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UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION
BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

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In the matter of
Entergy Corporation
Pilgrim Nuclear Power Station
License Renewal Application

Docket No. 50-293

OFFICE OF SECRETARY
RULEMAKINGS AND
ADJUDICATIONS STAFF

PILGRIM WATCH PRESENTS STATEMENTS OF POSITION, DIRECT TESTIMONY AND EXHIBITS UNDER 10 CFR 2.1207

[Modified Per Request ASLB Order of February 21, 2008, section c, page 2]

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Pursuant to the ASLB Order of February 21, 2008 [section c, page 2] calling for Pilgrim Watch "...to provide specific citations to the testimony of its (or any other party's) experts and to exhibits, as relevant, for each of the statements made in its Statement of Position of January 29, 2008..." Pilgrim Watch resubmits its Statement of Position of January 29, 2008. Citations are underlined for the ASLB's convenience.

Pursuant to § 2.1207(a) Process and Schedule for Submissions and Presentations in an Oral Hearing, and the Atomic Safety and Licensing Board's (ASLB) December 19, 2007 Order revising the schedule for submissions[1], Pilgrim Watch presents our initial written statements of position and written testimony with supporting affidavits on the admitted contention.

Pilgrim Watch contends that the Aging Management Program for buried pipes and tanks fails to provide reasonable assurance that they will perform their safety function; and therefore the aging management program must be supplemented with a more robust inspection system and effective monitoring well program or the Application denied.

[1] Order (Revising Schedule for Evidentiary Hearing and Responding to Pilgrim Watch's December 14 and 15 Motions),(December 19, 2007) (Scheduling Order).

In an operating license proceeding, the licensee generally bears the ultimate burden of proof. *Metropolitan Edison Co. (Three Mile Island Nuclear Station, Unit 1)*, ASLB-697, 16 NRC 1265, 1271 (1982), citing 10 CFR 2.325. A renewed license for Pilgrim Station may only be issued if Entergy demonstrates that its aging management program for buried pipes and tanks provides reasonable assurance that the Current Licensing Basis ("CLB") will be maintained, 10 CFR 54.29 (a).[2] Reasonable assurance has been defined in federal courts as requiring the demonstration of 95% certainty.[3] The 95% Confidence Standard has been accepted and applied by the NRC as the measure of "Reasonable Assurance." [4]

The Commission confirmed in *Florida Power & Light Co. (Turkey Point Nuclear Generating Plant, Units 3 and 4)*, 54 NRC 3, 10 (2001) that because corrosion and other effects become more severe over the extended license renewal period, an applicant for license renewal must document that its programs are adequate to manage the effects of aging, including sufficient inspection and testing. Pilgrim Watch contends that the AMP is not adequate by itself and the Applicant has not demonstrated otherwise, let alone at the required 95% confidence level.

Pilgrim Watch will demonstrate that leak detection via a more robust and comprehensive pipe/tank inspection protocol to *prevent* leaks and a robust monitoring well system to *detect* leaks is a necessary part, or supplement to, Pilgrim's Aging Management Program in order to actually provide reasonable assurance that the relevant components will perform their intended functions during the license renewal period. Our experts describe (1) the primary requirements of a comprehensive inspection program [Exhibit 1,

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[2] 10 CFR 54.29 (a) Actions have been identified and have been or will be taken with respect to the matters identified in Paragraphs (a)(1) and (a)(2) of this section, such that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the CLB, and that any changes made to the plant's CLB in order to comply with this paragraph are in accord with the Act and the Commission's regulations

[3] U.S. Supreme Court [*Daubert v. Merrell Dow Pharms.* 509 U.S. 579, 592 (1993); Texas Supreme Court in *Merrell Dow Pharms., Inc., v. Havner*, 953 S.W.2d 706, 723-24 (Tex. Sup. Ct 1997; federal government scientists as the minimum that is acceptable to prove each scientific fact in a case. [*See, e.g., U.S. v. Chase*, 2005 WL 757259, (Jan. 10, 2005 D.C. Super); *See generally,* Frederika A. Kaestle, et al., *Database Limitations on the Evidentiary Value of Forensic Mitochondrial DNA Evidence*, 43 Am. Crim. L. Rev. 53 (2006)

[4] Transcript of ACRS Meeting (Sept. 6, 2001), Citizens' Ex. 62 at 3.

Gundersen Decl]; and (2) the key requirements for a monitoring well system to be effective [Exhibit 2, Ahlfeld Decl].

I. BACKGROUND

On May 25, 2006 Pilgrim Watch filed its petition to intervene seeking the admission of five contentions.[5] On October 16, 2006, the Licensing Board admitted two of Pilgrim Watch's contentions, including an amended version of Contention I, into the PNPS license renewal proceeding. [6] Pilgrim Watch's Contention 1, as amended by the Board, stated,

> The Aging Management program proposed in the Pilgrim Application for license renewal is inadequate with regard to aging management of buried pipes and tanks that contain radioactively contaminated water, because it does not provide for monitoring wells that would detect leakage.

On June 8, 2007 Entergy filed a Motion for Summary Disposition of Pilgrim Watch Contention 1. On October 17, 2007, the Licensing Board issued a Memorandum and Order.[7] The Licensing Board denied Entergy's motion for summary disposition finding that there was a genuine dispute and "clarified" what remained at issue, saying [at 18] that,

> ...the only issue remaining before this licensing Board regarding Contention 1 is whether or not monitoring wells are necessary to assure that the buried pipes and tanks at issue will continue to perform their safety function during the license renewal period -, or, put another way, whether Pilgrim's existing AMPs have elements that provide appropriate assurance as required under relevant NRC

[5] Request for Hearing and Petition to Intervene by Pilgrim Watch (May 25, 2006) ("Pilgrim Watch Pet.").
[6] Memorandum and Order (Ruling on Standing and Contentions of Petitioners Massachusetts Attorney General and Pilgrim Watch), LBP-06-23, 64 N.R.C. 257 (2006).
[7] Memorandum and Order (Ruling on Entergy's Motion for Summary Disposition of Pilgrim Watch Contention I, Regarding Adequacy of Aging Management Program for Buried Pies and Tanks and Potential Need for Monitoring Wells to Supplement the Program), ASLBP No. 06-848-02-LR, October 17, 2007.

regulations that the buried pipes and tanks will not develop leaks so great as to cause those pipes and tanks to be unable to perform their intended safety functions.

A. Confidence Level Required To Establish "Assurance"

10 CFR 54.21(a)(3)[8] requires that a license renewal application demonstrate, for each component within scope of the license renewal rules, that the effects of aging are being adequately managed so that the intended functions will be maintained consistent with the current licensing basis (CLB) over the period of extended operations. The standard for demonstration is "reasonable assurance."

The Licensing Board in their Memorandum and Order, October 17, 2007 said [at 18] that,

> The only issue remaining is ...whether Pilgrim's existing AMPs have elements that provide *appropriate assurance* as required under relevant NRC regulations that the buried pipes and tanks will not develop leaks so great as to cause those pipes and tanks to be unable to perform their intended *safety functions*.

Therefore, it is important to clarify what "reasonable assurance" (or as the ASLB described as "appropriate assurance") and "safety functions" actually mean; and then determine whether the Applicant has provided the required assurance.

Entergy essentially avoids providing a definition. In the Initial Statement[9], at 3, they choose to define "reasonable assurance" by referring to the Nuclear Power Plant License Renewal Final Rule, 60 Fed Reg. 22,461, 22,479 (1995) ("... [the license renewal] process is not intended to demonstrate absolute assurance that structures or components will not fail, but rather that there is a reasonable assurance that they will perform such that the intended functions...are maintained consistent with the CLB").

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[8] 10 CFR 54.21, Exhibit 3

[9] Entergy's Initial Statement of Position on Pilgrim Watch Contention 1, January 8, 2008 [hereinafter "Initial Statement]

How does Entergy define "not intended to demonstrate absolute assurance?" We know that absolute certainty is 100%. Does that make 5%, 25%, 50.1% or some other number acceptable? We know that it is necessary to provide clarity to avoid platitudes.

Courts Generally Require Individual Scientific Facts to be established to 95% Confidence – Entergy has not provided this level of confidence

In the context of determining which scientific evidence to admit into court, the judiciary, supported by federal government scientists, has established 95% confidence as the minimum that is acceptable to prove each scientific fact in a case. For example, the Texas Supreme Court found that 95% confidence is normally the minimum necessary to scientifically prove causation:

> The generally accepted significance level or confidence level in epidemiological studies is 95%, meaning that if the study were repeated numerous times, the confidence interval would indicate the range of relative risk values that would result 95% of the time. *See DeLuca v. Merrell Dow Pharms., Inc.*, 791 F. Supp. 1042, 1046 (D.N.J.1992), *aff'd*, 6 F.3d 778 (3d Cir.1993); Linda A. Bailey et al., *Reference Guide on Epidemiology, in* FEDERAL JUDICIAL CENTER, REFERENCE MANUAL ON SCIENTIFIC EVIDENCE at 153 (1994) [other citations omitted].

Merrell Dow Pharms., Inc., v. Havner, 953 S.W.2d 706, 723-24 (Tex. Sup. Ct 1997). The Texas Supreme Court in *Havner* also approved of the Texas courts' use of the 95% confidence level as the minimum level acceptable for scientific testimony:

> We think it unwise to depart from the methodology that is at present generally accepted among epidemiologists [citations omitted]. Accordingly, we should not widen the boundaries at which courts will acknowledge a statistically significant association beyond the 95% level to 90% or lower values [*Id.* at 724.]

Federal governmental scientists have also urged courts to adopt the use of 95% confidence intervals. *See, e.g., U.S. v. Chase*, 2005 WL 757259, (Jan. 10, 2005 D.C. Super). The court found credible "the testimony of the government's experts that the use of 95% confidence interval is a standard approach that is generally accepted in the scientific community." [*Id. at 6*; *See generally*, Frederika A. Kaestle, et al., *Database Limitations on the Evidentiary Value of Forensic Mitochondrial DNA Evidence*, 43 Am. Crim. L. Rev. 53 (2006)].

The Supreme Court in *Daubert v. Merrell Dow Pharmaceuticals* set the relationship between the admissibility of scientific evidence and the standard of proof required by the jury in civil proceedings *Daubert v. Merrell Dow Pharms.* 509 U.S. 579, 592 (1993). "Since Daubert seeks to exclude scientifically unreliable evidence, the scientific evidence must conform to the accepted convention of 95 percent probability to be admissible."

Here [Docket # 50-293], Entergy says that they have offered proof to show that the Aging Management Program is sufficient to ensure corrosion is managed in order to maintain the intended functions of the buried components. For example, in Entergy's Initial Statement of Position on Pilgrim Watch Contention 1, January 8, 2008 concluded [at 15] that,

> The AMPs for the buried components within the scope ...provide reasonable assurance that such components will perform their intended functions during the period of extended operation.

However Entergy does not provide any hard data or quantification to establish the 95% confidence threshold that is mandated by *Daubert* and is essential to ensuring that the data meets the clear preponderance standard the Board must apply here.

Risk Must Be Taken Into Account Because We Are Talking About Providing Assurance That Key Safety Components In A Nuclear Reactor Perform as Intended.

Plaintiffs seeking redress through monetary damages must establish their scientific theories with greater than 95% confidence before courts will admit those theories into evidence, because that is the liability standard generally required by the scientific community. As a corollary, the cases show that a scientific conclusion that is less than 95% certain is generally not fit to present to a jury. Because a scientific assessment with less than 95% certainty would not be legally sufficient to allow a *single injured plaintiff* who has already suffered an injury to seek redress in federal court, *it cannot be sufficient to avert nuclear* accidents *that could harm thousands of people and cause devastating contamination.* It is essential, therefore, that the ASLB require Entergy to prove that the Aging Management Program is "sufficient to ensure" that the buried pipes and tanks perform their intended functions to at least the 95% confidence required by federal courts and scientists. Because Entergy has not, and can not make the required showing, the NRC should deny the license.

And finally, to meet the "not inimical" to public safety mandate of the AEA, the NRC must only permit licensees to use reliable scientific evidence. Federal courts have already determined that scientific proof to less than 95% confidence is unreliable. A licensee must be able to show, therefore, with 95% confidence that it has margins over minimum requirements to establish reasonable assurance of compliance with the CLB. Again, because Entergy cannot make this showing, it cannot meet the statutory mandate of the AEA and the license should be denied.

The 95% Confidence Standard Has Been Accepted and Applied by the NRC as the Measure of "Reasonable Assurance"

"Reasonable assurance" can not be a meaningless platitude. Its definition has proved somewhat elusive; although at a 2001 meeting of the Advisory Committee on Reactor Safeguards (ACRS) the NRC Staff said that the "95% confidence does define reasonable assurance" [Transcript of ACRS Meeting (Sept. 6, 2001), Exhibit 4.] The ACRS asked the NRC Staff whether a model that predicted results with 95% confidence would

Pilgrim Watch notes that in the License Application of Oyster Creek regarding the ongoing corrosion of the dry well, both the reactor operator and the NRC Staff have regarded the 95% confidence level as the equivalent of reasonable assurance. The NRC Staff stated in 1991 that the reactor operator "has repeatedly claimed" that the condition of the Oyster Creek drywell "is fully understood with a 95% confidence level. Therefore the same standard must necessarily apply at Pilgrim Station for the buried pipes/tanks Aging Management Program.

Summary

In order to answer the question posed by the Licensing Board [at 18],

> The only issue remaining is ...whether Pilgrim's existing AMPs have elements that provide *appropriate assurance* as required under relevant NRC regulations that the buried pipes and tanks will not develop leaks so great as to cause those pipes and tanks to be unable to perform their intended *safety functions*.

The following issues must be addressed: (1) Did the Applicant meet the 95% confidence level in showing that the pipes under consideration would not develop leaks so great to cause those components to be unable to perform their intended safety functions; and perhaps not exactly at 95% but certainly well beyond a flip of the coin?[10] (2) What evidence (facts) did the Applicant provide; and did that evidence meet the 95% confidence level or whatever very high standard chosen to meet the "reasonable assurance requirement?

At the same time risk must be taken into consideration because we are talking about key safety functions in a nuclear reactor. Monitoring is used to balance certainty and risk. The progression of the aging effect is monitored and action is taken *before* the risk gets too great - before failure. AMPs must be proactive not reactive for there to be reasonable

[10] A. Gundersen Decl. at 10 states that, "I conclude that the applicant has not shown with 95% certainty that the proposed AMP will in fact be able to detect any defects in the underground pipes and tanks."

provide reasonable assurance. *Id.* In response, the NRC Staff confirmed that the Staff is in favor of more quantification of the term reasonable assurance and that 95% confidence in a modeled result is adequate to provide reasonable assurance:

> MR. CARUSO: Dr. Wallis, this is Ralph Caruso from the staff. . . I think that your question is what does reasonable assurance mean, and I think that the ACRS has had this discussion with the Commission in the past about what reasonable assurance means, and I don't think there has ever been any definition that everyone has agreed to. This is an eternal question that we try to deal with, and it comes out of judgment to a large extent at this point. When we can quantify it, for example, and say setting safety limit MICPRs, we try to do that. We are trying to do our regulation in a more risk-informed manner, and that is another attempt to do it in a more quantifiable way. But right now these are the words that the law requires us to use to make a finding. So those are, unfortunately, the words that we use and they are not well defined.
>
> DR. WALLIS: But the law requires you to make a finding with 95 percent confidence.
>
> MR. CARUSO: No, the law requires us to make a reasonable assurance finding.
>
> DR. WALLIS: If your criterion is 95 percent confidence, then the fact that they have evaluated these uncertainties enables you to make that assessment.
>
> MR. CARUSO*: We could say that a 95 percent confidence does define reasonable assurance* . . . [Emphasis added]

assurance. So-called "engineering judgment" does not provide reasonable assurance; unless that judgment is backed up with verification at the required degree of certainty.

B. Buried Pipes within Scope

Pilgrim Watch's Motion for Clarification, December 21, 2007 argued that the buried components now under consideration include the buried pipes and tanks in the following systems: (1) standby gas treatment; (2) salt service water; (3) condensate storage; (4) fuel oil tanks and associated pipes; (5) station blackout diesel generator; (6) fire protection.

The ASLB denied the motion, January 11, 2008 and restricted the inquiry to the buried pipes/tanks within scope containing radioactively contaminated water. Therefore we are at present focused on pipes in the: (1) condensate storage condensate systems; (2) salt service water; and (3) standby gas treatment system.

1. Function of Components now within Scope

The buried components now within scope service the following systems: condensate storage, salt service water, standby gas treatment.

These buried pipes are considered to be of principal importance to plant safety and must not fail. What does failure mean? Buried pipe or tank failure means the unintentional release of its contents; and more generally the failure of the component to perform its intended function. Failure can occur by leakage, blockage, and equipment failure and so on. If the buried components under consideration fail, and are thereby unable to perform their intended function in their required manner, they are inoperable.

Does Pilgrim Station tolerate failure in these important safety systems?[11] Pilgrim Watch does not believe that they should. Failure tolerance in these systems would pose an

[11] 10 CFR 50 Appendix B, XVI requires that the licensee fix degradation; Appendix C, Article C.12, "Operability Leakage from Class 1, 2, and 3 Components", to NRC Inspection Manual Part 9900, Technical Guidance, Attachment to RIS 2005-20, ADAMS Accession No. ML052060365, "Upon discovery of leakage from a Class 1,2 or 3 pressure boundary component (*pipe wall*, valve body, pump casing, etc), the licensee must declare the component inoperable." Exhibit 5

unacceptable risk. Risk is a combination of both probability and consequences; and probability here is necessarily a guess and consequences potentially catastrophic. Probability is intertwined with statistics and it means looking back and analyzing data. Probability is only guess work here. Because as the NRC Safety Review Team pointed out, there is a paucity of data. They said in the Safety Evaluation Report[12] [at 3-37; Exhibit 6] that, "...in the past five years the applicant has had limited experience with the inspection of buried piping..." Hence there is little data to look back on and analyze. In addition there is no industry experience with reactors 40-60 years old to provide reliable predictive data. Consequences: inherent in any risk evaluation is a judgment of potential consequences. It is obvious that failure can not be tolerated in these important safety systems because failure in nuclear reactors safety systems can result in catastrophic harm to public health and the environment and to large economic costs to repair the facility and to decommission the site.

Pilgrim Watch's contention is principally concerned with leakage. The function of the pipes within scope is not only to carry fluids from point A to point B but also to *keep the liquid inside the pipe,* not let it travel into the ground; or to put it another way, to separate the liquid from the environment. Leaks or breaks are not part of the design.[13] Just as the diameter of the pipes is not optional, it has been determined that the pipes must be capable of holding a certain volume of material, not a lesser quantity as would occur with a leak or a smaller pipe diameter.

All buried pipes/tanks will eventually corrode. This is why the NRC and industry have recognized that preventative measures are important and that leaks shall not be

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[12] U.S. Nuclear Regulatory Commission, "Safety Evaluation Report Related to the License Renewal of Pilgrim Nuclear Power Station" issued as NUREG-1891;November 2007, ADAMS accession number ML073241016 [Hereinafter "Safety Evaluation Report" or "SER", Exhibit 6, all relevant pages].

[13] 10 CFR 50 Appendix B, XVI requires that the licensee fix degradation; Appendix C, Article C.12, "Operability Leakage from Class 1, 2, and 3 Components", to NRC Inspection Manual Part 9900, Technical Guidance, Attachment to RIS 2005-20, ADAMS Accession No. ML052060365, "Upon discovery of leakage from a Class 1,2 or 3 pressure boundary component (*pipe wall*, valve body, pump casing, etc), the licensee must declare the component inoperable." Exhibit 5

tolerated[14]. These reports discuss in detail all the possible and various mechanisms for degradation of the integrity of piping and particularly buried piping systems.

A leak in a pipe/tank will cause the component to eventually fail; leaks do not fix themselves and get worse over time[15]. Murphy's Law's humorous prediction that "Left to themselves, things always go from bad to worse" applies here.

The Brookhaven Report [at 145] warns that,

> "If buried pipe degradation is identified at an NPP, it may not be evident whether the pipe still complies with the plant licensing commitments or whether the degradation potentially has an immediate significant effect of plant risk. Normally, the licensee performs an evaluation of the degraded condition (note, if the licensee knows about it) which may include further inspections, testing, calculation/design review, and other actions to determine the severity of the condition, risk implications, and whether an immediate repair is needed." [However] "... These steps take time... "

The key issues are: (1) Without both comprehensive prevention and detection systems, including monitoring wells, it is unlikely a small leak will be noticed so that the secondary steps such as further inspections, testing and calculations will follow; (2) these steps take time and we do not want to risk that there may not be sufficient time; and (3) corrosion or small leaks may be exacerbated by a design basis event.[16]

In simple terms, we are dealing with a plumbing problem. Citizens here expect assurance, at a 95% confidence level, that buried pipes at Pilgrim Station do not leak or break– that

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[14] Ibid; and, Groundwater Contamination (Tritium) At Nuclear Plants-Task Force – Final Report, NRC, Sept 1, 2006, Exhibit 7 ; and, Risk Informed Assessment of Degraded Buried Piping Systems in Nuclear Power Plants; Brookhaven National Laboratory; US Nuclear Regulatory Commission, NUREG/CR 6876, June 2005, ML051650146 [hereafter Brookhaven Report], Exhibit 8.

[15] Gundersen Decl.,17.1

[16] Gundersen Decl.,17

they perform as intended - and that there are reliable means for prevention and detection. Entergy has failed to provide sufficient evidence to meet this standard.[17]

2. These components are within scope because they service the following important safety systems.

2.1. Condensate Storage System Buried Piping:

The safety function of the buried piping from the condensate storage tank to the reactor core isolation cooling (RCIC) and high pressure coolant injection (HPCI) system is to allow the necessary flow rate of water from the tank to the systems[18] - instead of into the ground/groundwater. The Condensate Storage Tank (CST) also provides make-up water to the main condenser hotwell. It has two functions. In event of an accident, the CST provides water that is delivered by various emergency pumps to the reactor vessel to compensate for water being lost through a broken pipe or whatever. During normal operation, the CST serves as a "surge tank." In BWRs like Pilgrim, steam produced in the reactor vessel spins the turbine/generator and gets turned back into water within the condenser. The water is pumped from the condenser to the reactor vessel to re-use in making more steam. The condenser is connected to the CST. When water level in the condenser drops, CST water flows in to restore the water level. When water level in the condenser gets too high, water flows back into the CST to return the condenser to the desired water level. The CST water is radioactively contaminated. This is of special concern to the community because if the pipes leak and contamination is released into the ground/groundwater, it will go into the Bay. However, this important this important

[17] Gundersen Decl., 10 and 15

[18] Cox Decl Entergy's Motion Summary Disposition, at 14 The condensate storage system falls within the scope of 10 C.F.R. § 54.4(a)(1) because it supplies water to the suction of the RCIC and HPCI pumps, which is performed by safety-related piping and valves that interface with RCIC and HPCI. Cox Decl. at ¶ 14. Similarly, the condensate storage system falls within 10 C.F.R. § 54.4(a)(3) because it provides a source of water to the HPCI and RCIC systems, which are credited in the 10 C.F.R. 50 Appendix R analysis for safe shutdown for fire protection. Cox Decl. at ¶ 14.[18] [Motion at 8].

"safety function" appears now to be excluded from the Hearing process. The pipes are made of stainless steel; the condensate tanks each contain 275,000 gallons of water.

2.2. Buried Piping in the Salt Service Water (SSW) System: The safety function of the buried piping in the SSW System is to allow the necessary flow rate of water from the ocean through the reactor to the systems to remove excess heat -instead of allowing the water to flow into the ground. In more detail, the SSW is used to remove heat from the reactor building closed cooling water (RBCCW) and the turbine building closed cooling water (TBCCW) systems. The RBCCW system sends cooling water to emergency equipment like the air conditioners inside the containment building. The TBCCW system sends cooling water to non-emergency equipment like the recombiner in the offgas system. The SSW system circulates ocean water through heat exchangers in the RBCCW and TBCCW systems. The SSW removes the heat, allowing cooling RBCCW and TBCCW water to be reused for cooling.[19] The water may become radioactively contaminated. If tubes were to leak inside the RBCCW or TBCCW heat exchangers, the SSW water is supposed to leak into the plant instead of the potentially radioactively contaminated RBCCW or TBCCW water leaking out, but that differential pressure is not always maintained and SSW might be radioactively contaminated. There is no real-time radiation monitor at the mouth of the discharge pipe. A leak anywhere in the SSW piping would impact the intended safety function of the reactor; and, although not of interest to the ASLB, a leak of contaminated water into the Bay would negatively impact public safety. The cooling water flow through the SSW piping ranged from 5.3 million gallons per day (MGD) to 15.6 MGD in 2006 depending on the season. The system is permitted for 19.4 MGD

2.3. The Buried Piping in the Standby Gas Treatment System (SGTS): The SGTS is used to improve the performance of the condenser (e.g., to enable it to "draw" steam through the turbine better), the condenser is maintained at pressure below atmospheric pressure, as low as possible. The SGTS is used to suck air from the condenser to maintain it at a lower pressure than outside air pressure. Part of the offgas system includes a re-

[19] Ibid, Cox Decl. at ¶ 15 Exhibit 9

combiner to match hydrogen and oxygen atoms to form water molecules. The non-condensibles (xenon, krypton, iodine, etc) are sent through a pipe from the AOG Building up the hill overlooking Cape Cod Bay to charcoal beds (instead of into the ground) and then released from the main stack vent. Contrary to the Applicant's Expert Testimony[20], at A-24 page 14, when the plant shuts down, [for any reason including regular scheduled refueling] radioactive water could collect in and leak from the offgas system piping. The leak of the contaminated water would indicate a breach in the piping. The function of the pipes is to keep the contents inside the pipes not into the ground. Non-condensable gas inputs to the off-gas system as listed in the FSAR are: Hydrogen:90 cfm@ 130 F; Oxygen: 45 cfm @130 F; Water Vapor: 21 to 31 cfm @ 130 F; Air: 12 to 40 cfm @75F.

C. WITNESSES

Pilgrim Watch's expert witnesses include Arnold Gundersen and Dr. David Ahlfeld. Their respective Curriculum Vitae are provided, Exhibits 1 and 2. Their Testimony and opinions on Pilgrim Watch's Contention 1 are based on their technical and personal knowledge of the issues raised in Contention 1.

The Applicant incorrectly says in their January 8, 2008 Initial Statement of Position [Hereinafter "Initial Statement"], at 6, that "neither has any experience or familiarity with the issues central to PW Contention 1."

Arnold Gundersen, for example, has a bachelor's and a Master's Degree in Nuclear Engineering from Rensselaer Polytechnic Institute (RPI) cum laude; and began his career as a reactor operator and instructor in 1971 and progressed to the position of Senior Vice President for a nuclear licensee. His more than 35 years of professional nuclear experience include and are not limited to: Nuclear Plant Operation, Nuclear Management, Nuclear Safety Assessments, Reliability Engineering, In-service Inspection, Criticality Analysis, Licensing, Engineering Management, Thermohydraulics, Radioactive Waste Processes, Decommissioning, Waste Disposal, Structural Engineering Assessments,

[20] Testimony of Alan Cox, Brian Sullivan, Steve Woods, William Spatoro, on Pilgrim Watch Contention 1, Regarding Adequacy of Aging Management Program for Buried Pipes and Tanks and Potential Need for Monitoring Wells to Supplement Program, January 8, 2008 [Hereinafter " Applicant's Expert Testimony"]

Cooling Tower Operation, Cooling Tower Plumes, Nuclear Fuel Rack Design and Manufacturing, Nuclear Equipment Design and Manufacturing, Prudency Defense, Employee Awareness Programs, Public Relations, Contract Administration, Technical Patents, Archival Storage and Document Control.

Dr. David Ahlfeld is a Professor in the Department of Civil and Environmental Engineering at the University of Massachusetts Amherst. He has taught, conducted research and worked on projects in the area of groundwater flow and contaminant transport in the subsurface for over 20 years. He has served as a hydrological expert for plaintiffs in important cases such as in the now famous Civil Action case. He is very familiar with leaking buried components, irrespective of the nature of the facility.

In judging the credibility of experts, we weighed the fact that the Applicant's four witnesses are employees of Entergy, on their pay roll. In contrast, Pilgrim Watch's experts are outside the system; and their vested interest in the outcome of these proceedings is solely to donate their time and expertise in the hopes that risk will be decreased and public health and safety better protected.

II. PILGRIM WATCH'S STATEMENT OF POSITION ON FACTUAL ISSUES

A. CORROSION

1. The pipes we are considering are underground; consequently leaks are not evident visually unless they are excavated.

This fact was pointed out by the NRC's Lessons Learned Task Force (LLTF).[21] They concluded that,

[21] Groundwater Contamination (Tritium) at Nuclear Plants-Task Force – Final Report, NRC, Sept 1, 2006, 3.2.2.3 Conclusions –Exhibit 7
http://adamswebsearch2.nrc.gov/idmws/doccontent.dll?library=PU_ADAMS^PBNTAD01&ID=062770207

> Systems or structures can experience undetected radioactive leaks over a prolonged period of time. Systems or structures that are buried or that are in contact with soil, such as SFPs, *tanks in contact with the ground, and buried pipes,* are particularly susceptible to undetected leakage." [Emphasis added]

It is widely understood by the industry that structures age or deteriorate, especially if buried. Brookhaven Report, at 147, Exhibit 8, says that,

> Buried piping systems can degrade. Such deterioration potentially could impair the operation of the system that contains the buried piping, and thus impact the overall risk of an NPP.

Because the pipes/tanks are buried degradation and leaks must be estimated by secondary means; such as from lessons learned from limited operating experience and from readings on level instruments or alarms. However, level instruments and alarms have set points that may not be set low enough to detect a small leak; they can malfunction or be incorrectly read; and they provide no information regarding potentially serious degradation. These secondary means are valuable but they are limited. An everyday experience explains, if the water pipe under your sink is dripping; you may not notice it and still be able to wash the dishes, but the basement in the interim gets flooded. Just as the homeowner can not predict when, or if, the "disaster" will occur from a pipe buried in the walls or floor, neither can Pilgrim accurately predict when a disaster may occur from a pipe or tank buried in the ground.

2. Buried piping systems at a nuclear power plant will corrode in some degree or another; potentially impair the operation of the system; and thus impact the overall safety.[22]

It is widely understood that structures age or deteriorate over time and that such aging is a serious problem and needs to be managed. The Brookhaven Report, Exhibit 8, says very plainly that, "Buried piping systems at a nuclear power plant can degrade" [and] "Such deterioration could impair the operation of the system that contains the buried piping, and thus impact the overall safety of the NPP" [at 97].

Degraded pipes at Pilgrim can impact overall safety in two ways. Corroded pipes not only allow liquid to leak into the ground/groundwater in violation of their intended function [10 CFR 50, Appendix B, XVI, Corrective Action, Exhibit 5]; but also allow debris to enter the pipe through the crack or hole and risk harming the system downstream.[23] This phenomenon appears counter intuitive. It is explained by the Bernoulli Principle[24] The higher the velocity of the liquids moving inside the pipes; the greater the opportunity for debris from outside to get inside the pipe. As explained by Pilgrim Watch's expert, Arnold Gundersen, "In this scenario rust particles, dirt and other contamination enter the pipe or tank through the hole thereby clogging downstream filters and heat exchangers, or the debris abrades the moving parts thus rendering the system

[22] Gundersen Decl. at 12.4.5
[23] Gundersen Decl. at 17

[24] Bernoulli's principle can be explained in terms of the law of conservation of energy. As a fluid moves from a wider pipe into a narrower pipe or a constriction, a corresponding volume must move a greater distance forward in the narrower pipe and thus have a greater speed. At the same time, the work done by corresponding volumes in the wider and narrower pipes will be expressed by the product of the pressure and the volume. Since the speed is greater in the narrower pipe, the kinetic energy of that volume is greater. Then, by the law of conservation of energy, this increase in kinetic energy must be balanced by a decrease in the pressure-volume product, or, since the volumes are equal, by a decrease in pressure. This would allow outside debris to enter a pipe under circumstances as described.

"*unable to perform the intended safety function*" [Gundersen Decl. 17.2] There is no evidence that the Applicant analyzed this phenomenon.

3. Corrosion grows if left unattended; and leaks do not fix themselves.[25]

Monitoring wells and a more robust inspection protocol are necessary to detect small leaks from the buried piping/tanks that, left alone, could become larger leaks [Gundersen Decl. at 18]. Whereas small leaks do not pose a serious challenge by themselves to the ability of the buried piping in the condensate system, for example, to get the required water volume from the condensate storage tank to the RCIC/HPCI systems, the "leak before break" concept suggests that the small leak could be indicative of deteriorating conditions that could lead to a pipe break. But "indicative" only works if one has the means to recognize the indication. The condensate storage tank is a very large tank equipped with level instruments. A small leak in a buried pipe connected to this tank is unlikely to be caught by the tank's installed level monitoring instruments, and the Applicant never demonstrated with 95% certainty that it would. The level monitoring would indicate a large break, but not a small leak preceding it. Thus, the monitoring wells and more robust inspections would provide greater assurance that the safety function of the buried piping is not lost or compromised. This would add "defense in depth."

There are level monitoring systems in the systems under consideration; however there is no proof provided by the Applicant that they will not show anything other than a large break, but not a small break preceding; nor, and most important, can they assess deterioration. Monitoring wells and more frequent and robust inspections would provide assurance that the safety function of the buried piping is not lost or compromised.

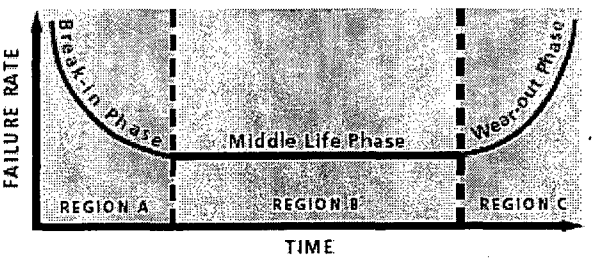
[25] Gundersen Decl. at 17

4. Aging and corrosion has been recognized as a serious problem – during the license extension, Pilgrim will be 40-60 years old.

4.1. Aging and corrosion has been recognized as a serious problem by the Brookhaven Report. The older the structure in question, the more likely it is for corrosion and leaks to occur. Pilgrim Station will be 40-60 years old during re-licensing. Industry experience is absent for degradation of buried components at nuclear reactors this old [self evident].

4.2. The Union of Concerned Scientists[26] explained the aging phenomenon by using the "Bathtub Curve," which was developed by NASA scientists studying statistically the lifetimes of both living and non-living things to describe the likelihood of aging related problems in nuclear plants. The curve, which is a graph of failure rate versus age, shows that after a relatively stable (bottom of the bathtub) period in the middle life of the subject, a steep rise in age-related failures occurs towards the end of its life. "The right-hand side of the curve, labeled Region C, is the wear-out phase. Due to aging, it takes less stress to cause failure in this phase, just as older people are more prone to breaking bones in a fall than younger people. Thus, the chances of failure increase with time spent in Region C" [Union of Concerned Scientists Report, *supra*, at 4].

Figure 1 The Bathtub Curve



Source: NASA, 2001.

[26] See U.S. Nuclear Plants in the 21st Century: The Risk of a Lifetime, by David Lochbaum, Union of Concerned Scientists. (May 2004); and "Using Reliability-Centered Maintenance As The Foundation For An Efficient And Reliable Overall Maintenance Strategy," National Aeronautics and Space Administration (NASA), 2001. Exhibit 10.

The renewal period of a nuclear plant would be its Region C, or wear-out phase. "As reactors approach or enter Region C [the wear-out phase] and become more vulnerable to failure, aging management programs should monitor the condition of the equipment and structures more frequently so as to affect repairs or replacements before minimum safety margins are compromised. Unfortunately, age-related degradation is being found too often by failures than by condition-monitoring activities" [*Id.* at 20].[27] Likewise, Pilgrim's AMP's do not provide the required "condition-monitoring activities."

4.3. It is important to make note that the aging process is a curve, not a straight-line. This tells us that corrosion is not linear but exponential. Therefore as the pipe ages the time between inspections must necessarily be shortened [self evident].

4.4. The ASLB will be asked to determine the specific age of each part of the buried pipes within scope - not simply: the average age of the component as a whole, or only the age of the most recently replaced section, or when linings or coatings were applied. It will be important to determine how many sections of the whole have reached the "wear-out" stage of their lifespan. In addition the ASLB will be asked to determine what the warranties were for the various parts making up the components under consideration; we know that failures due to corrosion are more apt to occur after the warranty period; and what parts remain that are counterfeit or substandard. [28] Entergy's prefiled testimony does not provide that information nor would they provide it to Pilgrim Watch when asked.

4.5. The ASLB will be asked to determine what pipes or pipe sections were replaced; and, more important, to see the specific reports that show the analysis of why they were replaced, what went wrong, and whether a root cause analysis was performed. [29]

NUREG-1891, the Safety Evaluation Report[30], at 3-37, Exhibit 6 says that operating experience at Pilgrim is limited. We know that the opportunities for analysis were often

[27] Gundersen Decl. at 16
[28] Gundersen Decl. at 12.4.6.2
[29] Gundersen Decl. at 12.5

missed in those limited past operating experiences. For example, the Declaration of Alan Cox in support of Entergy's Motion for Summary Disposition of Pilgrim Watch Contention 1, June 5, 2007, at FN 6, page 11, [Exhibit 11] says that,

> The inlet SSW carbon steel piping that was replaced with titanium piping in order to prevent interior corrosion was never removed from the ground so that the exterior coatings and surface of *the original carbon steel SSW inlet piping were not examined.* [Emphasis added]

5. The "epidemic" of reported leak events recently demonstrates the correlation between aging and corrosion; and that industry practices such as chemistry control, salt water service programs, wraps and coating do not prevent leaks.[31] For example:

- **Byron**: Corroded pipes recently failed at Byron NP in Rockford Illinois[32]. Exhibit 7's photographs of the corroded ESW System Piping, shows the nature and location of the leak. The corrosion process thinned the pipe walls below the minimum acceptable level (0.375 inches) in some places. Workers measured the thickness of some of the pipe walls at 0.047 inches before the rust was removed. Once the rust was removed, the remaining wall thickness went to zero – in other words rust was holding it together. It is not clear at this point whether corrosion occurred from the inside or outside of the pipe. In view of the large amount of rust, which was scraped off, one might suspect that corrosion occurred from the outside due to a leaking flange. Exelon declared the ESW systems inoperable and had to shut down both reactors as a result. *If the ESW system cannot function during an accident, the ability for the plant to avoid a reactor core meltdown with concurrent loss of containment is severely impaired if not entirely prevented.* The accident is likely to become catastrophic. Although this occurred at Byron, not Pilgrim, there is not any reason for complacency.

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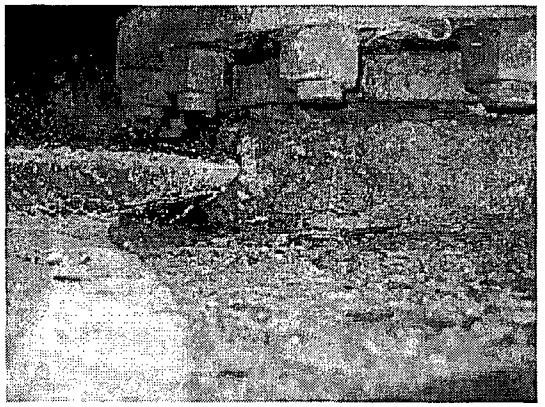
[30] NUREG-1891, Safety Evaluation Report, November 2007, ADAMS ML073241016.
[31] Gundersen Decl. at 15, 16
[32] (NRC Preliminary Notification of Event or Unusual Occurrence, PNO-III-07-021, "Both Units at Byron Shut Down Due to Leak in Pipe", October 23, 2007) ML072960109. Union of Concerned Scientists Issue Paper, Help Wanted: Dutch Boy at Byron (October 25, 2007), Exhibit 12.



▲ *The leak occurred as workers scraped rust from the heavily corroded ESW pipe. The pipe, which is specified to have a minimum wall thickness of 0.375 inches, had a measured wall thickness of 0.047 inches – before rust removal took that thickness to zero.*

- **Palisades**: December 11, 2007, Palisades reported that five new ground water monitoring wells were recently installed at Palisades in support of NEI's initiative. The initial sampling of one of the wells indicated 22,000 pico-curies per liter (pCi/l).[33] Palisade's *NRC Safety Review had been completed* and *Licensing Application approved*, January 2007.

- **Catawba**: October 9, 2007 Event Number: 43703 at Catawba reported that, "Thirty new ground water monitoring wells were recently installed at Catawba Nuclear Station in support of the Nuclear Energy Institute (NEI) Ground Water Initiative. The initial sampling of one of these wells displayed a level of tritium that triggered the communication protocol of the NEI initiative on ground water protection. The tritium concentration for this well was 42,335 picocuries per liter (pCi/l). The threshold for initiating the communication protocol is 20,000 pCi/l. The station is continuing to investigate the source of tritium identified in this well."

[33] Event No. 43882, Event Notification report, December 11, 2007

Pilgrim NPS: The SER[34] [at 37, Exhibit 6] pointed out that, "...in the past five years, the applicant has had *limited* experience with the inspection of buried piping..." The scarcity of available information concerning buried pipe failures at Pilgrim makes assessment of the existing deterioration impossible. The SER reported some leaks that occurred in the fire water distribution system and salt water service system.

It is important to emphasize that simply because Entergy had not looked nor had in the past, or today, an effective monitoring well program to detect leaks does not mean that leaks are not occurring now or about to occur tomorrow.

Most recently, December 2007, Pilgrim as part of the NEI's Ground Water Protection Initiative[35] reported that they discovered tritium from the four groundwater wells that they activated and sampled on November 29, 2007. At this date, details are not available. Four monitoring wells are insufficient. Pilgrim Watch's expert, Dr. David Ahlfeld, [Ahlfeld Decl at 2] noted,

> Indeed, a 4-well monitoring system is more typical of that used for a retail gasoline station or a small municipal (non-hazardous) landfill. That it should be considered adequate for a large industrial facility such as PNPS is unrealistic.

In addition to aging, it is clear that reactors that installed monitoring wells are discovering leaks – a fact that speaks in support of our request to supplement the AMP with a robust and effective monitoring well program.

