accounted for in the assessment.

Step 8 (Table 12) provides guidelines for evaluation of containment integrity based on the assessment results from Steps 6 and 7. The evaluation includes comparing the estimated wall thickness with the minimum required wall thickness for the containment vessel and the penetration lines that constitute the containment pressure boundary. The estimated wall thickness needs to be greater than the minimum required wall thickness by an acceptable margin. The margin will be based on how reliably the corrosion damage can be detected, characterized, and mitigated. This margin includes accessibility for inspection of the damaged surface, the inservice inspection techniques used, and the accessibility for repair of a deteriorated coating. The fatigue usage factor for the bellows at the end of next operating period should be less than one by an acceptable margin. This margin should include the uncertainties in the available fatigue life data for damaged or repaired bellows.

Step 9 (Table 13) selects appropriate guidelines to mitigate aging during the next operating period. Identifying specific actions to be taken at a given plant will depend on the conditions at that plant. The following items provide examples of possible actions:

Table 12. Structural integrity evaluation for LWR metal containments (Step 8).

Step 8. Evaluate Containment Integrity at the End of the Next Operating Period

8.1 Compare the estimated minimum wall thickness of the containment vessel at the end of the next operating period (Substep 6.3) with the required minimum wall thickness (Substep 1.5)

8.1.1 Is the estimated minimum wall thickness greater than the required minimum wall thickness?

8.1.2 Determine whether the locations identified in Substeps 6.1.1 and 6.3 are accessible to inspection and recoating.

8.2 Compare the estimated minimum wall thickness at the end of the next operating period (Substep 6.4) with the required minimum wall thickness (Substep 1.5) of the lines penetrating BWR pressure suppression pool

8.2.1 Is the estimated minimum wall thickness greater than the required minimum wall thickness by an acceptable margin?

8.2.2 Are the sites identified in Substep 6.1.1 accessible to inspection?

8.3 Determine whether the estimated fatigue usage factor for the containment shell is less than one by an acceptable margin.

8.4 Determine whether the estimated sizes of flaws in the containment vessel wall are acceptable.

8.5 Is the fatigue usage factor for bellows less than one by an acceptable margin?

8.6 Determine whether the estimated stress corrosion cracking damage to the bellows is acceptable.

8.7 Determine whether the estimated wear damage is acceptable.

- Repair activities will reduce corrosion damage to the metal containment and fatigue damage to the bellows.
- Supplemental surveillance of the environment (that is, temperature, humidity, and chemistry of water in the BWR pressure suppression pool) will aid in a more accurate estimate of corrosion damage.
- Focused transducers may be used to size extensive corrosion damage, including deep pits. The electromagnetic acoustic transducer is a potential tool to detect extensive corrosion damage in vessel walls embedded in concrete.
- Enhanced underwater inspection techniques are available to detect and size corrosion damage in the BWR pressure suppression pool without draining it.
- Thickness measurements at a large number of points on the vessel wall may be necessary for obtaining statistically reliable data on wall thinning. Frequent measurements of thickness may be necessary for accurate determination of corrosion rates.
- Corrosion at the inaccessible sites on the containment vessel might be mitigated by cathodic protection. Effectiveness of cathodic protection need to be monitored.

Table 13. Identification of actions to mitigate aging in LWR metal containments (Step 9).[a]

Step 9. Select Mitigative Actions

9.1 Continued operation to the end of the next operating period if acceptable safety margins exist on containment vessel wall thickness, penetration lines wall thickness, and bellows fatigue life

9.2 Maintenance activities during next operating period

- 9.2.1 Repair metal shell where significant flaws are present or significant wall thinning has occurred.
- 9.2.2 Repair surface coating
- 9.2.3 Repair sealant at the metal-concrete interface
- 9.2.4 Repair bellows
- 9.2.5 Minimize coolant leakage
- 9.2.6 Keep drains unblocked

9.3 Supplemental surveillance of environment

9.4 Cathodic protection for surfaces that are inaccessible to coating

9.5 Enhanced inservice inspection

- 9.5.1 Improved detection and sizing capability
  - Magnetic particle testing
  - Eddy current testing
  - Ultrasonic inspection with focused transducer
  - Electromagnetic acoustic transducer
  - Underwater inspection techniques
- 9.5.2 Statistically reliable of wall thickness measurements
  - Selection of number of points where measurements are made

a. The mitigative actions discussed in the report are listed here. The selection of the specific actions will depend on the conditions at a given plant.