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[34] Safety Evaluation Report, Related to the License Renewal of Pilgrim Nuclear Power Station, Docket No. 50-293, US NRC, November 2007

[35] Industry Ground Water Protection Initiative, Final Guidance Document, NEI 07-07, August 2007. http://adamswebsearch2.nrc.gov/idmws/doccontent.dll?library=PU_ADAMS^PBNTAD01&ID=073240116

6. Corrosion rates are hard to predict and can not be assumed to be either gradual or linear[36].

The Brookhaven Report said, at 32, that, "...it is evident that predicting an accurate degradation rate for buried piping system is difficult to achieve..." and, at 103, "...different segments of the pipe may degrade at different rates."

Rates cannot be assumed to be gradual, denoting slow and linear. The aging process is composed of a spectrum of rates because the materials that the pipes are made of are composites. For example, steel is composed of crystals and thereby has a multitude of crystal boundaries. Steel is not uniform on either the micro or macro level. Steel has been "worked" to become the final product and therefore has internal stresses. These stresses represent areas of high internal energy and will deteriorate faster than the stress free areas. Hence there is a spectrum of aging rates within the component to deal with and the term "gradual" may not apply to all areas within the component, at least not in the extreme. And we have to look at the extremes not the "average" rate because the average does not leak, the extremes do.

Corrosion rates are not linear, either. As we discussed above, aging of mechanical components follow the "bath-tub" curve and the mere fact that it is a curve means that the failure rate is non linear.

7. Degradation Mechanisms specific to Pilgrim NPS

The Brookhaven Report describes the various degradation mechanisms. The report summarizes them as, "The predominant aging effects are loss of material and fouling/biofouling." The report says that, "most occurrences of loss of material are manifested as either general wall thinning or localized loss of material/pitting" [at 145].

[36] Gundersen Decl. at 12.4.5.6

There is no need to review the fundamentals of corrosion; instead we will highlight what is specific to Pilgrim.

7.1. Pilgrim's pipes, under consideration, are made of metals – carbon steel, stainless steel and titanium - all metals corrode.

The piping under consideration is made of metal– all metals corrode, some more so than others. We know from the Brookhaven Report and everyday experience that these metals can fail by localized corrosion phenomena which is accelerated by stress or may be initiated due to poor design, installation, or maintenance [Brookhaven Report at 26, Exhibit 8].

Entergy's Initial Statement at 10 says that the piping under consideration is made of carbon steel, stainless steel or titanium.

- The SSW Service discharge piping is made of carbon steel. Carbon steel has poor corrosion resistance. [Brookhaven at 26]
- The SSW inlet piping is made of titanium. Titanium fouls more easily from marine organisms [Brookhaven at 128].
- The CSW piping is made of stainless steel.

Entergy's Initial Statement at 10 says that, "Stainless steel is resistant to corrosion in soils;" and, "...titanium...is immune to corrosion in soils." Entergy is incorrect. Stainless steel and titanium are known as passive metals which form a "passive" oxide layer on their surface that makes it immune to general corrosion until the oxide layer is breached, which *will eventually happen*; then corrosion occurs on the bare metal underneath. The oxide layer can be breached by a variety of factors.

For example:

Radionuclides hasten degradation in pipes carrying radioactive material by degrading the passive oxide layer. This phenomenon would affect the CSS piping, SSW discharge piping and potentially the off gas treatment system piping. Recent research by Dr. Bellanger [37] adds to our understanding of these degradation mechanisms by pointing out that low energy radionuclides will hasten degradation in pipes carrying radioactive material by degrading the passive oxide layer, too. Bellanger explains that gamma rays and neutrons have the highest energies and can break the metal bonds in interior metallic structures causing damage quickly and in easily monitored ways. Consequently these types of radiation and the best alloys to use to mitigate their effects have been extensively researched. However, the same is not true of low energy radiation which effects metal structures in a different way but can still cause appreciable and extensive corrosion. Low energy radiation degrades the passive oxide layers that protect metals. Without this protective layer the metals are easily corroded.

Further some stainless steels are inherently more susceptible than others. The Brookhaven Report says that most stainless steels used in buried piping at nuclear plants are Type 304 and 316. Type 304 is more susceptible than 316; the latter is lower in carbon. If Pilgrim is using Type 304, it is especially susceptible to embrittlement and cracking [NUREG/CR 5754, The Oak Ridge Report [38]]. The ASLB will be asked to determine if, and where, Type 304 is used in PNPS' buried pipes.

7.2. Corrosion occurs both on external and internal surfaces.[39] Pilgrim's site's environmental features are conducive to both types of corrosion.

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[37] G. Bellanger, Corrosion Induced by Low Energy Radionuclides: Modeling of Tritium and Its Radiolytic and Decay Products Formed in Nuclear Installations (Elsevier Publications, 2 006), ISBN 0 08 0445101.

[38] NUREG/CR-5754 [ORNL/TM-11876], "Boiling Water Reactor Internals Degradation Study," Oak Ridge National Laboratory Report for NRC, September, 1993 ML040300570

[39] Gundersen Decl. at 7.2

The Brookhaven Report explains at 32, Exhibit 8, that the rate of degradation of steel buried components is a function of environmental variables, metallurgical variables, and hydrodynamic variables.

7.2.1. External Corrosion:

(1) Water and Moisture: It is basic that water and moisture are needed for external corrosion to occur (Brookhaven Report at 26, Exhibit 8). It deteriorates the outside coating and wraps. Pilgrim sits on low land directly beside Cape Cod Bay. The FEIS described the soil as sandy, silt and clay – all soil types that retain moisture.[40] Entergy's Prefiled Testimony, at A83, tries to present a different picture. They say that, "...piping is placed on a bed of sand or specifically engineered fill before it is covered by another layer of fill. The sand or fill is very porous and allows water to percolate through. Thus it does not retain moisture and generally has high resistivity to corrosion." Sand retains moisture. For example: the "drywell shell" at Oyster Creek corroded quite badly in the sand bed area and, a more mundane example, children build sandcastles regularly on the beach. In addition, over the years sand washes down and silt and clay soils above wash down into the area surrounding the pipe. Moisture increases from rain and snow percolating downwards. Water in the soil travels both vertically and horizontally; and it is obvious that the adjacent ocean provides a very moist environment [self evident]. Improbable implications made by Entergy's expert should make the ASLB suspicious of other so-called statements of fact.

(2) Catholic Depolarizers: If moisture is present and the coating has deteriorated one needs additionally a cathodic depolarizer – a substance to further the cathodic reaction in

[40] Topography source: Pilgrim Nuclear Power Station, Boston Edison Company Docket No. 50-293, May 1972 –U.S. Atomic Energy Commission, Division of Radiological and Environmental Protection, Final EIS "The station site is along the rocky western shoreline of Cape Cod Bay. The geology of the site is recognized as primarily glacial deposits. The natural surface stratum in the station area consists of approximately 20 feet of silty and clayey fine sands with scattered boulders. Bedrock is about 30 to 90 feet below mean sea level." P. 9 "Surface topography is such that surface drainage from the station is seaward and surface water will not leave the Station property otherwise" P.10, Exhibit 13.

order for corrosion to occur. This may be oxygen; certain microorganisms (bacteria, algae, fungi) or low pH generated by acid rain or the increased acidity of the ocean due to pollution; or the chloride ion (Cl).

Oxygen: The forgoing factors apply to Pilgrim's site and specifically to where the pipes are buried. For example, Entergy says in their discussion of corrosion of stainless steels, Entergy's Exhibit 5, at 27,[41] that, "Oxygen takes part in the cathodic reaction and a supply of oxygen is therefore, in most circumstances, a prerequisite for corrosion in soil. Entergy's Prefiled Expert Testimony [A-63] explains that the "CSS and SSW system buried piping…is covered with sand…" Pilgrim Watch knows that the supply of oxygen is high in sand and would further the cathodic reaction. Entergy's Exhibit 5 [at 26, attached in PW's Exhibit 14] says, "…the supply of oxygen is comparatively large above the ground water table." We know that groundwater is generally encountered 20 feet below ground level. The distance from the ground surface for the systems listed …is as follows: Condensate tank piping: ranges from 7 to 10 feet; SSW piping: 10 feet; Off-gas piping: a minimum of 6 feet below ground in paved area and 5 feet below ground elsewhere."

pH: Regarding pH: The pH scale goes from 0 to 14 with pH 7 as the neutral point; as the amount of hydrogen ions in the soil increases the soil pH decreases thus becoming more acidic. From pH 7 to 0 the soil is increasingly more acidic. Soils tend to become acidic as a result of: (1) rainwater leaching away basic ions (calcium, magnesium, potassium and sodium); (2) carbon dioxide from decomposing organic matter and root respiration dissolving in soil water to form a weak organic acid; (3) formation of strong organic and inorganic acids, such as nitric and sulfuric acid, from decaying organic matter; and (4) pollution –acid rain and increased acidity in ocean water.[42]

Entergy's Expert Testimony, at A83, tries to downplay the role the pH factor would play at PNPS. They say that, "During construction of PNPS, the site was excavated for the construction of various buildings. During excavation, all rock over six inches, shrubs and

[41] Entergy's Exhibit 5 is in Pilgrim Watch's Appendices as Exhibit 14.
[42] Soil pH, http://en.wikipedia.org/wiki/Soil_pH ; Brookhaven Report at 3.4,Exhibit 8.

trees were removed from the soil...plants biodegrade, release compounds that may increase soil pH. (This) precaution serve(s) to reduce corrosivity of the soil environment." However the site was constructed in the 1960's, plants reappear in less than 35 or 40 years. It rains in Plymouth; and New England receives carbon pollution from the mid-west resulting in increased acidity in our environment [self evident]. Entergy claims the soil pH is 6.2 - 6.82, no studies are provided for evidence. Further we doubt their numbers because soil acidity varies – over time and over a small geographic area. If the numbers are in fact correct, a pH level of around 6.3-6.8 is the optimum range preferred by most soil bacteria. Bacteria furthers the cathodic reaction. [43]

Chloride Ion: Entergy's Exhibit 5, at 27, PW's Exhibit 14, says that, "Another of the most important conditions for corrosion to occur is the chloride ion CI)..." Chloride is naturally abundant in seawater [self evident]. Pilgrim sits at the shoreline of Cape Cod Bay.

Stray Currents: Additionally underground corrosion is amplified by stray currents which are present in one degree or another at power generating stations [Brookhaven 3.4].

(3) Soil Testing: Entergy has provided no documents showing that a recent analysis of the soils surrounding the specific pipes has occurred. We would have to see the study to assess its methodology and the assumptions or factors considered during the any soil inspection. Their expert [Prefiled Testimony at A87] simply says that he "reviewed the 1992 soil analysis taken near the SSW system loop A and loop B" (a limited sample

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[43] Brookhaven Report at 27, Exhibit 8,"Microbiologically Influenced Corrosion: Microbiologically influenced corrosion, known as MIC, is corrosion caused by the presence and/or activities of microorganisms in biofilms on the surface of the pipe. Microorganisms have been observed in a variety of environments that include seawater, natural freshwater (lakes, rivers, wells), soils, and sediment. The microbiological organisms include bacteria, fungi, and algae They have been known to tolerate a wide range of temperatures, pH values, oxygen concentrations, and extreme hydrostatic pressure. These microorganisms can influence corrosion by effects such as the destruction of the protective surface films, creating corrosive deposits, and/or altering anodic and cathodic reactions depending on the environment and organism(s) involved. MIC affects most alloys such as steel (including stainless and galvanized), ductile iron, and copper. It is more common to find MIC inside buried piping; however, it may also occur on the outside of the pipe."

taken 16 years ago); and he cited an October 2005 analysis of groundwater – claimed to be a good indicator of soil condition. Soil acidity varies from place to place even in a small backyard lawn, let alone at Pilgrim's reactor site, and it varies from season to season. Additionally we would like to see a history of backfilling in the specific area where the pipes are buried. Entergy's Exhibit 5, at 26, in PW's Exhibit 14, warns that, "Any metal buried by backfilling is in disturbed soil and is subject to corrosion attack" [and, at 7] "Be aware that backfilling an excavated area could increase the corrosion susceptibility in that area of the buried piping or tanks due to changing soil conditions."

Entergy's Exhibit 5 says, at 11, that the corporate *Buried Piping and Tanks Inspection and Monitoring Program* framework calls for "soil resistivity measurements...must be taken at least once per 10 years unless areas are excavated and backfilled or if the soil conditions are known to have changed for any reason." The ASLB will be asked to determine how this corporate framework will be applied to Pilgrim Station and to document the rationale for their specific plan.

7.2.2. Internal Corrosion: The rate of degradation on interior surfaces is a function of aggressive chemicals, pH level, dissolved oxygen and biological elements [Brookhaven at 32, in Exhibit 8].

Salt, for example, is an especially aggressive chemical on interior surfaces, as well. As said above, Pilgrim sits directly beside Cape Cod Bay – seawater. Commonsense alone indicates that salt water and air are corrosive. For example, we know that it is far wiser to buy a used car that was driven in the American Southwest than one from Plymouth. In addition to everyday experience, industry experience at Pilgrim has shown that salt water exposure resulted in degradation of some of the components. For example Pilgrim's Safety Evaluation Report, November 2007, at 3-37 (hereinafter SER) described corrosion in the Salt Water Service System.

> ...SSW system has had leaks on the buried inlet (screen house to auxiliary bays) piping due to internal corrosion. The original piping material was rubber-lined

carbon steel wrapped with reinforced fiberglass, coal tar saturated felt, and heavy Kraft paper. The leaks were determined to be results of the rubber lining *degrading from contact with sea water.* These pipes were replaced in 1995 and 1997 with the same external and internal coating as for the original pipe. [Emphasis added]

Metallurgy: In addition to such variables as aggressive chemicals, oxygen, degrading marine and plant life, metallurgy affects corrosion. This is where welds come into play and why it is important to determine the number of welds in the pipes under consideration and their condition. Pipe joints are welded together and either the weld metal, the heat affected zone or the base metal can corrode preferentially. It is common to see failures at welds because where there is a welded joint between two sections of pipe there is a breakdown in the coating which exposes the weld metal and also creates a location where flow is upset and becomes highly turbulent, thereby accelerating corrosion. This is why it is important that every weld should be inspected from the inside and the damage assessed to establish a "baseline" analysis for any future AMP. Obviously it is impossible to assess the damage visually from the outside – the pipes are buried- UT measurement must be made over the full periphery of each weld from the inside. Special attention must be given to those welds that are upstream or downstream of a flow disturbance.

7.2.3. Flow Accelerated Corrosion (FAC): FAC is a pipe wall thinning phenomena in which the thinning rate is accelerated by flow velocity.[44] FAC includes wall thinning by electrochemical corrosion, erosion-corrosion and cavitation-corrosion. All three are affected by flow velocities. Although the main causes of FAC (turbulence intensity, material compositions, oxygen content and pH) have been identified, the behavior of FAC is not completely understood. Wall thinning is a local phenomenon. Local geometry, local metal composition and local turbulence affect FAC rates. Once local

[44] Gundersen DECL at 18.1.3 basis statement that, "Special Attention must also be given to those welds located upstream or downstream of a flow disturbance."

corrosion has begun, geometrical changes as they occur further intensify the local turbulence, thereby increasing FAC in a non-linear rate. [45]

The identification of locations where FAC rates are the highest is made difficult by the fact that the local turbulence is not a directly measured quantity, nor is the local flow velocity. In operating reactors one must use thermal hydraulic computer codes such as RELAP to calculate average velocities throughout the plant. Because of the indirect method of determining turbulence, considerable data must be collected over a period time to assure that the location with the highest propensity for FAC are properly identified.

According to NRC guidelines in NUREG 1800, A.1.2.3.4, the detection of wall thinning due to FAC should occur *before* there is a loss of the structure and the components intended function(s). Wall thinning must be monitored or inspected to ensure that the structure and component's intended function(s) will be adequately maintained during license renewal. Sample size and frequency of wall thinning measurements must be conducted in a timely manner so as not to exceed the minimum design thickness of the component. The licensee must provide information that links the parameters to be monitored or inspected to wall thinning. The Applicant's Prefiled Testimony is silent on this subject. Without evidence explaining how they are dealing with it, we add one more brick to our case that assurance is not provided by the applicant.

7.3. The potential risk of corrosion and leaks at Pilgrim might be increased by the inadvertent use of counterfeit or substandard parts. [46]

Components constructed to commercial standard and/or made of substandard parts would have a greater tendency to corrode. Pilgrim has potentially nonconforming pipe fittings and flanges still in place. Fittings and flanges are the more likely areas to leak than

[45] In 1986 accident at Surry, some areas on the feed water pipe elbow were almost completely eroded while adjacent areas were much less affected. The J-tubes on the distribution feed ring exhibited a similar phenomenon. NRC Information Notice No 86-106 "Feed Water line break" (Dec 16, 1986): NRC Bulletin 87-01 "Thinning Pipe Walls in Nuclear Plants" (July 9, 1987).

[46] Gundersen DECL 12.4.6.2

straight piping. The United States Government Accounting Office [47] reported that PNPS is suspected of having received counterfeit or substandard pipe fittings and flanges. This could make leaks more likely.

In Entergy's Motion for Summary Disposition [Material Fact 44, included in Exhibit 15], Entergy stated that,

> NRC Bulletin 88-05 alerted utilities to potential counterfeit and substandard pipe fittings and flanges, and the previous PNPS owner and operator identified, located and remediated, *as appropriate*, any counterfeit and substandard pipe fittings and flanges at PNPS. Cox Decl. at ¶ 44. [Emphasis added]

Pilgrim Watch notes that "as appropriate" does not answer the question of how many counterfeit/ substandard pipe fittings and flanges were replaced and the location of those still in the ground; nor were we provided with a definition of "as appropriate"- or more simply the rationale for leaving substandard/counterfeit parts in an operating nuclear reactor. Further was the determination made of whether to replace or leave the part(s) in place based generically or site specific for Pilgrim; and was the analysis made assuming only a 40 year license? If that is the case, their adequacy should be re-analyzed for an additional 20 years of operations in order to provide assurance when granting the license; there is no evidence provided that they have done so. Substandard parts mean that the aging management analysis for structures and components under consideration is necessarily deficient because it is not possible to perform a probabilistic risk assessment when components are substandard.

The NRC Groundwater Contamination at Nuclear Power Plants-Final Report, September 1, 2006, Task Force at Executive Summary, ii warned that,

[47] United States General Accounting Office, Report to the Chairman, Subcommittee on Oversight and Investigations, Committee on Energy and Commerce, House of Representatives, Nuclear Safety and Health Counterfeit and Substandard Products Are A Government Wide Concern, GAO/RCED-91-6, October 1990.Exhibit 15

"Some of the power plant components that contain radioactive liquids that have leaked were constructed to commercial standards, in contrast to plant safety systems that are typically fabricated to more stringent requirements. The result is a lower level of assurance that these types of components will be leak proof over the life of the plant"

The NRC's Lessons Learned Task Force raises another important question. Are the pipes and fittings "constructed to commercial standards", in contrast to plant safety systems that are typically fabricated to more stringent requirements?

7.4. Plymouth is not immune to seismic activity; although the probability of such an event is admittedly low. Buried pipes/tanks are not flexible and the coatings become brittle with age; therefore more susceptible to breakage during seismic events.[48]

Corroded piping and brittle coatings can crack as a result of tremors from an earthquake, pipes are inflexible and as they age they become brittle in all or part. The potential of earthquakes occurring from 2012 to 2032 can not be dismissed. There is no evidence that the Applicant or the NRC Staff specifically evaluated whether or not the AMP is adequate for buried pipes in relation to this new knowledge regarding predicted seismic effects.

We know that New England is not immune to strong temblors and specialists say that a major event in only a matter of time.[49] It is only a matter of time before the Northeast is struck by a major quake, according to earthquake specialists at the US Geological Survey in Virginia, who have placed Boston on a list of the top 26 risk areas in the nation. Indeed, a major quake has occurred somewhere in the Eastern United States about every 100 years.

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[48] Gundersen Decl. 17.3.4; Brookhaven, Section 5

[49] *New England not immune to strong temblors and specialists say that a major event in only a matter of time,* Boston Globe, Bryan Bender, April 16, 2006, Exhibit 16.

New data developed disclose a substantially higher likelihood of significant earthquake activity in the this area and although the probability that a major earthquake will hit the Eastern US is much lower than in the West, the potential impact is significantly higher. In the Eastern United States, according to researchers, the rocks transmit earthquake waves more easily than in the West. Therefore, a rupture, brought on by pressure built up over hundreds of years, would be felt over a much larger geographic area. Smaller earthquakes occur regularly in the Eastern states, including New England. On November 17, 2005 a minor quake, measuring 2.5 on the Richter scale, was detected in Plymouth.

The Prefiled Testimony showed no evidence that the buried pipes were analyzed for potential seismic events from 2012-2032.

B. FAILURE MECHANISMS

Based upon our expert, Arnold Gundersen's professional experience as the Senior Vice-President of an ASME XI In-Service Inspection Division, he explains in his attached declaration, Exhibit 1, that there are several challenging scenarios in which these unidentified leaks can and will jeopardize the design and intended function of safety related systems and components at the Pilgrim Nuclear Power Station. More specifically, the recently discovered Tritium releases show that undetected leaks may already have occurred, in Pilgrim's underground pipes and tanks, thereby causing them to malfunction in such a way as to be *"unable to perform the intended safety function"*. Therefore he estimates that there are at least three possible scenarios that may be the result of the flaws in Pilgrim's AMP.

1. In the first scenario, there may be a loss of intended safety function if a leak has occurred and has gone undetected by the Applicant's AMP. If a leak could spontaneously heal itself, we would not need an AMP for pipes and tanks. Unfortunately, leaks, once begun and whether observed or not, will continue to grow as evidenced by the newly discovered Tritium leaks. These leaks may be

caused by external abrasion, internal corrosion, galvanic attack or other factors as yet to be uncovered. (Gundersen Decl 17.1)

Leaks not only continue to increase in flow, but in fact the rate of expansion for leaks actually accelerates once a pinhole has been created in the pipe or tank wall.

After the initial pinhole, water begins to exit the tank or pipe, at an ever-accelerating rate as the hole expands. In fact, mathematically speaking, the leak rate growth is proportional to the square of the holes radius.

Given that the Aging Management Plan has not detected some underground leaks as suggested in paragraph 12 and by the newly discovered Tritium leaks, it then becomes quite likely that if a safety function is required, the leak may either divert the required water or reduce the required line pressure rendering the pipe and tank system *"unable to perform the intended safety function"*.

Transient flow and pressure changes that would occur if there is a design basis event will exacerbate leak growth and further reduce the ability *"to perform the intended safety function"*. According to the NRC's website, a design basis accident (event) is "a postulated accident that a nuclear facility must be designed and built to withstand without loss to the systems, structures, and components necessary to assure public health and safety." In my opinion, the recent pipe failures at the Byron Nuclear Power Station in Illinois are the perfect example for this discussion. At Byron, safety-related flanges on pipes were weeping so badly that they certainly would have been unable to have withstand the flow and pressure transient associated with actually requiring the system to operate in its safety mode. Without adequate Aging Management oversight, such a scenario could be mirrored at the Pilgrim Nuclear Power Station.

2. The second scenario is similar to the first in that a growing leak remains undetected by an inadequate Aging Management System. However, unlike the first scenario, in which a system failure is caused by allowing water to exit the expanding hole(s), in this scenario rust particles, dirt and other contamination

enter the pipe or tank through the hole thereby clogging downstream filters and heat exchangers, or the debris abrades the moving parts thus rendering the system "*unable to perform the intended safety function*" [Gundersen Decl. 17.2]

3. The third scenario acknowledges the presence of the initial leak that may or may not have grown significantly. However, in this scenario, it is the structural weakness created by the hole or holes in the pipe or tank, which render the system "*unable to perform the intended safety function*". [Gundersen Decl 17.3]

> The hole or holes act as stress risers and increase the likelihood of gross failure under the stress of accident conditions.
>
> Given that the inadequacies of the Aging Management Plan have allowed the creation of a hole or holes, and that the applicant has not structurally analyzed the presence of such holes, it is my opinion that the system would be operating outside its regulatory design basis criteria.
>
> Holes that reduce the structural integrity of pipes are particularly worrisome at elbows and flanges (similar to the aforementioned Byron incident) and would render the pipe or tank "*unable to perform the intended safety function*" in the event of a Safe Shutdown Earthquake (SSE). As the nuclear industry well knows, the small earthquake at the Perry Nuclear Power Plant in Ohio did cause leaks in plant piping, and this mild earthquake was not at all comparable to a SSE.
>
> According to NRC regulations, all nuclear power stations must have certain structures, systems, and components requisite to safety, designed to sustain and remain functional in the event of maximum earthquake potential. Unidentified holes in safety related underground pipes place those pipes in an unanalyzed condition outside the scope of the regulatory design basis for the Applicant's Pilgrim Nuclear Power Plant.
>
> In light of the newly discovered Tritium leaks, it may in fact be true that a significant safety system has already been compromised. Moreover, it

seems in fact that the applicant Entergy's Aging Management System did not uncover those leaks, or did not do so in a timely manner.

III. MANAGING INTERNAL AND EXTERNAL CORROSION

To manage internal and external corrosion at Pilgrim Station, the Initial Statement, at 8, explains that the following will be relied upon during license renewal: metals, linings, coatings, soil, and handling; the Buried Piping and Tanks Inspection Program; water chemistry and the service water integrity program; and additional monitoring programs for the CSS and SSW Systems.

Further, the Applicant claims in their Initial Statement [at 15] that the "AMPs for those buried components within the scope of license renewal...are programs that have been shown to be effective by operating experience and the GALL report, and thus provide reasonable assurance that such components will continue to perform their intended function during the period of extended operation."

Contrary to the Applicant's conclusion, Pilgrim Watch will demonstrate why these measures do not provide reasonable assurance at the required 95% confidence level and that Entergy has failed to provide sufficient facts indicating otherwise.

Pilgrim Watch's expert summarized our position that, "based upon my review of Pilgrim's AMP, it is my opinion that the applicant has not shown that the proposed AMP is adequate to assess and assure that underground piping and tanks will be able to withstand the stresses of an additional 20-year license extension." [Gundersen Decl. 11 at page 3]

Entergy's claim is baseless on a very fundamental level. No reactor has operated 40 years, 50, years, 55 years or 60 years. There is no operating experience. And as far as operational experience at Pilgrim Station to date, it was described in the SER as "limited experience with the inspection of buried piping" [SER at 3-37, Exhibit 6]; and, even that limited experience showed that corrosion – pipe failure - occurred.

Defense-in depth: Entergy's logic that only the AMP is needed contradicts the fundamental approach to safety in the nuclear industry, defense-in-depth. Time and again, defense-in-depth is used to provide layers. The intent is to provide numerous, highly reliable layers. When multiple layers are provided with each layer having as few and as small holes as possible, the risk that all the holes line up to cause all layers to fail is minimized. But Entergy wants a single layer, the AMP. If the AMP were 100 percent reliable, a single layer would suffice. But the record is abundantly clear that the AMP is not 100 percent reliable. The NRC's generic communications program is filled with reports of AMP failures.[50] If the AMP were full-proof, the continual expansions and revisions to it would not be present. There have been continual revisions, so it is not full-proof.

A. Effectiveness of Metals, Linings, Coatings, Soil, and Handling

BPTIP measures used to "protect" against corrosion include: (1) metals and cured in place lining that they incorrectly claim are "corrosion resistant;" (2) protective coal tar or epoxy coatings for buried piping; and (3) procedures and precautions that they incorrectly claim "ensure piping structures are installed in non corrosive soil and are excavated and handled in a manner that does not damage the coating" [Entergy's Initial Statement at 9]. The foregoing is overboard – a wish not a reality.

1. Metals and cured in place lining are not "corrosion resistant."

[50] See, for example: http://www.nrc.gov/reading-rm/doc-collections/gen-comm/info-notices/2007/in200701.pdf ;http://www.nrc.gov/reading-rm/doc-collections/gen-comm/info-notices/2004/in200409.pdf ;http://www.nrc.gov/reading-rm/doc-collections/gen-comm/info-notices/2004/in200405.pdf

The Applicant says, at 10, that the CSW buried piping is made of stainless steel and that it is "resistant to corrosion." Stainless Steel is not corrosion resistant as discussed above, at II A. 7.1. The Brookhaven Report, at 29, Exhibit 8, discusses industry experience with corrosion of stainless steel. For example Information Notice 85-30 was issued to alert reactors of significant pitting at H.B. Robinson Unit 2 due to MIC identified in stainless steel sections of a service water system after an extended outage. The importance of the example is that stainless steel is not a magic bullet - corrosion is far more complex.

2. External coating: Protective coal tar or epoxy coatings for buried piping provide initial protection but no guarantee, they eventually deteriorate especially in moist soils such as Pilgrim's; coatings may be improperly applied to the pipe; and/or damaged during installation or accidentally from work performed in the area for other purposes.

Operating Experience: The SER, 3-37, Exhibit 17, sites specific historical experiences – Salt Service Water system (SSW) - states that,

> "...SSW system has had leaks on the buried inlet (screen house to auxiliary bays) piping due to internal corrosion. The original piping material was rubber-lined carbon steel wrapped with reinforced fiberglass, coal tar saturated felt, and heavy Kraft paper. The leaks were determined to be results of the rubber lining degrading from contact with sea water. These pipes were replaced in 1995 and 1997 with the *same external and internal coating as for the original pipe*." [Emphasis added]

3. Soil and Handling: Procedures and precautions are incorrectly claimed to "ensure piping structures are installed in non corrosive soil and are excavated and handled in a manner that does not damage the coating."

3.1. Soil: Pilgrim is directly beside the ocean; the soil by definition is corrosive. First it is a basic fact that you need water and moisture for external corrosion to occur; it deteriorates the outside coating. In order for the metal pipe to corrode you need a

cathodic depolarizer. As explained above, this may be oxygen as occurs in the soil; bacteria; low pH generated by decayed organic matter and acid rain; and stray currents that occur at a power generating station. Entergy has provided no documents showing a recent analysis of the soils surrounding these pipes. We would have to see the study to assess its methodology and the assumptions or factors considered during any soil inspection. Their expert [Entergy's Prefiled at A87] simply says that he "reviewed the 1992 soil analysis taken near the SSW system loop A and loop B and an October 2005 analysis of groundwater" – claimed to be a good indicator of soil condition. The soil analysis was done 16 years ago; and analysis of the ground water does not tell all we need to know. Soil acidity varies from place to place even on a small lawn, let alone Pilgrim's reactor site. Entergy's own *Buried Piping and Tanks Inspection Program*, at 11, says that "soil resistivity measurements must be taken at least once per 10 years unless areas are excavated or backfilled or if soil conditions are known to have changed for any reason" [Exhibit 14, page 11].

3.2. Excavation and handling: Entergy's claim that piping structures are, "excavated and handled in a manner that does not damage the coating" is overboard - human and mechanical error have occurred and are likely to occur again. For example, the SER, at 3-37, Exhibit 17, described a leak in the fire water underground distribution system and that the probable cause was induced, "most likely by fabrication anomalies compounded by marginal installation leaks." Operating experience, as the SER explain, is limited; therefore we have no idea, and neither does the Applicant, what other fabrication anomalies compounded by marginal installation leaks has, or will, occur.

4. Pilgrim Watch concludes with the obvious that coatings deteriorate. Therefore cathodic protections, more frequent inspections and monitoring wells are required to decrease risk.[51]

4.1. Cathodic protection: The Gall Report (NUREG-1801, Rev 1, XI, M-96, September 2005, at 10, Exhibit 18) says quite clearly that pits have been detected on the outside of

[51] Gundersen Decl. at 18.2

buried pipe after far less than 60 years. However coated pipe that has been cathodically protected has been unaffected after 60 years of service. The Brookhaven Report at 4.1 describes the system. Cathodic protection is a technique which connects a metal of higher potential (anode) to the buried metallic piping. This creates an electrochemical cell than causes the lower potential pipe to become a cathode thereby protecting it from corrosion. In Galvanic protection systems, anodes are used which have a natural potential more reactive than that of the structure being protected. They are used at some reactor sites. They, like anything else, are not 100%. However their use adds another arrow in the quiver and helps reduce risk. *There is no evidence provided that the pipes at Pilgrim are cathodically protected, in whole or part.*

Pilgrim's expert [Gundersen Decl 18.2], the GALL and the Brookhaven Report, as well as surveys recommended by NACE,[52] make strong recommendations that preventative measures, as well as monitoring, must include cathodic protection. Entergy and the NRC Staff blithely disregard this advice and formulate the AMP as repairing leaks when they occur – waiting until the horse has left the barn to check and then close the door.

B. Buried Piping and Tanks Inspection Program

1. Description Buried Piping and Tanks Inspection Program (BPTIP)

The Applicant describes the inspection and Aging Management Programs for underground pipes and tanks at Pilgrim in Appendix A.2.1.2. and B.1.2 of the renewal filing, Exhibit 19.

The BPTIP breaks down into three parts.

a. Appendix A.2.1.2. Buried Pipes and Tanks Inspection Program page A-14 states that buried components are inspected when excavated during maintenance

[52] National Association of Corrosion Engineers (NACE) RP-0285; RP-0169-96; SP-0285; SP-0169-2002

and if "trending" identifies a susceptible location, this area with a history of corrosion might have additional inspections, coating or replacement.

b. Focused inspections will be performed within 10 years of the license renewal unless an "opportunistic inspection" which allows assessment of pipe condition without excavation, occurs within the ten-year period – either visual or by, "Inspections via methods that allow assessment of pipe condition without excavation may be substituted for inspections requiring excavation solely for the purposes of inspection." These latter inspections can include phased array Ultrasonic Testing (UT) technology that provides indication of wall thickness for buried piping without excavation. The application says that use of such methods to identify the effects of aging is preferable to excavation for visual inspection, which could result in damage to coatings or wrapping. (Application, B.1.2, page B-17).

c. *"Prior to entering the period of extended operation,* the applicant is to verify that at least one opportunistic or focused inspection is performed during the past ten years."

2. BPTIP does not provide reasonable assurance.

Pilgrim Watch, contrary to the Applicant, demonstrates that the BPTIP does not provide assurance and certainly not at the 95% confidence level.

2.1. Periodic or Opportunistic Inspections when Excavated During Maintenance:

The BPTIP describes the program as, "Buried components are inspected when excavated during maintenance and if "trending" identifies a susceptible location, this area with a history of corrosion *might* have additional inspections, coating or replacement." (Emphasis added)

The Applicant explained both in the Prefiled Testimony and in their Motion for Summary Disposition the purpose of this part of the BPTIP.

> The purpose of the *periodic and opportunistic inspections* under the PNPS BPTIP is to ensure that the protective coatings are being maintained in place to protect against corrosion of the *external surfaces* of the buried components. *If* coatings on buried components are maintained, the coatings will prevent the soil from adversely affecting the exterior surface of the components such that they can continue to perform their intended function. (Emphasis added) [Entergy's expert, Cox Decl. at ¶¶ 23-24, Exhibit 20]

This does not provide assurance for five fundamental reasons.

2.1.1. The first issue is that the inspections only focus on external surfaces; and we know deterioration can occur as well from the inside. Brookhaven at 41, Exhibit 8, said that,

> Since degradation mechanisms can cause aging effects on the interior and /or exterior of buried piping systems, information about the condition of the inside and outside surface of buried piping is important.

We know that if a corrosion - induced leak was to occur from the inside of the pipe, and then the outside wraps would become wet next as a result and exacerbate external corrosion. [53]

2.1.2. Second, the program appears to leave detecting a leak or corrosion to happenstance. It limits knowledge of corrosion to the area that happened to be excavated during maintenance; and we do not have 95 % assurance that lessons learned can be applied to the remaining sections of the component or to other components. For example if the area that "just happened" to be examined was not a weld, dead spot, elbow or

[53] Gundersen 12.4.6.3 says that, "My 35-years in nuclear engineering has shown me again and again that corrosion from the inside can bring about failure."

fitting then the parts of the components most susceptible to corrosion would have been missed. And more basically we know from the Brookhaven Report that we can not assume that corrosion is constant across a pipe. Brookhaven at 103, Exhibit 8, says specifically that, "...different segments of the pipe may degrade at different rates."

2.1.3. Third, "This area with a history of corrosion *might* have additional inspections, coating or replacement"; then, again, it might not – there is no assurance. There is no requirement for the licensee to take any action – fixing it, do further inspections, perform a root cause analysis. According to The Brookhaven Report, FN 97,, Exhibit 8, "Although future inspections are an option, there is no requirement to do so."

The Brookhaven Report was written in 2005, and three years later, there still is no requirement even after the recent "epidemic" of reports of leaks from reactors around the country.

The LLTF issued recommendations to address leaks of contaminated liquids, some from buried pipes and tanks. Many of their recommendations obviously apply to leaks of other liquids – corrosion is corrosion. The implementation status of those recommendations as of November 19, 2007 was recently issued.[54] The LLTF had 26 recommendations; only 7 have been completed.

For example, recommendations left un-done that are pertinent include:

- LLTF recommendation (2) says that, "The NRC should develop guidance to the industry for detecting, evaluating, and monitoring releases from operating facilities via unmonitored pathways." It is merely in-progress as of November 19, 2007. Without requirements for detecting, monitoring and evaluation releases, how is the public provided 95% assurance?

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54 http://adamswebsearch2.nrc.gov/idmws/doccontent.dll?library=PU_ADAMS^PBNTAD01&ID=073240116

- Recommendation (5) "Develop guidance to define the magnitude of the spills and leaks that need to be documented by the licensee..." Again, "in-progress" so that the licensee remains in charge of when and what to report.

- Recommendation (7), "The NRC should evaluate the need to enact regulations and/or provide guidance to address remediation;" and again "in-progress." There remains no requirement to fix or remediate the problem; and we know that corrosion gets worse with time and leaks or breaks do not fix themselves. Assurances of safety require specified criteria for component repair or replacement. It should not be an option - relying on a licensee judgment call that well may be based more on economics than safety.

- LLTF Recommendation (17), "Inspection guidance should be developed to review onsite contamination events including events involving contamination in ground water;" the status is "in-progress."

This says to us that inspections will continue "willy-nilly" - problems will be discovered by "happenstance." NRC does not have a target date to complete implementation or review of the LLFT recommendations. There is no assurance that they will be implemented, or implemented in such a way so as to provide 95% confidence.

2.1.4. Fourth: No mention is made that if deterioration is found during the opportunistic inspection anywhere on the component that it will trigger further inspections along that component. NUREG-6876 warned at 129, Exhibit 8, that degradation of coatings or linings is an indication that other locations along the pipe should be inspected because degradation at those locations might be more severe than at the observed locations.

2.1.5. Fifth: Pilgrim Station's new monitoring well program is inadequate as a supplement to the BPTIP for detection purposes. Pilgrim Watch's hydrology expert, David Ahlfeld said,

> The 4-well monitoring system apparently used by Entergy does not meet reasonable standards for monitoring network design.

And

> Indeed, a 4-well monitoring system is more typical of that used for a retail gasoline station or a small municipal (non-hazardous) landfill. That it should be considered adequate for a large industrial facility such as PNPS is unrealistic. [Ahlfeld Decl. at 3]

2.2. BPTIP (step 2) says that focused inspections will be performed within 10 years of the license renewal unless an "opportunistic inspection" which allows assessment of pipe condition without excavation, occurs within the ten-year period – either visual or by, "Inspections via methods that allow assessment of pipe condition without excavation may be substituted for inspections requiring excavation solely for the purposes of inspection."

Pilgrim Watch contends that a loosely defined inspection half way through the 20 year license after the reactor has been in operation for 50 years is hardly reassuring to the public - at any confidence level. Neither the Applicant nor the NRC Staff has provided evidence to demonstrate otherwise. In point of fact they can not. No reactor has operated 45, 50 or 60 years so that there is no industry experience for the effectiveness of the AMP.

2.2.1. The elements of the focused inspection program lack any specificity. Instead it provides a general framework - ultimate flexibility - for the licensee to decide what they will or will not do.

They include [NUREG-1801, Rev.1, X I M32, Exhibit 18]:

- BPTIP: "A determination of the sample size based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience."

Right from the start it is clear that sample size will be small because operating experience at Pilgrim is limited. The Final SER Report stated, at 3-37, Exhibit 17, that, "...in the past five years, the applicant has had limited operating experience with the inspection of buried piping..."

Additionally, they have had no detection method - monitoring wells and hence they have had no way of accurately knowing what pipes/tanks are leaking now or have leaked in the past.

The new and totally inadequate 4-well monitoring system did detect tritium. It will take many months to determine the source. It suggests that had an effective system been in place over the years, operational history of leaks could well be as extensive as at some other reactors around the country.

In regard to the "environment" neither the applicant nor NRC has provided any evidence [recent hydrological-geological studies] to indicate the soil properties (*present-day* environment) surrounding the buried pipes in scope.

- BPTIP: "Identification of the inspection locations in the system or component based on the aging effect; determination of examination technique; evaluation of the need for follow- up examinations if aging related degradation is found."

In order to provide any assurance that this program will be effective, there are many questions to be answered. For example: [Gundersen Decl. at 12.4.6.4]

  - Who chooses the sampling location - the licensee or NRC?
  - How large a sample is required, < 1%, < 5%? We need a number.

- Are samples required to be taken from the most susceptible locations, such as from low flow areas/dead spot, elbows, joints, and welds?
- Are samples taken from the same locations, inspection after inspection, to establish trending as well as from new locations along the pipe? The Brookhaven Report, at 129, said that degradation of coatings or linings is an indication that other locations along the pipe should be inspected because degradation at those locations might be more severe than at the observed locations.

- The BPTIP says that there is an "evaluation of the need for follow-up examination."

Again, in order to provide any assurance that this program will be effective, there are many questions to be answered. For example:

- Who is the evaluator – the NRC or the Licensee?
- Is there a pass/fail grade to determine when a "follow up examination" is required? This appears to be a situation where the licensee writes their exam and then grades it.

- BPTIP: In NUREG-1801's, exhibit 18, discussion of the detection of aging effects they say, "The inspection includes a representative sample of the system population, *where practical*, focuses on the bounding or lead components most susceptible to aging due to time in service, severity of operating conditions, and lowest design margin."

Pilgrim Watch finds "where practical" very troubling. This allows convenience and money to be the driving force behind what is practical to examine; and further there is no assurance that where it is not practical to examine that corrosion does not exist.

Entergy's Prefiled Exhibit 5 (5.5), Exhibit 14, takes it a step further and says that, "[5] the determination of the inspection locations may also consider (the) ease of access to the inspection point..." However what assurance is there that the easy places to inspect are

the ones that should be inspected – the location that is corroded or that will indicate serious corrosion down the line?

2.2.2 NUREG-1801 seems to imply that an actual one-time inspection may not occur. It says that, "One-time inspection, *or any other action or program*, created to verify the effectiveness of the AMP and confirm the absence of an aging effect, is to be reviewed by the staff on a plant-specific basis."

How are citizens provided assurance that aging is managed to a 95% confidence standard when we are simply told that there *might* be some "other action or program" created down the road that will be determined adequate based on undefined criteria?

Last, as explained in Appendix B of the Application, Exhibit 19, the inspections that do not include excavation can include phased array Ultrasonic Testing (hereinafter UT). This technique provides indication of wall thickness for buried piping without excavation. The application says that use of such methods to identify the effects of aging is preferable to excavation for visual inspection, which could result in damage to coatings or wrapping. (Application, B.1.2, page B-17, Exhibit 19). However, UT methods to measure the thickness of the component, as stated by the applicant would not necessarily detect a hole or crack in the component. And "array UT technology" implies testing only selected areas of the pipe/tank, not testing along the entire structure's surface area. Simply testing selected areas can miss holes, cracks or vulnerably thin sections of these components. The application also states that these methods have not been used in the past, so there is no operating experience to rely on.

2.2.3. Pilgrim Watch concludes that the "One-Time Inspection Program" provides no assurance and Entergy has failed to demonstrate otherwise.

It may tell something about the condition of the component the day the inspection occurs and only for an unspecified number of components and for an unspecified section of the component(s). But it will not tell what will happen on the increasingly aging components

1-10 days, months, or years after the inspection; or on the sections of the components not inspected.

Especially troubling is that the corrective action protocol lacks any substantive requirements and leaves the decision making effectively to the Applicant. For example, Entergy's Prefiled Exhibit 5 [Pilgrim Watch's, Exhibit 14], *Buried Piping and Tanks Inspection and Monitoring Program*, at 14, says that,

> 5.8 Corrective Actions: A Condition Report (CR) shall be written if acceptance criteria are not met. The corrective action *may* include engineering evaluations, scheduled evaluations, scheduled inspections, and change of coating or replacement of corrosion susceptible components. Components that do not meet acceptance criteria shall be dispositioned by engineering. [Emphasis added].

The only requirements if acceptance criteria are not met are to write a report (there is no indication that the report is shared outside of Pilgrim) and to leave any decision about what to do, or not do, to the engineering department. This can hardly be interpreted as providing "reasonable assurance" to the public.

Because the conditions for corrosion are present at this facility, and because there is evidence that corrosion has already occurred [SER, November 2007 at 3-37, Exhibit 17], Pilgrim's aging management plan must supplement the inspection protocol, as described by Arnold Gundersen, Exhibit 1.

2.3. BPTIP, step 3: "Prior to entering the period of extended operation, the applicant is to verify that there is at least one opportunistic or focused inspection performed during the past ten years."

The inspection prior to entering extended operation does not provide any assurance either that there will not be leaks or breaks that could develop as to cause those components to be unable to perform their intended safety function.

2.3.1 The inspection prior to license renewal encompasses all the inspection weaknesses, described above.

2.3.2. It allows potentially 19 years between inspections. The original forty year license ends 2012. If Entergy performed that one opportunistic inspection in 2003 and chooses not to perform another one time inspection until just before 2022, 19 years would have transpired between inspections. This means that there could be two "inspections," of one sort or another, in 29 years of operations of a plant designed and built in the 1960's. This does not add up to 95% certainty.

2.3.3. In addition there is no mention of the precise age of the components that will be inspected in the 10-year period prior to re-licensing. NUREG-1801, Rev 1, XI M-107, September 2005, Exhibit 18, says that,

> ...the applicant should schedule the inspection no earlier than 10 years prior to the period of extended operation...as a plant will have accumulated at least 30 years of use before inspections under this program begin, sufficient times will have elapsed for aging effects, if any, to be manifest.

Pilgrim Watch wants to know whether Entergy adhered to this and that the portion(s) of the component(s) inspected were in fact 30 years of age or older.

2.3.4. **Baseline analysis**: The one time opportunistic or focused inspection performed during the past ten years prior to extended operations must not be confused with establishing a baseline analysis. In fact Entergy in their Exhibit 5 (Pilgrim Watch's Exhibit 14), section 3.0 definitions, defines baseline inspection as, "The inspection of a new or replaced component that has not previously been involved in plant operations."

Instead, Pilgrim Watch asserts that this portion of the aging management program must be enhanced and Pilgrim required including a complete and thorough base line analysis prior to license extension [Gundersen Decl.18.1].

The proposed AMP does not provide any hard evidence regarding the baseline/current conditions of buried tanks and piping [including weld junctures] nor do they provide any support for postulated or "typical" corrosion rates within the facility.

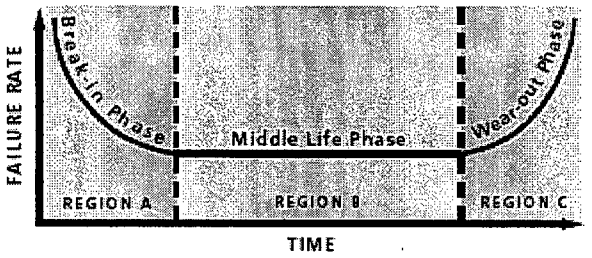
Because it will be virtually impossible to assess the extent of the damage visually from the outside (as the pipes and tanks are buried), ultrasonic testing (UT) measurements must be made over the full periphery of each weld from the inside. Special attention must be given to those welds that are located upstream or downstream of a flow disturbance.

It will not be possible to assess possible damage below the coating in the pipe/tank body. Therefore all piping needs to be pressure tested to at least twice the operating pressure. The inability of the Applicant to perform pressure tests should be no reason for relief [Gundersen Decl at 18.1.4].

3. Buried Piping and Tanks Inspection Program - Summary

The BPTIP does not provide assurance, certainly not at the 95% confidence level. Corrosion has occurred at Pilgrim Station in less than 40 years of operations and experience has been very limited; there is no industry experience with the AMP so there is no assurance going forward about what will happen in 50 years. Deterioration of buried pipes in nuclear power plants is well established. It is axiomatic that failure rate increases over time.

Figure 1 The Bathtub Curve



Source: NASA, 2001.

As reactors continue to operate beyond 40 years it is essential to assess the effects of age-related degradation more frequently than the current program calls for.

Pilgrim Watch believes that NUREG-1801, Rev. 1, Sept 2005, XI M-105, Exhibit 18, supports our contention that additional confirmation is appropriate. It says that,

> Program Description: The program includes measures to verify the effectiveness of an aging management program (AMP) and confirm the significance of an aging effect. Situations in which additional confirmation is appropriate include (a) an aging effect is not expected to occur but the *data is insufficient* to rule out with reasonable confidence; (b) an aging effect is expected to progress very slowly in the specified environment, but the *local environment may be more adverse* that that generally expected; or (c) the characteristics of the aging effect include a *long incubation period.* For these cases, there is to be confirmation that either the aging effect is indeed not occurring, or the aging effect is occurring very slowly so as not to affect the component or structure intended function during the period of extended operation" [emphasis added].

Situations in which NUREG 1801 found additional confirmation appropriate apply to Pilgrim.

3.1. Pilgrim's operating experience is limited so that there is insufficient information. The SER at 3-37, Exhibit 17, says that "... in the past 5 years, the applicant has had limited

experience with the inspection of buried piping, mainly on the fire water underground distribution system." Therefore operating experience is limited simply to portions of two systems - the Salt Water Service System and the Fire Water Protection System. We have no experience with the condensate system or gas treatment system. What little experience is discussed shows that there has been corrosion – external and internal – and hence the type of failures identified could have occurred anywhere in buried piping systems if they had taken more opportunities to inspect the system or had installed monitoring wells near to those systems to detect leaks.

3.2. The aging effect can not be adequately predicted –whether it is expected to progress very slowly or very rapidly. There has not been a complete investigation to establish as baseline rate. The local environment – aggressive nature of the soil – has not been properly evaluated. Any corrosion rate at this point is guess work. The NUREG warns the "local environment may be more adverse than that generally expected. " Our best guess is that it is indeed, discussed above at pages 26-29.

C. WATER CHEMISTRY AND SERVICE WATER PROGRAMS

In addition to the BPTIP the Applicant claims in their Prefiled Testimony that other more routine programs are effective in preventing corrosion – Water Chemistry & the Service Water Integrity Program. These two programs address internal corrosion. There is no evidence provided that they provide reasonable assurance at the 95% confidence level.

1. Water Chemistry Program – no assurance

1.1. The applicant states that the water chemistry program in addition to the BPTIP should provide assurance. However the Applicant does not provide hard data to satisfy the 95% confidence rule. The GALL Report, NUREG-1801, Rev 1, September 2005

explains at XI M-11, Exhibit 18, that, "This is a mitigation program and does not provide for detection of aging effects."

1.2. NUREG-1801, Rev.1, XI M2, Exhibit 18, states that, "The water chemistry programs are generally effective in removing impurities from intermediate and high flow areas ... (and)...may not be effective in low flow or stagnant flow areas." The Applicant does not provide: data to indicate whether and where the components under consideration have low flow or stagnant flow areas; any previous examination schedule of those areas and results from those examinations; and last there is no indication of proposed examinations in the future of those low flow and stagnant flow areas. NUREG-1801, Rev.1, XI M2 claim of "generally effective" is a too vague term to provide assurance.

1.3. Consider, also, that the water chemistry program at Pilgrim is judged on the period of time that it has been in effect in the past and the age of the component when the water chemistry program began. The licensee does not provide the "start date;" nor did they provide the date that changes to the program were made and the reasons for the changes.

1.4. Further the applicant states in non-quantitative terms in their Prefiled Expert Testimony [at A91 and A92] that it "minimize(s) the potential for loss of material and cracking due to internal corrosion" (by) "limiting the levels of contaminants...that could cause loss of material and cracking." Even they do not claim, or provide evidence, that it eliminates the loss of material or cracking. Also, we are concerned about what may happen not by design or plan – for example what may happen as a result of personnel error or error in the water chemistry instrumentation.

1.5. Last, there is no evidence presented that reactors that have leaked around the country, leaked because either they did not have a water chemistry program or that it was inferior to the program at Pilgrim. Further there is no evidence of where the Tritium discovered in a well or boring at Pilgrim December 2007 came from; whether it came from a leak in a pipe within scope; and whether a root cause analysis had been done to demonstrate that the corrosion was due to an ineffective chemistry control program.

1.6. Entergy says in their Expert Prefiled Testimony [at A 93] that the effectiveness of the Water Chemistry Control Program at PNPS has been confirmed by operating experience. Their claim is overboard. The SER [at 3-37], Exhibit 6, specifically said that "...in the past five years, the applicant has had limited experience with the inspection of buried piping." Because of limited inspections and no monitoring well program, the Applicant has no basis to prove the effectiveness of their program.

2. Service Water Integrity Program - degradation identified

2.1. This program, like the Chemistry Control Program, addresses internal corrosion. Interior corrosion can work its way through to the exterior; and as the Brookhaven Report warned [at 129, Exhibit 8] degradation to the pipe interior coating and or lining may cause fouling of the line and equipment which can affect performance of the system.

2.2. The SSW Program is a method to reduce – not prevent – corrosion. There are no monitoring wells to detect leaks if and when they occur; and the inspection program has been limited in the past and the BPTIP provides limited inspections in the future.

2.3. The Applicant does not provide any data that would satisfy that the program provides assurance – certainly not at the 95% confidence level.

For example, the Applicant's Prefiled Expert Testimony [at A99] admits that the program is inconsistent with the program outlined in NUREG-1801.

- Not all the components at PNPS are internally coated – example, the titanium inlet piping.

- NUREG-1801 specifies testing and inspections annually and during refueling re-fueling outages. Pilgrim only tests during refueling outages, not annually.

2.4. Entergy's Prefiled Expert Testimony [at A96] says that, "Under the program (Service Water Integrity Program), the components of the SSW system are *routinely* inspected for internal loss of material and other aging effects that can degrade the SSW system."

"Routinely inspected" does not satisfy NUREG-1801 nor does it provide enough detail to assure how complete the inspection is. The re-fueling inspections that occur every 18 months are clearly only partial inspections. The Applicant's Prefiled Testimony [at 98] says that, "The in-service inspection program for the SSW currently requires PNPS to undertake a complete ultrasonic or visual of the CIPP...after the CIPP has been in service for 20 years..." "Routinely inspected" does not provide enough detail to assure that inspections occur with sufficient frequency or are complete enough to identify a problem before there is a leak.

2.5. Operational History shows degradation, it does not provide assurance. The SER [at 3-37, Exhibit 6] sites specific historical experiences – regarding the Salt Service Water system (SSW), it states that,

> "...**SSW system has had leaks on the buried inlet** (screen house to auxiliary bays) piping due to internal corrosion. The original piping material was rubber-lined carbon steel wrapped with reinforced fiberglass, coal tar saturated felt, and heavy Kraft paper. The leaks were determined to be results of the rubber lining degrading from contact with sea water. These pipes were replaced in 1995 and 1997 with the *same external and internal coating as for the original pipe.*" [Emphasis added]

This tells us that salt water provides a corrosive environment; that the pipes were replaced awhile back with the same external and internal coatings so that they are likely to leak again.

The SER goes on to describe the SSW discharge,

"In addition, the **SSW buried discharge piping** (also rubber-lined carbon steel with external pipe wrapping) from the auxiliary bays to the discharge canal experienced severe internal corrosion due to failure of the rubber lining."

And,

"Since then, the entire length of both SSW buried discharge loops have been lined internally with pipe linings cured in place-"B" Loop in 2001 and "A" Loop in 2003."

What this very limited "operating experience" demonstrates is not that the program in place is acceptable but that there is corrosion and a demonstrated need for more frequent inspections and monitoring wells added to the aging management program. Entergy claims that the operational history did not impair the intended function of the system.

Byron Nuclear Power Station's experience of rust holding the system together provides a warning to all reactors that greater assurance is required.

2.6. An additional factor not mentioned by Entergy is that the screens at the intake to filter debris have not worked in the past. Therefore more debris, corrosive materials, entered the system at that time. The operational history of the screens since the piping was relined in 1995 and 1997 needs to be determined.

D. ADDITIONAL SURVEILLANCE PROGRAMS FOR THE CSS AND SSW

1. Condensate Storage System (CSS) piping: Although not part of the AMP, Entergy's Prefiled Initial Statement, at 13, discusses the various level indicators and monitoring schedule of those indicators in the CST. We are told that the CST is equipped with a level indicator which is monitored every four hours and that the water level is maintained to be above 30 feet, only 11 feet of water is required to operate for the HPCI and RCIC function. Thus the CSTs would have to loose 20 feet of water before the intended

function would be impaired. Further the assured source of water for the HPCI and RCIC is the suppression pool.

Pilgrim Watch sees the following potential problems.

- The indicators and the monitoring of those indicators could be flawed. For example in 1992, 1994 and 2001 NRC Inspection Reports for Pilgrim discussed the failure of a monitoring level device needed to show the water level over the core.[55] An example demonstrating that monitoring devices do not always work according to design.

- Second if the systems they have in place work, a small leak would go undetected for an extended period. Such a small leak would gradually degrade the external coatings on the pipe in the vicinity of the leak setting the stage for the leak to increase to the point that the system can not operate as intended.

- Third the indicators tell nothing about corrosion; they can not predict a pending failure.

2. SSW System Buried Piping: Entergy reports that they monitor the system by performing a monthly flow rate test on the seawater flow through the system. They claim that monitoring wells would not be more effective because: (a) the "SSW does not normally contain radiation; (b) the piping is over 200 feet long and using wells would be difficult and inefficient; and (c) if radiation was found a monitoring well would not distinguish a leak from the SSW from any other underground leak.

Pilgrim Watch takes issue with Entergy's argument.

(a) The SSW piping system can contain radioactive water. The SSW system circulates ocean water through heat exchangers in the RBCCW and TBCCW systems. The SSW

[55] NRC Event Report 37938, 04-21-01; 50-293, 04-92.

removes the heat, allowing cooling RBCCW and TBCCW water to be reused for cooling. The water may become radioactively contaminated. If tubes were to leak inside the RBCCW or TBCCW heat exchangers, the SSW water is supposed to leak into the plant instead of the potentially radioactively contaminated RBCCW or TBCCW water leaking out, but that differential pressure is not always maintained and SSW might be radioactively contaminated. There is no real-time radiation monitor at the mouth of the discharge pipe. A leak anywhere in the SSW piping would impact the intended safety function of the reactor; and, although not of interest to the ASLB, a leak of contaminated water into Cape Cod Bay could negatively impact public safety. Second monitoring wells could check for some other indicator of leakage such as salinity. Well testing does not require the water to be radioactive.

(b) The length of the pipe – 200 feet- is irrelevant. A longer length pipe simply would require more wells.

Because Entergy uses their prefiled testimony to argue that monitoring wells are unimportant; Pilgrim Watch will take an equal opportunity and explain why their arguments are indeed hollow and that an effective monitoring well system is important.

E. Entergy's Buried Piping and Tanks Inspection Program and Monitoring Program (11/19/07)[56]

Entergy initiated a new program 11/19/07, the *Buried Piping and Tanks Inspection Program and Monitoring Program*, Entergy's Prefiled Testimony, Exhibit 5 [called here "The Program"].

The Program demonstrates that Entergy agrees with Pilgrim Watch that the AMPs for buried components within scope are not sufficiently effective to provide reasonable assurance that such components will perform their intended functions either now, or

[56] Entergy's Buried Piping and Tanks Inspection Program and Monitoring Program, 11/19/07, Entergy's Pre-Filed Testimony, Exhibit 5, January 8, 2008; attached here as Exhibit 14; and ADAMS ML080160268.

during the period of extended operations, and therefore in Entergy's view a supplemental program is required. The Program was written after these proceedings began and certainly well after the Gall Report.

The purpose of Entergy's document is to provide requirements for each site to develop its site specific Program. It is a framework. The Program specifies the content, scope, ranking methodology, priorities and inspection frequency of the buried piping and tanks.

Considering that both the Petitioner and Applicant agree that more should be done to provide reasonable assurance, the Program should be examined to determine what elements of it should be enhanced and turned into commitments in order for the license to be approved. It should be obvious that the public requires a commitment, not simply a voluntary plan, and for it to be plant specific, not simply generic.

Section by Section Analysis [Gundersen Declaration at 12]

1. **Section 5.0**, subsection [1] at page 7 acknowledges right at the beginning that "The risk of a failure caused by corrosion, directly or indirectly, is probably the most common hazard associated with buried piping and tanks."

Steps required in building a risk assessment tool are discussed in Section 5.0, subsection [2] on page 7. However the program fails in that it does not require a complete baseline review. There is no indication that the entire component is supposed to be examined; instead escape hatches are provided to the licensee - such as [at 2a] "the size of each section shall reflect practical considerations of operation, maintenance, and cost of data gathering with respect to the benefit of increased accuracy." Any program worth its salt would require a thorough baseline inspection along the entire length of the pipe.

2. **Section 5.2, Scope Program** subsection [3] at page 8 acknowledges the validity of Pilgrim Watch's initial contention that, "The program shall include buried or partially

buried piping and tanks that, if degraded, could provide a path for radioactive contamination of groundwater. Some examples are: Buried piping containing contaminated liquids." Entergy agrees that "radioactive contamination of groundwater" is an important issue and belongs in the Buried Piping and Tanks Inspection and Monitoring Program.

3. Section 5.4 Identification of Buried Piping and Tanks to be Inspected and Prioritized, page 9, Subsection [1] directs the licensee to develop a list of all systems containing buried piping and tanks and to identify those sections, collecting physical drawings, piping/tank installation specifications, piping design tables and other data needed to support inspection activities. Pilgrim Watch knows that the criteria must specify other key parts of the components. For example: wall thickness; number and location of welds, elbows, flow restrictions; blank flanges; high velocity portions; whether the component has substandard parts; the age of the components parts; cathodic protection; last inspection date and report number; and manufacturers warranty, if any. This information is the type of information that is needed when the NRC Staff conducts their safety evaluation so that the SER Report will be meaningful; unfortunately it was not available. The license application decision should be delayed until the information is available and critically reviewed.

Subsection [4] categorizes the piping into high, medium and low impact. High impact components require prompt attention. We agree that they should require prompt attention however Entergy's definition of "prompt" allows considerable delay –high impact buried sections shall be examined within 9 months of issuance of the procedure; and no date is given when the procedure shall be initiated. The impact assessment lists radioactive contamination as "High Risk" once again confirming the validity of Pilgrim Watch's initial contention that radioactive contamination belongs in this adjudication process. Note Table 1 below:

Table 1 Impact Assessment

	High	Medium	Low
Safety (Class per EN-DC-167)	Safety Related	Augmented QP and Fire Protection	Non-Safety Related
Public Risk	Radioactive Contamination e.g. Tritium	Chemical/Oil Treated System gases	Untreated Water SW, Demin Water
Economics (Cost of buried equipment failure to plant)	>$1M or Potential Shutdown	>$100K<$1M	<$100K

Notes:

1. Any buried section with at least one High Impact rating gets an overall High Impact rating.
2. Any buried section with no High Impact Rating but at least one Medium Impact rating gets an overall Medium Impact rating.
3. Any buried section with all Low Impact ratings is to be rated as Low Impact.

4. Section 5.5, Table 4 on page 13, "Inspection Intervals vs. Inspection Priority" reflects the outcome from an assessment of the risks from buried piping and tanks.

For example:

(a) Buried piping and tanks having high risk are specified as having an initial inspection period of 5 years with a re-inspection interval of 8 years. The time interval is too long.

(b) It does not tell how much of the component will be inspected.

(c) There is no requirement to shorten a subsequent inspection based upon the degree of corrosion discovered at the time of the prior inspection.

(d) Absent from this procedure is the prudent and practical guidance to conduct the inspection provisions of this procedure when opportunities present themselves, regardless of the inspection intervals in Table 4. For example, if a section of buried piping categorized as having "Low" inspection priority is excavated for other reasons, this excavation procedure should direct/require workers to take advantage of the opportunity and perform inspections- corrosion is neither linear nor constant across the component's length.

(e) In subsection [5], the determination of inspection locations may also consider the "ease of access to inspection point." However we know that ease of location and lack of

corrosion do not necessarily go together. In fact the odds are that a component that is difficult to access has never been inspected – all the more reason to inspect it.

5. **Section 5.6, Parameters to be Inspected**, page 13, lists: external coatings and wrapping condition; pipe wall thickness degradation; tank plate thickness degradation; and cathodic protection system performance, if applicable. The attributes that must be considered in tabulating risk are too narrow. They include: (a) soil resistivity measurement; (b) drainage risk weight; (c) material risk weight; (d) cathodic protection/coating risk weight.

The list should be expanded to include, for example, the age of the component's parts; the number of high risk corrosion areas in component such as welds, dead spots etc; counterfeit or substandard part not replaced. The list is silent on internal corrosion and we know that corrosion from the inside can bring about a failure. The section is silent on the size of the sample required; its location; and the rational for the sampling protocol – if, in fact, a sample is taken and not an inspection of the entire component.

Table 2 Corrosion Risk Assessment

Soil Resistivity, Ω-cm (Note 1)	Corrosivity Rating	Soil Resistivity Risk Weight
>20,000	Essentially Non-corrosive	1
10,001-20,000	Mildly Corrosive	2
5,001-10,000	Moderately Corrosive	4
3,001-5,000	Corrosive	5
1,000-3,000	Highly Corrosive	8
<1,000	Extremely Corrosive	10
Drainage		**Drainage Risk Weight**
Poor	Continually Wet	4.0
Fair	Generally Moist	2.0
Good	Generally Dry	1.0
Material (Note 2)		**Material Risk Weight**
Carbon and Low Alloy Steel		2.0
Cast and Ductile Iron		1.5
Stainless Steel		1.5
Copper Alloys		1.0
Concrete		0.5
Cathodic Protection	**Coating**	**CP/Coating Risk Weight**
No CP	No Coating	2.0
No CP	Degraded Coating	2.0
No CP	Sound Coating	1.0
Degraded CP	No Coating	1.0
Degraded CP	Degraded Coating	1.0
Degraded CP	Sound Coating	0.5
Sound CP	No Coating	0.5
Sound CP	Degraded Coating	0.5
Sound CP	Sound Coating	0.5

Notes:
1. Soil resistivity measurements must be taken at least once per 10 years unless areas are excavated and backfilled or if soil conditions are known to have changed for any reason.

2. Attachment 9.6 gives further insight to the corrosion of materials in soils.

6. **Section 5.7,** on page 13, provides vague remarks about **acceptance criteria** for any degradation of external coating, wrapping and pipe wall or tank plate thickness. It says that they should be based on current plant procedures; and if not covered by plant procedures then new procedures need to be developed before the inspections. The

pass/fail grade should be clearly defined. For example what precisely constitutes an "unacceptable" from an "acceptable" degraded external wrapping? The LLTF was very specific that "significant" and other such descriptions need definition.

7. **Section 5.8, Corrective Actions**, page 14, says that "a condition report (CR) shall be written if acceptance criteria are not met. Pilgrim Watch knows that any and all inspections should generate a written 'condition report' regardless of what is or is not found to maintain a permanent paper trail of all inspections.

The corrective actions *may* include engineering valuations, scheduled inspections, and change of coating or replacement of corrosion susceptible components. Components that do not meet acceptance criteria shall be *dispositioned* by engineering. [Emphasis added].

This provides no assurance to public safety for the following reasons.

a. The corrective actions *may* include engineering valuations, scheduled inspections, and change of coating or replacement of corrosion susceptible components; and they just "may not." There are no guarantees.

b. The licensee's own engineering department will deal with it; but there is no clear definition of how they will deal with it. Whatever happened to the concept that this Program would consist of layers of supervision so that the NRC would play some sort of oversight role in this program? Who sees the Condition Reports – or to put it another way, where are the reports kept, who has access to those reports, do they have to be sent to the NRC and if so under what conditions and time schedule? A more basic issue is that Condition Reports are unlikely to be written or, if they are written, to actually say anything as explained directly below.

8. **Section 5.12 Inspection Methods and Technologies/Techniques**, subsection [1] on page 15 specifies steps to be taken for Visual Inspections of buried piping and tanks. Step (g) directs the workers: "A CR [condition report] shall be initiated if the acceptance

criteria are not met." A review of steps (a) through (f) reveal a lack of objective, or even subjective, acceptance criteria that could trigger a condition report:

a. When opportunities arise, buried sections of piping and tanks "should be examined to quantify deposit accumulation...and those results documented." As long as exposed piping is examined and damage chronicled, the acceptance criteria are met – no condition report.

b. "Look for signs of damaged coatings or wrapping defects"-as long as workers look the acceptance criteria are met. Only not looking would fail to meet the acceptance criterion and trigger a condition report.

c. "The interior of piping may be examined by divers, remote cameras, robots or moles when appropriate." The combination of "may" and "when appropriate" means the acceptance criterion is met when examinations are performed or not.

d. "Use holiday tester to check excavated areas of piping for coating defects." When coating defects are found for exposed area of piping using a holiday tester, the acceptance criteria is met and no condition report is written.

e. If visual inspection reveals coatings or wrappings not to be intact, further inspection of piping for signs of pitting, MIC, etc is required. If the additional inspection is performed, the acceptance criterion is satisfied and no condition report is warranted whether damage is found or not.

f. Inspect below grade concrete for indication of cracking and loss of material. As long as the inspection is performed, the acceptance criterion is satisfied whether damage is found or not.

9. Section 5.12 subsection [2] on page 16 specifies the steps to be taken for Non-Destructive Testing of buried piping and tanks. No steps direct workers to initiate

condition report(s) regardless of how extensive the piping and/or tank damage is identified.

10. Section 5.9 Preventive Measures, at 14, "...the existing cathodic protection system *may* be updated or a new Cathodic Protection system *may* be installed. Pilgrim Watch has explained that cathodic protection *should* be installed. The emphasis should be on prevention not waiting to discover failures before acting.

11. Summary: reasonable assurance is not provided by this new program. The Program needs real commitments and we need to see how it is upgraded and precisely put into place at Pilgrim. The ASLB should delay its determination on the application until the program is in place and may be evaluated.

F. ENTERGY CONTENDS REASONABLE ASSURANCE PROVIDED BASED UPON CONFORMANCE TO: NRC GUIDANCE; THE GALL REPORT; INDUSTRY PRACTICES; PNPS OPERATING EXPERIENCE; AND THE SER REVIEW

The Applicant does not demonstrate "reasonable assurance" at the 95% confidence level and as such Entergy does not meet what is the minimally acceptable level of proof. In essence their assertions are at the level of platitudes.

1. Consistent With NRC Regulatory Requirements/ Guidance:

The fact that the AMPs are consistent with NRC regulatory requirements/ guidance does not provide reason to regard the AMPs as adequate. There is no evidence presented that reactors with reported leaks leaked because they violated NRC regulatory requirements/guidance.

The NRC Groundwater Contamination (Tritium) at Nuclear Plants-Task Force – Final Report, Sept 1, 2006[57] studied radioactive leaks from a variety of sources – certainly not just from the safety-related pipes at issue here. However the report basically addresses leaks therefore there are valuable lessons that apply. The LLTF stated in the Executive Summary ii, that,

> "The task force did identify that *under the existing regulatory requirements* the potential exists for unplanned and unmonitored releases of radioactive liquids to migrate offsite into the public domain undetected."

For example, the LLTF questioned the maintenance rule [LLTF consolidated recommendations list at B-1]

> The staff should assess whether the maintenance rule adequately covers SSCs [structures, systems, components]...

This says to Pilgrim Watch that the LLTF determined that current rules, guidance, maintenance practices need to be looked at again and cannot simply be relied upon for assurance - as the Applicant, NRC Staff and their experts appear willing to do.

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[57] The Liquid Radioactive Release Lessons Learned Task Force (LLTF) was established by the NRC Director of Operations on March 10, 2006, in response to incidents at Braidwood, Indian Point, Byron and Dresden related to unplanned, unmonitored releases of radioactive liquids into the environment. The scope of the task force work included reviews of industry experience, associated public health impacts, the NRC regulatory framework, related NRC inspection and enforcement programs industry reporting requirements, past industry actions following significant releases, international perspectives, and NRC communication with public stakeholders. The focus of the Task Force was on releases of radioactive liquids that were neither planned nor monitored. The findings have a direct bearing on Pilgrim Watch's contention [Exhibit 7].

LLTF looked at problems in reactors operating during their first 40-year license period – not at reactors, like Pilgrim that will operate an additional 20 years and whose components in that period will add an additional 10 years of operations until the next inspection.

Further the LLTF based their "lessons learned" only on a sample of reactors that had identified leaks – not on reactors, such as Pilgrim, that may have unidentified leaks and would provide new lessons. The LLTF stated in their Executive Summary ii that,

> ...relatively low leakage rates may not be detected by plant operators, even over an extended period of time.
>
> Leakage that enters the ground below the plant may be undetected because there are generally no NRC requirements to monitor the groundwater onsite for radioactive contamination.
>
> Contamination in groundwater onsite may migrate offsite undetected.

Because of negative industry experience, the NRC is in the process of revising regulatory guidance and inspection procedures. Until those actions are finalized, it would be wrong to proceed with re-licensing until the NRC publishes proposed rules to implement the recommendations and they can be evaluated and commented upon by the public before being finalized. Any revised NRC rules must be applied completely and immediately to all operating plants.

2. Conformance with Standard Industry Practice: Conformance with standard industry practice is no basis for the Applicant to rest their claim that the BPTIP and the Water Chemistry/Salt Water Integrity Program provide reasonable assurance, either.

It appears that reactors with leaks apparently used standard industry practice, too; the Applicant does not provide evidence that all of the reactors with unmonitored leaks had flouted industry practice and were subsequently cited for violating pertinent NRC rules and standard practices.

Pilgrim Watch, in the Response to Entergy's Motion for Summary Disposition looked at Dresden for lessons learned. The LLTF suggested in their discussion of Dresden that "standard industry practice" should be looked at and *improved.*

Mr. Davis, the NRC Staff's expert, in NRC Staff Response to Entergy's Motion of Summary Disposition, June 28, 2007, explained why relying on industry experience may need to be qualified. Davis said, at 16 [Pilgrim Watch Exhibit 21] that,

> "...industry practice has shown that properly applied coatings will prevent corrosion *as long as* the soil is not extremely aggressive (as Entergy states is not the case at Pilgrim) or *unless there is damage during application of the coating and handling of the pipe*." [Emphasis added]

We know that human error is always a factor that needs to be addressed. Coatings may not always be properly applied. Davis warns that damage may occur during application of coating and handling of the pipe. Damage could have happened at Pilgrim, too, and gone undetected or could happen in the future. The Applicant shows no proof that they have thoroughly inspected the entire system within scope to determine otherwise. Davis relied on Entergy's self assessment of the soil; NRC does not indicate otherwise nor does the staff define what the qualitative term "extremely" actually means; and NRC Staff in the Final SER provides no indication that the staff tested soil to determine if it was "extremely aggressive" or not.

3. Conformance with the Gall Report is no basis for the Applicant to rest their claim that the BPTIP and the Water Chemistry/Salt Water Integrity Program provide reasonable assurance, certainly not at the 95% confidence level.

It is important to recognize that the Lessons Learned Task Force (LLTF) issued their report *after* the Gall Report. The NRC is in the process of taking actions on Task Force Recommendations after the Gall. Hence, the fact that, "The AMPs are consistent with NRC guidance and with the Gall report" – guidance and a report written *before* 2006 – clearly becomes less important. The NRC's generic communications program is filled

with reports of AMP failures.[58] If the AMP was fool-proof, the continual expansions and revisions to it would not be present.

Most important Entergy wrote their new Buried Piping and Tanks Inspection and Monitoring program on November 19, 2007 Program, well after the Gall Report, indicating that they, too, appreciate that more has to be done to provide reasonable assurance.

4. Pilgrim's Own Operating Experience: There is a paucity of operating experience. Operating experience is limited at Pilgrim simply to portions of two systems - the Salt Water Service System and the Fire Water Protection System. What little experience is discussed shows that there has been corrosion – external and internal – and hence the type of failures identified could have occurred anywhere in buried piping systems if they had taken more opportunities to inspect the system or had installed monitoring wells near to those systems to detect leaks.

The Safety Evaluation Report, November 2007, at 3-37, Exhibit 6, describes site specific historical experiences. NRC begins by describing corrosion in the fire underground distribution system.

> However, in the past five years, the applicant has had limited experience with the inspection of buried piping, mainly on the fire underground distribution system. This system, approximately 35 years old, consists of cement-lined malleable iron pipe with mechanical joints and no history of significant leaks other than two instances in 2002 and 2005.

[58] http://www.nrc.gov/reading-rm/doc-collections/gen-comm/info-notices/2007/in200701.pdf ; http://www.nrc.gov/reading-rm/doc-collections/gen-comm/info-notices/2004/in200409.pdf ; http://www.nrc.gov/reading-rm/doc-collections/gen-comm/info-notices/2004/in200405.pdf

Pilgrim Watch cautions the reader about the term "significant leaks." The LLTF warned [at Recommendation 5] that "significant contamination" was never defined. The SER goes on to describe the failure.

> In the first, the 8 inch underground line...failed, the *probable cause induced* most likely by minor fabrication anomalies compounded by marginal installation techniques. When examined, this piping was found to be in very good external condition overall except for a small area of surface corrosion attributed to marginal installation techniques.

They speculate, not know, the cause of the problem as "most likely by minor fabrication anomalies compounded by marginal installation techniques." There is no proof that "minor fabrication anomalies" and "errors in installation" are limited to one instance in the fire underground distribution system and not also the case in other components under consideration. Errors in manufacturing and installation do not announce themselves beforehand but require frequent inspections to become known.

NRC's says further that,

> In the second instance 8 inch underground line failed ...due to congestion and the presence of the tank (installed after the piping), it was not possible to dig up the piping for examination to determine the cause of the failure (*possibly* related to the tank installation). Apart from these two instances, a number of valves and piping excavated during maintenance were found to be in good condition.

Again, they speculate, not know, the cause of the problem; and little assurance is provided by "a number of valves and piping excavated during maintenance were found to be in good condition." We are not given the actual number; we are we told what % of the potential inventory that represented; we are not told if any were found that were not in good condition; and more basically they never define "good condition."

The Safety Evaluation Report, November 2007, at 3-37, Exhibit 6, goes on to describe leaks in the SSW buried inlet piping.

> "...SSW system has had leaks on the buried inlet (screen house to auxiliary bays) piping due to internal corrosion. The original piping material was rubber-lined carbon steel wrapped with reinforced fiberglass, coal tar saturated felt, and heavy Kraft paper. The leaks were determined to be results of the rubber lining degrading from contact with sea water. These pipes were replaced in 1995 and 1997 with the *same external and internal coating as for the original pipe.*" [Emphasis added]

After approximately 20 years of operations, repairs were required. We do not know how long the corrosion may have occurred prior to when it was addressed in 1995 and 1997 in order to establish a corrosion rate. Absent a corrosion rate, it is impossible to make predictions required for assurance.

According to the NRC Staff, these pipes were replaced in 1995 and 1997 with the *same external and internal coating as for the original pipe* so that it is as likely than not that they will corrode again, perhaps shortly into the extended license. Further corrosion is likely in other areas of the SSW and in other components within scope that have the same external and internal coating.

The applicant tells a different story. The Applicant [Motion for Summary Disposition, Material Fact 22] claims that new materials were used and that, "these new materials and coatings have superior corrosion resistance compared to the original materials and coatings." Who is right? The NRC said that they used the "*same external and internal coating as for the original pipe*" the Applicant claimed that they used "new materials and coatings." If the Applicant is right and they used new coatings, we do not know what "superior corrosion resistance" means. It is not a quantitative term – "superior" could mean anything. For example are these new materials and coatings superior to demonstrably inferior ones – up a notch but still not very good? There is no evidence

provided that the coatings will continue to have "superior corrosion resistance" for 10 or more years - until the next inspection. Also a very small leak might not be readily detectable by simple observation.

The NRC Safety Review [3-38], Exhibit 6, went on to describe internal corrosion in the buried discharge piping.

> "In addition, the SSW buried discharge piping (also rubber-lined carbon steel with external pipe wrapping) from the auxiliary bays to the discharge canal experienced severe internal corrosion due to failure of the rubber lining. Two forty-foot lengths of 22-inch diameter pipes (one on each loop) were replaced in 1999 with carbon steel coated internally and externally with epoxy. The replaced piping was examined with its wrapping removed and its external surface was found to have been in good condition. Since then the entire length of both SSW buried discharge loops have been lined internally with pipe linings cured in place- "B" loop in 2002 and "A" Loop in 2003."

The entire length of the discharge has been lined internally, and we do not have any assurance how long it will last or if it was properly applied.

We know corrosion can occur externally and only the replaced piping was examined when it was re-wrapped. What portion of the SSW discharge piping was not replaced; and what is the condition of its exterior coatings and surface?

Cox in Entergy's Motion for Summary Disposition at FN 6 [Exhibit 11] said that, "The inlet SSW carbon steel piping that was replaced with titanium piping in order to prevent corrosion *was never removed from the ground so that the exterior coatings and surface of the original carbon steel SSW inlet piping were not examined*" [Emphasis added].

The *discharge piping was not replaced* with titanium and still has the same carbon steel as the inlet piping did prior to replacement. We do not know the condition of the

discharge piping that was not replaced and there are no lessons learned from the inlet piping – it was not removed from the ground to be examined. They never looked. However, because they replaced only the original piping at the inlet, the discharge piping remains suspect.

The Applicant and NRC Staff have no basis to claim that "operating experience provides assurance that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation." Operating experience is too limited. The little experience shows corrosion and the failure of their preventive methods, wraps and coatings. There has not been enough experience to establish a baseline corrosion rate so that there is no ability to make timely and accurate predictions.

5. NRC Staff Safety Evaluation Report (SER), Exhibit 6: Pilgrim's Final Safety Evaluation Report was issued in November 2007. According to the NRC,

> The primary objectives of license renewal inspection activities are to review the documentation, implementation, and effectiveness of the programs and activities associated with an applicant's license renewal program to verify that there is reasonable assurance that the effects of aging will be adequately managed such that the intended function of components and structures within the scope of license renewal will be maintained consistent with the current licensing basis during the period of extended operation.[59]

We understand that technically Entergy's License Application is at issue here, and not the quality of the NRC Staff's review and Final Report. However, the report is important because it can not help but influence the ASLB's and public's deliberations on the assurance provided by the AMP; and the Staff Report is undeniably an important component of the licensing process.

[59] http://www.nrc.gov/reactors/operating/licensing/renewal/process.html#inspect-prog

Therefore it is important to look at the quality of NRC's License Renewal Program. A recent report by the NRC Office of Inspector General (OIG), *Office of Inspector General's Audit of NRC's License Renewal Program*[60] made clear that we can not rely on the SER's conclusion that aging will be adequately managed so that the intended functions will be maintained consistent with the CLB over the extended period.

The OIG's audit revealed that the NRC Staff's license renewal review process is so weak that reviewers often completely fail to address key evaluation criteria such as the licensee's operating experience. In Section C of the report, the OIG concluded that,

> "Operating experience plays an important role in license renewal and the license renewal staff is expected to review plant-specific operating experience, including corrective actions. Yet, audit team members *do not review operating experience consistently*. Furthermore, most audit team members do *not conduct independent verification* of operating experience, instead relying on license-supplied information. This is because program managers have not established requirements and controls to standardize the conduct and depth of such reviews. In the absence of conducting independent verification of plant-specific operating experience, license renewal auditors may not have adequate assurances that relevant operating experience was captured in the licensee's renewal application of NRC's consideration." [OIG-07-A-15, at 18, Exhibit 22]

Pilgrim's SER fits this description.

The SER at Pilgrim says at 3-38 that, "The staff reviewed the operating experience presented in the LRA and interviewed the applicant's technical personnel to confirm that the plant-specific operating experience revealed no degradation not bounded by industry experience." In other words, they reviewed what was in the LRA and then asked the licensee if what they had put in the LRA was correct.

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[60] *Office of Inspector General's Audit of NRC's License Renewal Program*, OIG-07-A-15, September 6, 2007. Exhibit 22. ADAMS ML072490486

There is no evidence of independent verification or field work. This is not a review. It looks like simply parroting what the licensee said without performing independent checks on the veracity or completeness of the statements.