- Magnetic particle testing and eddy-current testing can be used to detect and size surface flaws on the vessel wall without removing surface coating.

The final Step 10 (Table 14) covers reevaluating the containment condition when a mitigative action is implemented in Step 9. This reevaluation will indicate working back through Steps 6 and 7 unless the option or action points to a significant design change resulting in a revised design basis (that is, new stress analysis), a materials change, a change in projected operating history, better inspection results, or supplemental surveillance information. These cases would involve updating Steps 4 and 5 also. The safety consequences of the various options and actions are plant-specific and need to be addressed in detail through the reevaluation process.

Table 14. Reassessment of the condition of LWR metal containment (Step 10).

Step 10.	**Reevaluate Containment Integrity at the End of the Next Operating Period if Significant Mitigative Actions are Identified in Step 9**	
	10.1	Update information in Steps 4 and 5
	10.2	Return to Steps 6 and 7 to estimate damage at the end of the next operating period
	10.3	Follow Step 8 to evaluate containment integrity
	10.4	Follow Step 9 to reevaluate the actions to be taken.

6. CONCLUSIONS

This report presents insights for aging management of BWR Mark I and PWR ice-condenser-type metal containments. The major aging related concerns are corrosion and fatigue damage. The report reviews the field experience and evaluates inspection and mitigation techniques for the aging damage. A generic approach is presented for effective and comprehensive aging management of metal containments to ensure their safe operation. The major conclusions related to corrosion damage are as follows:

- Corrosion damage to the embedded portion of a metal containment is of major concern. Another major concern is the corrosion of the inaccessible outside surface of the Mark I and Mark II drywells.

- The BWR Mark I emergency core cooling system piping that penetrates the torus below the waterline is susceptible to corrosion but is not inspected during inservice inspection.

- Maintenance of the surface coatings and the sealants at the metal-concrete interface is the best protection against corrosion.

- Electromagnetic acoustic transducers, if further developed, may be used for inspection of corrosion damage in the embedded portion of the BWR metal containments. This technique has been used in the laboratory to detect corrosion-like damage in steel plates.

- Evaluation of the half-cell potential technique could determine its usefulness for detecting corrosion damage to the embedded portion of the metal shell. This technique has the potential to become an effective detection technique because it has been already developed to detect corrosion of reinforcing bars in concrete bridge decks.

- Standard ultrasonic pulse-echo techniques do not reliably size containment corrosion damage if the outside surface has become very rough, which causes scattering of the ultrasonic waves. A focused transducer can be used up to a certain higher level of roughness before its performance also degrades.

- Underwater inspection and local repair of deteriorated coating and corroded base metal of several BWR suppression pools have been successfully performed.

- Cathodic protection has not worked in mitigating corrosion of the Oyster Creek drywell wall adjacent to the sand pocket region. However, long-term repair of the coating has been performed to effectively stop the corrosion. The repair included establishing permanent access to the drywell outside surface, removing the sand, and recoating the affected surface.

- The penetration line bellows are susceptible to transgranular stress corrosion cracking. Leaking bellows can be replaced with the new ones that are assembled in situ.

Key conclusions related to fatigue are as follows:

- Rough containment surfaces caused by extensive corrosion damage may result in significantly reduced fatigue life.

- Surface damage and flaws can reduce the fatigue life of the bellows.

- Magnetic particle, magnetographic, and eddy-current techniques can detect and size surface fatigue cracks in weld regions underneath 0.4-mm- (15-mils-) thick intact coating. Visual inspection can detect these flaws only if the flaws have caused coating deterioration.

7. REFERENCES

10 CFR 50, Appendix J,1989. "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors," *Code of Federal Regulations*, U.S. Office of the Federal Register.

10 CFR 50, Appendix J, 1986. "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors," *Code of Federal Regulations*, U.S. Office of Federal Register.

10 CFR 100 1991. "Reactor Site Criteria," *Code of Federal Regulations*, U.S. Office of the Federal Register.

ACI 1983. ACI Standard 318, "Building Code Requirements for Reinforced Concrete," *Manual of Concrete Practice*, American Concrete Institute, Detroit, pp. 318–28.

Alers, G. A., and L. R. Burns 1987. "EMAT Designs for Special Applications," *Materials Evaluation*, *45*, October, p. 1184.

ANSI 1967. ANSI N5.9, "Protective Coatings for the Nuclear Industry," American National Standards Institute, New York.

ANSI 1972a. ANSI N101.2, "Protective Coatings for Light Water Nuclear Reactor Containment Facilities," American National Standards Institute, New York.

ANSI 1972b. ANSI N101.4, "Quality Assurance for Protective Coatings Applied to Nuclear Facilities," American National Standards Institute, New York.

Arup, H. 1983. "The Mechanisms of the Protection of Steel by Concrete," *Corrosion of Reinforcement in Concrete Construction*, A. P. Crane (editor), Society of Chemical Industry/Ellis Horwood Limited, Chichester, United Kingdom, pp. 151–157.

ASM 1978. *Metals Handbook, Properties and Selection: Irons and Steels*, Volume 1, ninth edition, American Society for Metals, Philadelphia, pp. 717–723.

ASME 1992a. *ASME Boiler and Pressure Vessel Code*, Section III, Division 1, "Rules for Construction of Nuclear Power Plant Components," American Society of Mechanical Engineers, New York.

ASME 1992b. *ASME Boiler and Pressure Vessel Code*, Section XI, "Rules for In-Service Inspection of Nuclear Power Plant Components," American Society of Mechanical Engineers, New York.

ASME 1992c. *ASME Boiler and Pressure Vessel Code*, Section II, "Material Specifications," American Society of Mechanical Engineers, New York.

ASME 1989. "Case N-315: Repair of Bellows Section III, Division 1," *Cases of ASME Boiler and Pressure Vessel Code*, Section III, Division 1, American Society of Mechanical Engineers, New York.

ASME 1965. *ASME Boiler and Pressure Vessel Code*, Section VIII, American Society of Mechanical Engineers, New York.

ASTM 1991. "Standard Test Method for Half-Cell Potentials of uncoated Reinforcing Steel in Concrete," *Annual Book of ASTM Standards*, ASTM C876-91, Vol. 03.02, American Society for Testing and Materials, Philadelphia.

ASTM 1990. "Standard Practice for Use of the Terms Precision and Bias in ASTM Test Methods," *Annual Book of ASTM Standards*, ASTM E 177-90a, American Society for Testing and Materials, Philadelphia.

ASTM 1972. "Localized Corrosion—Cause of Metal Failure," STP 516, American Society for Testing and Materials, Philadelphia.

Beissner, R. E. and A. S. Birring 1988. *Nondestructive Evaluation Methods for Characterization of Corrosion*, NTIAC-88-1, Southwest Research Institute, San Antonio.

Birring, A. S., A. Smith, and R. L. Brackett 1985. "Development of a Methodology for Underwater Inspection of Steel Structure," *Proceedings of ASME Fourth International Offshore Mechanics and Arctic Engineering Symposium*, Vol. II, pp. 916–420.

Burgreen, D. 1975. *Design Methods for Power Plant Structures*, first edition, C. P. Press, New York.

Burkhardt, G. L. and J. L. Fisher 1990. *Development of Magnetographic Technique for Inspecting Containment Welds Through Coatings*, EPRI NP-6609, Electric Power Research Institute, Palo Alto, pp. 28-1.

Canadian Standards 1987. "Periodic Inspection of CANDU Nuclear Power Plant Containment Components," CSA N285.5, Canadian Standards Association, Rexdale, Ontario.

Catawba 1990. *Abnormal Degradation of Steel Containment Vessels due to Corrosion by Standing Water in the Annulus Area*, Docket 50-413, January 3, Catawba Nuclear Station Unit 1.

Commonwealth Edison 1986. "Drywell Fire—Correction to Fire Evaluation Report," Docket 50-249, Dresden Station Unit 3.