Further, we know that the Applicant's reports are limited. For example:

Entergy can only report what they know and without extensive and comprehensive inspections and monitoring wells they can not possibly know the extent of corrosion or whether there are leaks or breaks. Second, reports about leaks that Entergy knows about may not be complete. The LLTF spoke of this at B-1, Exhibit 7, and recommended that,

> (5) Develop guidance to define the magnitude of the spills and leaks that need to be documented by the licensee under 10 CFR 50.75 (g). Also, clearly define "significant contamination." Summaries of spills and leaks documented under 10 CFR 50.75 (g) should be included in the annual radioactive effluent release report (Section 3.2.1 and 3.4).

NRC has not made clear to the licensee what had to be documented; nor defined "significant contamination." Therefore what NRC reviewed was self-selected or interpreted as "significant" by the licensee to be worthy of putting into the LRA. Regarding reporting requirements, the LLFT states at 19, Exhibit 7,

> No specific regulatory requirements for licensees to conduct routine onsite environmental surveys and monitoring for potential abnormal spills and leaks of radioactive liquids. However, 10CFR 50.72(g) requires that licensees keep records of information important to the safe and effective decommissioning of the facility. These records include information about known spills.

The key word is "known." Neither the NRC Staff affidavit provided by James Davis nor the Safety Evaluation Report indicated whether NRC Audit Staff had access to these records or not; and if they did have access, whether they reviewed these records.

The OIG found further fault with the review process in that there is no standard governing what is required in the report or the methodology to be used in the review. Quality assurance is missing.

We conclude that the SER does not provide the Board or the public with an adequate basis to form an opinion about whether the NRC's aging management programs for buried pipes and tanks in scope provide adequate protection to public health and safety during the license renewal term, as required. Until the problems identified by the OIG are fixed and proper NRC staff inspections performed at Pilgrim, the license application should be put on hold.

It is clear that although Pilgrim was not among the sites sampled by the OIG, the Pilgrim NRC SER Team's methodology appears to have all the weaknesses highlighted by the OIG.

The experience at Palisades is a warning. The Palisades' application for license extension was accepted 01/07. The Palisades' SER, (50-255) was issued September 2006, and like Pilgrim's SER, they concluded, at 3-16, that the effects of aging would be managed to their satisfaction. December 11, 2007, Palisades reported that five new ground water monitoring wells were recently installed at Palisades in support of NEI's initiative. The initial sampling of one of the wells indicated 22,000 pico-curies per liter (pCi/l).[61]

For the foregoing reasons, reasonable assurance is not demonstrated by: conformance to NRC guidance; the Gall Report; industry practices; PNPS' operating experience; or the assurances by the SER Final Report- and certainly there was no demonstration of proof with 95% certainty.

[61] Event No. 43882, Event Notification report, December 11, 2007, Exhibit 23

IV. PILGRIM WATCH CONTENDS THAT THE AMP REQUIRES SUPPLEMENTS TO PROVIDE ASSURANCE THAT THE BURIED PIPES AND TANKS WITHIN SCOPE WILL PERFORM THEIR INTENDED SAFETY FUNCTION

Pilgrim Watch and their experts have reviewed the Aging Management Program for Pilgrim Station and conclude that the applicant has not addressed the monitoring of its underground components that are within scope to assure their integrity if Pilgrim's license is extended to operate an additional twenty years to 2032.

Arnold Gundersen says that,

> The information provided by the AMP is vague and non-specific and cannot be used to conclude that any and all underground piping will ever be examined during the license extension period. Furthermore, I conclude that the applicant has not shown with 95 percent certainty that the proposed AMP will in fact be able to detect any defects in the underground pipes and tanks. Moreover, based upon my review of Pilgrim's AMP, it is my opinion that the applicant has not shown that the proposed AMP is adequate to assess and assure that underground piping and tanks will be able to withstand the stresses of an additional 20-year license [Gundersen Decl at 9, 10, and 11].

Dr. David Ahlfeld adds that,

> Entergy describes several methods they use to prevent leaks from occurring, however, Entergy has not demonstrated that they have sufficient means of detecting leaks if they occur. [Ahlfeld Decl at 1]

In order to protect public health and safety at this particular site the AMPs must be supplemented with a more robust and frequent inspection protocol and a comprehensive monitoring well program as part of the license going forward.

A. MORE ROBUST AND COMPREHENSIVE INSPECTION PROTOCOL

The Brookhaven Report [Exhibit 8] provided ample reason for better inspections. They stated at 97 that,

> Buried piping systems at a nuclear power (NPP) can degrade.... Such deterioration could impair the operation of the system that contains the buried piping, and thus impact the overall risk of the NPP.

The Gall Report [Nureg-1801, Rev. 1 XI M-96, September, 2005 at 10, Exhibit 18], says that pits have been detected on the outside of buried pipe after far less than 60 years.

Pilgrim has operated less than 40 years and we have already seen corrosion and leaks. There is no experience with the BPTIP; therefore we can not predict with an ounce of certainty what will happen in the following 45, 50, 55 or 60 years of operations. Deterioration of pipes in nuclear plants in well established. It is axiomatic that failure rates increase over time. As reactors continue to operate beyond 40 years, it is essential to closely assess the effects of age-related degradation.

Pilgrim Watch's expert, Arnold Gunderson recommends that, "...there are at least four separate approaches available to Entergy and the ASLB to mitigate serious consequences of undetected leaks." [Gundersen Decl. at 18]

> 18. It is my belief, as the Expert Witness retained by Pilgrim Watch, that there are at least four solutions available to Entergy and the ASLB to mitigate the serious consequences of undetected leaks. Contention 1, as delineated in this proceeding, is that the frequency of the monitoring proposed by the Applicant is insufficient to ensure that the required safety margins would be maintained throughout any extended period of operation. The Board appropriately suggested a possible weakness in the Applicant's (Pilgrim Nuclear Power Station) Aging Management Program to detect leaks, and this problem seems to be borne out by the recently discovered on-site

Tritium leaks. I suggest that this problem may be minimized by four separate approaches:

- Establish critical Baseline Data;
- Reduce the future corrosion rate;
- Improve monitoring frequency and coverage;
- Increase the Monitoring Well Program to actively look for leaks once they have occurred.

18.1. Establish Critical Baseline Data: In view of the fact that industry as a whole and Pilgrim, specifically, have experienced corrosion and leaks, as evidenced at Pilgrim by the recently discovered Tritium leaks, it is important that critical Baseline Data be collected via a top to bottom examination of the safety-related buried pipes/tanks.

18.1.1. Such an inspection must entail special attention to points of vulnerability – such as at elbows, welds, joints, and at any dead spaces where liquid can sit.

18.1.2. Examinations must include inspection both inside and outside.

18.1.3. Special attention must also be given to those welds located upstream or downstream of a flow disturbance.

18.1.4. Since it is not possible to assess possible damage below the coating in the pipe body, in addition all piping must be pressure tested to at least twice the operating pressure. Inability to perform pressure tests for any reason should not be cause for relief.

18.1.5. Baseline data is critical so that trending is established. NUREG/CR 6876 states, at 32, "...it is evident that predicting an accurate degradation rate for buried piping systems is difficult to achieve..."

18.1.6. After a baseline is established then regular examinations afterwards can better determine the need for mitigation before, not after, a problem develops.

18.2. Reduce corrosion rates: The Applicant can and should implement a thorough Cathodic Protection Program (CPP) on all underground pipes and tanks. I found no reference to such a program in the application submitted by Energy. A CPP would reduce the likelihood of leaks. [62]

18.3. Improve monitoring frequency and coverage: In an attempt to minimize the size and frequency of leaks, in my opinion, the AMP should be augmented to require more frequent and more comprehensive inspections of all underground pipes and tanks.

18.3.1. Specifically, I believe that a 100 percent internal visual inspection of all underground pipes and tanks must be implemented.

18.3.2. The inspection cycle should be such that all pipes and tanks are inspected every ten years, however, I believe that the Applicant should be required to break the testing interval down such that one sixth of all pipes and tanks are inspected during each refueling outage. (This assumes 18 month refueling outages, or six every ten years.)

18.3.3. Finally, it is my opinion that the Applicant should be required to inspect one sixth of the lineal piping, one sixth of the elbows and flanges, and one sixth of the tank seams at each outage, even if such inspections lengthen the outage time.

18.3.4. For example, when I was reviewing the Aging Management System at Entergy's Nuclear Vermont Yankee (ENVY) Power Station, I noted that the AMP was often neglected in order to assure the outage was not extended. Therefore is my opinion that the Applicant Entergy should certify that each portion of the AMP on the pipes and tanks is accomplished in the order agreed upon and

[62] Pilgrim Watch makes note that Entergy's Exhibit 5, at 14, states simply that "...Cathodic Protection system may be updated or a new Cathodic Protection system may be installed. For plants with installed Cathodic Protection Systems..."There is no indication that they have Cathodic Protection; and there are no commitments.

completed at every outage. As an Intervenor with standing on Contention 1, Pilgrim Watch should be allowed to review copies of the certified piping inspection reports prior to the end of each outage to assure that the work was completed as ordered.

18.4. Increase the Monitoring Well Program to actively look for leaks once they have occurred: According to Pilgrim Watch's expert, Dr. David P. Ahlfeld, in order to meet the minimum criteria for an effective monitoring well program at Pilgrim, such a program should made part of the license going forward so that it is enforceable and not simply voluntary and must follow the steps in monitoring network design as outlined in Dr. Ahlfeld's declaration. In the absence of any leaks at the Applicant's Pilgrim Nuclear Power Station, I believe that my recommendations would be necessary to the evaluation of Pilgrim's application for a 20-year extension to its current operating license. However, given the recently discovered Tritium leaks at Entergy's Pilgrim Plant and other reactors around the country, my recommendations are critical to the continued operation of Pilgrim to the end of its current license, without any consideration of a license extension.

18.4.1. In light of the newly discovered Tritium leaks, it may in fact be true that a significant safety system has already been compromised.

18.4.2. I believe it will most likely take at least one year to trace the path of the unanticipated Tritium releases.

18.4.3. The release of Tritium indicates a leak in a system that in the past was radioactive.

18.4.4. I believe such a leak means that testing should immediately be undertaken that searches for Cesium 134 and Cesium 137, Cobalt 60, and other gamma emitters as well as Strontium 90.

18.4.5. As a nuclear engineering senior vice-president overseeing decommissioning of nuclear sites and an author of the DOE Decommissioning

Handbook, I believe it is critical that these newly discovered Tritium releases be accurately monitored. The evidence I reviewed as an expert witness regarding Florida Power and Light's St. Lucie Nuclear Power Plant, and the documents I have reviewed pertaining to the decommissioning effort at the former Connecticut Yankee Nuclear Power Plant Site, clearly show how far and wide Tritium and other radioactive isotopes may spread before their release is uncovered.

18.4.6. Therefore in my opinion, and given Pilgrim's proximity to the environmentally sensitive Bay and salt marshes, a rigorous and expanded Monitoring Well program should be ordered and immediately undertaken at and around the Pilgrim Nuclear Power Plant Site.

Corrective Actions: Pilgrim Watch makes note of the fact that corrective actions essentially are optional and left up to the licensee.

Exhibit 5, at 14, "5.8 Corrective Actions: A Condition Report (CR) shall be written if acceptance criteria are not met. The corrective action *may* include engineering evaluations, scheduled evaluations, scheduled inspections, and change of coating or replacement of corrosion susceptible components. Components that do not meet acceptance criteria shall be dispositioned by engineering." [Emphasis added]. The only requirements if acceptance criteria are not met are to write a report for themselves and to leave any decision about what to do, or not do, to the engineering department. This can hardly be interpreted as providing "reasonable assurance" to the public.

Specific criteria for component repair and replacement must be spelled out and required. Additionally a root cause analysis should be required which would force the licensee to examine other similar situations in buried pipes and tanks to provide the requisite assurance the public deserves.

B. MONITORING WELL PROGRAM REQUIRED TO SUPPLEMENT THE AGING MANAGEMENT PROGRAM

1. Pilgrim Watch maintains that monitoring wells clearly belong back in the discussion, as a supplement to the AMP.

Our reasons are as follows:

a. Entergy's Buried Piping and Tanks Inspection and Monitoring Program, November 19, 2007, Entergy's Prefiled Testimony's Exhibit 5 makes clear that monitoring is an important function of the Buried Pipes and Inspection Program.

In the ASLB's December 19, 2007 Order, the majority left it up to the Applicant to decide whether monitoring wells are relevant. The Order says at 1,

> Unless and until the Applicant expressly advises this Board and the Agency that it intends to rely upon monitoring wells for making its determination that buried pipes and tanks are not leaking at such great rates that they cannot satisfy their intended safety functions, information related to monitoring wells is irrelevant to the issues at hand before the Board.

First, it is clear from the Applicant's Prefiled Testimony that they consider monitoring and radioactive contamination important and have not ruled out monitoring wells for leak detection. In fact they installed (4) monitoring wells in November 2007.

Second, in Entergy's Exhibit 5, *Buried Piping and Tanks Inspection and Monitoring Program,* monitoring and radioactive contamination in groundwater are given priority. The protocol is called both an inspection and *monitoring* program – it is not phrased as either an inspection program or a monitoring program.

Third, Exhibit 5, Section 5.2, Scope of Program says "The Program shall include buried piping and tanks that, if degraded, could provide a path for radioactive contamination of groundwater." Identifying whether corrosion of buried piping has led to leaking radioactive contamination is identified as important in the *Buried Piping and Tanks Inspection and Monitoring Program.*

Fourth, in fact radioactive contamination is not simply "important" but it is given "high priority" in the Program, at 9 - "any buried section with at least one High Impact rating gets an overall high impact rating."

Table 1: Impact Assessment

	High	Medium	Low
Safety (Class per En-DC-167	Safety Related	Augmented QP and Fire Protection	Non-Safety Related
Public Risk	Radioactive Contamination e.g. Tritium	Chemical/Oil Treated System Gases	Untreated Water SW, Demin Water
Economics (Cost of buried equipment failure to plant	>1M or Potential Shutdown	>100 K < 1 M	< 100K

Notes: 1. any buried section with at least one High Impact rating gets an overall High Impact rating.

The high safety risk has little to do with whether the pipes carry enough water from point A to point B; instead the risk rests only on one thing – public and worker's health may be adversely affected because of the leakage from pipes carrying radioactively contaminated water. Any acceptable AMP must ensure, with not less than 95% confidence that the public health will not be affected by such leakage. The procedures that Entergy has provided will not provide 95% confidence that leakage will be detected before it gets to a place where it could affect public health – into Cape Cod Bay and on our beaches and dinner tables – or affect worker's health.

Fifth, in Exhibit 5 at 16 the Applicant describes leak detection, [Inspection Methods and Technologies/Techniques, (2.i.)] as a "method for detection, locating and measuring leakage: LT includes but is *not limited to* pressure testing, vacuum testing, and tracer gas detection (ASME Section V)" Emphasis added. The key words are "*not limited to*". This

implies other methods of detection are not excluded leaving the door open for monitoring wells.

Leak detection, not simply prevention, is identified as an important part of the Buried Piping and Tanks Inspection and Monitoring Program; and we argue that monitoring wells are a necessary supplement to the AMP at this site in order to decrease risk and can not be properly excluded from these proceedings.

b. The Nuclear Regulatory Commission issued a proposed rule, published January 22, 2008 in the *Federal Register*, page 3812, Exhibit 24. It is designed to prevent future "legacy sites" with insufficient funds for decommissioning by requiring licensees to minimize the introduction of residual radioactivity at their sites during operations.

This ruling says in essence that to prevent legacy sites, buried pipes and tanks are not supposed to leak contamination into the ground and if they do leak, that those leaks can be identified.

The proposed rule would require licensees to conduct their operations so as to *identify* the occurrences of residual radioactivity at their sites, particularly in the subsurface soil and ground water, and *minimize* the introduction of additional residual radioactivity.

They explain that there are a variety of monitoring methods to evaluate subsurface characteristics, and these are highly site specific with respect to their effectiveness.

The proposed rule goes on to say that, one or more of the licensees affected by this proposed rulemaking may find that compliance with the monitoring requirements will mean the installations of ground water monitoring wells and surface monitoring devices at their sites [Fed Register, 3833]. Monitoring wells are suited to Pilgrim's site because the pipes are buried so a leak is not visually evident; and the topography of the Pilgrim site is such that, were a leak to develop in an underground pipe or tank, the contaminated water would most likely migrate seaward and drain into the ocean unnoticed.

It is obvious that the "intended safety functions" of the buried pipes/tanks are multiple. Entergy's own Buried Pipes and Tanks Inspection and Monitoring Program now recognizes that preventing and identifying corrosion in buried pipes and tanks and preventing and identifying radioactive contamination is a top priority, not simply getting the liquid from Point A to Point B. The NRC's proposed rule emphasizes another important safety function – identifying leaks to prevent future legacy sites.

c. Pilgrim Watch holds that that the intended safety functions of buried pipes/tanks are multiple and include: (1) keeping the liquid inside the component and not to allow leakage into the ground, the principle function of any pipe; (2) service the system it feeds; (3) prevent radioactive contamination from entering the ground that could result in significant harm to the health and safety of the public; and (4) prevent future legacy sites.

d. The Applicant's AMPs are insufficient to enable it to determine whether or not certain buried pipes and tanks are leaking at such rates that they cannot satisfy their respective intended safety functions. Both a more robust inspection system and a monitoring well program to detect leaks are required.

2. Monitoring Network Design

Pilgrim Watch's expert, Dr. David Ahlfeld explains that,

> Groundwater monitoring networks are commonly used as a means of detecting leaks from a wide variety of facilities. To make the monitoring network an effective means of detecting leaks, the network should be designed so that a pollutant release under any plausible leak scenario will be detected, with high degree of certainty. The design of a monitoring network includes determination of plausible leak scenarios, determination of expected fate and transport of the leaking substances and then placement of the detection network so that these transporting substances will be detected.

This general guideline for monitoring network design is expanded upon below, with reference to specific features of the Pilgrim Nuclear Power Station (PNPS). These constitute the steps in monitoring network design which, with appropriate documentation, would constitute an adequate design. As noted below, many of these steps are similar to those recommended in the Nuclear Energy Institute (NEI) Industry Ground Water Protection Initiative – Final Guidance Document (NEI 07-07, August, 2007). [Ahlfeld Exhibit 2]

Dr. Ahlfeld outlines steps in a monitoring network design – steps that were largely ignored by Entergy in designing their monitoring well program that went into service in November, 2007.

Steps in Monitoring Network Design [Ahlfeld Decl. at 2]

1) Determination of all plausible leak locations. This would include consideration of all piping segments and tanks that are placed below the ground surface and are part of system components that are within scope. For purposes of monitoring network design, leaks from any of the plausible locations would be presumed to release water contaminated with radionuclides or oil. This step is similar those recommended in the NEI Guidance Document (Objective 1.2 Site Risk Assessment) where buried piping is described as being a credible mechanism for leaking materials to reach groundwater.

2) Identification of the specific contaminant species that would be present in the leaking water or oil from each of the system components. A set of indicator contaminants should be selected for each system component that can, if detected in groundwater, uniquely identify the component. Particular emphasis should be on those contaminants that are least likely to sorb and thus be most rapidly transported.

3) Consideration of the fate and transport of each indicator contaminant from each of the plausible leak locations.

a. This analysis would include prediction of subsurface transport pathways from all identified source locations. This prediction would consider vertical migration of leaking water through the unsaturated zone to the water table. It would also account for the direction and rate of groundwater flow. Such predictions must be based upon understanding of groundwater behavior at the site derived from a recently-conducted detailed site characterization as recommended in the NEI Guidance Document (Objective 1.1 Site Hydrology and Geology). This is particularly important at PNPS where building, paving and changes to storm drainage may significantly affect local flow behavior.

b. Transport of a particular contaminant along identified transport pathways must be analyzed. For each contaminant it is necessary to account for the initial concentration of the contaminant in the leaking liquid and the effects of dispersion, sorption, radioactive decay or other processes that may affect concentrations of the contaminant at the monitoring well.

4) The NEI Guidance Document (Objective 1.3 On-Site Groundwater Monitoring) recommends a monitoring system that will "ensure timely detection" of leaks. This will be accomplished with placement of monitoring wells so that all predicted transport pathways are intercepted with a high degree of certainty. The placement of monitoring wells should consider both the areal (plan view) location and also the vertical location of the well screens. A complete monitoring system will also include upgradient control wells which are intended to provide ambient groundwater conditions and help to confirm groundwater flow directions. The PNPS is a particularly challenging site for placement of monitoring wells. Because of the short distance between possible leak sites and the coast line

(assuming that groundwater flow is generally towards the sea), the potential is high for a narrow transport pathway to convey contaminants between monitoring wells unless they are closely spaced. This suggests that a high density of monitoring wells will be needed to detect leaks with adequate assurance.

5) Understanding of the fate and transport of indicator contaminants can be used to determine the appropriate frequency of water sample collection at the monitoring wells and the required detection limits for analysis. In particular, the dilution of contaminated water as it mixes with ambient water during transport must be considered. Detection limits for contaminant analysis should be as low as practical so that dilution of contaminants does not mask the presence of leaks. [Ahlfeld Decl]

Recent experience at PNPS [Ahlfeld Decl. at 3]

Recently, Entergy reported finding tritium at levels up to about 3000 pCi/L in monitoring wells on site. These initial monitoring results highlight flaws in the monitoring system at PNPS and provide a contrast to appropriate monitoring design.[63]

Based on the map provided by Entergy in its recent filing, four monitoring wells have been placed at the site. These are generally located between the reactor and the shoreline. The wells are spaced approximately 200 feet apart. I am not aware of any recent hydrogeologic studies that have been conducted to determine current groundwater flow directions and rates. Hence, the suitability of these wells to actually intercept plausible leakage transport pathways is unknown.

Based on my estimation of the locations of pipe runs and plausible leak locations, this number of wells is entirely inadequate to provide the assurance of detection called for in the NEI guidance and in industry practice. Given the short distance

[63] Reports: discovery in Pilgrim wells fuels debate, Boston Globe, December 20, 2007; Analysis Tritium samples for Massachusetts Department of Public Health split samples, December 5, 2007, Exhibit 26.

from likely pipe locations and the shore, it is highly likely that a leak of radiological contaminants could migrate through the groundwater and pass between these widely-spaced wells or perhaps flow beneath them without detection. It is useful to contrast the PNPS plan with Entergy's Indian Point NPS which has many times more monitoring wells. Indeed, a 4-well monitoring system is more typical of that used for a retail gasoline station or a small municipal (non-hazardous) landfill. That it should be considered adequate for a large industrial facility such as PNPS is unrealistic. [64]

The selection of tritium as the indicator contaminant raises a problem since tritium may be present in several of the potential leak sources that are within scope (e.g. condensate storage tank and salt service water systems). Hence, tritium does not provide a unique indicator of the component which is the source of the leak. A better designed monitoring system would seek a range of radionuclides that, taken together, serve as specific source indicators.

Presuming that the tritium detected originated at PNPS, the question arises as to the specific mechanism by which this tritium came to be at, for example, well MW 201. It has been suggested by PNPS personnel, as reported in the press, that this tritium is from rainfall sources. Presumably, the transport pathway for this would be airborne tritium captured by passing raindrops with rainfall subsequently infiltrating to the subsurface. But this transport pathway may be limited if, as is presumably the case, the monitoring wells are placed in a paved area of the site where rainfall can not infiltrate. There are alternative theories for the source of tritium. A small pipe leak producing a transported plume of tritium that happens to travel near to monitoring well MW 201 might account for the observed levels of tritium. Alternately, a larger pipe leak producing a large plume of tritium with concentrations much larger that 3000 pCi/L might exist in the subsurface between wells MW 201 and MW 202. In this scenario, the diluted edge of the plume happens to travel near to monitoring wells MW 201 and MW

[64] Approximate location Monitoring Wells, Document Provided by Entergy, Exhibit 25

202. These alternate hypotheses highlight the fact that with so few monitoring wells, it is impossible to determine with any degree of certainty what contaminants may exist in the subsurface.

In summary, groundwater monitoring networks can be used as part of a leak detection system and are widely used for this purpose. Well-established protocols exist for proper design of monitoring networks including well and screen placement, sampling frequency and selection of sampled contaminants. The 4-well monitoring system apparently used by Entergy does not meet reasonable standards for monitoring network design. [Ahlfeld Decl. at 4]

Because it is necessary to both detect and prevent leaks and for all the aforementioned reasons discussed in this Statement, Pilgrim Watch objects to leaving the monitoring program as a "voluntary" program.

Voluntary means that there is no ability to enforce compliance - no accountability. The issue is too important, as we have demonstrated, to leave to industry's whims. We recognize that monitoring wells are a double-edged sword for industry. There are benefits to the industry but certainly potential economic costs. Honest monitoring and testing of samples risk hard evidence of releases that can be used against the company for claims of health consequences – a "smoking-gun," if you will - and as a demonstration of over-all corrosion and inadequate quality control onsite. Effective monitoring may also point to small leaks that the industry for economic reasons would prefer ignoring gambling that the corrosion is small enough to get them through the license without the expense of digging it up, inspecting and replacing. For these aforementioned reasons, we want the monitoring system to be required so that decisions will be based on protecting public health and safety and not driven by the bottom-line.

V. ARGUMENT

A. Entergy Must Prove Its AMP Is Adequate

The Licensee bears the burden of proof: In an operating license proceeding, the licensee generally bears the ultimate burden of proof. *Metropolitan Edison Co. (Three Mile Island Nuclear Station, Unit 1)*, ASLB-697, 16 NRC 1265, 1271 (1982), citing 10 CFR 2.325. Here a renewed license may only be issued if Entergy demonstrates that its aging management program for buried pipes and tanks provides reasonable assurance that the Current licensing Basis ("CLB") will be maintained [10 CFR 54.29]. The Commission confirmed in *Florida Power & Light Co. (Turkey Point Nuclear Generating Plant, Units 3 and 4)*, 54 NRC 3, 10 (2001) that because corrosion and other effects become more severe over the extended license renewal period, an applicant for license renewal must document that its programs are adequate to manage the effects of aging, including sufficient inspection and testing:

> Part 54 requires renewal applicants to demonstrate how their programs will be effective in managing the effects of aging during the proposed period of extended operation...Applicants must identify any additional actions, i.e., maintenance, replacement of parts, etc., that will need to be taken to manage adequately the detrimental effects of aging. Adverse aging effects generally are gradual and thus can be detected by programs to *ensure sufficient inspections and testing.* [60 Fed. Reg. 22,462 (May 8, 1995)] at 22,475. 54 N.R.C. at 7 [emphasis added].

Here the admitted contention was clarified by the Board's Order October 17, 2007, at 17,

> ...prevention of leaks *per se* is not a stated objective of any relevant aging management program. On the other hand, prevention of an aging- induced leak

> large enough to compromise the ability of buried pipes or tanks to fulfill their intended safety function is a clear goal of an AMP. Thus at issue here is the following fundamental question: *Do the AMPs for buried pipes and tanks, by themselves, ensure that such safety-function-challenging leaks will not occur, or must some sort of leak detection devic*es such as monitoring wells proposed by Intervenors be installed to meet the obligation?

Further the Board noted, at 17-18, that

> ...some AMPs involve measures to prevent and detect corrosion, which, if not prevented and/or timely detected, will result in leakage. Thus, while leak prevention is not a stated objective, it is implicit in the AMPs.
>
> Contention 1 involves the challenge that leak detection is a necessary AMP element to ensure safety function performance. Whether this is or is not the case is the matter in dispute, involving experts who disagree. The Pertinent issue in dispute is whether leak detection via a system of monitoring wells is necessary as part of Pilgrim's aging management program to ensure that relevant components perform their intended functions during the license renewal period. Thus the only issue remaining before this Licensing board regarding Contention 1 is whether or not monitoring wells are necessary to assure that the buried pipes and tanks at issue will continue to perform their safety function during the license renewal period ____or, put another way, *whether Pilgrim's existing AMPs have elements that provide appropriate assurance as required under relevant NRC regulations that the buried pipes and tanks will not develop leaks so great as to cause those pipes and tanks to be unable to perform their intended safety functions*. [Emphasis added]

Because the licensee generally bears the ultimate burden of proof, *Entergy* must show that the AMPs program will provide appropriate assurance as required under relevant NRC regulations that the buried pipes and tanks will not develop leaks so great as to

cause those pipes and tanks to be unable to perform their intended safety functions. They failed to do so.

Entergy did not properly respond to the two key questions that began our discussion.

(1) Did the Applicant meet the 95% confidence level in showing that the pipes under consideration would not develop leaks so great to cause those components to be unable to perform their intended safety functions; and perhaps not exactly at 95% but certainly well beyond a flip of the coin? Answer, "No."

(2) Did the evidence (facts) provided by the Applicant meet the 95% confidence level or whatever very high standard chosen to meet the "reasonable assurance requirement? Answer, "No."

B. It is *not* the burden of Pilgrim Watch to prove that the AMPs for buried pipes and tanks do not, by themselves, ensure that such safety-function-challenging leaks will not occur; instead the Applicant must demonstrate that there is reasonable assurance that the buried pipes within scope will perform their intended safety functions, defined as providing 95% certainty

Pilgrim Watch has argued that the Applicant's claim that the AMPs provide assurance is baseless. In the context of determining which scientific evidence to admit into court, the judiciary, supported by federal government scientists, has chosen 95% confidence as the minimum that is acceptable to prove each scientific fact in a case. They have not done so; therefore they have entered no evidence that is acceptable.

Pilgrim Watch's expert, Arnold Gundersen said specifically,

> In my opinion the factual record submitted by the applicant Entergy does not meet the burden of proof required by a licensee, much less with 95% certainty, that the Aging Management Program *will identify* leaks, or that any leaks already identified by the AMP will not expand further in the pipes or tanks thereby leaving the Pilgrim Nuclear Power Station and its environs without a critical back-up safety system. For example, the Byron Station Nuclear Power Plant in Illinois recently detected what appeared to be a very small weeping pipe. However, upon closer inspection, the integrity of the pipe was grossly undermined and was in imminent danger of a catastrophic failure. [Gundersen Decl at 15]

And Dr. David Ahlfeld in response to the ASLB's October 17, 2007, question at 17,

> Do the AMPs for buried pipes and tanks, by themselves, ensure that such safety-function-challenging leaks will not occur, or must some sort of leak detection devices such as monitoring wells proposed by Intervenors be installed to meet the obligation?"

Responded that,

> The Pilgrim facility has several components that are within scope from which detectable contaminants could leak into the subsurface. These include buried pipes and tanks servicing the condensate storage system, offgas system piping, salt service water system and fuel oil systems. Entergy describes several methods they use to prevent leaks from occurring, however, Entergy has not demonstrated that they have sufficient means of detecting leaks if they occur.

Pilgrim Watch has explained why the AMP does not provide reasonable assurance that the CLB will be maintained.

In fact, it is as likely that some of the buried pipes within scope currently do not meet the established acceptance criteria for their primary intended function – isolated the liquid from the environment. Entergy has not proven otherwise – they have not performed a

thorough baseline inspection of each and every part, and if they had we have every reason to believe that they would have encountered leaks, wall thinning, pits, cracks or other signs of corrosion in their travels. This statement is hardly overboard. Consider that there is neither a vigorous inspection program nor robust monitoring well program. The 4-well monitoring system installed late 2007 discovered tritium – and that monitoring system does not even meet reasonable standards for monitoring network design. We can only guess what an adequate system would find.

There has been no compelling demonstration by the licensee that the buried pipes are not seriously corroded or leaking now or will not anytime soon. Further there was no convincing demonstration that the NRC Staff in their safety review has any real idea either. PNPS' past experience is admittedly limited and shows simply that there has been corrosion. The SER at 3-37, says clearly "that there is no operating experience for the new Buried Piping and Inspection Program."

Because Entergy has made no serious proposal to put into place a comprehensive inspection program and monitoring program, meeting the minimum design criteria described by Arnold Gundersen and Dr. Ahlfeld [Exhibits 1 and 2], and NRC has not revised Regulatory Guide 4.1 or other pertinent documents to assure us that our needs our met, the current state of the buried pipes/tanks program is the best state that they could be during any period of extended operation. We have demonstrated that is not sufficient to protect public health and safety.

ASLB's in other licensing cases have ruled that valid practices are generally those accepted by the NRC Staff in approving Entergy's application. The SER Final Document approved Entergy's Buried Piping and Tanks Inspection Program (at 3.0.3.2.1). However we have shown that the Office of Inspector General's Report casts a serious shadow over the NRC Staff evaluations, here and elsewhere, so that they simply cannot be relied upon at this stage.

> "Operating experience plays an important role in license renewal and the license renewal staff is expected to review plant-specific operating experience, including

corrective actions. Yet, audit team members do not review operating experience consistently. Furthermore, most audit team members do not conduct independent verification of operating experience, instead relying on license-supplied information. This is because program managers have not established requirements and controls to standardize the conduct and depth of such reviews. In the absence of conducting independent verification of plant-specific operating experience, license renewal auditors may not have adequate assurances that relevant operating experience was captured in the licensee's renewal application of NRC's consideration." [OIG-07-A-15, at 18]

Because there is no basis to accept the SER Final document, for this reason alone, the license should be denied.

VI. CONCLUSION

For the foregoing reasons, Pilgrim Watch's position is that the record shows that Pilgrim Station cannot be re-licensed because the aging management program for buried pipes and tanks, by themselves, do not provide reasonable assurance that *by themselves,* that such safety-function-challenging leaks will not occur, and must be supplemented with more robust and frequent inspections and a comprehensive monitoring well program.

Respectfully submitted,

Mary Lampert

Mary Lampert, pro se
Pilgrim Watch
March 3, 2008

PILGRIM WATCH PRESENTS STATEMENTS OF POSITION, DIRECT TESTIMONY AND EXHIBITS UNDER 10 CFR 2.1207 [03.03.08]

EXHIBITS

Exhibit 1, Gundersen Decl. and CV
Exhibit 2, Ahlfeld Decl. and CV
Exhibit 3, 10 CFR 54.21
Exhibit 4, Transcript of ACRS Meeting
Exhibit 5, 10 CFR 50, Appendix B, XVI; Appendix C, Article C.12, "Operability Leakage from Class 1, 2, and 3 Components", to NRC Inspection Manual Part 9900, Technical Guidance, Attachment to RIS 2005-20

Exhibit 6, Safety Evaluation Report

Exhibit 7, Groundwater Contamination (Tritium) at Nuclear Plants-Task Force – Final Report, NRC, Sept 1, 2006,

Exhibit 8, Risk Informed Assessment of Degraded Buried Piping Systems in Nuclear Power Plants; Brookhaven National Laboratory; US Nuclear Regulatory Commission, NUREG/CR 6876, June 2005

Exhibit 9, Cox Decl. at ¶ 15

Exhibit 10, U.S. Nuclear Plants in the 21st Century: The Risk of a Lifetime, by David Lochbaum, Union of Concerned Scientists. (May 2004); and "Using Reliability-Centered Maintenance as The Foundation For An Efficient And Reliable Overall Maintenance Strategy," National Aeronautics and Space Administration (NASA), 2001.

Exhibit 11, Declaration of Alan Cox in support of Entergy's Motion for Summary Disposition of Pilgrim Watch Contention 1, June 5, 2007, at FN. 6, page 11,

Exhibit 12, Union of Concerned Scientists Issue Paper, Help Wanted: Dutch Boy at Byron (October 25, 2007),

Exhibit 13, Topography source: Pilgrim Nuclear Power Station, Boston Edison Company Docket No. 50-293, May 1972 –U.S. Atomic Energy Commission, Division of Radiological and Environmental Protection, Final EIS

Exhibit 14, Entergy's Prefiled Testimony, "Exhibit 5"

Exhibit 15, United States General Accounting Office, Report to the Chairman, Subcommittee on Oversight and Investigations, Committee on Energy and Commerce, House of Representatives, Nuclear Safety and Health Counterfeit and Substandard Products Are A Government Wide Concern, GAO/RCED-91-6, October 1990

Exhibit 16, *New England not immune to strong temblors and specialists say that a major event in only a matter of time,* Boston Globe, Bryan Bender, April 16, 2006,

Exhibit 17, The SER, 3-37,

Exhibit 18, Gall Report (NUREG-1801, Rev 1, XI, M-96, September 2005, at 10,)

Exhibit 19, Pilgrim in Appendix A.2.1.2.; and B.1.2 of the renewal filing

Exhibit 20, BPTIP External Cox Decl. at ¶¶ 23-24,

Exhibit 21, Davis DECL.

Exhibit 21, OIG-07-A-15

Exhibit 23, Event No. 43882, Event Notification report, December 11, 2007

Exhibit 24, Federal Register, page 3812, Legacy Sites
Exhibit 25, approximate location Monitoring Wells, Document Provided by Entergy

Exhibit 26, Reports: discovery in Pilgrim wells fuels debate, Boston Globe, December 20, 2007; Analysis Tritium Samples for Massachusetts Department of Public Health, December 5, 2007

EXHIBIT 1

Arnold Gundersen Declaration and CV

DOCKET NO. 50-293-LR
ASLBP NO. 06-848-02-LR
PILGRIM WATCH
EXHIBIT ONE

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION
Before the
ATOMIC SAFETY AND LICENSING BOARD

In the matter of ENTERGY NUCLEAR GENERATION CO., LLC and ENTERGY NUCLEAR OPERATIONS, INC. (Pilgrim Nuclear Power Station) License Renewal Application	January 26, 2008 Docket No. 50-293-LR ASLBP No. 06-848-02-LR

DECLARATION OF ARNOLD GUNDERSEN
SUPPORTING
PILGRIM WATCH'S PETITION FOR
CONTENTION 1

I, Arnold Gundersen, declare as follows:

1. My name is Arnold Gundersen. I am sui juris. I am over the age of eighteen (18) years old. I have personal knowledge of the facts contained in this Declaration.

2. Pilgrim Watch has retained me as an expert witness in the above captioned matter.

3. I have a Bachelor's and a Master's Degree in Nuclear Engineering from Rensselaer Polytechnic Institute (RPI) cum laude.

4. I began my career as a reactor operator and instructor in 1971 and progressed to the position of Senior Vice President for a nuclear licensee. A copy of my Curriculum Vitae is attached.

5. I have qualified as an expert witness before the NRC ASLB relating the proposed uprate at the Entergy Nuclear Vermont Yankee Nuclear Power Station and before the State of Vermont Public Service Board regarding that same matter.

6. I was an author of the first edition of the Department of Energy (DOE) Decommissioning Handbook.

7. My more than 35 years of professional nuclear experience include and are not limited to: Nuclear Plant Operation, Nuclear Management, Nuclear Safety Assessments, Reliability Engineering, In-service Inspection, Criticality Analysis, Licensing, Engineering Management, Thermohydraulics, Radioactive Waste Processes, Decommissioning, Waste Disposal, Structural Engineering Assessments, Cooling Tower Operation, Cooling Tower Plumes, Nuclear Fuel Rack Design and Manufacturing, Nuclear Equipment Design and Manufacturing, Prudency Defense, Employee Awareness Programs, Public Relations, Contract Administration, Technical Patents, Archival Storage and Document Control.

8. My declaration is intended to support Pilgrim Watch's Contention 1 and is specific to issues regarding the integrity of Pilgrim Nuclear Power Station's underground pipes and the ability of Pilgrim's Aging Management Program to determine their integrity.

9. I have reviewed the Aging Management Program (AMP) for Pilgrim Station and conclude that the applicant has not adequately addressed the monitoring of its underground pipes and tanks to assure their integrity if in fact Pilgrim Nuclear Power Station's license to operate is extended by an additional twenty years. The information provided by the AMP is vague and non-specific and cannot be used to conclude that any and all underground piping will ever be examined during the license extension period.

10. Furthermore, I conclude that the applicant has not shown with 95 percent certainty that the proposed AMP will in fact be able to detect any defects in the underground pipes and tanks.

11. Moreover, based upon my review of Pilgrim's AMP, it is my opinion that the applicant has not shown that the proposed AMP is adequate to assess and assure that underground piping and tanks will be able to withstand the stresses of an additional 20-year license extension.

12. Apparently Entergy itself has recognized the inadequacy of its Aging Management Program, for *after* these proceedings began and *after* Pilgrim Watch brought these inadequacies to Entergy's attention through this Intervention, Energy initiated a new program that attempts to address the inadequacies of its AMP for buried tanks and pipes. Entitled, Buried Piping and Tanks Inspection Program and Monitoring Program, Exhibit 5 [Hereinafter called "The Program"], it was initiated on November 11, 2007 and just recently provided as an Appendix to Energy's Prefiled Testimony, January 8, 2008.

    12.1. By initiating this Program, Entergy has shown that it agrees with Pilgrim Watch that the current AMPs for buried components are not sufficiently effective to provide reasonable assurance that such components will perform their intended functions either now or during their proposed period of extended operations and therefore a supplemental program is required.

    12.2. The purpose of Entergy's document is to provide requirements for each of its nuclear power plant sites to develop a site specific Program. The evidence I reviewed shows that the Program as presented is only a framework. The Program specifies only the framework for the content, scope, ranking methodology, priorities and inspection frequency of the buried piping and tanks on a generic, one size fits all basis and is not specific to Entergy's Pilgrim Nuclear Power Plant.

    12.3. Considering that both the Petitioner and Applicant agree that more should be done to provide reasonable assurance, it is my opinion that the Program should be fully examined in order to determine what elements should be

enhanced and turned into formal commitments by the licensee in order to receive license extension approval. Given the recent tritium findings (see Section 16 in this Declaration), in my opinion the Public requires a firm commitment from Entergy Pilgrim, not simply a voluntary plan that the plant may choose to adhere to or not. Just as importantly, given the unique attributes of the Pilgrim Site, the Program must be plant specific, not simply a generic one-size fits all approach.

12.4. My Section by Section Analysis of Entergy's Buried Piping and Tanks Inspection Program and Monitoring Program (11/19/07)[1] is below:

12.4.1. Section 5.0, subsection [1] at page 7 acknowledges right at the beginning that "The risk of a failure caused by corrosion, directly or indirectly, is probably the most common hazard associated with buried piping and tanks.

12.4.1.1. Section 5.0, subsection [2] on page 7 lists the steps required in building a risk assessment tool. However, in my opinion, the Program fails in that it never requires a complete baseline review.

12.4.1.2. Moreover, it appears to me that there is no indication that the entire component is supposed to be examined; instead *escape clauses are provided to the licensee* - such as [at 2a] "the size of each section shall reflect practical considerations of operation, maintenance, and cost of data gathering with respect to the benefit of increased accuracy."

12.4.1.3. In my experience, any program worth its salt would require a thorough baseline inspection along the entire length of the pipe.

[1] Entergy's Buried Piping and Tanks Inspection Program and Monitoring Program, 11/19/07, Entergy's Pre-Filed Testimony, Exhibit 5, January 8, 2008.