Cook, J. F., J. A. Holm, and G. D. Lassahn 1988. *Nondestructive Examination of Welds Through Painted Surfaces*, EPRI NP-5834, Electronic Power Research Institute, Palo Alto.

Crooker, T. W., and B. N. Leis (eds.) 1981. *Corrosion-Fatigue: Mechanics, Metallurgy, Electrochemistry, and Engineering*, ASTM STP 801, American Society for Testing and Materials, Philadelphia.

Davis, J. A. and J. D. Kellner 1989. "Electrochemical Principles Applied to Operating Pipelines," CORROSION/89, paper 412, April 17–21, 1989, New Orleans.

Doughty, D. 1981. "Cathodic Protection of Water Storage Tanks," presented at *National Association of Corrosion Engineers, Western Regional Conference, November 1981.*

Dresden 1988. Licensee Event Report 88-022-00, Docket 50-237, Dresden Nuclear Power Station "Heat Damage to Upper Elevation Drywell Components due to Closed Ventilation Hatches," December 13.

Duane Arnold Energy Center 1990. "Control Rod Drive Insert/Withdraw Line Leakage and Indications at One Bundle Due to High Cycle Fatigue," Licensee Event Report, Docket 50-331, August 23.

EJMA 1980. *Standards of the Expansion Joint Manufacturers Association, Inc.*, fifth edition, Expansion Joint Manufacturers Association, White Plains, New York.

EPRI 1990. *Detection and Control of Microbiologically Influenced Corrosion*, EPRI NP-6815s-D, Electric Power Research Institute, Palo Alto.

EPRI 1986. "Notes of EPRI Coatings Research Workshop," *Proceedings of Coatings Research Workshop, Charlotte, North Carolina, March 25–26*, Electric Power Research Institute, Palo Alto.

Federal Register 1992. "Augmented Inservice Inspection Requirements for Mark I and Mark II Steel Containments, Refueling Cavities, and Associated Drainage Systems," 57 FR 225, Friday, November 20, pp. 54860–54864.

Fontana, M. 1986. *Corrosion Engineering*, 3rd edition, McGraw Hill, New York, p. 39.

General Public Utilities 1987. "Oyster Creek Drywell Corrosion," General Public Utilities Nuclear Presentation to NRC, November 13.

Gordon, B. M. 1988. "Corrosion Issues in the BWR and Their Mitigation for Plant Life Extension," *Proceedings of the ANS Topical Meeting on Nuclear Power Plant Life Extension, Snowbird, Utah*, American Nuclear Society, pp. 180–187.

Gordon, B. M. and G. M. Gordon 1987. "Corrosion Evaluation of the Oyster Creek Drywell," F&PMT Transmittal, No. 87-178-003 Rev. 1, General Electric Corporation, March 6.

Heidersbach, R. H. 1987. "Cathodic Protection," *Materials Handbook, Ninth Edition, Volume 13, Corrosion*, pp. 466–477.

Hoepner, D. W. 1971. "Corrosion-Fatigue Considerations in Materials Selections and Engineering Design," *Corrosion-Fatigue: Chemistry, Mechanics and Microstructure Conference, Storrs, Connecticut, June 14–18*, pp. 3–6.

Koegh, P. 1984. "The PWR Integrated Leak Rate Test, A Review of Experiences and Results," *Proceedings of the Second Workshop on Containment Integrity*, NUREG/CP-0056, pp. 15–30.

Krautkramer, J., and H. Krautkramer 1990, *Ultrasonic Testing of Materials*, 4th edition, Springer-Verlag, New York, p. 145.

Kuniya, J., M. Fukai, and I. Masaoka 1988. "Hydrogen Induced Cracking in Cold Worked, Creviced Type 304 Austenitic Stainless Steel," *Third International Symposium on Environmental Degradation of Materials in Nuclear Power Systems—Water Reactors, Traverse City, Michigan, August 30–September 3, 1987*, The Metallurgical Society, Warrendole, Pennsylvania, pp. 383–388.

Langer, B. F. 1962. "Design of Pressure Vessels for Low-Cycle Fatigue," *Journal of Basic Engineering*, September, pp. 389–402.