12.4.2. In my opinion, Section 5.2 Scope Program subsection [3] on page 8 clearly acknowledges the validity of Pilgrim Watch's initial contention by stating that "The program shall include buried or partially buried piping and tanks that, if degraded, could provide a path for radioactive contamination of groundwater. Some examples are: Buried piping containing contaminated liquids." In this section, it appears to me that Entergy agrees that "radioactive contamination of groundwater" is an important issue and belongs in the Buried Piping and Tanks Inspection and Monitoring Program as originally voiced by Pilgrim Watch in this contention.

12.4.3. In Section 5.4, Identification of Buried Piping and Tanks to be Inspected and Prioritized, page 9, Subsection [1] the licensee is directed to develop a list of all systems containing buried piping and tanks and to identify those sections by collecting physical drawings, piping/tank installation specifications, piping design tables and other data needed to support inspection activities.

12.4.3.1. In my experience, *the criteria must specify other key parts of the components*. For example:

- wall thickness,
- number and location of welds,
- elbows,
- flow restrictions,
- blank flanges,
- high velocity portions,
- the age of the components parts,
- cathodic protection,
- last inspection date and report number, and
- manufacturers warranty - if any.

12.4.3.2. The information specified above is the type of information that the NRC Staff requires when it conducts its safety evaluation so that the SER Report will be meaningful.

12.4.3.3. Since it was not available for NRC review, it is my opinion that the license application decision should be delayed until the information has not only been made available, but also has been critically reviewed.

12.4.4. Subsection [4] categorizes the piping into high, medium and low impact.

12.4.4.1. High impact components require prompt attention. I believe and Pilgrim Watch concurs that high impact components should receive prompt attention.

12.4.4.2. However Entergy's definition of "prompt" allows considerable delay in that they claim that high impact buried sections of piping shall be examined within 9-months of issuance of the procedure.

12.4.4.3. More disturbingly, under impact assessment Entergy lists radioactive contamination as "High Risk". Therefore, in my opinion, Entergy is once again confirming, via its own documents, the validity of Pilgrim Watch's initial contention that radioactive contamination clearly belongs in this adjudication process.

Note Table 1 Below: Entitled Impact Assessment

Table 1 Impact Assessment

	High	Medium	Low
Safety (Class per EN-DC-167)	Safety Related	Augmented QP and Fire Protection	Non-Safety Related
Public Risk	Radioactive Contamination e.g. Tritium	Chemical/Oil Treated System gases	Untreated Water SW, Demin Water
Economics (Cost of buried equipment failure to plant)	>$1M or Potential Shutdown	>$100K<$1M	<$100K

Notes:

1. Any buried section with at least one High Impact rating gets an overall High Impact rating.
2. Any buried section with no High Impact Rating but at least one Medium Impact rating gets an overall Medium Impact rating.
3. Any buried section with all Low Impact ratings is to be rated as Low Impact.

12.4.5. In Section 5.5 Table 4 on page 13, "Inspection Intervals vs. Inspection Priority" the Program Entergy proposes to initiate reflects the outcome from an assessment of the risks from buried piping and tanks. For example, buried piping and tanks having high risk are specified as having an initial inspection period of 5 years with a re-inspection interval of 8 years. In my opinion:

12.4.5.1. The time interval is proposed in the Program is too long.

12.4.5.2. It does not tell how much of the component will be inspected;

12.4.5.3. And, there is no requirement to shorten a subsequent inspection based upon the degree of corrosion discovered at the time of the prior inspection.

12.4.5.4. Also absent from this procedure is the prudent and practical guidance to conduct the inspection provisions of this procedure when opportunities present themselves, regardless of the inspection intervals noted in Table 4.

12.4.5.5. For example, if a section of buried piping categorized as having "Low" inspection priority is excavated for other reasons, my experience leads me to believe that this procedure should direct workers to take advantage of the opportunity and perform inspections when the pipe has been excavated for other purposes. Such an addition to the Program both protects public safety and health and protects the environment, and is also most cost effective.

12.4.5.6. Corrosion is neither linear nor constant across the component's length. Therefore, in my opinion it is a concern and not a sound engineering practice that in subsection [5], the Program specifies that the determination of inspection locations may also consider the "ease of access to inspection point." Industry evidence has proven time and again that ease of location and lack of corrosion do not necessarily go hand in hand. In fact, the odds are that if a component is difficult to access, then most likely it has never been inspected, which I believe is an even more important reason to inspect that particular pipe, pipe segment, elbow or weld.

12.4.6. In Section 5.6, entitled Parameters to be Inspected on page 13, the Program lists:

- external coatings and wrapping condition;
- pipe wall thickness degradation;
- tank plate thickness degradation; and
- cathodic protection system performance, if applicable.

12.4.6.1. In my opinion, the Program's attributes that must be considered in tabulating risk are simply too narrow. They include:

(a) soil resistivity measurement;
(b) drainage risk weight;

(c) material risk weight;
(d) cathodic protection/coating risk weight.

12.4.6.2. I believe that the list should be expanded to include, for example[2]:

- the age of the component's parts;
- the number of high risk corrosion areas in components such as welds, dead spots etc;
- counterfeit or substandard parts not replaced.

12.4.6.3. Moreover, the list appears to be silent on internal corrosion. My 35-years in nuclear engineering has shown me again and again that corrosion from the inside can bring about a failure.

Table 2 Corrosion Risk Assessment

Soil Resistivity, Ω-cm (Note 1)	Corrosivity Rating	Soil Resistivity Risk Weight
>20,000	Essentially Non-corrosive	1
10,001-20,000	Mildly Corrosive	2
5,001-10,000	Moderately Corrosive	4
3,001-5,000	Corrosive	5
1,000-3,000	Highly Corrosive	8
<1,000	Extremely Corrosive	10
Drainage		**Drainage Risk Weight**
Poor	Continually Wet	4.0
Fair	Generally Moist	2.0
Good	Generally Dry	1.0
Material (Note 2)		**Material Risk Weight**
Carbon and Low Alloy Steel		2.0
Cast and Ductile Iron		1.5
Stainless Steel		1.5
Copper Alloys		1.0
Concrete		0.5
Cathodic Protection	**Coating**	**CP/Coating Risk Weight**
No CP	No Coating	2.0
No CP	Degraded Coating	2.0
No CP	Sound Coating	1.0
Degraded CP	No Coating	1.0
Degraded CP	Degraded Coating	1.0
Degraded CP	Sound Coating	0.5
Sound CP	No Coating	0.5
Sound CP	Degraded Coating	0.5
Sound CP	Sound Coating	0.5

Notes:
1. Soil resistivity measurements must be taken at least once per 10 years unless areas are excavated and backfilled or if soil conditions are known to have changed for any reason.

2. Attachment 9.6 gives further insight to the corrosion of materials in soils.

12.4.6.4. Finally, and most importantly, this Section of Entergy's proposed Program is completely silent on the size of the sample required; its location; and the rational for the

[2] This Program list is meant to serve as an example and therefore should not be limited to only the components I have delineated in this brief Declaration.

sampling protocol – if, in fact, a sample is taken rather than an inspection of the entire component.

12.4.7. In my opinion, Section 5.7, on page 13 of the Program provides only vague remarks regarding the acceptance criteria for any degradation of external coating, wrapping and pipe wall or tank plate thickness.

12.4.7.1. Furthermore, the Program notes that degradation acceptance criteria should be based upon current plant procedures; *and* if not covered by current plant procedures then new procedures should be developed prior to any inspections.

12.4.7.2. In my opinion this alleged pass/fail grading system should be clearly defined. For example what precisely constitutes an unacceptable degraded external wrapping from an acceptably degraded external wrapping?

12.4.7.3. Most importantly, the LLTF was very specific that "significant" and other such descriptions require specific definitions.

12.4.8. In the Program's Section 5.8, Corrective Actions, on page 14, it is noted that "a condition report (CR) *shall* be written if acceptance criteria are not met.

12.4.8.1. Furthermore, the Program states that such corrective actions *may* include engineering valuations, scheduled inspections, and change of coating or replacement of corrosion susceptible components. Components that do not meet acceptance criteria shall be *dispositioned* by engineering. [Emphasis added].

12.4.8.2. In my opinion this aspect of the Program provides no assurance to public safety and health. The corrective actions *may [or may not]* include engineering valuations, scheduled inspections, and change of coating or replacement of corrosion susceptible components.

- Where are the Program's guarantees?
- Whatever happened to the concept that this Program would consist of layers of supervision so that the NRC would play some sort of oversight role in this program?
- Who will see these Condition Reports?
- – Or to put it another way, Where are the reports kept, who has access to those reports, do they have to be sent to the NRC and if so under what conditions and time schedule?

12.4.8.3. A more basic issue is that Condition Reports are unlikely to be written or, if they are written, to actually say anything as explained directly below.

12.4.9. Section 5.12 Inspection Methods and Technologies/Techniques, subsection [1] on page 15 specifies steps to be taken for Visual Inspections of buried piping and tanks. Step (g) directs the workers: "A CR [condition report] shall be initiated if the acceptance criteria are not met."

12.4.9.1. In my opinion, a review of steps (a) through (f) as written in Entergy's Program reveals a lack of objective, or even subjective, acceptance criteria that could trigger a condition report. Please note below:

a) When opportunities arise, buried sections of piping and tanks "should be examined to quantify deposit accumulation…and those results documented." According to the Program, as long as exposed piping is examined and damage chronicled, then the acceptance criteria are met and there is no condition report.

b) "Look for signs of damaged coatings or wrapping defects". Again, according to the Program, as long as workers do an examination, then the acceptance criteria are met. Only not looking would fail to meet the acceptance criterion and trigger a condition report.

c) "The interior of piping may be examined by divers, remote cameras, robots or moles when appropriate." In my opinion, the combination of "may" and "when appropriate" means the acceptance criterion is met whether examinations are performed or not.

d) "Use holiday tester to check excavated areas of piping for coating defects." Following the Program, when coating defects are found for exposed area of piping using a holiday tester, then the acceptance criteria is met and again no condition report is required.

e) If a visual inspection reveals coatings or wrappings not to be intact, further inspection of piping for signs of pitting, MIC, etc is required. However, the way the Program has been created, once the additional inspection is performed, the acceptance criterion is satisfied and no condition report is warranted whether or not damage is uncovered.

f) Inspect below grade concrete for indication of cracking and loss of material. Finally, once again, the Program is

designed so that as long as the inspection is performed, the acceptance criterion is satisfied whether or not damage is uncovered, nor is any record of the status of damage or its significance recorded.

12.4.10. In Section 5.12 subsection [2] on page 16 the Program specifies the steps to be taken for Non-Destructive Testing of buried piping and tanks. No steps direct workers to initiate condition report(s) regardless of how extensive the piping and/or tank damage identified may be.

12.4.11. On page 14 Section 5.9 Preventive Measures, the Program stated that "...the existing cathodic protection system *may* be updated or a new Cathodic Protection system *may* be installed. Pilgrim Watch has explained that cathodic protection *should* be installed. The emphasis should be on prevention not waiting to discover failures before acting.

12.5. Most revealing of all Entergy's proposed Program contains no provision for root cause analysis of any identified degradations. Furthermore, the Program does not expand the sample size when problems are identified. I believe this is a critical weakness, which treats each failure as an isolated situation rather than look at the broader ramifications of the problem.

12.6. In summary, it is my opinion that reasonable assurance is not provided by this new Entergy Program. In order to be even minimally effective, Entergy's Program needs real commitments and the Public needs to see how the Pilgrim specific Program will be designed and what recommended site specific safeguards will be put into place at Pilgrim, rather than accepting a loosely designed generic one size fits all style program. Therefore, I believe that the ASLB should delay its

determination on the application until the program is in place and may be evaluated.

13. Already, the record to date in these proceedings support my conclusion that the AMP may not be adequate to prevent or detect leaks in underground pipes and tanks. The Atomic Safety and Licensing Board (ASLB) has suggested that it is not necessary for the existing AMP to prevent or detect failures in underground pipes and tanks. Accordingly, the ASLB said,

    13.1. "...prevention of leaks per se is not a stated objective of any relevant aging management program. On the other hand, prevention of an aging- induced leak large enough to compromise the ability of buried pipes or tanks to fulfill their intended safety function is a clear goal of an AMP. Thus at issue here is the following fundamental question: Do the AMPs for buried pipes and tanks, by themselves, ensure that such safety-function-challenging leaks will not occur, or must some sort of leak detection devices such as monitoring wells proposed by Intervenors be installed to meet the obligation?" *Memorandum and Order, Docket No. 50-293-LR, ASLB No. 06-848-02-LR, October 17, 2007, P.17*

    Additionally, the ASLB also noted that:

    13.2. "...only issue remaining before this licensing Board regarding Contention 1 is whether or not monitoring wells are necessary to assure that the buried pipes and tanks at issue will continue to perform their safety function during the license renewal period -, or, put another way, whether Pilgrim's existing AMPs have elements that provide appropriate assurance as required under relevant NRC regulations that the buried pipes and tanks will not develop leaks so great as to cause those pipes and tanks to be unable to perform their intended safety functions." *Ibid., P.17*

14. My understanding of NRC regulations is that in operating license proceedings, the licensee bears the ultimate burden of proof.

15. In my opinion the factual record submitted by the applicant Entergy does not meet the burden of proof required by a licensee, much less with 95% certainty, that the Aging Management Program <u>will identify</u> leaks, or that any leaks already identified by the AMP will not expand further in the pipes or tanks thereby leaving the Pilgrim Nuclear

Power Station and its environs without a critical back-up safety system. For example, the Byron Station Nuclear Power Plant in Illinois recently detected what appeared to be a very small weeping pipe. However, upon closer inspection, the integrity of the pipe was grossly undermined and was in imminent danger of a catastrophic failure.

16. All parties involved in these proceedings to evaluate the viability of a 20-year life extension at the aged Pilgrim Nuclear Power Station are certainly aware that leaks in underground piping and tanks have frequently occurred at other operating nuclear power plants. As recently as November 29, 2007, the presence of Tritium was discovered at the Pilgrim Nuclear Power Plant Site. At the concentrations detected the Tritium undoubtedly came from the plant. Experience in isolating Tritium leaks at other nuclear plants has shown that it will take at least one year to accurately determine the origin of the leak and how broadly it has spread and contaminated surrounding areas. More importantly for this discussion, until the source and magnitude of the leak is uncovered, one cannot determine which system or systems may be compromised.

17. Based upon my professional experience as the Senior Vice-President of an ASME XI In-Service Inspection Division, it is my opinion there are several challenging scenarios in which these unidentified leaks can and will jeopardize the design and intended function of safety related systems and components at the Pilgrim Nuclear Power Station. More specifically, the recently discovered Tritium releases show that undetected leaks may already have occurred, in Pilgrim's underground pipes and tanks, thereby causing them to malfunction in such a way as to be "*unable to perform the intended safety function*". Therefore in my estimation, there are at least <u>three possible scenarios</u> that may be the result of the flaws in Pilgrim's AMP.

    17.1. <u>In the first scenario</u>, there may be a loss of intended safety function if a leak has occurred and has gone undetected by the Applicant's AMP. If a leak could spontaneously heal itself, we would not need an AMP for pipes and tanks. Unfortunately, leaks, once begun and whether observed or not, will continue to grow as evidenced by the newly discovered Tritium leaks.

These leaks may be caused by external abrasion, internal corrosion, galvanic attack or other factors as yet to be uncovered.

17.1.1. Leaks not only continue to increase in flow, but in fact the rate of expansion for leaks actually accelerates once a pinhole has been created in the pipe or tank wall.

17.1.2. After the initial pinhole, water begins to exit the tank or pipe, at an ever-accelerating rate as the hole expands. In fact, mathematically speaking, the leak rate growth is proportional to the square of the hole's radius.

17.1.3. Given that the Aging Management Plan has not detected some underground leaks as suggested in paragraph 12 and by the newly discovered Tritium leaks, it then becomes quite likely that if a safety function is required, the leak may either divert the required water or reduce the required line pressure rendering the pipe and tank system *"unable to perform the intended safety function"*.

17.1.4. Transient flow and pressure changes that would occur if there is a design basis event will exacerbate leak growth and further reduce the ability *"to perform the intended safety function"*. According to the NRC's website, a design basis accident (event) is "a postulated accident that a nuclear facility must be designed and built to withstand without loss to the systems, structures, and components necessary to assure public health and safety." In my opinion, the recent pipe failures at the Byron Nuclear Power Station in Illinois are the perfect example for this discussion. At Byron, safety-related flanges on pipes were weeping so badly that they certainly would have been unable to have withstand the flow and pressure transient associated with actually requiring the system to operate in its safety mode. Without adequate Aging Management oversight,

such a scenario could be mirrored at the Pilgrim Nuclear Power Station.

17.2. The second scenario is similar to the first in that a growing leak remains undetected by an inadequate Aging Management System. However, unlike the first scenario, in which a system failure is caused by allowing water to exit the expanding hole(s), in this scenario rust particles, dirt and other contamination enter the pipe or tank through the hole thereby clogging downstream filters and heat exchangers, or the debris abrades the moving parts thus rendering the system "*unable to perform the intended safety function*".

17.3. The third scenario acknowledges the presence of the initial leak that may or may not have grown significantly. However, in this scenario, it is the structural weakness created by the hole or holes in the pipe or tank, which render the system "*unable to perform the intended safety function*".

17.3.1. The hole or holes act as stress risers and increase the likelihood of gross failure under the stress of accident conditions.

17.3.2. Given that the inadequacies of the Aging Management Plan have allowed the creation of a hole or holes, and that the applicant has not structurally analyzed the presence of such holes, it is my opinion that the system would be operating outside its regulatory design basis criteria.

17.3.3. Holes that reduce the structural integrity of pipes are particularly worrisome at elbows and flanges (similar to the aforementioned Byron incident) and would render the pipe or tank "*unable to perform the intended safety function*" in the event of a Safe Shutdown Earthquake (SSE). As the nuclear industry well knows, the small earthquake at the Perry Nuclear Power Plant in Ohio did

cause leaks in plant piping, and this mild earthquake was not at all comparable to a SSE.

17.3.4. According to NRC regulations, all nuclear power stations must have certain structures, systems, and components requisite to safety, designed to sustain and remain functional in the event of maximum earthquake potential. Unidentified holes in safety related underground pipes place those pipes in an unanalyzed condition outside the scope of the regulatory design basis for the Applicant's Pilgrim Nuclear Power Plant.

17.4. In light of the newly discovered Tritium leaks, it may in fact be true that a significant safety system has already been compromised. Moreover, it seems in fact that the applicant Entergy's Aging Management System did not uncover those leaks, or did not do so in a timely manner.

18. It is my belief, as the Expert Witness retained by Pilgrim Watch, that <u>there are at least four solutions available to Entergy and the ASLB to mitigate the serious consequences of undetected leaks</u>. Contention 1, as delineated in this proceeding, is that the frequency of the monitoring proposed by the Applicant is insufficient to ensure that the required safety margins would be maintained throughout any extended period of operation. The Board appropriately suggested a possible weakness in the Applicant's (Pilgrim Nuclear Power Station) Aging Management Program to detect leaks, and this problem seems to be borne out by the recently discovered on-site Tritium leaks. <u>I suggest that this problem may be minimized by four separate approaches:</u>

- Establish critical Baseline Data;
- Reduce the future corrosion rate;
- Improve monitoring frequency and coverage;
- Increase the Monitoring Well Program to actively look for leaks once they have occurred.

18.1. Establish Critical Baseline Data: In view of the fact that industry as a whole and Pilgrim, specifically, have experienced corrosion and leaks, as evidenced at Pilgrim by the recently discovered Tritium leaks, it is important that critical Baseline Data be collected via a top to bottom examination of the safety-related buried pipes/tanks.

18.1.1. Such an inspection must entail special attention to points of vulnerability – such as at elbows, welds, joints, and at any dead spaces where liquid can sit.

18.1.2. Examinations must include inspection both inside and outside.

18.1.3. Special attention must also be given to those welds located upstream or downstream of a flow disturbance.

18.1.4. Since it is not possible to assess possible damage below the coating in the pipe body, in addition all piping must be pressure tested to at least twice the operating pressure. Inability to perform pressure tests for any reason should not be cause for relief.

18.1.5. Baseline data is critical so that trending is established. NUREG/CR 6876 states, at 32, "...it is evident that predicting an accurate degradation rate for buried piping systems is difficult to achieve..."

18.1.6. After a baseline is established then regular examinations afterwards can better determine the need for mitigation before, not after, a problem develops.

18.2. Reduce corrosion rates: The Applicant can and should implement a thorough Cathodic Protection Program (CPP) on all underground pipes and tanks. I found no reference to such a program in the application submitted by Energy. A CPP would reduce the likelihood of leaks.

18.3. Improve monitoring frequency and coverage: In an attempt to minimize the size and frequency of leaks, in my opinion, the AMP should be augmented to require more frequent and more comprehensive inspections of all underground pipes and tanks.

18.3.1. Specifically, I believe that a 100 percent internal visual inspection of all underground pipes and tanks must be implemented.

18.3.2. The inspection cycle should be such that all pipes and tanks are inspected every ten years, however, I believe that the Applicant should be required to break the testing interval down such that one sixth of all pipes and tanks are inspected during each refueling outage. (This assumes 18 month refueling outages, or six every ten years.)

18.3.3. Finally, it is my opinion that the Applicant should be required to inspect one sixth of the lineal piping, one sixth of the elbows and flanges, and one sixth of the tank seams at each outage, even if such inspections lengthen the outage time.

18.3.4. For example, when I was reviewing the Aging Management System at Entergy's Nuclear Vermont Yankee (ENVY) Power Station, I noted that the AMP was often neglected in order to assure the outage was not extended. Therefore is my opinion that the Applicant Entergy should certify that each portion of the AMP on the pipes and tanks is accomplished in the order agreed upon and completed at every outage. As an Intervenor with standing on Contention 1, Pilgrim Watch should be allowed to review copies of the certified piping inspection reports prior to the end of each outage to assure that the work was completed as ordered.

18.4. <u>Increase the Monitoring Well Program to actively look for leaks once they have occurred:</u> According to Pilgrim Watch's expert, Dr. David P.

Ahlfeld, in order to meet the minimum criteria for an effective monitoring well program at Pilgrim, such a program should made part of the license going forward so that it is enforceable and not simply voluntary and must follow the steps in monitoring network design as outlined in Dr. Ahlfeld's declaration. In the absence of any leaks at the Applicant's Pilgrim Nuclear Power Station, I believe that my recommendations would be necessary to the evaluation of Pilgrim's application for a 20-year extension to its current operating license. However, given the recently discovered Tritium leaks at Entergy's Pilgrim Plant and other reactors around the country, my recommendations are critical to the continued operation of Pilgrim to the end of its current license, without any consideration of a license extension.

18.4.1. In light of the newly discovered Tritium leaks, it may in fact be true that a significant safety system has already been compromised.

18.4.2. I believe it will most likely take at least one year to trace the path of the unanticipated Tritium releases.

18.4.3. The release of Tritium indicates a leak in a system that in the past was radioactive.

18.4.4. I believe such a leak means that testing should immediately be undertaken that searches for Cesium 134 and Cesium 137, Cobalt 60, and other gamma emitters as well as Strontium 90.

18.4.5. As a nuclear engineering senior vice-president overseeing decommissioning of nuclear sites and an author of the DOE Decommissioning Handbook, I believe it is critical that these newly discovered Tritium releases be accurately monitored. The evidence I reviewed as an expert witness regarding Florida Power and Light's St. Lucie Nuclear Power Plant, and the documents I have reviewed pertaining to the decommissioning effort at the

former Connecticut Yankee Nuclear Power Plant Site, clearly show how far and wide Tritium and other radioactive isotopes may spread before their release is uncovered.

18.4.6. Therefore in my opinion, and given Pilgrim's proximity to the environmentally sensitive Bay and salt marshes, a rigorous and expanded Monitoring Well program should be ordered and immediately undertaken at and around the Pilgrim Nuclear Power Plant Site.

Conclusion:

Based upon my 35-year nuclear safety and nuclear engineering experience, it is my professional opinion that the issues discussed above are serious safety considerations germane to the subject of this ASLB proceeding: Entergy's application to extend the operation of its Pilgrim Nuclear Power Station for an additional 20 years. Furthermore, following my complete review of the facts as delineated in the above discussion, it is my professional opinion that the proposed AMP is inadequate and that several remedies are available to the Applicant that will minimize the probability of a leak occurring, minimize detection of any possible leaks and meet the SSE and design basis accident regulatory criteria by enabling all systems to *"perform the intended safety function"*.

I declare under penalty of perjury that the foregoing is true and correct.
Executed this day, January 26, 2008 at Burlington, Vermont.

Arnold Gundersen, MSNE, RO
1/26/08 Fairewinds Associates, Inc

CURRICULUM VITAE

Arnold Gundersen
June 2007

Education And Training

ME NE	Masters of Engineering Nuclear Engineering Rensselaer Polytechnic Institute, 1972 U.S. Atomic Energy Commission Fellowship Thesis: Cooling Tower Plume Rise
BS NE	Bachelor of Science Nuclear Engineering Rensselaer Polytechnic Institute, 1971 Cum Laude, 3.74 out of 4.0 James J. Kerrigan Scholar
RO	Licensed Reactor Operator, U.S. Atomic Energy Commission License # OP-3014

Special Qualifications – including and not limited to:
Nuclear Safety Expert Witness; 37-years of nuclear industry experience and oversight; former nuclear industry Senior Vice President; nuclear engineering management assessment; prudency assessment; Employee Awareness Programs; nuclear power plant licensing and permitting production, assessment, and review; public communications, contract administration, assessment and review; former Licensed Reactor Operator; systems engineering, radioactive waste processes and storage issue assessment, technical patents, federal and congressional hearing testimony, decommissioning, waste disposal, source term reconstructions, thermal discharge assessment, aging plant management assessment

Special Remediation Expertise
Director of Engineering, Vice President of Site Engineering, and the Senior Vice President of Engineering at Nuclear Energy Services (NES).

- Department of Energy chose NES to write *DOE Decommissioning Handbook* because NES had a unique breadth and depth of nuclear engineers and nuclear physicists on staff.
- Personally wrote the "Small Bore Piping" chapter of the DOE's first edition Decommissioning Handbook, personnel on my staff authored other sections, and I reviewed the entire Decommissioning Handbook.
- Served on the Connecticut Low Level Radioactive Waste Advisory Committee for 10 years from its inception
- Managed groups performing analyses on dozens of dismantlement sites in order to thoroughly remove radioactive material from nuclear plants and their surrounding environs.
- Managed groups assisting in decommissioning the Shippingport nuclear power reactor. Shippingport was the first large nuclear power plant ever decommissioned. The decommissioning of Shippingport included remediation of the site after decommissioning.
- Managed groups conducting site characterizations (preliminary radiation surveys prior to commencement of removal of radiation) at the radioactively contaminated West Valley site in upstate New York.
- Personnel reporting to me assessed dismantlement of the Princeton Avenue Plutonium Lab in New Brunswick, NJ. The lab's dismantlement assessment was stopped when we uncovered extremely toxic and carcinogenic underground radioactive contamination.
- Personnel reporting to me worked on decontaminating radioactive thorium at the Cleveland Avenue nuclear licensee in Ohio. The thorium had been used as an alloy in turbine blades. During that project, previously undetected extremely toxic and carcinogenic radioactive contamination was discovered below ground after an aboveground gamma survey had purported that no residual radiation remained on site.

Publications

Co-author — *DOE Decommissioning Handbook, First Edition*, 1981-1982, Authorship solicited by DOE

Co-author — *Decommissioning the Vermont Yankee Nuclear Power Plant: An Analysis of Vermont Yankee's Decommissioning Fund and Its Projected Decommissioning Costs*, November 2007, Presented to Vermont State Senator Ginny Lyons and Vermont State Auditor Tom Salmon

Co-author — *Decommissioning Vermont Yankee – Stage 2 Analysis of the Vermont Yankee Decommissioning Fund – The Decommissioning Fund Gap*, December 2007, Presented to Vermont State Senators and Legislators

Co-author — *Vermont Yankee Comprehensive Vertical Audit – VYCVA – Recommended Methodology to Thoroughly Assess Reliability and Safety Issues at Entergy Nuclear Vermont Yankee*, January 2008, Presented to US Senator Bernie Sanders and to the Vermont State Senate Finance Committee

Patents
Energy Absorbing Turbine Missile Shield – U.S. Patent # 4,397,608 – 8/9/1983

Committee Memberships
ANSI N-198, Solid Radioactive Waste Processing Systems
Three Rivers Community College Nuclear Academic Advisory Board
Founding Member of Connecticut Low Level Radioactive Waste Advisory Committee (Member for 10 years)
Founding Member National Nuclear Safety Network

Honors
James J. Kerrigan Scholar 1967–1971
Tau Beta Pi (Engineering Honor Society), RPI, 1969
(1 of 5 in Sophomore class of 700)
B.S. Degree, Cum Laude, RPI (3.74 GPA) 1971
U.S. Atomic Energy Commission Fellowship, 1972
Publicly commended to U.S. Senate by NRC Chairman, Ivan Selin, in May 1993
"It is true...everything Mr. Gundersen said was absolutely right; he performed quite a service."

Teacher of the Year – 2000, Marvelwood School

Nuclear Consulting and Expert Witness Testimony

Peach Bottom Reactor Litigation
Evaluated extended 28-month outage caused by management breakdown and deteriorating condition of plant.

Commonwealth Edison
In depth review and analysis for Commonwealth Edison to analyze the efficiency and effectiveness of all Commonwealth Edison engineering organizations, which support the operation of all of its nuclear power plants.

Western Atlas Litigation
Evaluated neutron exposure to employees and license violations at this nuclear materials licensee.

Three Mile Island Litigation
Evaluated unmonitored releases to the environment after accident, including containment breach, letdown system and blowout. Proved releases were 15 times higher than government estimate and subsequent government report.

PennCentral Litigation
Evaluated license violations and material false statements by management at this nuclear engineering and materials licensee.

Federal Congressional Testimony
Publicly recognized by NRC Chairman, Ivan Selin, in May 1993 in his comments to U.S. Senate, "It is true...everything Mr. Gundersen said was absolutely right; he performed quite a service."

State of Connecticut
Assisted the State in drafting Whistle-blower Protection legal statutes, the strongest in the United States.

Nuclear Regulatory Commission (NRC)
Assisted the NRC Inspector General in investigating illegal gratuities paid to NRC Officials by Nuclear Energy Services (NES) Corporate Officers. In a second investigation, assisted the Inspector General in showing that material false statements (lies) by NES corporate president caused the NRC to overlook important license violations.

International Nuclear Safety Testimony
Worked for ten days with the President of the Czech Republic (Vaclav Havel) and the Czech Parliament on their energy policy for the 21st century. Continue to work with Czech Friends of the Earth on Czech Energy and Environmental Issues

State of Vermont Public Service Board
Expert witness retained by New England Coalition to testify to the Public Service Board on the reliability, safety, technical, and financial ramifications of a proposed increase in power (called an uprate) to 120% at Entergy's 31-year-old Vermont Yankee Nuclear Power Plant. April 2003 to present

U.S. Senators Jeffords and Leahy (2003 to 2005)
Provided the Senators and their staff with periodic overview regarding technical, reliability, compliance, and safety issues at Entergy Nuclear Vermont Yankee (ENVY).

10CFR 2.206 filed with the Nuclear Regulatory Commission
Filed 10CFR 2.206 petition with NRC requesting confirmation of Vermont Yankee's compliance with all General Design Criteria.

State of Vermont Legislative Testimony to Senate Finance Committee
Testimony to the Senate Finance Committee, 2006 regarding Vermont Yankee decommissioning costs, reliability issues, design life of the plant, and emergency planning issues.

Finestone v FPL
Plaintiffs' Expert Witness for Federal Court Case with Attorney Nancy LaVista, from the firm Lytal, Reiter, Fountain, Clark, Williams, West Palm Beach, FL.
This case involved twenty-six families in a cancer cluster alleging illegal radiation releases from nearby nuclear power plant caused children's cancers.

Production request, discovery review, preparation of deposition questions and attendance at Defendant's experts for deposition, preparation of expert witness testimony, preparation for Daubert Hearings, ongoing technical oversight, source term reconstruction.

U.S. Nuclear Regulatory Commission Atomic Safety and Licensing Board (NRC-ASLB) Expert witness retained by New England Coalition to provide Atomic Safety and Licensing Board with an independent analysis of the integrity of the Vermont Yankee Nuclear Power Plant condenser. (2006)

U.S. Senators Bernie Sanders and Congressman Peter Welch (2007)
Briefed Senator Sanders, Congressman Welch and their staff members regarding technical and engineering issues, reliability and aging management concerns, regulatory compliance, waste storage, and nuclear power reactor safety issues confronting the U.S. nuclear energy industry.

State of Vermont Environmental Court
Expert witness retained by New England Coalition to review Entergy and Vermont Yankee's analysis of alternative methods to reduce the heat discharged by Vermont Yankee into the Connecticut River. Provided Vermont's Environmental Court with analysis of alternative methods systematically applied throughout the nuclear industry to reduce the heat discharged by nuclear power plants into nearby bodies of water. This report included the review of condenser and cooling tower modifications. (Docket 89-4-06-vtec 2007)

Appeal to the Vermont Supreme Court
Expert Witness Testimony in support of New England Coalition's Appeal to the Vermont Supreme Court Concerning: Degraded Reliability at Entergy Nuclear Vermont Yankee as a Result of the Power Uprate. New England Coalition represented by Attorney Ron Shems of Burlington, VT (March 2006 to 2007)

U.S. Nuclear Regulatory Commission Atomic Safety and Licensing Board (NRC-ASLB) MOX Limited Appearance Statement to Judges Michael C. Farrar (Chairman), Lawrence G. McDade, and Nicholas G. Trikouros for the he "Petitioners": Nuclear Watch South, the Blue Ridge Environmental Defense League, and Nuclear Information & Resource Service have filed Contention 2: Accidental Release of Radionuclides, requesting a hearing concerning faulty accident consequence assessments made for the MOX plutonium fuel factory proposed for the Savannah River Site. (September 14, 2007)

Experience

Teaching and Academic Administration

Burlington High School

Mathematics Teacher – 2001 to present

Physics Teacher – 2004 to 2006

The Marvelwood School – 1996-2000

Chairman: Mathematics and Physics Department

Taught both mathematics and physics.

Director of Summer School and Director of Residential Life

Awarded Teacher of the Year – June 2000

Additional teaching experience: The Forman School, St. Margaret's School, and college level Advanced Nuclear Reactor Physics Lab at RPI (Rensselaer Polytechnic Institute).

Nuclear Engineering 1970 to 1990

Nuclear Energy Services, Division of PCC (Fortune 500 company) 1979 to 1990

Corporate Officer and Senior Vice President - Technical Services

Responsible for overall performance of the company's Inservice Inspection (ASME XI), Quality Assurance (SNTC 1A), and Staff Augmentation Business Units.

Senior Vice President of Engineering

Responsible for the overall performance of the company's Site Engineering, Boston Design Engineering and Engineered Products Business Units. Integrated the Danbury based, Boston based and site engineering functions to provide products such as fuel racks, nozzle dams, and transfer mechanisms and services such as materials management and procedure development.

Vice President of Engineering Services

Responsible for the overall performance of the company's field engineering, operations engineering, and engineered products services. Integrated the Danbury based and field based engineering functions to provide numerous product and services required by nuclear utilities.

General Manager of Field Engineering

Managed and directed NES' multi-disciplined field engineering staff on location at various nuclear plant sites. Site activities included structural analysis, procedure development, technical specifications and training. Have personally applied for and received one patent.

Director of General Engineering

Managed and directed the Danbury based engineering staff. Staff disciplines included structural, nuclear, mechanical and systems engineering. Responsible for assignment of personnel as well as scheduling, cost performance, and technical assessment by staff on assigned projects. This staff provided major engineering support to the company's nuclear waste management, spent fuel storage racks, and engineering consulting programs.

New York State Electric and Gas Corporation (NYSE&G) — 1976 to 1979

Supervisor, Reliability Engineering

Organized and supervised reliability engineers to upgrade performance levels on seven operating coal units and one that was under construction. Applied analytical techniques and good engineering judgments to improve capacity factors by reducing mean time to repair and by increasing mean time between failures.

Lead Power Systems Engineer

Supervised the preparation of proposals, bid evaluation, negotiation and administration of contracts for two 1300 MW NSSS Units including nuclear fuel, and solid-state control rooms. Represented corporation at numerous public forums including TV and radio on sensitive utility issues. Responsible for all nuclear and BOP portions of a PSAR, Environmental Report, and Early Site Review.

Northeast Utilities Service Corporation (NU) — 1972 to 1976

Engineer

Responsible Nuclear Engineer assigned to Millstone Unit 2 during start-up phase. Lead the high velocity flush and chemical cleaning of condensate and feedwater systems and obtained discharge permit for chemicals. Developed Quality Assurance Category 1 Material, Equipment and Parts List. Modified fuel pool cooling system at Connecticut Yankee, steam generator blowdown system and diesel generator lube oil system for Millstone. Evaluated Technical Specification Change Requests.

Associate Engineer

Responsible Nuclear Engineer assigned to Montague Units 1 & 2. Interface Engineer with NSSS vendor, performed containment leak rate analysis, assisted in preparation of PSAR and performed radiological health analysis of plant. Performed environmental radiation survey of Connecticut Yankee. Performed chloride intrusion transient analysis for Millstone Unit 1 feedwater system. Prepared Millstone Unit 1 off-gas modification licensing document and Environmental Report Amendments 1 & 2.

Rensselaer Polytechnic Institute (RPI) — 1971 to 1972

Critical Facility Reactor Operator, Instructor

Licensed AEC Reactor Operator instructing students and utility reactor operator trainees in start-up through full power operation of a reactor.

Public Service Electric and Gas (PSE&G) — 1970

Assistant Engineer

Performed shielding design of radwaste and auxiliary buildings for Newbold Island Units 1 & 2, including development of computer codes.

Vetted as expert witness in nuclear litigations, federal, international, and state hearings including but not limited to: Three Mile Island, US Federal Court, US NRC ASLB, Vermont State Public Service Board, Czech Senate, Connecticut State Legislature, Western Atlas Nuclear Litigation, U.S. Senate Nuclear Safety Hearings, Peach Bottom Nuclear Power Plant Litigation, and OIG NRC.

Public Service, Cultural, and Community Activities

Sunday School Teacher, Christ Episcopal Church, Roxbury, CT
Parents Association Washington Montessori School
High School Guest Lecturer on Nuclear Safety Issues (30+ times)
Episcopal Marriage Encounter: Basic Training & Group Leadership Training, Presenting Team [with wife] – Provided weekend communication and dialogue workshops weekend retreats/seminars, Administrative Couple – supervised Connecticut Episcopal Marriage Encounter – 5 years
Co-Founder Parents Association Berkshire School
Co-Chair Annual Appeal Berkshire School
Featured Nuclear Safety Expert for Television, Newspaper and Radio, including but not limited to CNN (Earth Matters), The Crusaders, WPTZ VT, WZBG CT
Founding Board Member NNSN – National Nuclear Safety Network
Ongoing Public Testimony to Committees of the Vermont State Legislature
Tutoring of Refugee Students – Lost Boys of the Sudan and others
Certified Foster Parent State of Vermont – 2004 to 2007
Working with Burlington Electric Department (BED) on solar modifications to Burlington High School (BHS)
Mentoring former students regarding college and employment questions and applications.

EXHIBIT 2

Dr. David Ahlfeld Declaration and CV

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

Before The Atomic Safety And Licensing Board

In the Matter of
Entergy Corporation
Pilgrim Nuclear Power Station
License Renewal Application

Docket # 50-293-LR

January 28, 2008

Declaration of David P. Ahlfeld, PhD, PE
Regarding
Groundwater Monitoring Requirements for PNPS

I am presently a Professor in the Department of Civil and Environmental Engineering at the University of Massachusetts, Amherst. I have taught, conducted research and worked on projects in the area of groundwater flow and contaminant transport in the subsurface and related topics for over 20 years.

Decades of experience with subsurface facilities, much of it since Pilgrim was constructed, indicates that, even with the best-intentioned efforts of leak prevention, leaks of contaminants into the subsurface can and do occur. There are numerous instances of this across many industries and examples at nuclear power plants. Leakage can occur for a period and then stop or it can continue at a low flow rate for extended periods. These and other leakage modes produce subsurface contamination that is virtually impossible to detect without the use of direct sampling methods such as monitoring wells.

The Pilgrim facility has several components that are within scope from which detectable contaminants could leak into the subsurface. These include buried pipes and tanks servicing the condensate storage system, offgas system piping, salt service water system and fuel oil systems. Entergy describes several methods they use to prevent leaks from occurring, however, Entergy has not demonstrated that they have sufficient means of detecting leaks if they occur.

Groundwater monitoring networks are commonly used as a means of detecting leaks from a wide variety of facilities. To make the monitoring network an effective means of detecting leaks, the network should be designed so that a pollutant release under any plausible leak scenario will be detected, with high degree of certainty. The design of a monitoring network includes determination of plausible leak scenarios, determination of

expected fate and transport of the leaking substances and then placement of the detection network so that these transporting substances will be detected.

This general guideline for monitoring network design is expanded upon below, with reference to specific features of the Pilgrim Nuclear Power Station (PNPS). These constitute the steps in monitoring network design which, with appropriate documentation, would constitute an adequate design. As noted below, many of these steps are similar to those recommended in the Nuclear Energy Institute (NEI) Industry Ground Water Protection Initiative – Final Guidance Document (NEI 07-07, August, 2007).