Lipford, B. L. and J. C. Flynn, 1993. "Drywell Corrosion Stopped at Oyster Creek," *Power Engineering*, November, pp. 47–50.

Logan, H. L. 1966. *The Stress Corrosion of Metals*, John Wiley & Sons, New York.

Malhotra, V. M. and N. J. Carino (eds.) 1991, *CRC Handbook on Nondestructive Testing of Concrete*, CRC Press, Boston, p. 222.

Mathur, C. F. 1987. *Microbiological Analysis of Oyster Creek Corrosion Samples*, York College of Pennsylvania for GPU Nuclear Corporation, February 2.

Maxfield, B. M. and A. Kuramoto 1988. *The Feasibility of Using Electromagnetic Acoustic Transducers to Detect Corrosion in Mark I containment Vessels*, EPRI NP-6090, Electric Power Research Institute, Palo Alto.

McGuire Nuclear Station 1990. Unit 1, *Licensee Event Report*, Docket 50-369, May 30.

McGuire Nuclear Station 1989. Units 1 and 2, *Licensee Event Report* 369/89-20, Docket No. 50-369, September 25.

Merrick, E. A., et al. 1984. "Replacement Options for Damaged Bellows," *Metallic Bellows and Expansion Joints: Part II*, ASME, PVP-Vol. 83, pp. 85–133.

Miller, R. L. 1977. *Results of Short-Term Corrosion Evaluation Tests at Raft River*. DOE Report, TREE–1176, October.

Miller, I. and J. E. Freund 1965. *Probability and Statistics for Engineers*, 2nd Edition,:Prentice-Hall, Inc., New Jersey.

Multiple Dynamics (Multiple Dynamics Corporation preparer) 1987. *Plant Layup and Equipment Preservation Sourcebook*, EPRI NP-5106, Electric Power Research Institute, Palo Alto, pp. 2–25.

Munger, C. G. 1984. *Corrosion Protection by Protective Coatings*, National Association of Corrosion Engineers, Houston.

NACE 1984. *Corrosion Basics—An Introduction*, National Association of Corrosion Engineers Houston.

Naus, D. J. 1986. *Concrete Component Aging and its Significance Relative to Life Extension of Nuclear Power Plants*, NUREG/CR-4652, ORNL/TM-10059.

NSP (Northern States Power Company) 1988. *Monticello Nuclear Generating Plant, Updated Safety Analysis Report*, Revision 6.

NSP (Northern States Power Company) 1989. *Monticello BWR Life Extension Study*: Phase 2, EPRI NP-6541-M, Electric Power Research Institute, Palo Alto, October 1989.

Nucleonics Week 1988. *29*, 43, October 27, p. 1.

NUTECH 1982. *Enrico Fermi Atomic Power Plant Unit 2, Plant Unique Analysis Report*, Volume 3: Vent System Analysis, DET-04-028-3, Revision 0, prepared for Detroit Edison Company, NUTECH Engineers, Inc., San Jose, California.

NUTECH 1982b. *Monticello Nuclear Generating Plant, Plant Unique Analysis Report*, Volume 3: Vent System Analysis, NSP-74-103, Revision 1, 30.2874.0103, prepared for Northern States Power Company, NUTECH Engineers, Inc., San Jose, California.

Oyster Creek Nuclear Generating Station 1989. *Drywell Cathodic Protection, Operating, and Maintenance Manual*, revised, Oyster Creek Nuclear Generating Station, New Jersey.

Oyster Creek Nuclear Generating Station 1987. "November 13, 1987, Meeting with GPU Nuclear Corporation (GPUN) to Discuss Matters Related to Oyster Creek Drywell Corrosion," Docket 50-219, November 30.

Pope, D. H. 1986. *A Study of Microbiologically Influenced Corrosion in Nuclear Power Plants and a Practical Guide for Countermeasures*, EPRI NP-4582, Electric Power Research Institute, Palo Alto, pp.1-2 through 1-3.

Schramm, R. E., and A. Van Clark, Jr. 1988. *Ultrasonic Railroad Wheel Inspection Using EMATs*, NISTIR 88-3906, Report No. 18, National Institute of Standards and Technology, Gaithersburg, Maryland.

Sea Test Service 1988. *Reliability of Magnetic Particle Inspection Performed Through Coatings*, EPRI NP-5951, Electric Power Research Institute, Palo Alto.

Shah, V. N. and P. E. MacDonald, (eds.) 1993. *Aging and Life Extension of Major Light Water Reactor Components*, Elsevier Science Publishers, Amsterdam, Netherlands, pp. 11–22 and 559–568.

Shigley, J. E. 1983. *Mechanical Engineering Design*, 2nd edition, McGraw-Hill, New York.

SSPC (Steel Structures Painting Council) 1985. *Systems and Specifications: Steel Structures Painting Manual*, Volume 2, fourth edition, Steel Structure Painting Council, New York.

Stoller (S. M. Stoller Corporation) 1987. "Fire In Annular Space—Hot Slag Ignited Polyurethane Foam—Extent of Damage, Corrective Measures Not Determined," *Nuclear Power Experience*, BWR-2, XIV.B.738, April.

Stols, R. (Nuclear Licensing Administrator) 1991. Letter (with attachments) to Thomas E. Murley, Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission, "Quad Cities Nuclear Power Station Units 1 Primary Containment Bellows Assembly," Docket 50–254, April 19.

Stuart, C. O. 1993. "Underwater Coating Repair Cuts Nuclear Maintenance Costs," *Power Engineering*, July, pp. 31–34.

Szklarska-Smialowska, Z. 1986. *Pitting Corrosion of Metals*, National Association of Corrosion Engineers, Houston.

Uhlig, H. H., and R. W. Revie 1985. *Corrosion and Corrosion Control*, third edition, John Wiley & Sons, New York.

Uhlig, H. H. 1948. *The Corrosion Handbook*, John Wiley & Sons, New York.

USNRC 1991a "Degradation of Steel Containments," USNRC Information Notice 86-99, Supplement 1, February 14.

USNRC 1991b. Meeting summary, Docket No. 50-219, "Summary of July 24, 1991 Meeting with GPU Nuclear Corporation (GPUN) to Discuss Matters related to Oyster Creek Drywell Corrosion and Containment Reliability," August 2, 1991.

USNRC 1990. "Degraded Coatings and Corrosion of Steel Containment Vessel," USRC Information Notice 89-79, Supplement 1, June 29.

USNRC 1989a. "Torus Shells with Corrosion and Degraded Coatings in BWR Containments," USNRC Information Notice 88-82, May 2, 1989.

USNRC 1989b. "Degraded Coatings and Corrosion of Steel Containment Vessels," USNRC Information Notice 89-79, December 1.

USNRC 1988a. "Torus Shells with Corrosion and Degraded Coatings in BWR Containments," USNRC Information Notice 88-82, October 14.

USNRC 1988b. Inspection Reports 50-220/88-09 and 50-410/88-09, Nine Mile Point Nuclear Station, Units 1 and 2, performed by the U.S. Nuclear Regulatory Commission, May.

USNRC (1987a). *Licensed Operating Reactors, Status Summary Report, Data as of 12-31-86*, NUREG-0200, Vol. 11, No. 1.

USNRC 1987b. "Request for Additional Information—Assessment of License Measures to Mitigate and/or Identify Potential Degradation of Mark I Drywells," Generic Letter 87-05, May, U.S. Nuclear Regulatory Commission.

USNRC 1986a. "Degradation of Steel Containments," USNRC Information Notice 86-99, December 8.

USNRC 1986b. Office of Nuclear Regulatory Research, *Containment System Leakage Testing*, Task MS 021-5.

USNRC 1986c. "Fire in Compressible Material at Dresden Unit 3," USNRC Information Notice 86-35, May 15.

USNRC 1980. *Safety Evaluation Report, Mark I Containment Long-Term Program*, NUREG-0661.

USNRC 1981. *Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants—LWR Edition*, NUREG–0800.

USNRC 1973a. "Quality Assurance Requirements for Protective Coatings Applied to Water Cooled Nuclear Power Plants," Regulatory Guide 1.54, U.S. Nuclear Regulatory Commission.

USNRC 1973b. "Design Limits and Loading Combinations for Metal Primary Reactor Containment System Components," Regulatory Guide 1.57, U.S. Nuclear Regulatory Commission.