Steps in Monitoring Network Design

1) Determination of all plausible leak locations. This would include consideration of all piping segments and tanks that are placed below the ground surface and are part of system components that are within scope. For purposes of monitoring network design, leaks from any of the plausible locations would be presumed to release water contaminated with radionuclides or oil. This step is similar those recommended in the NEI Guidance Document (Objective 1.2 Site Risk Assessment) where buried piping is described as being a credible mechanism for leaking materials to reach groundwater.
2) Identification of the specific contaminant species that would be present in the leaking water or oil from each of the system components. A set of indicator contaminants should be selected for each system component that can, if detected in groundwater, uniquely identify the component. Particular emphasis should be on those contaminants that are least likely to sorb and thus be most rapidly transported.
3) Consideration of the fate and transport of each indicator contaminant from each of the plausible leak locations.
    a. This analysis would include prediction of subsurface transport pathways from all identified source locations. This prediction would consider vertical migration of leaking water through the unsaturated zone to the water table. It would also account for the direction and rate of groundwater flow. Such predictions must be based upon understanding of groundwater behavior at the site derived from a recently-conducted detailed site characterization as recommended in the NEI Guidance Document (Objective 1.1 Site Hydrology and Geology). This is particularly important at PNPS where building, paving and changes to storm drainage may significantly affect local flow behavior.
    b. Transport of a particular contaminant along identified transport pathways must be analyzed. For each contaminant it is necessary to account for the initial concentration of the contaminant in the leaking liquid and the effects of dispersion, sorption, radioactive decay or other processes that may affect concentrations of the contaminant at the monitoring well.
4) The NEI Guidance Document (Objective 1.3 On-Site Groundwater Monitoring) recommends a monitoring system that will "ensure timely detection" of leaks. This will be accomplished with placement of monitoring wells so that all predicted transport pathways are intercepted with a high degree of certainty. The

placement of monitoring wells should consider both the areal (plan view) location and also the vertical location of the well screens. A complete monitoring system will also include upgradient control wells which are intended to provide ambient groundwater conditions and help to confirm groundwater flow directions. The PNPS is a particularly challenging site for placement of monitoring wells. Because of the short distance between possible leak sites and the coast line (assuming that groundwater flow is generally towards the sea), the potential is high for a narrow transport pathway to convey contaminants between monitoring wells unless they are closely spaced. This suggests that a high density of monitoring wells will be needed to detect leaks with adequate assurance.

5) Understanding of the fate and transport of indicator contaminants can be used to determine the appropriate frequency of water sample collection at the monitoring wells and the required detection limits for analysis. In particular, the dilution of contaminated water as it mixes with ambient water during transport must be considered. Detection limits for contaminant analysis should be as low as practical so that dilution of contaminants does not mask the presence of leaks.

Recent Experience at PNPS

Recently, Entergy reported finding tritium at levels up to about 3000 pCi/L in monitoring wells on site. These initial monitoring results highlight flaws in the monitoring system at PNPS and provide a contrast to appropriate monitoring design.

Based on the map provided by Entergy in its recent filing, four monitoring wells have been placed at the site. These are generally located between the reactor and the shoreline. The wells are spaced approximately 200 feet apart. I am not aware of any recent hydrogeologic studies that have been conducted to determine current groundwater flow directions and rates. Hence, the suitability of these wells to actually intercept plausible leakage transport pathways is unknown.

Based on my estimation of the locations of pipe runs and plausible leak locations, this number of wells is entirely inadequate to provide the assurance of detection called for in the NEI guidance and in industry practice. Given the short distance from likely pipe locations and the shore, it is highly likely that a leak of radiological contaminants could migrate through the groundwater and pass between these widely-spaced wells or perhaps flow beneath them without detection. It is useful to contrast the PNPS plan with Entergy's Indian Point NPS which has many times more monitoring wells. Indeed, a 4-well monitoring system is more typical of that used for a retail gasoline station or a small municipal (non-hazardous) landfill. That it should be considered adequate for a large industrial facility such as PNPS is unrealistic.

The selection of tritium as the indicator contaminant raises a problem since tritium may be present in several of the potential leak sources that are within scope (e.g. condensate storage tank and salt service water systems). Hence, tritium does not provide a unique indicator of the component which is the source of the leak. A better designed monitoring

system would seek a range of radionuclides that, taken together, serve as specific source indicators.

Presuming that the tritium detected originated at PNPS, the question arises as to the specific mechanism by which this tritium came to be at, for example, well MW 201. It has been suggested by PNPS personnel, as reported in the press, that this tritium is from rainfall sources. Presumably, the transport pathway for this would be airborne tritium captured by passing raindrops with rainfall subsequently infiltrating to the subsurface. But this transport pathway may be limited if, as is presumably the case, the monitoring wells are placed in a paved area of the site where rainfall can not infiltrate. There are alternative theories for the source of tritium. A small pipe leak producing a transported plume of tritium that happens to travel near to monitoring well MW 201 might account for the observed levels of tritium. Alternately, a larger pipe leak producing a large plume of tritium with concentrations much larger that 3000 pCi/L might exist in the subsurface between wells MW 201 and MW 202. In this scenario, the diluted edge of the plume happens to travel near to monitoring wells MW 201 and MW 202. These alternate hypotheses highlight the fact that with so few monitoring wells, it is impossible to determine with any degree of certainty what contaminants may exist in the subsurface.

In summary, groundwater monitoring networks can be used as part of a leak detection system and are widely used for this purpose. Well-established protocols exist for proper design of monitoring networks including well and screen placement, sampling frequency and selection of sampled contaminants. The 4-well monitoring system apparently used by Entergy does not meet reasonable standards for monitoring network design.

I declare that under penalty of perjury that the foregoing reflects my true opinion in these matters.

David P. Ahlfeld, PhD, PE

Biographical Sketch

David P. Ahlfeld
Department of Civil and Environmental Engineering
University of Massachusetts, Amherst, MA 01002

Education

Humboldt State Univ., Arcata, California	B.S. in Environmental Resources Engineering,	1983
Princeton University,	M.A. in Civil Engineering,	1985
Princeton University	Ph.D. in Civil Engr. and Oper. Research,	1983-1987

Academic Appointments

Professor, Department of Civil and Environmental Engineering, University of Massachusetts, September 2004 to present.
Associate Professor, Department of Civil and Environmental Engineering, University of Massachusetts, January 1998 to September 2004.
Associate Professor, Department of Civil and Environmental Engineering, University of Connecticut, September 1994 to January 1998.
Assistant Professor, Department of Civil Engineering, University of Connecticut, January 1988 to August 1994.
Lecturer, Department of Civil Engineering and Operations Research, Princeton University, Spring semester 1987 and Spring semester 1988

Selected Recent Publications

M.G. Kennedy, D.P. Ahlfeld, D.P. Schmidt, J.E. Tobiason, "Three Dimensional Modeling for Estimation of Hydraulic Retention Time in a Reservoir", in press, Journal of Environmental Engineering.

D.P. Ahlfeld, "Nonlinear Response of Streamflow to Groundwater Pumping For A Hydrologic Streamflow Model", Advances in Water Resources, January 2004, Vol 27, pgs 349-360.

D. P. Ahlfeld, A. Joaquin, J.E. Tobiason and D. Mas, "Case Study: Impact of Reservoir Stratification on Interflow Travel Time", Journal of Hydraulic Engineering, December 2003, Vol 129, No. 12, pp. 966-975.

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D.P. Ahlfeld and E.H. Hill, III, " The Sensitivity of Remedial Strategies to Design Criteria", Groundwater, Vol. 34, No. 2, March-April 1996, pgs 341-348.

EXHIBIT 3

10 CFR 54.21

§ 54.21 Contents of application--technical information.

Each application must contain the following information:

(a) An integrated plant assessment (IPA). The IPA must--

(1) For those systems, structures, and components within the scope of this part, as delineated in § 54.4, identify and list those structures and components subject to an aging management review. Structures and components subject to an aging management review shall encompass those structures and components--

(i) That perform an intended function, as described in § 54.4, without moving parts or without a change in configuration or properties. These structures and components include, but are not limited to, the reactor vessel, the reactor coolant system pressure boundary, steam generators, the pressurizer, piping, pump casings, valve bodies, the core shroud, component supports, pressure retaining boundaries, heat exchangers, ventilation ducts, the containment, the containment liner, electrical and mechanical penetrations, equipment hatches, seismic Category I structures, electrical cables and connections, cable trays, and electrical cabinets, excluding, but not limited to, pumps (except casing), valves (except body), motors, diesel generators, air compressors, snubbers, the control rod drive, ventilation dampers, pressure transmitters, pressure indicators, water level indicators, switchgears, cooling fans, transistors, batteries, breakers, relays, switches, power inverters, circuit boards, battery chargers, and power supplies; and

(ii) That are not subject to replacement based on a qualified life or specified time period.

(2) Describe and justify the methods used in paragraph (a)(1) of this section.

(3) For each structure and component identified in paragraph (a)(1) of this section, demonstrate that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation.

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

(c) An evaluation of time-limited aging analyses.

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

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

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

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

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

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

EXHIBIT 4

Transcript of ACRS Meeting
(Sept. 6, 2001

Official Transcript of Proceedings

NUCLEAR REGULATORY COMMISSION

Title: Advisory Committee on Reactor Safeguards

Docket Number: (not applicable)

Location: Rockville, Maryland

Date: Thursday, September 6, 2001

Work Order No.: NRC-004 Pages 304-491

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION
+ + + + +
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
485TH ACRS MEETING
+ + + + +
THURSDAY
SEPTEMBER 6, 2001
+ + + + +
ROCKVILLE, MARYLAND
+ + + + +

The Advisory Committee met at the Nuclear Regulatory Commission, Two White Flint North, Room T2B3, 11545 Rockville Pike, at 8:30 a.m., Dr. George E. Apostolakis, Chairman, presiding.

PRESENT:
DR. GEORGE E. APOSTOLAKIS, Chairman
DR. MARIO V. BONACA, Vice Chairman
DR. F. PETER FORD, Member
DR. DANA A. POWERS, Member
DR. STEPHEN L. ROSEN, Member
DR. WILLIAM J. SHACK, Member
DR. THOMAS S. KRESS, Member at Large
DR. JOHN D. SIEBER, Member
DR. GRAHAM B. WALLIS, Member.

ACRS STAFF:
DR. JOHN T. LARKINS, Executive Director
CAROL A. HARRIS, ACRS/ACNW
HOWARD J. LARSON, ACRS/ACNW
SAM DURAISWAMY, ACRS
DR. SHER BAHADUR, ACRS
PAUL A. BOEHNERT, ACRS
MICHAEL T. MARKLEY, ACRS

NRC STAFF:
RALPH LANDRY

answers and all of that.

But what are you going to do when you have got that? I mean, there has still got to be some relationship with these uncertainties to margins and acceptance criteria, and so on.

I am not sure that the staff really has thought that through. Do you have any comments on that?

MR. LANDRY: At this point, we would just have to say we are continuing to study that, and we are trying to define.

DR. WALLIS: Well, that's typical. I mean, you see, there must be a criterion, some acceptance criterion, when they want to uprate the power to some point where it is meeting some boundary.

Then how big the uncertainties are in the code are very important to know, and whether you may step over that boundary or not. So it seems to me that maybe the acceptabilities then are going to depend upon the use.

Yes, they have got a good code, and they have an assessment of uncertainty, and then look at something like power uprate, and start using this code, and then you can figure out perhaps how big the uncertainty or what is the effect of the uncertainty on your decision about whether or not they should be allowed to uprate power.

MR. CARUSO: Dr. Wallis, this is Ralph Caruso from the staff. We do actually have some criterion in this area for AOOs. For example, we set a safety limit minimum critical power ratios to ensure that 99.9 percent of the rods don't undergo boiling transition.

I think that your question is what does reasonable assurance mean, and I think that the ACRS has had this discussion with the Commission in the past about what reasonable assurance means, and I don't think there has ever been any definition that everyone has agreed to.

This is an eternal question that we try to deal with, and it comes out of judgment to a large extent at this point. When we can quantify it, for example, and say setting safety limit MICPRs, we try to do that.

We are trying to do our regulation in a more risk-informed manner, and that is another attempt to do it in a more quantifiable way. But right now these are the words that the law requires us to use to make a finding.

So those are, unfortunately, the words that we use and they are not well defined.

DR. WALLIS: But the law requires you to make a finding with 95 percent confidence.

MR. CARUSO: No, the law requires us to make a reasonable assurance finding.

DR. WALLIS: If your criterion is 95 percent confidence, then the fact that they have evaluated these uncertainties enables you to make that assessment.

MR. CARUSO: We could say that a 95 percent confidence does define reasonable assurance, but --

DR. WALLIS: That is the thing that I think is not being worked out yet. I mean, you have got the tools to do it, but if someone comes around like tomorrow and says reasonable assurance is 99 percent, then you have still got the tools to do it, but where you come out on allowing some change in the plant may be different.

MR. CARUSO: I really hate to pass the buck on this, but I do believe that this has been the subject of some extensive discussions with the Commission about the definition of reasonable assurance, and I don't believe that anyone has come up with an acceptable definition for all the parties involved.

DR. WALLIS: So maybe my --

MR. CARUSO: This is a little bit beyond my pay grade as they say.

DR. WALLIS: -- saying that you have got a good tool is, but the staff isn't quite sure how to use it, is a true statement.

MR. CARUSO: I can't explain why. I don't want to get into philosophy on this particular issue.

DR. WALLIS: It is not philosophy. It is really very real.

EXHIBIT 5

10 CFR 50 Appendix B, XVI
&
Appendix C, Article C.12, "Operability Leakage from Class 1, 2, and 3 Components", to NRC Inspection Manual Part 9900, Technical Guidance, Attachment to RIS 2005-20

Appendix B to Part 50--Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants

Introduction. Every applicant for a construction permit is required by the provisions of § 50.34 to include in its preliminary safety analysis report a description of the quality assurance program to be applied to the design, fabrication, construction, and testing of the structures, systems, and components of the facility. Every applicant for an operating license is required to include, in its final safety analysis report, information pertaining to the managerial and administrative controls to be used to assure safe operation. Every applicant for a combined license under part 52 of this chapter is required by the provisions of § 52.79 of this chapter to include in its final safety analysis report a description of the quality assurance applied to the design, and to be applied to the fabrication, construction, and testing of the structures, systems, and components of the facility and to the managerial and administrative controls to be used to assure safe operation. For applications submitted after September 27, 2007, every applicant for an early site permit under part 52 of this chapter is required by the provisions of § 52.17 of this chapter to include in its site safety analysis report a description of the quality assurance program applied to site activities related to the design, fabrication, construction, and testing of the structures, systems, and components of a facility or facilities that may be constructed on the site. Every applicant for a design approval or design certification under part 52 of this chapter is required by the provisions of 10 CFR 52.137 and 52.47, respectively, to include in its final safety analysis report a description of the quality assurance program applied to the design of the structures, systems, and components of the facility. Every applicant for a manufacturing license under part 52 of this chapter is required by the provisions of 10 CFR 52.157 to include in its final safety analysis report a description of the quality assurance program applied to the design, and to be applied to the manufacture of, the structures, systems, and components of the reactor. Nuclear power plants and fuel reprocessing plants include structures, systems, and components that prevent or mitigate the consequences of postulated accidents that could cause undue risk to the health and safety of the public. This appendix establishes quality assurance requirements for the design, manufacture, construction, and operation of those structures, systems, and components. The pertinent requirements of this appendix apply to all activities affecting the safetyrelated functions of those structures, systems, and components; these activities include designing, purchasing, fabricating, handling, shipping, storing, cleaning, erecting, installing, inspecting, testing, operating, maintaining, repairing, refueling, and modifying.

As used in this appendix, "quality assurance" comprises all those planned and systematic actions necessary to provide adequate confidence that a structure, system, or component will perform satisfactorily in service. Quality assurance includes quality control, which comprises those quality assurance actions related to the physical characteristics of a material, structure, component, or system which provide a means to control the quality of the material, structure, component, or system to predetermined requirements.

I. Organization

The applicant [1] shall be responsible for the establishment and execution of the quality assurance program. The applicant may delegate to others, such as contractors, agents, or consultants, the work of establishing and executing the quality assurance program, or any part thereof, but shall retain responsibility for the quality assurance program. The authority and duties of persons and organizations performing activities affecting the safety-related functions of structures, systems, and components shall be clearly established and delineated in writing. These activities include both the performing functions of attaining quality objectives and the quality assurance functions. The quality assurance functions are those of (1) assuring that an appropriate quality assurance program is established and effectively executed; and (2) verifying, such as by checking, auditing, and inspecting, that activities affecting the safetyrelated functions have been correctly performed. The persons and organizations performing quality assurance functions shall have sufficient authority and organizational freedom to identify quality problems; to initiate, recommend, or provide solutions; and to verify implementation of solutions. There persons and organizations performing quality assurance functions shall report to a management level so that the required authority and organizational freedom, including sufficient independence from cost and schedule when opposed to safety considerations, are provided. Because of the many variables involved, such as the number of personnel, the type of activity being performed, and the location or locations where activities are performed, the organizational structure for executing the quality assurance program may take various forms, provided that the persons and organizations assigned the quality assurance functions have the required authority and organizational freedom. Irrespective of the organizational structure, the individual(s) assigned the responsibility for assuring effective execution of any portion of the quality assurance program at any location where activities subject to this appendix are being performed, shall have direct access to the levels of management necessary to perform this function.

II. Quality Assurance Program

The applicant shall establish at the earliest practicable time, consistent with the schedule for accomplishing the activities, a quality assurance program which complies with the requirements of this appendix. This program shall be documented by written policies, procedures, or instructions and shall be carried out throughout plant life in accordance with those policies, procedures, or instructions. The applicant shall identify the structures, systems, and components to be covered by the quality assurance program and the major organizations participating in the program, together with the designated functions of these organizations. The quality assurance program shall provide control over activities affecting the quality of the identified structures, systems, and components, to an extent consistent with their importance to safety. Activities affecting quality shall be accomplished under suitably controlled conditions. Controlled conditions include the use of appropriate equipment; suitable environmental conditions for accomplishing the activity, such as adequate cleanness; and assurance that all prerequisites for the given activity have been satisfied. The program shall take into account the need for special controls, processes, test equipment, tools, and skills to attain the required quality, and the need for verification of quality by inspection and test. The program shall provide for indoctrination and training of personnel performing activities affecting quality as necessary to assure that suitable proficiency is achieved and maintained. The applicant shall regularly review the status and adequacy of the quality assurance program. Management of other organizations participating in the quality assurance program shall regularly review the status and adequacy of that part of the quality assurance program which they are executing.

III. Design Control

Measures shall be established to assure that applicable regulatory requirements and the design basis, as defined in § 50.2 and as specified in the license application, for those structures, systems, and components to which this appendix applies are correctly translated into specifications, drawings, procedures, and instructions. These measures shall include provisions to assure that appropriate quality standards are specified and included in design documents and that deviations from such standards are controlled. Measures shall also be established for the selection and review for suitability of application of materials, parts, equipment, and processes that are essential to the safety-related functions of the structures, systems and components.

Measures shall be established for the identification and control of design interfaces and for coordination among participating design organizations. These measures shall include the establishment of procedures among participating design organizations for the review, approval, release, distribution, and revision of documents involving design interfaces.

The design control measures shall provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program. The verifying or checking process shall be performed by individuals or groups other than those who performed the original design, but who may be from the same organization. Where a test program is used to verify the adequacy of a specific design feature in lieu of other verifying or checking processes, it shall include suitable qualifications testing of a prototype unit under the most adverse design conditions. Design control measures shall be applied to items such as the following: reactor physics, stress, thermal, hydraulic, and accident analyses; compatibility of materials; accessibility for inservice inspection, maintenance, and repair; and delineation of acceptance criteria for inspections and tests.

Design changes, including field changes, shall be subject to design control measures commensurate with those applied to the original design and be approved by the organization that performed the original design unless the applicant designates another responsible organization.

IV. Procurement Document Control

Measures shall be established to assure that applicable regulatory requirements, design bases, and other requirements which are necessary to assure adequate quality are suitably included or referenced in the documents for procurement of material, equipment, and services, whether purchased by the applicant or by its contractors or subcontractors. To the extent necessary, procurement documents shall require contractors or subcontractors to provide a quality assurance program consistent with the pertinent provisions of this appendix.

V. Instructions, Procedures, and Drawings

Activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. Instructions, procedures, or drawings shall include appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished.

VI. Document Control

Measures shall be established to control the issuance of documents, such as instructions, procedures, and drawings, including changes thereto, which prescribe all activities affecting quality. These measures shall assure that documents, including changes, are reviewed for adequacy and approved for release by authorized personnel and are distributed to and used at the location where the prescribed activity is performed. Changes to documents shall be reviewed and approved by

the same organizations that performed the original review and approval unless the applicant designates another responsible organization.

VII. Control of Purchased Material, Equipment, and Services

Measures shall be established to assure that purchased material, equipment, and services, whether purchased directly or through contractors and subcontractors, conform to the procurement documents. These measures shall include provisions, as appropriate, for source evaluation and selection, objective evidence of quality furnished by the contractor or subcontractor, inspection at the contractor or subcontractor source, and examination of products upon delivery. Documentary evidence that material and equipment conform to the procurement requirements shall be available at the nuclear powerplant or fuel reprocessing plant site prior to installation or use of such material and equipment. This documentary evidence shall be retained at the nuclear powerplant or fuel reprocessing plant site and shall be sufficient to identify the specific requirements, such as codes, standards, or specifications, met by the purchased material and equipment. The effectiveness of the control of quality by contractors and subcontractors shall be assessed by the applicant or designee at intervals consistent with the importance, complexity, and quantity of the product or services.

VIII. Identification and Control of Materials, Parts, and Components

Measures shall be established for the identification and control of materials, parts, and components, including partially fabricated assemblies. These measures shall assure that identification of the item is maintained by heat number, part number, serial number, or other appropriate means, either on the item or on records traceable to the item, as required throughout fabrication, erection, installation, and use of the item. These identification and control measures shall be designed to prevent the use of incorrect or defective material, parts, and components.

IX. Control of Special Processes

Measures shall be established to assure that special processes, including welding, heat treating, and nondestructive testing, are controlled and accomplished by qualified personnel using qualified procedures in accordance with applicable codes, standards, specifications, criteria, and other special requirements.

X. Inspection

A program for inspection of activities affecting quality shall be established and executed by or for the organization performing the activity to verify conformance with the documented instructions, procedures, and drawings for accomplishing the activity. Such inspection shall be performed by individuals other than those who performed the activity being inspected. Examinations, measurements, or tests of material or products processed shall be performed for each work operation where necessary to assure quality. If inspection of processed material or products is impossible or disadvantageous, indirect control by monitoring processing methods, equipment, and personnel shall be provided. Both inspection and process monitoring shall be provided when control is inadequate without both. If mandatory inspection hold points, which require witnessing or inspecting by the applicant's designated representative and beyond which work shall not proceed without the consent of its designated representative are required, the specific hold points shall be indicated in appropriate documents.

XI. Test Control

A test program shall be established to assure that all testing required to demonstrate that structures, systems, and components will perform satisfactorily in service is identified and performed in accordance with written test procedures which incorporate the requirements and acceptance limits contained in applicable design documents. The test program shall include, as appropriate, proof tests prior to installation, preoperational tests, and operational tests during nuclear power plant or fuel reprocessing plant operation, of structures, systems, and components. Test procedures shall include provisions for assuring that all prerequisites for the given test have been met, that adequate test instrumentation is available and used, and that the test is performed under suitable environmental conditions. Test results shall be documented and evaluated to assure that test requirements have been satisfied.

XII. Control of Measuring and Test Equipment

Measures shall be established to assure that tools, gages, instruments, and other measuring and testing devices used in activities affecting quality are properly controlled, calibrated, and adjusted at specified periods to maintain accuracy within necessary limits.

XIII. Handling, Storage and Shipping

Measures shall be established to control the handling, storage, shipping, cleaning and preservation of material and equipment in accordance with work and inspection instructions to prevent damage or deterioration. When necessary for particular products, special protective environments, such as inert gas atmosphere, specific moisture content levels, and temperature levels, shall be specified and provided.

XIV. Inspection, Test, and Operating Status

Measures shall be established to indicate, by the use of markings such as stamps, tags, labels, routing cards, or other suitable means, the status of inspections and tests performed upon individual items of the nuclear power plant or fuel reprocessing plant. These measures shall provide for the identification of items which have satisfactorily passed required inspections and tests, where necessary to preclude inadvertent bypassing of such inspections and tests. Measures shall also be established for indicating the operating status of structures, systems, and components of the nuclear power plant or fuel reprocessing plant, such as by tagging valves and switches, to prevent inadvertent operation.

XV. Nonconforming Materials, Parts, or Components

Measures shall be established to control materials, parts, or components which do not conform to requirements in order to prevent their inadvertent use or installation. These measures shall include, as appropriate, procedures for identification, documentation, segregation, disposition, and notification to affected organizations. Nonconforming items shall be reviewed and accepted, rejected, repaired or reworked in accordance with documented procedures.

XVI. Corrective Action

Measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. The identification of the significant condition adverse to quality, the cause of the condition, and the corrective action taken shall be documented and reported to appropriate levels of management.

XVII. Quality Assurance Records

Sufficient records shall be maintained to furnish evidence of activities affecting quality. The records shall include at least the following: Operating logs and the results of reviews, inspections, tests, audits, monitoring of work performance, and materials analyses. The records shall also include closely-related data such as qualifications of personnel, procedures, and equipment. Inspection and test records shall, as a minimum, identify the inspector or data recorder, the type of observation, the results, the acceptability, and the action taken in connection with any deficiencies noted. Records shall be identifiable and retrievable. Consistent with applicable regulatory requirements, the applicant shall establish requirements concerning record retention, such as duration, location, and assigned responsibility.

XVIII. Audits

A comprehensive system of planned and periodic audits shall be carried out to verify compliance with all aspects of the quality assurance program and to determine the effectiveness of the program. The audits shall be performed in accordance with the written procedures or check lists by appropriately trained personnel not having direct responsibilities in the areas being audited. Audit results shall be documented and reviewed by management having responsibility in the area audited. Followup action, including reaudit of deficient areas, shall be taken where indicated.

[35 FR 10499, June 27, 1970, as amended at 36 FR 18301, Sept. 11, 1971; 40 FR 3210D, Jan. 20, 1975; 72 FR 49505, Aug. 28, 2007]

[1] While the term "applicant" is used in these criteria, the requirements are, of course, applicable after such a person has received a license to construct and operate a nuclear power plant or a fuel reprocessing plant or has received an early site permit, design approval, design certification, or manufacturing license, as applicable. These criteria will also be used for guidance in evaluating the adequacy of quality assurance programs in use by holders of construction permits, operating licenses, early site permits, design approvals, combined licenses, and manufacturing licenses.

OPERABILITY DETERMINATIONS & FUNCTIONALITY ASSESSMENTS FOR RESOLUTION OF DEGRADED OR NONCONFORMING CONDITIONS ADVERSE TO QUALITY OR SAFETY

Code Cases that describe methods, criteria, or requirements different from the Code referenced in 10 CFR 50.55a cannot be used without prior NRC review and approval unless they are endorsed in Regulatory Guide 1.147, "Inservice Inspection Code Case Acceptability, ASME Section XI, Division 1." Code Case N–513, which describes an acceptable alternative to the methods described in the Code for the acceptance of a flaw in a Class 3 moderate-energy piping system, is endorsed in RG 1.147. A flaw that is evaluated in accordance with, and meets the acceptance criteria of, Code Case N–513 is acceptable to both ASME and to the NRC. If the flaw does not satisfy the requirements of Code Case N–513, the system containing the flaw is inoperable.

NRC has accepted Code Case N–513 for application in the licensees inservice inspection programs, with the following conditions:

a. Specific safety factors in paragraph 4.0 of Code Case N–513 must be satisfied, and

b. Code Case N–513 may not be applied to:
   (1) components other than pipe and tubing,
   (2) leakage through a gasket,
   (3) threaded connections employing nonstructural seal welds for leakage prevention (through-seal weld leakage is not a structural flaw, but thread integrity must be maintained), and
   (4) degraded socket welds.

If a flaw exceeds the thresholds of the ASME Code, Generic Letter 90-05, Code Case N–513, or any other applicable NRC-approved Code Case, the system containing the flaw is inoperable until the NRC approves an alternative analysis, evaluation, or calculation to justify the system's return to service with the flaw and the subsequent operability of the system. The inoperable system is subject to the applicable TS LCO before receiving the NRC approval for the alternative analysis, evaluation, or calculation.

C.12 Operational Leakage From Code Class 1, 2, and 3 Components

Leakage from the reactor coolant system, as specified in TSs, is limited to specified values in the TSs depending on whether the leakage is from identified, unidentified, or specified sources such as the steam generator tubes or reactor coolant system pressure isolation valves. If the leakage exceeds TS limits, the LCO must be declared not met and the applicable conditions must be entered. For identified reactor coolant system leakage within the limits of the TS, the licensee should determine operability for the degraded component and include in the determination the effects of the leakage on other components and materials.

Existing regulations and TSs require that the structural integrity of ASME Code Class 1, 2, and 3 components be maintained in accordance with the ASME Code. In the case of specific types of degradation, other regulatory requirements must also be met. If a leak is discovered in a Class 1, 2, or 3 component in the conduct of an inservice inspection, maintenance activity, or facility operation, corrective measures

may require repair or replacement activities in accordance with IWA-4000 of Section XI. In addition, the leaking component should be evaluated for flaws according to IWB-3000, which addresses the analytical evaluation and acceptability criteria for flaws.

The TSs do not permit any reactor coolant pressure boundary (RCPB) leakage. The operational leakage LCO must be declared not met when pressure boundary leakage is occurring. Upon discovery of leakage from a Class 1, 2, or 3 pressure boundary component (pipe wall, valve body, pump casing, etc.), the licensee must declare the component inoperable. Evidence of leakage from the pressure boundary indicates the presence of a through-wall flaw. It may be possible to use visual methods to determine the exterior dimension(s) and orientation of a through-wall flaw in a leaking component. When the outside surface breaking dimension of a through-wall flaw is small, the length and extent of the flaw inside the component wall may be quite long and potentially outside the limits established by the Code. For these reasons the component is declared inoperable while methods such as ultrasonic examination are performed to characterize the actual geometry of the through-wall flaw. However, after declaring inoperability for leakage from Class 3 moderate-energy piping, the licensee may evaluate the structural integrity of the piping by fully characterizing the extent of the flaw using volumetric methods and evaluating the flaw using the criteria of paragraph C.3.a of Enclosure 1 to GL 90-05. If the flaw meets the criteria, the piping can subsequently be deemed operable but degraded until relief from the applicable Code requirement or requirements is obtained from the NRC. Alternatively, the licensee can evaluate the structural integrity of leaking Class 3 moderate-energy piping using the criteria of Code Case N–513, which is approved with limitations imposed by the NRC staff and incorporated by reference in 10 CFR 50.55(a)(b)(2)(xiii). The limitations imposed by the NRC staff are as follows:

a. Specific safety factors in paragraph 4.0 of Code Case N–513 must be satisfied, and

b. Code Case N–513 may not be applied to:
   (1) components other than pipe and tubing,
   (2) Leakage through a gasket,
   (3) threaded connections employing nonstructural seal welds for leakage prevention (through seal weld leakage is not a structural flaw, but thread integrity must be maintained), and
   (4) degraded socket welds.

Following the declaration of inoperability, the licensee may also decide to evaluate the structural integrity of leaking Class 2 or 3 moderate-energy piping using the criteria of Code Case N–513–1. The same limitations imposed by the NRC staff on Code Case N–513 apply to Code Case N–513–1. Code Case N–513–1 has been reviewed and found acceptable by the NRC. However, Code Case N–513–1 has not yet been incorporated into RG 1.147 or the Code of Federal Regulations for generic use. Therefore, until Code Case N–513–1 is approved for generic use in either RG 1.147 or 10 CFR 50.55a, the licensee must request relief and obtain NRC approval to use Code Case N–513–1.

If the piping meets the criteria of ASME Code Case N–513, continued temporary service of the degraded piping components is permitted. If the licensee decides to control the leakage by mechanical clamping means, the requirements of Code Case 523-2, •Mechanical Clamping Devices for Class 2 and 3 Piping Section XI, Division 1," may be followed, as referenced in 10 CFR 50.55a(b)(2)(xiii). This Code Case is to maintain the structural integrity of Class 2 and 3 piping which is 6 inches (nominal pipe size) and smaller and shall not be used on piping larger than 2 inches (nominal pipe size) when the nominal operating temperature or pressure exceeds 200°F or 275 psig. These and other applicable Code Cases which have been determined to be acceptable for licensee use without a request or authorization from the NRC are listed in RG 1.147. These Code Cases do not apply to Class 1 pressure boundary components.

The NRC has no specific guidance or generically approved alternatives for temporary repair of flaws (through-wall or non-through-wall) in Class 1, 2, or 3 high-energy system components, or for Class 2 or 3 moderate-energy system pressure boundary components other than piping. Therefore, all such flaws in these components must be repaired in accordance with Code requirements, or relief from Code requirements must be requested of and approval obtained from the NRC.

C.13 Structural Requirements

Structures may be required to be operable by the TSs, or they may be related support functions for SSCs in the TSs. Examples of structural degradation are concrete cracking and spalling, excessive deflection or deformation, water leakage, rebar corrosion, missing or bent anchor bolts, and degradation of door and penetration sealing. If a structure is degraded, the licensee should assess the structure's capability of performing its specified function. As long as the identified degradation does not result in exceeding acceptance limits specified in applicable design codes and standards referenced in the design basis documents, the affected structure is either operable or functional.

NRC inspectors, with possible headquarters support, should review licensees' evaluations of structural degradations to determine their technical adequacy and conformance to licensing and regulatory requirements.

END

EXHIBIT 6

NUREG-1891

NUREG-1891

Safety Evaluation Report
Related to the License Renewal of Pilgrim Nuclear Power Station

Docket No. 50-293

Entergy Nuclear Operations, Inc.

U.S. Nuclear Regulatory Commission
Office of Nuclear Reactor Regulation
Washington, DC 20555-0001

adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2 AMPs That Are Consistent with the GALL Report with Exceptions and/or Enhancements

In LRA Appendix B, the applicant stated that the following AMPs are, or will be, consistent with the GALL Report with exceptions or enhancements:

- Buried Piping and Tanks Inspection Program
- BWR CRD Return Line Nozzle Program
- BWR Feedwater Nozzle Program
- BWR Penetrations Program
- BWR Stress Corrosion Cracking Program
- BWR Vessel ID Attachment Welds Program
- BWR Vessels Internals Program
- Diesel Fuel Monitoring Program
- Fatigue Monitoring Program
- Fire Protection Program
- Fire Water System Program
- Metal-Enclosed Bus Inspection Program
- Oil Analysis Program
- Reactor Head Closure Studs Program
- Reactor Vessel Surveillance Program
- Service Water Integrity Program
- Structures Monitoring Program
- Water Control Structures Monitoring Program
- Water Chemistry Control - Closed Cooling Water Program

For AMPs that the applicant claimed are consistent with the GALL Report, with exception(s) and/or enhancement(s), the staff performed an audit and review to confirm that those attributes or features of the program for which the applicant claimed consistency were indeed consistent. The staff also reviewed the exception(s) and/or enhancement(s) to the GALL Report to determine whether they were acceptable and adequate. The results of the staff's audits and reviews are documented in the following sections.

3.0.3.2.1 Buried Piping and Tanks Inspection Program

Summary of Technical Information in the Application. LRA Section B.1.2, "Buried Piping and Tanks Inspection," describes the new Buried Piping and Tanks Inspection Program as consistent, with exception, with GALL AMP XI.M34, "Buried Piping and Tanks Inspection."

This program includes (a) preventive measures to mitigate corrosion and (b) inspections to manage the effects of corrosion on the pressure-retaining capability of buried carbon steel, stainless steel, and titanium components. Preventive measures are in accordance with standard industry practice for maintaining external coatings and wrappings. Buried components are

inspected when excavated during maintenance. There will be a focused inspection within the first 10 years of the period of extended operation unless an opportunistic inspection (or an inspection via a method that assesses pipe condition without excavation) occurs within this ten-year period.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report and documented a detailed audit evaluation of this AMP in Audit and Review Report Section 3.0.3.2.1. The staff reviewed the exception to determine whether the AMP remained adequate to manage the aging effects for which it is credited.

The staff reviewed those portions of the Buried Piping and Tanks Inspection Program for which the applicant claims consistency with GALL AMP XI.M34 and finds them consistent. Furthermore, the staff concludes that the applicant's Buried Piping and Tanks Inspection Program provides reasonable assurance of management of the effects of aging so components crediting this program can perform intended functions consistent with the CLB during the period of extended operation. The staff finds the applicant's Buried Piping and Tanks Inspection Program acceptable as consistent with the recommended GALL AMP XI.M34, "Buried Piping and Tanks Inspection," with the exceptions as described:

Exception. The LRA states an exception to the GALL Report program element "detection of aging effects," specifically:

> For cases of excavation solely for the purpose of inspection – methods such as "phased array" UT will be used to determine wall thickness without excavating.

The proposed exception eliminates the possibility of inadvertent excavation related damage during inspection while assessing the component. As the technology becomes available for the nuclear industry, applicants may use this technology to examine the condition of buried piping. On this basis, the staff finds this exception acceptable.

Operating Experience. LRA Section B.1.2 states that there is no operating experience for the new Buried Piping and Tanks Inspection Program.

However, in the past five years, the applicant has had limited experience with the inspection of buried piping, mainly on the fire water underground distribution system. This system, approximately 35 years old, consists of cement-lined malleable iron pipe with mechanical joints and no history of significant leaks other than during two instances in 2001 and 2005. In the first, the 8-inch underground line downstream of 8-L-22 failed, the probable cause induced most likely by minor fabrication anomalies compounded by marginal installation techniques. When examined, this piping was found to be in very good external condition overall except for a small area of surface corrosion attributed to marginal installation techniques. In the second instance, the 8-inch underground pipe failed in the area of the N2 tank adjacent to the emergency diesel generator (EDG) building. Due to congestion and the presence of the tank (installed after the piping), it was not possible to dig up the piping for examination to determine the cause of the failure (possibly related to the tank installation). Apart from these two instances, a number of valves and piping excavated during maintenance were found to be in good condition.

From an additional historical perspective, the SSW system has had leaks on the buried inlet (screenhouse to auxiliary bays) piping due to internal corrosion. The original piping material was

rubber-lined carbon steel wrapped with reinforced fiberglass, coal tar saturated felt, and heavy Kraft paper. The leaks were determined to be results of the rubber lining degrading from contact with sea water. These pipes were replaced in 1995 and 1997 with the same external and internal coatings as for the original pipe.

In addition, the SSW buried discharge piping (also rubber-lined carbon steel with external pipe wrapping) from the auxiliary bays to the discharge canal experienced severe internal corrosion due to failure of the rubber lining. Two 40-foot lengths of 22-inch diameter pipes (one on each loop) were replaced in 1999 with carbon steel coated internally and externally with epoxy. The replaced piping was examined with its wrapping removed and its external surface was found to be in good condition. Since then, the entire length of both SSW buried discharge loops have been lined internally with pipe linings cured in place – "B" Loop in 2001 and "A" Loop in 2003.

The staff reviewed the operating experience presented in the LRA and interviewed the applicant's technical personnel to confirm that the plant-specific operating experience revealed no degradation not bounded by industry experience.

The staff confirmed that the "operating experience" program element satisfies the criterion defined in the GALL Report and in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Section A.2.1.2, the applicant provided the UFSAR supplement for the Buried Piping and Tanks Inspection Program. The staff reviewed this section and determined that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

The LRA states that this program will be implemented before the period of extended operation (Commitment No. 1).

Conclusion. On the basis of its audit and review of the applicant's Buried Piping and Tanks Inspection Program, the staff finds that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exception and its justification and determined that the AMP, with the exception, is adequate to manage the aging effects for which it is credited. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.2 BWR CRD Return Line Nozzle Program

Summary of Technical Information in the Application. LRA Section B.1.3, "BWR CRD Return Line Nozzle," describes the existing BWR CRD Return Line Nozzle Program as consistent, with exceptions, with GALL AMP XI.M6, "BWR Control Rod Drive Return Line Nozzle."

Under this program, the applicant has cut and capped the CRD return line nozzle to mitigate cracking and continued ISI examinations to monitor the effects of crack initiation and growth on intended functions of the CRD return line nozzle and cap. In 2003, a structural weld overlay was

EXHIBIT 7

Groundwater Contamination (Tritium) At Nuclear Plants, Task Force Final Report, NRC, Sept. 1, 2006,

LIQUID RADIOACTIVE RELEASE LESSONS LEARNED TASK FORCE FINAL REPORT

September 1, 2006

Task Force Members:

Stuart Richards, NRR
Timothy Frye, NRR
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Thomas Nicholson, RES
George Kuzo, Region II
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Stacie Sakai, NRR
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EXECUTIVE SUMMARY

The Liquid Radioactive Release Lessons Learned Task Force (LLTF) was established by the NRC Executive Director for Operations on March 10, 2006, in response to incidents at Braidwood, Indian Point, Byron, and Dresden related to unplanned, unmonitored releases of radioactive liquids into the environment. The scope of the task force work included reviews of industry experience, associated public health impacts (if any), the NRC regulatory framework, related NRC inspection and enforcement programs, industry reporting requirements, past industry actions following significant inadvertent releases, international perspectives, and NRC communications with public stakeholders.

The task force included representatives from all four regional offices: the Office of Nuclear Reactor Regulation (NRR), the Office of Nuclear Materials Safety and Safeguards (NMSS), the Office of Nuclear Regulatory Research (RES), the Office of Public Affairs (OPA), the Office of the Executive Director for Operations (OEDO), and a representative from the State of Illinois.

The focus of the task force was on releases of radioactive liquids that were neither planned nor monitored. An understanding of the routine discharge of radioactive materials from a nuclear power plant is necessary to gain a perspective on the unplanned releases.

Virtually all commercial nuclear power plants routinely release radioactive materials to the environment in liquids and gases. These releases are planned, monitored, and documented. NRC regulations in 10 CFR Part 20 and in 10 CFR Part 50 place limits on these releases to ensure the impact on public health is very low. On an annual basis, NRC guidelines require that the release of radioactive material in a liquid form from a nuclear power plant must not result in a radiation dose of greater than 3 millirem to any individual in an unrestricted area. All licensees routinely report to the NRC that they are well within this limit.

To place 3 millirem of radiation in perspective, the average member of the public in the United States receives a radiation dose of about 360 millirem per year, primarily from natural sources such as radon in the soil and cosmic radiation, and from medical sources such as diagnostic X-rays. A passenger on a single cross country airplane flight receives a radiation dose of about 3 millirem due to the flight occurring at a high altitude, resulting in a reduction in shielding of cosmic radiation by the earth's atmosphere.

In accordance with NRC regulations, nuclear power plant operators are required to submit an annual report to the NRC detailing the amount of radioactive material released to the environment during the past year. This report estimates the public health impact of the releases. Nuclear power plant operators are also required by NRC regulations to monitor the environment in the vicinity of the nuclear power plant to assess the cumulative impact of the radioactive material that has been released. On an annual basis, the results of the environmental monitoring program are submitted to the NRC. Both of these reports for all nuclear power plants regulated by the NRC are available to the public via the NRC website.

Most of the events that have recently received increased attention from the NRC have involved tritium, which is a radioactive isotope of hydrogen. However, the task force did not limit its review to tritium related events. Other radioactive isotopes have been inadvertently released into the environment. An example is leakage from spent fuel pools, particularly where the pool contains fuel with degraded outer cladding material, thereby allowing fission products to be released from the fuel into the pool water.

The most significant conclusion of the task force regarded public health impacts. Although there have been a number of industry events where radioactive liquid was released to the environment in an unplanned and unmonitored fashion, based on the data available, the task force did not identify any instances where the health of the public was impacted.

The task force did identify that under the existing regulatory requirements the potential exists for unplanned and unmonitored releases of radioactive liquids to migrate offsite into the public domain undetected. The following elements collectively contribute to this conclusion:

- Some of the power plant components that contain radioactive fluids that have leaked were constructed to commercial standards, in contrast to plant safety systems that are typically fabricated to more stringent requirements. The result is a lower level of assurance that these types of components will be leak proof over the life of the plant.

- Some of the components that have leaked were not subject to surveillance, maintenance, or inspection activities by NRC requirements. This increases the likelihood that leakage in such components can go undetected. Additionally, relatively low leakage rates may not be detected by plant operators, even over an extended period of time.

- Portions of some components or structures are physically not visible to operators, thereby reducing the likelihood that leakage will be identified. Examples of such components include buried pipes and spent fuel pool.

- Leakage that enters the ground below the plant may be undetected because there are generally no NRC requirements to monitor the groundwater onsite for radioactive contamination.

- Contamination in groundwater onsite may migrate offsite undetected. Although the power plant operator is required by NRC regulations to perform offsite environmental monitoring, the sampling locations are typically mostly in the vicinity of the point of release of the normal discharge flow path. For example, at Braidwood, most of the environment water samples were being taken near where the discharge pipe empties into the river, a distance of about 5 miles from the plant.

Furthermore, if groundwater contamination is detected, it may be difficult to monitor and to predict the movement of the contamination in the groundwater. The flow of groundwater can be influenced by a variety of factors and can be quite complex.

Another aspect of inadvertent releases of radioactive material to the environment that was illuminated by the Braidwood and Indian Point events was the level of public concern that can result. At both sites, media coverage was wide-spread. Concerns were expressed by Members of Congress, as well as by State and local officials. The Braidwood event led to the State of Illinois enacting legislation requiring reporting of events at a threshold well below that presently required by the NRC. Senator Obama of Illinois has introduced legislation in the United States Senate that would require additional reporting on a nationwide basis. Public meetings in the vicinity of the plants were widely attended, and the opinion expressed by the audiences was generally negative toward both the plant operator and the NRC. The events also led to the submission of a petition to the NRC in accordance with the provisions of 10 CFR 2.206. This petition was co-sponsored by 28 different public groups or individuals, and requested that the NRC take certain actions that the petitioners believed was warranted to protect public health.

When considering recommendations to be made as the result of the task force review, the task force members were challenged to weigh the likely benefit of implementing recommendations against the cost. The task force concluded that the relative potential benefit to protection of public health would generally be low, because the realistic potential for long term undetected radioactive leakage resulting in a more than minor radiation dose to members of the public is low. However, as illustrated by the Braidwood and Indian Point events, the task force concluded that the positive benefit to the NRC's goal of openness could be significant. The recommendations contained in the report reflect this judgement.

deviations from the sampling schedule are required to be documented in the annual radiological environmental monitoring report.

The regulatory guidance provides built-in flexibility in the scope of the REMP. It provides a generic minimum program and also states that individual sites may have special local characteristics which have to be addressed on a site specific basis. It also allows licensees to reduce the scope and frequency of the sampling program, without NRC approval, based on historical data. What NRC inspectors have typically seen is that if a licensee's environmental samples have not detected licensed radioactive material in several years, then the licensee typically reduces the scope and sample frequency of the associated environmental pathway. The guidance is designed to allow the REMP to focus its sampling protocol on the more dose significant pathways and to drop sampling in those areas that result in the lowest dose. NRC inspections have observed reductions in the scope and frequency of licensee programs, but in all cases the minimum required sampling of the required pathways continues.

Reporting Requirements

As discussed above, there are no specific regulatory requirements for licensees to conduct routine on-site environmental surveys and monitoring for potential abnormal spills and leaks of radioactive liquids. However, 10 CFR 50.75(g) requires that licensees keep records of information important to the safe and effective decommissioning of the facility. These records include information on known spills or other unusual occurrences involving the spread of contamination in and around the facility or site. These records may be limited to instances when significant contamination remains after any cleanup procedures or when there is reasonable likelihood that contamination may have spread to inaccessible areas. The rule does not define the magnitude of the spills and leaks that need to be documented by the licensee. Also, the rule does not define "significant contamination" that needs to be recorded after the cleanup process. Licensees maintain records of information on spills and leaks at their facilities. There is no requirement that this information must be submitted to the NRC. However, the records are available for review by NRC inspectors.

Although 10 CFR 50.75(g) discusses the requirement for records of any remaining residual contamination, there are no regulatory requirements which require remediation while the power plant is operating. A licensee's decision to remediate contamination before the plant is decommissioned is typically based on several factors, including ALARA considerations for potential worker and public dose, cost, feasibility, disposal options, and external stakeholder considerations.

The NRC has clearly defined radiation limits for the decommissioning of a nuclear reactor and release of the facility or site for unrestricted use by members of the public. The requirements are contained in 10 CFR Part 20, Subpart E - "Radiological Criteria for License Termination." The NRC will terminate a Part 50 license and allow the site to be used for any purpose provided that any remaining reactor produced radioactive contamination does not result in an annual dose above 25 mrem. The dose is calculated from all environmental pathways; air, water, food products, residential occupancy and/or industrial use.

10 CFR Part 20, Subpart M — Reports

Section 20.2202 provides criteria for notification of incidents. For incidents involving the release of licensed radioactive material, the reporting criteria is that immediate notification of the NRC is required when the event may have caused or threatens to cause a large dose in excess of regulatory limits to an individual (i.e, 25 rem to the whole body, 75 rem to the lens of the eye, or a shallow-dose equivalent skin or extremity dose of 250 rads). Note that 1 rem is equal to 1000 mrem.

Incidents which require notification within 24 hours involve radiation doses which are lower than

Dresden Storage Tank Piping Leak

In 2004, leakage was discovered in the supply line piping between the condensate storage tank and the high pressure coolant injection (HPCI) system. The piping is approximately 175 feet long and is located in a dirt trench. The licensee replaced approximately 75 feet of piping where leaks had been identified in 2004. The replaced section of piping is buried in a low-strength grout material. In February, 2006, the licensee identified elevated levels of tritium in a monitoring well located near the underground piping. The licensee suspects that the current leak is from the 100 feet of piping that was not replaced in 2004. The licensee had planned to replace the piping in June, 2006 prior to the identification of elevated tritium. The condensate storage tank and associated piping is made of aluminum and is not categorized as Class I. In addition, the licensee has not categorized the condensate storage tank and the associated piping to the HPCI system as safety related. The licensee's UFSAR lists the safety related water source as the torus for the HPCI system. The piping is classified as non-safety related, although the licensee lists it as Augmented Quality under the Exelon quality assurance program. The piping is designed to meet ANSI B31.1 standards. The piping is wrapped with polypropylene pipe wrap material to provide protection from corrosion and electrolysis. The piping consists of 12-inch, 16-inch, 18-inch and 24-inch diameter sections having a nominal wall thickness of 0.375-inch. The required installation testing includes hydrotesting and visual inspection. The licensee's technical specifications require quarterly HPCI surveillance using the subject section of piping as part of the flow path. In addition, the Exelon excavation procedures have the licensee visually inspect the buried piping if the area is excavated in the future. The task force could not identify any generic regulatory requirements that applied to maintenance, surveillance, or routine testing of non-safety related condensate storage tanks and associated piping.

3.2.2.3 Conclusions

Review of regulatory requirements for SSCs that have experienced unmonitored or unplanned liquid radioactive effluent releases as described above, leads to the following conclusions:

(1) Systems containing radioactive liquid that are designated as safety-related, or that are addressed under some aspect of a licensee's quality assurance program, are generally subject to maintenance, inspections, tests, and/or other quality assurance requirements that provide added assurance that the system will not leak, or if it does leak, that the leakage will be detected. Systems that are not safety-related and that are not covered under the quality assurance program generally are subject to less of these measures.

(2) Systems or structures can experience undetected radioactive leaks over a prolonged period of time. Systems or structures that are buried or that are in contact with soil, such as SFPs, tanks in contact with the ground, and buried pipes, are particularly susceptible to undetected leakage.

(3) SFP leakage may be reduced by improved maintenance and trending of the telltale leak detection/monitoring system.

(4) SFP performance deficiencies are not specifically addressed in the NRC inspection program significance determination process.

(5) Leakage from components containing radioactive liquids may be reduced by the use of improved materials, the use of higher level consensus code repair/replacement requirements, improved quality assurance, improved design standards, improved and expanded inspection requirements, improved protection of buried components (galvanic protection, coatings) and/or improved design considerations.

APPENDIX B

CONSOLIDATED RECOMMENDATIONS LIST

CONSOLIDATED RECOMMENDATIONS LIST

(1) The staff should review and develop a position to address using lake water that contains licensed radioactive material for other site purposes, such as for use in the fire protection system (Section 2.0)

(2) The NRC should develop guidance to the industry for detecting, evaluating, and monitoring releases from operating facilities via unmonitored pathways (Sections 3.1 and 3.4).

(3) The NRC should revise the radiological effluent and environmental monitoring program requirements and guidance to be consistent with current industry standards and commercially available radiation detection technology (Section 3.2.1).

(4) Guidance for the REMP should be revised to limit the amount of flexibility in its conduct. Guidance is needed on when the program, based on data or environmental conditions, should be expanded (Section 3.2.1).

(5) Develop guidance to define the magnitude of the spills and leaks that need to be documented by the licensee under 10 CFR 50.75(g). Also, clearly define "significant contamination." Summaries of spills and leaks documented under 10 CFR 50.75(g) should be included in the annual radioactive effluent release report (Section 3.2.1 and 3.4).

(6) The staff should provide guidance to the industry which expands the use of historical information and data in their 50.75(g) files to the operational phase of the plant. The data provides good information on current and future potential radiological hazards that are important during routine operation, and can aid in planning survey and monitoring programs (Sections 3.2.1 and 3.4).

(7) The NRC should evaluate the need to enact regulations and/or provide guidance to address remediation (Section 3.2.1).

(8) The NRC should require adequate assurance that leaks and spills will be detected before radionuclides migrate offsite via an unmonitored pathway (Sections 3.2.1, 3.2.2, and 3.4).

(9) To support one possible option for recommendation (6) of Section 3.2.1, regulatory guidance should be developed to define acceptable methods to survey and monitor on-site groundwater and sub-surface soil for radionuclides (Section 3.2.1).

(10) The NRC should revise radioactive effluent release program guidance to upgrade the capability and scope of the in-plant radiation monitoring system, to include additional monitoring locations and the capability to detect lower risk radionuclides (i.e., low energy gamma, weak beta emitters, and alpha particles) (Section 3.2.1).

(11) Determine whether there is a need for improved design, materials, and/or quality assurance requirements for SSC's that contain radioactive liquids for new reactors (Section 3.2.2).

(12) The staff should consider whether further action is warranted to enhance the performance of SFP telltale drains at nuclear power plants (Section 3.2.2).

(13) The staff should verify that there has been an evaluation of the effects of long term SFP leakage (boric acid) on safety significant structures (concrete, rebar), or the staff should perform such an evaluation (Section 3.2.2).

(14) The staff should assess whether the maintenance rule adequately covers SSCs that contain radioactive liquids (Section 3.2.2).

(15) The staff should verify that the license renewal process reviews degradation of systems containing radioactive material such as those discussed in this report (Section 3.2.2).

(16) The NRC staff should open a dialogue with the States regarding the application of the NPDES system to discharges of radioactive materials to promote a common understanding of how the associated legal requirements in this area are addressed (Section 3.2.3).

(17) Inspection guidance should be developed to review onsite contamination events including events involving contamination of ground water (Section 3.3).

(18) The inspection program should be revised to provide guidance to evaluate effluent pathways such that new pathways are identified and placed in the ODCM as applicable. In addition, guidance should be included as to when a new release path becomes "permanent" for purposes of inclusion in the ODCM and routine annual reporting (Section 3.3).

(19) Limited, defined documentation of significant radioactive releases to the environment should be allowed in inspection reports for those cases where such events would not normally be documented under the present guidance (Section 3.3).

(20) The staff should revise the Public Radiation SDP to better address the range of events that can occur, including unplanned, unmonitored releases or spills (Section 3.3).

(21) 10 CFR 20.1406 requires in part that applicants for licenses shall describe in their application how facility design and procedures for operation will minimize contamination of the environment. The NRC should develop regulatory guidance to describe acceptable options to meet this requirement (Sections 3.4 and 3.5).

(22) NRC should evaluate whether the present decommissioning funding requirements adequately address the potential need to remediate soil and groundwater contamination, particularly if the licensee has no monitoring program during plant operation to identify such contamination (Section 3.4).

(23) The NRC should consider the development of guidance on the evaluation of radionuclide transport in groundwater. American National Standard (ANSI/ANS) 2.17 addresses this issue and is being extensively updated (Section 3.5).

(24) The NRC's guidelines for "immediate notification" public communications should continue to be based on public health and safety considerations. To support the NRC's openness goals, the NRC staff should consider whether to notify the public of radioactive releases to the environment that are not significant from a radiation dose perspective, but that could be of general public interest nonetheless (Section 3.6).

(25) NRC staff should review NUREG/BR-0308, "Effective Risk Communication," and other training tools to ensure an event's risk is provided with appropriate context (Section 3.6).

(26) Nuclear power plant licensees should consider entering into agreements with local and state agencies to voluntarily report preliminary information on significant radioactive liquid releases that do not otherwise trigger reporting requirements. The present industry groundwater protection initiative may address this (Section 3.6).

EXHIBIT 8

Risk Informed Assessment of Degraded Buried Piping Systems in Nuclear Power Plants, Brookhaven National Laboratory; US Nuclear Regulatory Commission, NUREG/CR 6876,

June 2005,

Brookhaven Report

NUREG/CR-6876
BNL-NUREG-74000-2005

Risk-Informed Assessment of Degraded Buried Piping Systems in Nuclear Power Plants

Brookhaven National Laboratory

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

3.1.1 Aging Mechanisms

The primary aging mechanisms that directly affect buried metallic/steel piping are described below. Aging mechanisms affecting polymer piping are not discussed because polymer buried piping are rarely used at NPPs. Aging mechanisms of concrete pipe are also not discussed because buried concrete pipe is primarily used at NPPs for large diameter lines due to their significant weight. These large diameter lines provide the ability for personnel to gain access and perform periodic inspections. Therefore, the focus of this research study is limited to buried metallic pipe. Information for aging mechanisms and effects of concrete pipe would be similar to those already described for concrete members in NUREG/CR-6715.

General Corrosion

General corrosion is a degradation of the pipe surface that results in loss of material over a region without appreciable localized attack. Corrosion is caused by a direct current that flows from a metal such as a buried pipe to an electrolyte such as the soil material. Corrosion occurs at the location where the current exits the pipeline to enter the soil. Corrosion depends on the electrical resistance and potential of the electric circuit that is developed. Corrosion varies with the moisture content of the soil. If the soil is dry, very little corrosion is expected to occur, while in soils with higher moisture content, the resistivity drops and higher rates of corrosion would occur.

Corrosion is also a function of the level of oxygen in the soil. Where oxygen is more plentiful, the rate of corrosion is initially high and then is slowed by the corrosion products that remain adhered to the pipe surface. Corrosion products however cannot be relied upon to prevent corrosion because they do not adhere tightly to the pipe, may be thin, and may not exist throughout the pipe.

General corrosion rates vary depending on many design and environmental parameters. A discussion of general corrosion rates in steel pipe is provided in Section 3.4

Because of the poor corrosion resistance of carbon steel pipes, they are often lined or coated on the inside with bonded polymeric coatings, cement-mortar, or elastomers. On the outside, buried pipes are usually protected by coal tar epoxy coatings and wrappings. Buried piping is also protected at many plants by a cathodic protection system which is described in Section 4.1 of this report.

Pitting Corrosion

Pitting corrosion is a localized form of corrosion that forms cavities or holes in the material. Pitting corrosion occurs when chemical attack breaks through the passive film that protects the metal surface. Once a pit penetrates the passive film, an electrochemical (galvanic) reaction develops. The metal in the pit becomes anodic while the surface outside the pit is cathodic. The exposed surface outside the pit is cathodically protected and can lead to a large cathode to anode ratio which can accelerate the anodic reaction in the pit. The reaction in the pit leads to a reduction in the pH and an increase in the chloride ion concentration. The acidic chloride environment is aggressive to most metals and thereby propagates the pit growth. It is possible for most of a pipe section to show little corrosion while some deep pits may develop.

indicated that there was internal coating degradation of buried piping at three of the six plants visited. Remedial action was taken by the licensees after the degradation resulted in inadequate flow conditions or unacceptable water quality.

3.3 Important Aging Effects for Use in this Study

Although there are numerous aging mechanisms possible for buried piping, the analysis described in this report is based on the aging effect or manifestation of the degradation, not what causes the degradation. This approach is taken because to achieve the objective of developing degradation acceptance criteria (DAC), the degradation criteria will need to be developed in terms of observable levels of degradation which normally correspond to aging effects such as loss of material in the pipe wall. Based on Table 3.3, the primary aging effects that are caused by almost all aging mechanisms are thinning of the pipe wall over a region and localized loss of material/pitting in the pipe wall. The remaining aging effect of loss/reduction in flow is not addressed because this aging effect can be monitored by measuring performance parameters of the system such as flow rates, pressure, and sampling of the fluid.

Degradation to the internal or external coatings as reported in Table 2.2 for some plants is not considered because the coating is a protective material whose deterioration can lead to wall thinning or pitting of the pipe wall at some time in the future, only if no action is taken. As long as degradation of the steel pipe has not occurred, degradation of the coating does not affect overall plant risk. The purpose of this study is to develop DAC on degraded buried piping and not acceptance criteria on the coating material. It is expected that any degradation identified with the interior or exterior coating of buried piping will be repaired unless otherwise justified.

3.4 Degradation Rates For Corrosion and Localized Loss of Material/Pitting

The rate of degradation of steel buried piping is a function of environmental variables, metallurgical variables, and hydrodynamic variables. Environmental variables that can affect the degradation rates occur on the exterior surface of the buried pipe and inside surface of the pipe. For the external surface of the pipe, the rate of degradation is a function of parameters such as aggressive chemicals, oxygen, pH level, and stray currents that may exist in the soil material and groundwater (if present). The rate of degradation on the interior pipe surface is a function of fluid parameters such as fluid velocity, temperature, aggressive chemicals, pH level, dissolved oxygen, and biological elements. Metallurgical variables consist of the chemical composition of various elements in the pipe material such as the weight percentage of chromium, molybdenum, and copper in the steel, which may affect the degradation rate. Hydrodynamic variables such as fluid velocity, piping configuration, and roughness of the pipe inner surface also affect the degradation rate.

Other variables that may affect the degradation rate are: time, type of corrosion/degradation, and whether the piping is pressurized. Depending on the conditions and time period of interest, the degradation rate may not be constant with respect to time. The two types of aging effects which are evaluated in this study (general wall thinning and localized loss of material/pitting) may have some effect on the degradation rate of the buried pipe. In addition, the degradation rate is also expected to be affected by piping that is normally operating and thus "continuously" subject to internal pressure, and by piping that is normally in standby and thus is not subject to internal pressure at all times.

Based on the above discussion, it is evident that predicting an accurate degradation rate for buried piping systems is difficult to achieve, and beyond the scope of this research program.

Therefore, a literature search was performed to determine what are typical degradation rates for buried piping systems that might be appropriate for use in nuclear power plants. Based on EPRI Report TR-103403 (1993), general corrosion rates vary from 1 to >10 mils/year (1 mil per year = 0.0254 mm per year (0.001 in. per year)) for carbon steel and low alloy steels in fresh water at temperatures of 1.67°C to 40.6°C (35°F to 105°F). Assuming 3 mils/year and a 40 year life, this results in a loss of thickness equal to approximately 0.318 cm (1/8 in.), which should have been considered as corrosion allowance in the original design of buried pipe. Corrosion rates of stainless steels, nickel based alloys, and copper alloys have much lower corrosion rates, often less than 1 mil per year. These materials would be used in buried piping subjected to more aggressive environments such as seawater or brackish waters, or where safety concerns require more corrosion-resistant material.

Since there wasn't much more information that could be identified specifically for buried piping, data on degradation rates for above ground piping systems were also searched. Degradation occurrences reported in NRC Information Notices were identified and reviewed. Information Notices that provided quantitative data on degradation rates are IN 2001-09; IN 86-106, Supplement 3; IN 87-36; IN 91-18; and IN 92-35. A review of these Information Notices indicates that the degradation rates for the reported occurrences generally went as high as 60 mils per year, with one case for localized thinning at 90 mils per year. It should be noted that most of these cases occurred in high energy lines such as feedwater systems and it could be argued that their degradation rates are more severe than what would be expected in buried piping systems operating at lower pressures, temperatures, and fluid velocities. On the other hand, these above ground piping systems are not subjected to the external environment that buried piping may be exposed to. Often this external environment in buried piping is mitigated by means of external coatings on the pipe or sometimes by the use of cathodic protection systems. The information provide by these Information Notices do give a measure of perhaps the upper bound of what might be expected in buried piping systems.

Based on the above discussion, it appears that a reasonable range of degradation rates for buried piping would be between 1 and 100 mils per year. This information is only provided as guidance on typical values that have been reported. The selection of an appropriate degradation rate is the responsibility of the individual performing the assessment, based on the conditions that exist for a particular buried piping system.

4 DETECTION OF AGE-RELATED DEGRADATION AND CONDITION ASSESSMENT

4.1 Inspection Methods

Inspection methods for the degradation of buried piping can be based on visual, non-destructive, or destructive methods. Since degradation mechanisms can cause aging effects on the interior and/or exterior of buried piping systems, information about the condition of the inside and outside surface of buried piping is important. Large diameter lines such as portions of the service water system usually can be examined by manual visual inspection provided there is access to the line. Smaller diameter lines however, are not easily accessible and require other techniques which have been improved significantly over recent years. The methods that can be used to inspect the condition of buried piping are described below. The use of a particular method depends on the size of the line, access to the interior or exterior surface, pipe material, aging effect of interest, and cost.

Visual Inspection

This is the most common form of inspection of the condition of the interior or exterior buried piping. For interior examination of large diameter lines, inspections are usually performed during plant outages where a trained individual (inspector) enters the pipeline to examine the condition of the pipe surfaces, coatings (if applicable), welds, and mechanical joints. If the water in the line is not drained, inspections can still be performed using trained divers. The inspector can identify any fouling of the pipe, loss of wall thickness, degradation of coating, and identify the extent of any other degradation. Loss of wall thickness can be identified using a pit gauge to measure pit depth, ultrasonic test (UT) meter to measure general loss of material, and tape measure to record the area of the corroded region. Inspection for coating degradation would include examination for cracking, blistering, debonding, peeling, erosion, and general loss of coating material. During the inspection the inspector can collect any built-up material due to fouling or corrosion by-products for subsequent analysis. In addition, the inspector can insert and remove coupons which can be evaluated for degradation of the pipe material.

Sometimes, an indication of the condition of the interior surface for buried piping can be determined by examining accessible entry points where the buried piping rises above the ground surface or enters into buildings. This may not be reliable though if conditions of the buried piping section are different than the accessible portions of pipe above ground or within the buildings. This may be due, as an example, to stagnant water in the buried piping section which may not exist in the other regions being examined.

Visual inspections from inside the pipe cannot identify degradation on the outside surface of the pipe unless corrosion or pitting penetrates the thickness of the pipe. Therefore, to obtain complete knowledge of the condition of a buried pipe, examination of the inside and outside surface is recommended. The same visual inspection methods described above can be used to examine the exterior surface of the pipe; however, excavation would be needed to gain access to the exterior pipe surface.

Cameras

Cameras can be used for visual inspection of buried pipes. These cameras provide visual type information without the need for direct personnel inspection or excavation to gain access to buried pipe. These cameras are useful for smaller diameter lines where direct visual inspection by personnel is not possible. Presently, these cameras are tethered and may be difficult to

6 RISK EVALUATION OF DEGRADED BURIED PIPING SYSTEMS

Buried piping systems at a nuclear power plant (NPP) can degrade, as described in the previous sections. Such deterioration potentially could impair the operation of the system that contains the buried piping, and thus impact the overall risk of an NPP.

Currently, buried piping is not systematically inspected. Accordingly, a failure of a buried pipe is "discovered" because the failure is self-revealing[1], or a failure or degradation of a buried pipe is "discovered" because of another event, such as excavation that is performed for unrelated items. If the "discovery" indicates that the pipe has failed, then a repair[2] has to be completed to return it to normal condition. If the "discovery" indicates that the pipe has not failed, but it has degraded, the regulatory question that arises is: "does the pipe have to be repaired immediately, or is it acceptable for the plant to continue operating?[3]" In essence, the methods and criteria described in this report provide guidance to the NRC staff to assist them in answering this question.

These methods assess the increase in projected risk as a function of time from the time of inspection to answer the question in the previous paragraph. In this way, they estimate the number of years before the plant risk becomes unacceptable. The expression "projected risk" means that the risk is evaluated at some time after the time of inspection.

The increase in projected risk is assessed from the time of inspection because it is known that the pipe has not failed at this time, and the objective of the evaluation is to assess whether continued operation of the pipe (plant) from this time leads to "unacceptable" risk. Figure 6.1 depicts relevant events as a function of time from the start of life of a buried pipe.

To estimate the effect of buried piping degradation on plant risk, five nuclear plant sites having buried piping systems were selected. Section 6.1 describes the process used to select the five nuclear plant sites with buried piping systems. Each site may have one or more NPPs; to simplify the discussion, this report refers to one site simply as an NPP or a plant.

To develop degradation acceptance criteria, which is one of the stated goals of this research, a quantitative measure of "acceptable risk" is needed. Section 6.2 defines what is considered to be acceptable risk, the conditions for which it is applicable in this study, and the quantitative risk acceptance criteria.

The evaluation of the risk associated with degrading buried piping depends on the type of system that contains this piping. Section 6.3 discusses some top-level considerations for developing methods for estimating this risk, including a classification of the plant's systems for the purpose of assessing this risk. Section 6.3 concludes that all the systems with buried piping of the five nuclear plants selected fall into two categories:

---

[1] A failure of a buried pipe is self-revealing, for example, when a system that is normally operating fails in such a way that the failure becomes visible to plant personnel.

[2] In this section the term "repair" is used in a very broad sense, including replacement. In other words, when a "repair" is carried out, it is considered that the pipe is returned to a condition that meets the plant's current licensing basis.

[3] If the buried pipe is degraded but not failed, the licensee is still expected to evaluate the degraded condition to determine if any corrective action needs to be taken depending on the evaluation findings and the level of degradation. Although future inspections are an option, there is no requirement to do so.

The ED provides the amount, in percentage terms, that was lost from the required wall thickness for pressure and other loads. Now the existing DAC table corresponding to a pipe with a thickness equal to (t_r) and percent wall loss equal to ED can be used to determine the number of years to reach a level of degradation that would potentially have a significant effect on plant risk. Therefore, the recommended approach for Case B, when OL > CA, is to use the existing Table 7.3 for DAC and reading off the number of years at the row corresponding to the equivalent observed wall loss percentage (ED) as defined above. An example of how to apply this approach to a pipe that is degraded beyond the corrosion allowance is provided in Section 7.3.

7.3 Guidance on the Use of Degradation Acceptance Criteria

If buried pipe degradation is identified at an NPP, it may not be evident whether the pipe still complies with the plant licensing commitments or whether the degradation potentially has an immediate significant effect on plant risk. Normally, the licensee performs an evaluation of the degraded condition which may include further inspections, testing, calculation/design review, and other actions to determine the severity of the condition, risk implications, and whether an immediate repair is needed. Since these steps may take time, often beyond a week, the methodology and DAC developed in this report provides guidance to the NRC staff for making an assessment in a timely manner whether the degraded condition potentially has an immediate significant effect on plant risk. This knowledge is important in order to provide input that can help determine whether immediate repairs are warranted, or whether the appropriate investigation, inspection, aging management, or other actions can be determined in the normal course of evaluating the condition. The methodology and DAC can not be used by the industry to justify existing degraded conditions; licensees are still required to meet their commitments regarding the plant's current licensing basis.

This section provides the guidelines for using the DAC. It describes what the DAC are, how to use them, the acceptable range of conditions permitting their use, and recommendations if the DAC cannot be satisfied. More specifically, the DAC provides the number of years required for the buried pipe to reach a degradation level that would potentially have a significant effect on plant risk. To utilize the DAC, developed in Section 7.2, there were a number of variables and parameters that were used in the various stages of the research study. Therefore, a number of conditions must be satisfied to permit the use of the DAC. These conditions are described in this section of the report.

It should be noted that the analyses were performed for SA-106 Grade B carbon steel pipe. The results are considered applicable to stainless steel pipe as well because, most stainless steel buried piping systems use 304 and 316 type stainless steel material which have higher ultimate strength values and are more ductile than SA-106 Grade B carbon steel pipe.

The research described in this report developed DAC for general wall thinning and localized loss of material/pitting in buried piping. The types of buried piping systems, configurations, materials, and other conditions that must be satisfied to use the DAC have also been developed and presented below.

The results obtained are based on the service conditions that buried piping is designed for (e.g., pressure induced stresses less than ¼ of the minimum ultimate strength of the material and relatively low temperatures) and recognizing that seismic induced stresses in buried piping are self-limiting since deformations or strains are limited by seismic motions of the surrounding media. In addition, the DAC presented below arose from a probabilistic risk assessment which

8 CONCLUSIONS AND RECOMMENDATIONS

If buried pipe degradation is identified at an NPP, it may not be evident whether the pipe still complies with the plant licensing commitments or whether the degradation potentially has an immediate significant effect on plant risk. Normally, the licensee performs an evaluation of the degraded condition which may include further inspections, testing, calculation/design review, and other actions to determine the severity of the condition, risk implications, and whether an immediate repair is needed. Since these steps may take time, often beyond a week, the methodology and degradation acceptance criteria (DAC) developed in this report provide guidance to the NRC staff for making an assessment in a timely manner whether the degraded condition potentially has an immediate significant effect on plant risk. This knowledge is important in order to provide input that can help determine whether immediate repairs are warranted, or whether the appropriate investigation, inspection, aging management, or other actions can be determined in the normal course of evaluating the condition. The methodology and DAC can not be used by the industry to justify existing degraded conditions; licensees are still required to meet their commitments regarding the plant's current licensing basis.

To achieve the objectives of this study, fragility modeling procedures for degraded buried piping have been developed and the effect of degradation on fragility and plant risk has been determined. The effects of degradation over time were also included in the methodology. The analytical approach provides the technical basis for evaluating degraded buried piping at NPPs and provides guidelines for assessing the effects of degraded conditions on plant risk. The guidelines, which are identified as degradation acceptance criteria (DAC), are presented in tabular form for ease of use.

The effects of degradation over time were considered in developing the DAC in a manner that provides the number of years required for the buried pipe to reach a degradation level that would potentially have a significant effect on plant risk. If the degraded condition exceeds the criteria, then immediate repair would be required unless otherwise justified. If the degradation level is less than the criteria, then it is expected that the licensee will still evaluate the conditions that led to the degradation and may need to repair the degraded pipe based on the evaluation findings, the level of degradation, and the plant's current licensing basis.

8.1 Conclusions

8.1.1 Understanding of the Degradation of Buried Piping

The types of buried piping systems, material and design parameters, and analysis and design methods that can be used for buried piping at NPPs have been collected and evaluated. Based on a survey and review of license renewal applications, there are many different buried piping systems used at NPPs; however, the most predominant types are the service water, diesel fuel, fire protection, and emergency feedwater systems. The materials used for buried piping are primarily carbon steel and to a lesser extent stainless steel. Other materials which are not as common are low-alloy steel, galvanized steel, cast iron, fiberglass, copper nickel, ductile iron and Yoloy. Methods for the structural analysis and design of buried piping are available in the general literature and in various industry codes, standards, and guides.

The predominant aging effects and associated aging mechanisms for buried piping have been identified and summarized in this report. The predominant aging effects are loss of material and fouling/biofouling. Most occurrences of loss of material are manifested as either general wall thinning or localized loss of material/pitting. A number of occurrences of degraded buried piping

wall becomes thinner, the pressure induced stress increases, thereby increasing the probability of a pipe rupture failure.

Using the properties of buried carbon steel pipe, a methodology for developing buried piping fragility curves to predict probability of failure versus internal pressure was developed. Based on allowable variations in material and dimensional properties, it was shown that the tensile strength was the most significant random variable affecting the probability of failure. By using the minimum strength properties allowed by the material specification and by making reasonable assumptions on mean and upper limit strength values, a normal distribution of material strength was developed. Using this material strength distribution, pipe stress equations, and the assumption of uniform wall thinning, a series of fragility curves were analytically developed for undegraded pipes and for degraded pipes with different levels of percentage wall loss. In addition, a statistical evaluation of available test data on pressure tests of degraded pipes removed from service was performed to confirm the conservatism of these fragility curves and to demonstrate that the curves are applicable to piping with localized or pitting corrosion as well as uniform wall thinning.

Using the same methodology, a series of fragility curves were developed for carbon steel pipe ranging in size from 5.08 to 107 cm (2 in. to 42 in.) in diameter. These curves were developed for both undegraded and degraded pipes. Finally, by assuming that the internal pipe pressure is equal to the design pressure allowed by Code rules, plots of probability of failure versus percent wall loss were generated. These curves were combined on a single graph and showed that under design pressure, the variability of the probability of failure of degraded pipe at different percentage wall losses is within a factor of about 5.

8.1.5 Risk Evaluation of Degraded Buried Piping Systems

Buried piping systems at an NPP can degrade, as described in the previous sections of this report. Such deterioration potentially could impair the operation of the system that contains the buried piping, and thus impact the overall risk of an NPP. To develop a methodology that can estimate the effect of degraded buried piping on plant risk, a definition of the criterion to be used as a measure of significant risk was needed. For this study, the measure of significant plant risk was based on a change in core damage frequency (ΔCDF) of 1.0×10^{-6} per year. This was selected based on the guidelines provided in NRC RG 1.174, Rev. 1.

To determine the effects of buried piping degradation on plant risk, five NPP (sites) were selected for evaluation. The plants selected consist of McGuire 1 and 2; North Anna 1 and 2; Oconee 1, 2, and 3; Surry 1 & 2; and Hatch 1 & 2. These plants were selected because they contain many different buried piping systems and they have different attributes consisting of: reactor types, NSSS suppliers, containment types, architect/engineers, and locations in the United States. In addition, they contain both "frontline" and "support" systems with buried piping.

For the purpose of evaluating the contribution of the degradation of a buried piping system to plant risk, the systems in any NPP can be classified into several categories depending on whether the system's failure causes an initiating event, whether the system is normally operating, and other criteria. A review of the buried piping systems at these five plants determined that they fell into two categories. Analytical time-dependent methods were developed for these two categories to estimate the increase in plant risk due to degraded buried piping. Some parameters required by these methods were obtained by using the Standardized Plant Analysis Risk (SPAR) version 3 models of the five selected plants. A SPAR model is a level-1 probabilistic risk assessment (PRA) model of internal events during full-power operation.

EXHIBIT 9

COX

June 5, 2007

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

Before the Atomic Safety and Licensing Board

In the Matter of	)	
	)	
Entergy Nuclear Generation Company and	)	Docket No. 50-293-LR
Entergy Nuclear Operations, Inc.	)	ASLBP No. 06-848-02-LR
	)	
(Pilgrim Nuclear Power Station)	)	

DECLARATION OF ALAN COX IN SUPPORT OF ENTERGY'S MOTION FOR SUMMARY DISPOSITION OF PILGRIM WATCH CONTENTION 1

Alan Cox states as follows under penalties of perjury:

15. The purpose of the SSW system is to function as the ultimate heat sink for the reactor building closed cooling water and turbine building closed cooling water systems during plant operations. PNPS LRA at Section 2.3.3.2, p. 2.3-32. The buried piping in the SSW is made of titanium and carbon steel and consists of piping from the intake structure as well as two discharge loops. The intended functions of the SSW as they relate to the 10 C.F.R. § 54.4 scoping criteria are as follows:

EXHIBIT 10

U.S. Nuclear Plants in the 21st Century: The Risk of a Lifetime,

David Lochbaum,

Union of Concerned Scientists.

(May 2004)

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

Before The Atomic Safety And Licensing Board

In the Matter of
Entergy Corporation
Pilgrim Nuclear Power Station
License Renewal Application

Docket # 50-293-LR

January 24, 2008

DECLARATION OF DAVID LOCHBAUM

I, David Lochbaum, prepared the attached reports: "U.S. Nuclear Plants in the 21st Century: The Risk of a Lifetime," (Union Concerned Scientists, May 2004) *and* Union of Concerned Scientists Issue Brief, "Help Wanted: Dutch Boy at Byron" (Union of Concerned Scientists, October 25, 2007).

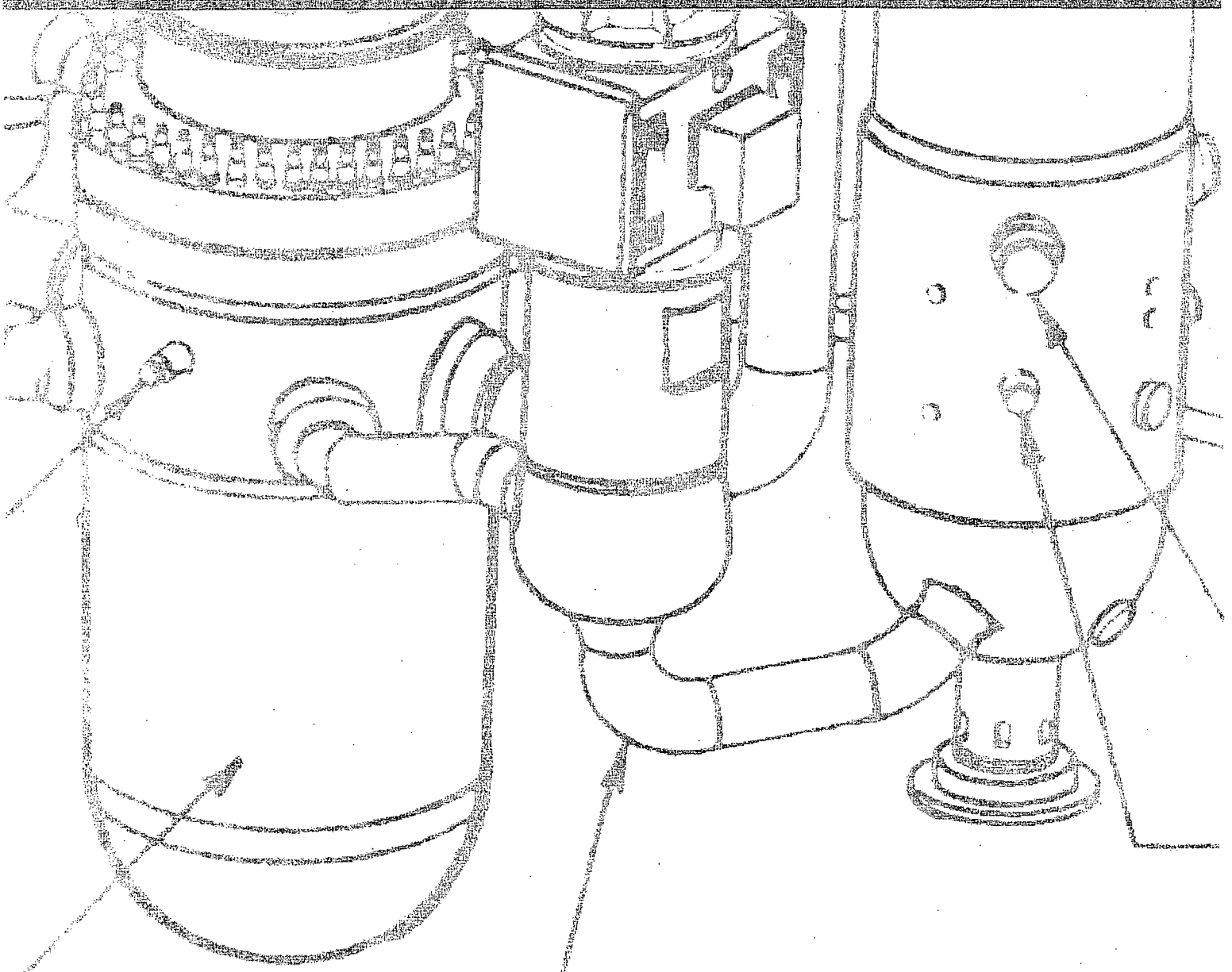
I stand by the contents of the reports today.

I declare that under penalty of perjury that the foregoing is true and correct.

David Lochbaum

U.S. Nuclear Plants in the 21st Century

THE RISK OF A LIFETIME



Union of Concerned Scientists
Citizens and Scientists for Environmental Solutions

U.S. Nuclear Plants in the 21st Century

THE RISK OF A LIFETIME

David Lochbaum

UNION OF CONCERNED SCIENTISTS

MAY 2004

David Lochbaum is a nuclear safety engineer in the UCS Clean Energy Program. He worked for nearly 20 years in the U.S. commercial nuclear power industry prior to joining UCS in 1996. He holds a degree in nuclear engineering from the University of Tennessee.

The Union of Concerned Scientists is a nonprofit partnership of scientists and citizens combining rigorous scientific analysis, innovative policy development, and effective citizen advocacy to achieve practical environmental solutions.

The UCS Clean Energy Program examines the benefits and costs of the country's energy use and promotes energy solutions that are sustainable both environmentally and economically.

More information about UCS and the Clean Energy Program is available on the World Wide Web at *www.ucsusa.org*.

The full text of this report is available on the UCS website or may be obtained from:

UCS Publications
Two Brattle Square
Cambridge, MA 02238-9105

Or, email *pubs@ucsusa.org* or call (617) 547-5552.

Cover: A line drawing showing the major components of a nuclear power plant. Source: Nuclear Regulatory Commission.