Wilson, R. F. 1987. Letter from R. F. Wilson, GPU Nuclear Corporation, to the USNRC, "Oyster Creek Drywell Containment," 5000-87-1421, November 20.

Wolfram, J. H., R. D. Rogers, and B. S. Buescher 1988. "A Summary of Microbial Influenced Corrosion in Nuclear Power Plants," *1988 ASME Pressure Vessel and Piping Conference, Pittsburgh, Pennsylvania, June 19–23.*

Wranglen, G. (1985). *An Introduction to Corrosion and Protection of Metals*, Chapman and Hall, New York.

NRC FORM 335 (2-89) NRCM 1102, 3201, 3202

U.S. NUCLEAR REGULATORY COMMISSION

BIBLIOGRAPHIC DATA SHEET

(See instructions on the reverse)

1. REPORT NUMBER (Assigned by NRC. Add Vol., Supp., Rev., and Addendum Numbers, if any.)

NUREG/CR-5314
EGG-2562
Vol. 5

2. TITLE AND SUBTITLE

Insights for Aging Management of Major LWR Components
Metal Containments

3. DATE REPORT PUBLISHED

MONTH	YEAR
March	1994

4. FIN OR GRANT NUMBER

A6389

5. AUTHOR(S)

V. N. Shah, S. K. Smith[a], U. P. Sinha

6. TYPE OF REPORT

Technical

7. PERIOD COVERED (Inclusive Dates)

8. PERFORMING ORGANIZATION – NAME AND ADDRESS (If NRC, provide Division, Office or Region, U.S. Nuclear Regulatory Commission, and mailing address; if contractor, provide name and mailing address.)

Idaho National Engineering Laboratory
Idaho Falls, ID 83415

a. Subcontract: Ogden Environmental and Energy Services
(formerly Multiple Dynamics Corporation)
29200 Southfield, Suite 103
Southfield, MI 48076

9. SPONSORING ORGANIZATION – NAME AND ADDRESS (If NRC, type "Same as above"; if contractor, provide NRC Division, Office or Region, U.S. Nuclear Regulatory Commission, and mailing address.)

Division of Engineering
Office of Nuclear Regulatory Research
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

10. SUPPLEMENTARY NOTES

11. ABSTRACT (200 words or less)

This report evaluates the available technical information and field experience related to management of aging damage to light water reactor metal containments. A generic aging management approach is suggested for the effective and comprehensive aging management of metal containments to ensure their safe operation. The major concern is corrosion of the embedded portion of the containment vessel and detection of this damage. The electromagnetic acoustic transducer and half-cell potential measurement are potential techniques to detect corrosion damage in the embedded portion of the containment vessel. Other corrosion-related concerns include inspection of corrosion damage on the inaccessible side of BWR Mark I and II containment vessels and corrosion of the BWR Mark I torus and emergency core cooling system piping that penetrates the torus, and transgranular stress corrosion cracking of the penetration bellows. Fatigue-related concerns include reduction in the fatigue life (a) of a vessel caused by roughness of the corroded vessel surface and (b) of bellows because of any physical damage. Maintenance of surface coatings and sealant at the metal-concrete interface is the best protection against corrosion of the vessel.

12. KEY WORDS/DESCRIPTORS (List words or phrases that will assist researchers in locating the report.)

aging, aging management, degradation sites and stressors, suppression pool, intergranular stress corrosion cracking, pitting, fatigue, ultrasonic, coating, inservice inspection, leak test, pressure test

13. AVAILABILITY STATEMENT

unlimited

14. SECURITY CLASSIFICATION

(This Page)
unclassified

(This Report)
unclassified

15. NUMBER OF PAGES

16. PRICE

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

OFFICIAL BUSINESS
PENALTY FOR PRIVATE USE, $300

SPECIAL FOURTH-CLASS RATE
POSTAGE AND FEES PAID
USNRC
PERMIT NO. G-67

120555139531 1 1AN1RM1R51R9
US NRC-OADM
DIV FOIA & PUBLICATIONS SVCS
TPS-PDR-NUREG
P-211
WASHINGTON DC 20555