Design: Mary Zyskowski

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Executive Summary

The risks for catastrophe change as nuclear reactors age, much like the risks for death by accident and illness change as people get older. Protection schemes must evolve to remain correlated with age if the threat level is to be minimized. For people, it means replacing protective measures for toddlers (such as safety plugs in electrical outlets) with parental watchfulness against teenage drinking and driving. It also means testing for signs of age-related illness (such as glaucoma, heart disease, and osteoporosis) as people get older. For nuclear reactors, it means aggressively monitoring risk during the three stages of plant lifetime: the break-in phase, middle life phase, and wear-out phase. The risk profile for these three phases of life curves like a bathtub. The Union of Concerned Scientists (UCS) identified the best ways to manage the risks from nuclear power at all points along the bathtub curve.

The Break-in Phase

Any new reactors that are built will start out on the high-risk break-in segment of the curve. Several nuclear plant disasters—Fermi, Three Mile Island, and Chernobyl to name just a few—demonstrated the perils of navigating this part of the curve. Literally thousands of unexpected safety problems surfaced at other nuclear plants. These surprises drove safety levels down and nuclear power's costs up unnecessarily. Public intervention in licensing proceedings led to numerous safety improvements, but recent changes to the licensing process limit the public's role to essentially that of a casual observer. If new reactors are built, we must benefit from these hard and expensive lessons by: (1) excluding new reactors from federal liability protection under the Price Anderson Act, thereby removing the current disincentive for vendors to design safety upgrades; (2) verifying safety performance against expectations on prototype reactors before commercial reactors are built; (3) conducting extensive inspections of new reactors during design and construction to verify compliance with safety requirements; and (4) allowing meaningful public participation in the licensing process.

The Middle Life Phase

Increasing the maximum power output while cutting back on safety inspections at existing reactors reduces the margin for error along the middle segment of the bathtub curve. The fact that 27 nuclear reactors have been shut down in the past two decades for safety problems that took a year or longer to fix demonstrates that errors are abundant and margins for error are still necessary. Many of the safety cutbacks at nuclear plants are being justified based on deficient risk assessments. These risk assessments have resulted in poor management decisions, such as the decision in 2001 allowing the Davis-Besse nuclear plant in Ohio to continue operating in an unsafe manner. Risk at existing reactors can be best managed by: (1) improving the

oversight of methods used by plant owners to find and fix errors; (2) ending the practice of risk-informed decision making using flawed risk studies; and (3) using risk insights not just to reduce unnecessary regulatory burdens but also to shore up regulatory gaps as well.

The Wear-out Phase

Today's aging reactors, and any reactors granted 20-year extensions to their current 40-year operating licenses, face the high-risk wear-out segment of the bathtub curve. Despite efforts to monitor the condition of aging equipment, there are recent age-related failures caused by monitoring the right areas using the wrong techniques and by monitoring the wrong areas using the right techniques. In addition, nuclear plants seeking license renewal conform not to today's safety standards, but to a unique assortment of regulations dating back nearly 40 years with countless exemptions, deviations, and waivers granted along the way. While each individual exemption or waiver may be justified as not reducing safety margins, the cumulative effect of so many exceptions can adversely affect safety. To properly manage the risk at aging reactors: (1) multiple inspection techniques must be required for high-risk equipment; (2) expanded inspections must be required for equipment currently considered less vulnerable to aging; and (3) all differences between today's safety regulations and the mix of regulations applicable to today's reactors must be identified and reviewed to verify that no safety gaps exist.

What Needs to Be Done

While the risks and reasons for the risks vary along the bathtub curve, the consequences of failing to manage the risks remain nearly constant—potentially massive releases of radioactivity into the atmosphere with devastating harm to people and places downwind.

An aggressive regulator consistently enforcing federal safety regulations provides the best protection against these risks. Sadly, America lacks such protection. Since UCS began its nuclear safety project nearly three decades ago, we have engaged the Nuclear Regulatory Commission and its predecessor, the Atomic Energy Commission, countless times. We advocated enforcement of existing regulations far more often than for adoption of new regulations. Regulations might provide adequate protection, but only when they are followed. By failing to consistently enforce the regulations, the NRC exposes millions of Americans to greater risk than necessary. The federal government must reform the NRC into a consistently effective regulator so it properly manages the risk at all points along the nuclear bathtub curve.

CHAPTER 1

Introduction

There is renewed debate about the role of nuclear power in America's energy future. Some people see new nuclear power plants on the horizon, citing proposed legislation calling for increased subsidies for an already heavily subsidized industry as evidence of the pending nuclear revival. Others see nuclear power only in America's rearview mirror. As evidence of nuclear power's demise, they cite the eight reactors permanently closed since 1990 due to unfavorable economics and the three new reactor designs certified by the Nuclear Regulatory Commission (NRC) in the late 1990s but collecting dust on the shelf because they are too expensive.

Whatever the future holds for nuclear power, the Union of Concerned Scientists (UCS) identified the best ways to manage the risks from nuclear power. Existing reactors have not reached and will never reach a nuclear nirvana where catastrophes cannot happen. With many of today's reactors being relicensed to operate for up to 60 years, proper risk management becomes essential in preventing the imagined nirvana from turning into a nightmare. None of the proposed new reactor designs is inherently safe, as amply documented by UCS in the early 1990s and recently reaffirmed by the industry's express demand that the 1957 Price-Anderson Act be amended to extend federal liability protection against catastrophes at new reactors. As long as a single nuclear reactor, of any age, operates in the United States, Americans must be protected from the inherent risks.

In this report, UCS deals only with the highest-priority safety problems and recommends steps to start the NRC on the path toward necessary reforms. These reforms would lay the proper foundation for the NRC to resolve long-standing safety problems at the more than 100 nuclear plants operating nationwide. Congress must sustain the NRC reform effort through completion of this entire process, to provide the American public with the protection they expect and deserve.

The Bathtub Curve

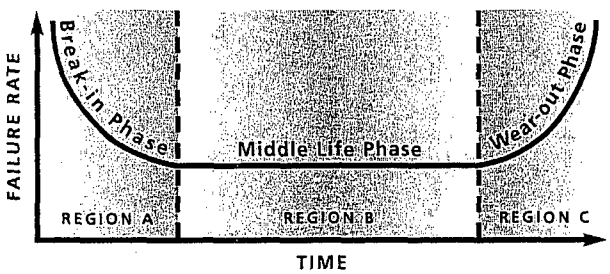
The risks for catastrophe change as nuclear reactors age, much like the risks for death by accident and illness change as people get older. Protection schemes must evolve to remain correlated with age if the threat level is to be minimized. For people, it means replacing protective measures for toddlers (such as safety plugs in electrical outlets) with parental watchfulness against teenage drinking and driving. It also means testing for signs of age-related illness (such as glaucoma, heart disease, and osteoporosis) as people get older. For nuclear reactors, it means aggressively monitoring risk during the three stages of plant lifetime: the break-in phase, middle life phase, and wear-out phase. The risk profile for these three phases of life curves like a bathtub.

The bathtub curve is drawn from statistical data about lifetimes of both living and nonliving things. If you monitored 10,000 widgets—light bulbs,

automobile tires, cats, cell phones, or nuclear reactors—and plotted how many expired in the first month, the second month, the third month, and so on, your graph would curve upward on either end from a flat middle section (like a bathtub.) The graph might not be symmetrical, but it would generally reflect low failure rates in the middle with higher failure rates on the ends.

The left-hand side of the bathtub curve, labeled Region A in Figure 1, represents the infant mortality or break-in phase of life. Infants are vulnerable to numerous illnesses until they grow stronger and build up immunities. Similarly, products may fail soon after being put to use due to manufacturing defects, material imperfections, or poor workmanship (U.S. Army Corps of Engineers, 2001). The steepness of the curve in Region A depends on factors such as the effectiveness of quality control measures applied during product manufacturing.

Figure 1 **The Bathtub Curve**



Source: NASA, 2001.

Region B, the middle portion of the bathtub curve, represents the useful lifetime for products and the peak health years for living things. Accidents and random events still occur, but at a lower rate than in Region A. The height (i.e., how far off the floor) and size (i.e., distance between ends) of the bathtub in Region B depends, for people, on factors such as environment and life-style choices.

The right-hand side of the curve, labeled Region C, is the wear-out phase. Due to aging, it takes less stress to cause failure in this region, just as older people are more prone to breaking bones in a fall than younger people. Thus, the chances of failure increase with time spent in Region C (NASA, 2001).

Applications of the Bathtub Curve

The bathtub curve concept is readily evident in everyday life. A new car comes with a warranty to cover problems during its break-in phase. When money is borrowed from a bank to buy a car, the loan term is typically three or four years—timed to be paid off before the car enters the wear-out phase. New shoes may be uncomfortable until they are worn in and then remain comfortable until worn out. And even the family pet is more fragile as a puppy and when long in the tooth than in the intervening years.

The mathematical exercise used to generate the bathtub curve does not mean the fate of a specific product or individual is preordained. Consider two identical new cars purchased from the same dealer on the same day. The first owner changes the engine oil and performs all other recommended maintenance tasks at the prescribed intervals. The second owner only changes the radio station. It is far more likely—but not guaranteed—that the first owner's car will have a longer useful life.

The bathtub curve concept also applies to nuclear power plants. The following sections examine how Regions A, B, and C of the bathtub curve dictate the risk from nuclear plant operation and recommend how that risk can be best managed.

CHAPTER 2

Nuclear Plant Safety in Region A

Every nuclear power reactor starts in Region A, where risk for accident and failure are high. Previously unrecognized vulnerabilities, manufacturing defects, material imperfections, and poor workmanship all contribute to high failure rates in newly operating nuclear reactors. As can be expected, some reactors did not get out of Region A without experiencing failure. Some of the worst failures include:

- The Fermi Unit 1 reactor in Michigan began commercial operation in August 1966. A partial meltdown on October 5, 1966, caused extensive damage to the reactor core. Age at time of failure: two months.

- The Three Mile Island Unit 2 reactor began commercial operation in December 1978. On March 28, 1979, a partial meltdown prompted the evacuation of nearly 150,000 people living near the plant. Age: three months.

- The St. Laurent des Eaux A1 reactor in France started up in June 1969. Nearly 400 pounds of fuel melted on October 17, 1969, when the online refueling machine malfunctioned. Age: four months.[1]

- The Browns Ferry Unit 1 reactor in Alabama began commercial operation in August 1974. A fire on March 22, 1975, caused severe damage to plant control equipment that required nearly a year's repairs to fix. Age: six months.[2]

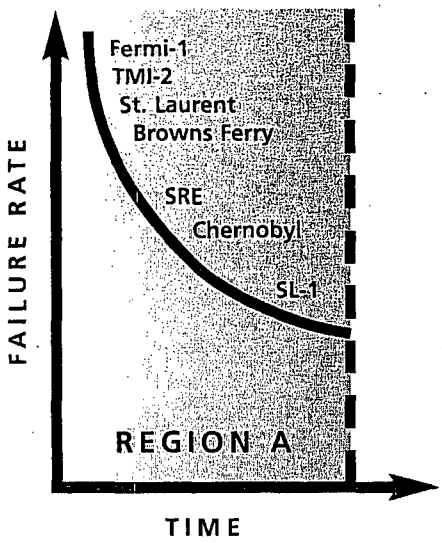
- The Sodium Research Experiment (SRE) reactor in California first attained full power in May 1958. On July 26, 1959, 12 fuel elements melted when the organic compound used to cool the reactor core decomposed and blocked the cooling flow channels. Age: one year, two months.

- The Chernobyl Unit 4 reactor started up in August 1984. It suffered the worst nuclear plant disaster in history on April 26, 1986, when two explosions destroyed the facility and ignited a reactor fire that burned for more than a week. Dozens of plant workers were killed and thousands of people permanently relocated due to radioactive contamination of the surrounding countryside. Age: one year, seven months.

- The SL-1 reactor in Idaho attained full power for the first time on October 24, 1958. An explosion within the reactor vessel on January 3, 1961, destroyed the reactor core and killed everyone at the site—the first fatal nuclear reactor accident in the United States. Age: two years, three months.

1 The St. Laurent des Eaux A1 reactor resumed operation in 1970.
2 The Browns Ferry Unit 1 reactor resumed operation in 1977.

Figure 2 **Major Failures at Region A Plants**



Source: Adapted from NASA, 2001.

Lessons Learned by Region A Failures

In some of these cases, the equipment intended to prevent accidents actually caused the accidents themselves or made them worse. For example, workers installed angled metal pieces just below the reactor core before Fermi Unit 1 began operation. This last-minute addition was intended to make the plant safer by dividing the molten core if it melted and slumped to the bottom of the reactor vessel. But one of the metal vanes broke free and blocked the cooling flow through the reactor core, causing—ironically—nuclear fuel to melt. In a far more tragic turn of events, the accident at Chernobyl occurred when workers performed a test of a proposed new backup system intended to allow the plant to operate more safely.

These accidents revealed problems that were not apparent on the blueprints, in the computer models, or in the laboratory. The problems required extensive safety upgrades at the surviving nuclear plants, but helped lower the risk of failure in the future. The fire at Browns Ferry Unit 1, for example, forced the rethinking of fire protection at nuclear power plants. New regulations were put in place to govern the construction of new nuclear plants and existing plants underwent substantial retrofits to reduce fire risk. Likewise, the meltdown at Three Mile Island Unit 2 prompted major changes in the design, maintenance, operation, and regulatory oversight of nuclear power plants. Had these accidents happened in Region B, the remedial efforts might have been more modest.

Nuclear Plant Growing Pains

Generic communications issued by the NRC demonstrate that nuclear power plants have had their fair share of problems. Table 1 (p.7) shows the number of generic communications issued annually by the NRC between 1971 and 2002. While some of these 2,500-plus issuances addressed non-power reactor problems, the majority addressed nuclear plant safety problems caused by bad design, defective manufacturing, faulty installation, unanticipated interactions, imperfect maintenance, and ineffective operation. (See the Appendix for representative examples of these communications.) The shape of the bathtub curve in Region A reflects that unanticipated problems either get flushed out and fixed or result in the permanent shutdown of the flawed reactor.

Price-Anderson: A Disincentive for Safety

The Price-Anderson Act was enacted in 1957 as a supplemental "insurance policy" for nuclear power plants. Private industry could not afford to develop commercial nuclear power plants due to the unprecedented high liability from a catastrophic

Table 1 **NRC Generic Communications, 1971–2002**

Year	Circulars	Generic Letters	Bulletins	Information Notices	Regulatory Issue Summaries	Total
1971	0	0	3	0	0	3
1972	0	0	3	0	0	3
1973	0	0	6	0	0	6
1974	0	0	16	0	0	16
1975	0	0	8	0	0	8
1976	7	0	8	0	0	15
1977	16	8	8	0	0	32
1978	19	42	14	0	0	75
1979	25	70	28	37	0	160
1980	25	113	25	45	0	208
1981	15	40	3	39	0	97
1982	0	31	4	56	0	91
1983	0	43	8	84	0	135
1984	0	24	3	94	0	121
1985	0	21	3	101	0	125
1986	0	17	4	110	0	131
1987	0	16	2	67	0	85
1988	0	20	11	64	0	95
1989	0	23	3	90	0	116
1990	0	7	2	82	0	91
1991	0	19	1	87	0	107
1992	0	9	3	86	0	98
1993	0	8	2	100	0	110
1994	0	4	2	90	0	96
1995	0	10	4	58	0	72
1996	0	7	2	72	0	81
1997	0	6	0	91	0	97
1998	0	5	0	45	0	50
1999	0	2	0	34	6	42
2000	0	0	0	22	25	47
2001	0	0	1	19	25	45
2002	0	0	2	36	23	61
Totals	**107**	**545**	**179**	**1,609**	**79**	**2,519**

accident. *The Wall Street Journal* reported that the cost of the 1986 Chernobyl accident significantly exceeded the collective economic benefits accrued from the dozens of Soviet nuclear power reactors operated between 1954 and 1986 (Hudson, 1990).

No nuclear plant owner wants to see a multi-billion-dollar investment go up in smoke, but Price-Anderson may prevent safety upgrades from being incorporated into new reactor designs. Without Price-Anderson, the added cost of developing and incorporating safety features is offset by reduced annual insurance premiums. With Price-Anderson providing equal liability protection regardless of risk, the cost of additional safety features becomes a financial impediment. The federal government must not encourage new nuclear reactors while discouraging important safety enhancements.

Build Now, Pay Later?

Some new reactor designs represent the next evolutionary step for nuclear power, incorporating features intended to make the plants safer and more economical. These features, however, are largely untested in the field or have very limited operating experience. Other new reactor designs have operated only in cyberspace and have never experienced the trials and tribulations of real-world operation. The gremlins hiding in their designs have not yet been exposed, let alone exorcised.

In order to avoid unnecessary risks, any new reactor design must first undergo a multiyear testing period. The need for and objectives of this testing was explained by a senior executive of the Japanese nuclear industry:

> *Most machinery requires a period of "breaking in," during which the interactions of components are smoothed*

and they become well fitted. . . . This start-up period, the period to the achievement of stable normal operations, is important because it is largely responsible for the physical "constitution" and "strength" of the plant thereafter. Thus, as with a new automobile, it is best not to impose excessive demands on the plant and to continue rated operation carefully during this period, which, depending on the plant, can range from a few to several years. We refer to this as the "fostering" stage of the plant.

Through periodic inspection carried out during the fostering stage, it is necessary to identify the weaknesses of the plant as well as its strengths. At the same time, any peculiarities of the plant should be understood and reflected in operating methods and maintenance, by which a strong plant constitution can be developed. (Takuma, 2002)

While the experiment with the prototype is under way, no commercial reactors of that type should be under construction. Instead, results found during the fostering stage should be obtained, analyzed, and factored into design and regulatory improvements. Only then should any new nuclear reactors be licensed and built.

Public Participation in the Licensing Process

Public input on nuclear power plant issues has long played an important role in the NRC's licensing process. The NRC itself has found that public participation greatly enhances safety levels:

Public participation in licensing proceedings not only can provide valuable assistance to the adjudicatory process, but on frequent occasions demonstrably has done so. It does no disservice to the diligence of either applicants generally or the regulatory staff to note that many of the substantial safety and environmental issues which have received the scrutiny of licensing boards and appeal boards were raised in the first instance by an intervenor. (AEC, 1974)

The NRC also enumerated the following benefits:

(1) Staff and applicant reports subject to public examination are performed with greater care; (2) preparation for public examination of issues frequently creates a new perspective and causes the parties to reexamine or rethink some or all of the questions presented; (3) the quality of staff judgments is improved by a hearing process which requires experts to state their views in writing and then permits oral examination in detail . . . and (4) Staff work benefits from two decades of hearings and Board decisions on the almost limitless number of technical judgments that must be made in any given licensing application. (Cotter, 1981)

The NRC's Atomic Safety and Licensing Board has documented many examples of reactor safety improvements resulting from public participation (ASLB, 1984), including:

1. Design and training improvements at the St. Lucie nuclear plant in Florida for coping with offsite power grid instabilities.

2. Upgraded requirements for turbine blade inspections and overspeed detection at the North Anna nuclear plant in Virginia.

3. Improvement and conformation of the plume exposure pathway Emergency Planning Zone at the San Onofre nuclear plant in California.

4. Upgraded effluent-treatment systems at the Palisades nuclear plant in Michigan and the Dresden nuclear plant in Illinois.

5. Control room design improvements at the Kewaunee nuclear plant in Wisconsin.

6. Upgraded requirements for steam generator tube leak plugging at the Beaver Valley nuclear plant in Pennsylvania.

Unfortunately, the NRC, bowing to industry pressure, recently revised its licensing process to virtually eliminate public participation, except in the role of casual observer (NRC, 2004). The lack of public input could drastically curtail discovery of important areas of safety improvement similar to those listed here.

Recommendations

The nuclear power plants operating in the United States today have long since exited Region A. The federal government advocates the construction of new nuclear power reactors to help meet future electricity needs, but any new reactor would have to navigate the same risky part of the bathtub curve that yielded meltdowns or explosions at Fermi, St. Laurent, Three Mile Island, SL-1, and Chernobyl. At best, new reactors might be able to incorporate the lessons learned from these nuclear disasters to lower the left edge of the bathtub curve. At worst, they will add their names to the list of infamous reactors populating Region A.

There are issues specific to new reactors that must be addressed to ensure they are managed and operated in the safest way possible. UCS recommends the following risk management policies:

1. New nuclear reactors must be excluded from liability protection under the Price-Anderson Act.
Promoters of new nuclear reactors contend that they are so safe that traditional measures employed to protect the public, such as warning sirens and emergency preparedness plans for nearby residents, are not needed. They also contend that the 10-mile emergency-planning zone can be reduced to a mere 400 meters. If these new reactors are truly so safe that the public need not be protected from technological disaster, then they are also so safe that their owners need not be protected from financial disaster.

2. New nuclear reactors must not go directly from blueprints to backyards.
The United States experienced the pain of building production reactors before learning lessons from prototype reactors as described by Daniel Ford, executive director of UCS in the 1970s:

> *A carefully managed development effort would also have required the building of prototypes for the large plants, just as Rickover did with his submarine reactor, which was thoroughly tested in a full-scale experimental facility at the A.E.C.'s remote testing station in Idaho. The A.E.C. did not impose such controls on the nuclear industry, which, as officials later acknowledged, rushed "from Kittyhawk to the Boeing 747" in less than two decades. The "experiment" of operating large reactors, whose advanced designs relied on complex, untried technology, was performed not in a faraway desert but at sites chosen by the utilities on the perimeter of the country's major metropolitan areas.* (Ford, 1986)

The safety retrofits to some of today's operating nuclear reactors were less effective and more costly than necessary because of this rushed approach. There's no reason to replicate this imprudent mistake.

3. The NRC must conduct extensive verifications of reactor design and construction to find and correct as many safety problems as possible before startup.
The nuclear power industry's chronic quality control problems during design and construction are legendary, as is the NRC's consistent inability to do anything about it. The NRC's own reports[3] on the daunting problems concluded:

> *The principal conclusion of this study is that nuclear construction projects having significant quality-related problems in their design or construction were characterized by the inability or failure of utility management to effectively implement a management system that ensured adequate control over all aspects of the project. . . . The major quality problems that have arisen in design were related to shortcomings in management oversight of the design process, including failure to implement quality assurance controls over the design process that were adequate to prevent or detect mistakes in an environment of many design changes. . . . The NRC made a tacit but incorrect assumption that there was a uniform level of industry and licensee competence. . . . Limited NRC inspection resources were so prioritized to address operations first, construction second, and design last, that inadequate inspection of the design process resulted.* (NRC, 1984)

Poor quality stopped the Marble Hill, Midland, and Zimmer nuclear power reactors from starting up despite nearly being completed. Similar woes didn't stop the South Texas Project, Grand Gulf, Diablo Canyon, and Palo Verde nuclear plants, but they added vast and totally unnecessary sums to the price tags. And design problems contributed to the severity of the SL-1, Fermi Unit 1, Browns Ferry Unit 1, and Three Mile Island Unit 2 accidents. The safety and financial implications of shoddy construction are still evident today. It must not be repeated.

4. The licensing process for new nuclear reactors must permit meaningful public participation.
Public participation in the NRC's licensing process will help to ensure that new reactors are operating as safely as possible. The NRC should allow public meetings for residents in and around towns where new reactors are slated for construction, allow public input on new or revised regulations pertaining to local plants, and provide opportunities for public comment on revised regulations that affect nuclear plants nationwide.

3 For examples, see U.S. House, 1984; U.S. House, 1982; and U.S. House, 1981.

CHAPTER 3

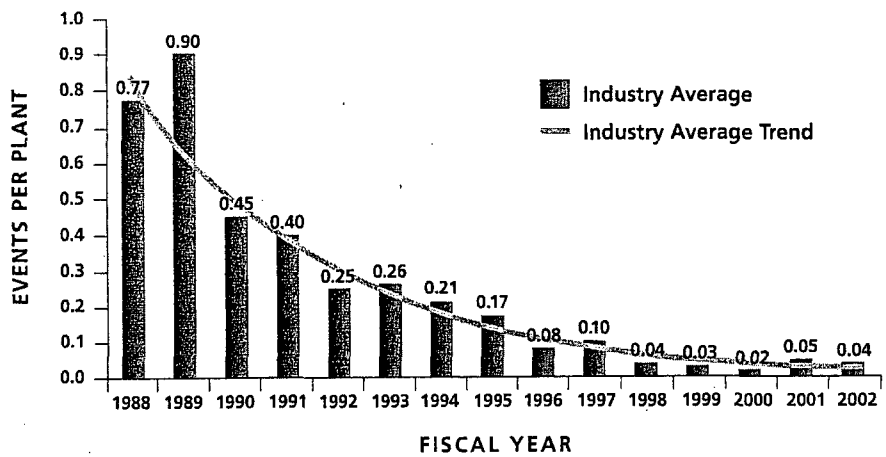
Nuclear Plant Safety in Region B

The NRC monitors trends in several areas of nuclear plant operation, including safety system failures, unplanned reactor shutdowns, emergency system starts, and significant events such as degraded fuel integrity and unplanned releases of radioactivity (Collins, 2003). The decreased occurrence of significant events over the past 15 years or so reflects the normal and expected transition of nuclear power plants from Region A to Region B (Figure 3).

Risk in Region B is lower than in Regions A or C, but it is not zero and it can increase if safety measures are not followed properly. For comparison purposes, middle-aged drivers are involved in fewer fatal motor vehicle accidents than younger and older drivers (Figure 4). But a 45-year-old who drinks and drives a car with bad brakes is probably a greater risk than a sober 16-year-old behind the wheel of a well-maintained car.

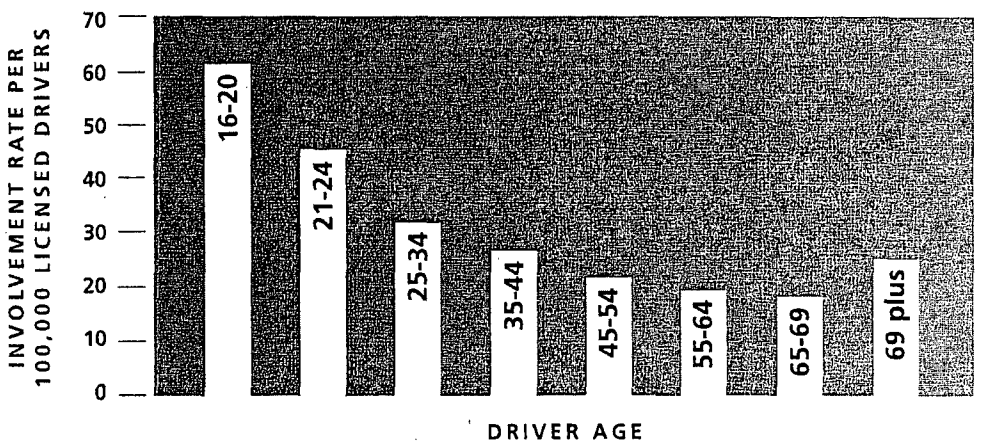
Some steps taken by the NRC over the years probably prevented plants from lingering too long in Region A. For example, in the late 1980s, the NRC determined that safety equipment was being called upon too often because of poor maintenance on equipment used to make electricity at the plant ("balance-of-plant" equipment). The NRC's regulations at that time required safety equipment to be highly reliable, but the regulations did not govern how often plant owners could put themselves in need of that safety equipment. Concerned that even highly reliable equipment will fail if called upon too often, the NRC issued its Maintenance

Figure 3 **Significant Events at Nuclear Plants, 1988-2002**



Source: Dyer, 2004.

Figure 4 **Driver Involvement Rate in Fatal Crashes by Age, 2001**



Source: NHTSA, 2002.

Rule in July 1991. This rule requires plant owners to perform better maintenance on equipment whose failure challenges safety equipment (Callan, 1997).

Problem Identification and Resolution Programs

"Problem identification and resolution" is how plant owners find and fix safety problems. As shown by Table 2 (p. 13), 27 nuclear power reactors have been shut down since 1984 for more than a year for extensive repairs to safety equipment. The year-plus durations of these shutdowns are *prima facie* evidence that problem identification and resolution programs at these facilities were seriously flawed if not totally dysfunctional. Years of overlooking problems and applying "band-aid" fixes at these plants resulted in a backlog of safety problems that took a long time to resolve. Effective problem identification and resolution programs could save plant operators time and money in the long term.

Risk Assessment Studies: Ineffective and Inconsistent

Probabilistic risk analyses (PRAs) attempt to calculate the odds of specific events occurring (such as the breaking of a pipe that carries cooling water to the reactor) and the odds of a plant's numerous safety systems being unable to prevent damage to the reactor core. All plant owners have conducted risk assessment studies for their facilities. But as reported by the NRC's Inspector General:

> *Senior NRC officials confirmed that the agency is highly reliant on information from licensee risk assessments. Agency officials also noted that there are no PRA standards, no requirements for licensee's PRAs to be updated or accurate, and that the quality of the assessments varies considerably among licensees.* (NRC, 2002)

The Davis-Besse reactor in Ohio is the most recent example of the consequences of deficient risk studies (see box, p. 15). UCS documented many instances in which the lack of PRA standards

Table 2 **Reactors Shut Down for Year-Plus Safety Repairs**

Reactor	Location	Shut Down	Restarted
Browns Ferry Unit 2	Alabama	September 1984	May 1991
Davis-Besse	Ohio	June 1985	December 1986
Sequoyah Unit 1	Tennessee	August 1985	May 1988
Sequoyah Unit 2	Tennessee	August 1985	November 1988
Pilgrim	Massachusetts	April 1986	January 1989
Peach Bottom Unit 2	Pennsylvania	March 1987	April 1989
Peach Bottom Unit 3	Pennsylvania	March 1987	November 1989
Nine Mile Point Unit 1	New York	December 1987	July 1990
Surry Unit 2	Virginia	September 1988	September 1989
Calvert Cliffs Unit 2	Maryland	March 1989	May 1991
Palo Verde Unit 1	Arizona	March 1989	June 1990
Calvert Cliffs Unit 1	Maryland	May 1989	April 1990
FitzPatrick	New York	November 1991	January 1993
Indian Point Unit 3	New York	March 1992	June 1995
South Texas Project Unit 1	Texas	February 1993	February 1994
South Texas Project Unit 2	Texas	February 1993	May 1994
Salem Unit 1	New Jersey	May 1995	April 1998
Salem Unit 2	New Jersey	June 1995	July 1997
Millstone Unit 2	Connecticut	February 1996	May 1999
Millstone Unit 3	Connecticut	March 1996	June 1998
Crystal River	Florida	September 1996	January 1998
LaSalle Unit 1	Illinois	September 1996	August 1998
LaSalle Unit 2	Illinois	September 1996	April 1999
Clinton	Illinois	September 1996	May 1999
DC Cook Unit 1	Michigan	September 1997	December 2000
DC Cook Unit 2	Michigan	September 1997	June 2000
Davis-Besse	Ohio	February 2002	March 2004

Source: Adapted from Lochbaum, 1999.

resulted in safety problems and allowed widely disparate results for virtually identical reactors (Lochbaum, 2000). Of particular concern is the NRC's treatment of generic safety issues. While plant-specific issues are routinely noted and resolved as one would expect them to be, generic safety issues affecting a large number of plants are assumed *not* to exist *until* they are resolved. Incredible as it may seem, the risk assessment studies assume there is zero chance that the generic safety issue will disable safety systems until the issue is resolved, at which time the studies continue to assume zero chance because the problem has been fixed.

The problems with risk assessment studies are well known, yet the NRC still makes regulatory decisions based in large part on their suspect results. And in the case of generic safety issues, the findings are clear, yet the NRC is sweeping them under the rug. It's "garbage in, garbage out," with millions of American lives in the balance.

Technical Specifications: Important, but Often Ignored

Technical Specifications, or Tech Specs in industry parlance, are part of the operating license issued by the NRC to the owner of each power reactor. Among other things, the Tech Specs define the minimum complement of safety equipment needed for safe reactor operation and how long the reactor can continue running when one or more pieces of the minimum complement are unavailable.

In the case of Davis-Besse, the NRC lacked absolute proof that Tech Specs were violated and allowed the reactor to continue operating despite overwhelming circumstantial evidence that cooling water was leaking from the reactor vessel, warranting a shutdown within six hours. Yet when the NRC has absolute proof that Tech Specs are violated, they rely on circumstantial evidence to allow reactors to continue operating. The following are just a few of many recent examples:

- In March 2003, the DC Cook Unit 2 reactor in Michigan was operating at full power when workers determined that the motor-driven auxiliary feedwater pump would be out of service to repair a broken motor longer than the 72 hours permitted by Tech Specs. The plant's owner requested permission for the reactor to remain at full power for an additional 36 hours while the broken safety pump was repaired. The NRC authorized this request based in large part on circumstantial evidence that the risk associated with extended plant operation was "less than the risk associated with performing a plant shutdown" (Grant, 2003).

- In August 2002, the Diablo Canyon Unit 2 reactor in California was operating at full power when workers determined that a faulty power cable had disabled one of the component cooling water pumps. The Tech Specs only allowed the reactor to continue operating for 72 hours with this pump broken. The NRC permitted the reactor to continue operating for an additional 72 hours while the power cable was replaced. The NRC determined that the additional operating time "will not involve a net increase in radiological risk" (Merschoff, 2002). It was later discovered that an isolation valve between the two redundant component cooling water headers had been damaged years ago and would have leaked excessively if closed following the rupture of one header (Becker, 2003).

- In April 2001, workers testing an emergency diesel generator at Prairie Island Unit 2 in Minnesota discovered a damaged engine cylinder. The Tech Specs permitted the reactor to operate for up to seven days with one broken emergency diesel generator. The NRC granted three more days for the reactor to operate without its full complement of emergency diesel generators. The NRC's decision was based on the plant owner's risk calculation reporting a "low likelihood" of an accident coinciding with an independent failure of the other emergency diesel generator (Grant, 2001a). After the broken emergency diesel generator was fixed and returned to service, the plant's owner discovered the engine cylinder damage had been caused by an incompatibility between its fuel oil and lubricating oil. The Calvert Cliffs nuclear plant in Maryland previously experienced this incompatibility problem in 1996 and the NRC warned all other plant owners about it. But Prairie Island's owner had not taken steps to avoid this known problem and as a result, *both* emergency diesel generators were damaged.

Table 3 **Generic Communications on PWR Containment**

Date Issued	Information Notice/ Bulletin Number	Title
5/88	IN 88-28	Potential for Loss of Post-LOCA Recirculation Capability Due to Insulation Debris Blockage
11/89	IN 89-77	Debris in Containment Emergency Sumps and Incorrect Screen Configurations
1/90	IN 90-07	New Information Regarding Insulation Materials Performance and Debris Blockage of PWR Containment Sumps
9/92	IN 92-71	Partial Plugging of Suppression Pool Strainers at a Foreign BWR
4/93	IN 93-34	Potential for Loss of Emergency Cooling Function Due to a Combination of Operational and Post-LOCA Debris in Containment
5/93	IEB 93-02	Debris Plugging of Emergency Core Cooling Suction Strainers
10/95	IEB 95-02	Unexpected Clogging of a RHR Pump Strainer While Operating in Suppression Pool Cooling Mode
10/95	IN 95-47	Unexpected Opening of a Safety/Relief Valve and Complications Involving Suppression Pool Cooling Strainer Blockage
5/96	IEB 96-03	Potential Plugging of Emergency Core Cooling Suction Strainers by Debris in Boiling-Water Reactors
10/96	IN 96-059	Potential Degradation of Post Loss-of-Coolant Recirculation Capability as a Result of Debris
5/97	IN 97-027	Effect of Incorrect Strainer Pressure Drop on Available Net Positive Suction Head

Source: Adapted from NRC, 2003.

"We can argue this, but this agency does not take precipitous action to shut down a nuclear plant because we have a suspicion of something without enough evidence to warrant it," said Brian Sheron, who, as an associate director in the NRC's office of nuclear reactor regulation, helped lead the staff evaluation of Davis-Besse. "If we were in the same situation again, we'd probably make the same decision" to allow them to operate until Feb. 16. (Mangels and Funk, 2002)

Davis-Besse reminded nearly everyone that the risk of nuclear plant operation in Region B is real. Davis-Besse also demonstrated that the risk will increase when a poor problem identification and resolution program along with misleading results from risk assessment studies permit Tech Specs to be tossed aside.

Consequently, Unit 2 was shut down that day for repairs (Grant, 2001b).

- In January 2001, workers testing the Division II emergency diesel generator at the Clinton nuclear plant in Illinois discovered damaged engine bearings. The Tech Specs permitted the reactor to operate for up to three days with one broken emergency diesel generator. The NRC granted 11 more days for the reactor to operate without its full complement of emergency diesel generators because the plant's owner promised not to test the Division I emergency diesel generator (and thus determine whether it also had the engine bearing problem) until after the known problem was fixed. (Bajwa, 2001). Clinton is a boiling-water reactor model 5 (BWR/5). According to the NRC, 90 percent of the overall threat for reactor core damage at BWR/5 plants is station blackout, which occurs when the plant is disconnected from its electrical grid and both the Division I and Division II emergency diesel generators are unavailable (NRC, 1996).

- In November 2000, one of three component cooling water pumps at the Fort Calhoun nuclear plant in Nebraska failed when its aged motor broke down. The Tech Specs permitted the reactor to operate for up to seven days with one component cooling water pump unavailable. The NRC granted 14 additional days to procure and install a replacement pump motor after determining that the extended outage time for the cooling water pump resulted in "minimal increase in core damage frequency" (Merschoff, 2000). Fort Calhoun is a combustion engineering PWR. According to the NRC, support systems such as the component cooling water system play an extremely important safety role because their failure "can compromise front-line system redundancy, leaving few options for successful plant shutdown" (NRC, 1996).

Recommendations

U.S. nuclear power plants are now operating in Region B of the bathtub curve. Just as the NRC's actions probably influenced how quickly nuclear plants traveled from Region A to Region B, the agency's actions—and inactions—can affect how quickly nuclear plants travel from Region B to Region C. Risk in Region B is not zero, but given that risk increases in Region C, the NRC must work to keep plants operating in Region B as long as possible, and properly manage them to keep risks at a minimum. To best manage the risk while in Region B:

1. The NRC must overhaul how it assesses problem identification and resolution programs.

A problem identification and resolution program is the most important measure of safety performance at a nuclear power plant, and should find problems before they become self-revealing and properly fix them the first time. Inadequate problem identification and resolution programs were a common cause for the 27 year-plus plant shutdowns listed in Table 2 (p.13). The NRC downplays evidence that these programs are inadequate unless they involve equipment that nearly caused a meltdown. There should be no exceptions. The NRC must do a better job of judging the health of these vital programs and force them to be fixed and properly used at all times.

2. The NRC must stop making risk-informed decisions using flawed risk assessment studies. Sound, risk-informed decisions about the nation's nuclear power plants must be made based on consistent, accurate risk assessment studies, especially with regard to generic safety issues. But this will not happen with the NRC's current risk assessment system. The NRC must adopt a system of standards for all power plants and enforce the system across the board—for all plants and for all types of safety issues—to ensure known risks are properly managed and resolved.

3. The NRC must back up its talk about a "double-edged sword" in risk-informed regulation. The NRC often states that risk insights cut both ways—they can trim regulations having little or no safety merit and they can also impose requirements in previously undervalued areas.[4] But in practice, the NRC's risk-informed sword is razor-sharp on the side that slashes regulations and dull on the side that enforces regulations.

The examples given earlier, and dozens like them, show that the NRC abides by or abandons its absolute proof standard as necessary to allow nuclear plants to continue operating. The NRC must immediately stop admitting or rejecting circumstantial evidence based on the answer it is seeking. The data must determine the outcome, not vice versa.

4 For examples, see King, 1999; NRC, 1999; and McGaffigan, 2001.

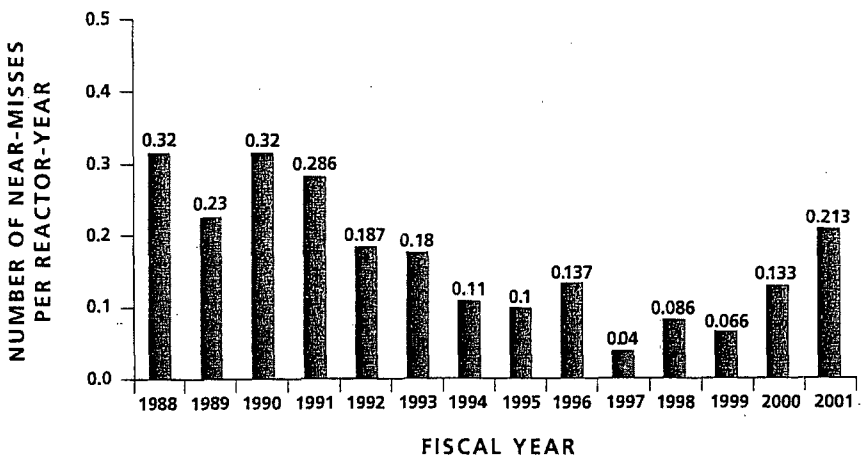
CHAPTER 4

Nuclear Plant Safety in Region C

In some respects, nuclear power plants are like cars. A car that is routinely maintained, washed and waxed regularly, and kept out of the elements will stay rust-free and reliable for years. But even with the best care, a car that is driven every day will eventually develop engine problems. Likewise, a properly maintained nuclear plant takes longer to enter Region C than a poorly maintained nuclear plant. But even the best-maintained nuclear plant enters Region C if operated long enough.

What is known with absolute certainty is that every nuclear plant operating in the United States today is moving toward Region C (if not already in it). While the number of significant events has decreased in recent years, the rate of "near-misses" (elevated risks of reactor meltdown) appears to have increased in recent years (Figure 5). In other words, while the number of events is decreasing, their severity is increasing, with the near-misses getting nearer and nearer to disaster. This upward trend may simply reflect normal statistical fluctuations or increasing risk in Region B from the NRC's flawed risk-informed decisions. More likely, the data suggest that some nuclear plants have entered Region C and are experiencing higher failure rates as expected.

Figure 5 **Significant Near-Misses at Nuclear Power Plants, 1988-2001**



Source: Collins, 2003.

Inadequate Aging Management Programs

As reactors approach or enter Region C and become more vulnerable to failure, aging management programs monitor the condition of equipment and structures so as to effect repairs or replacements before minimum safety margins are compromised. Unfortunately, age-related degradation is being found too often by failures than by condition-monitoring activities.

In recent years, there have been ample reports of age-related failures. Here are some examples:

- On February 18, 2001, workers at Oconee Unit 3 in South Carolina noticed boric acid on the exterior surface of the reactor vessel head around two CRDM nozzles. Further investigation found through-wall circumferential cracks in the nozzles above the j-groove weld areas where the nozzles were attached to the reactor vessel head. These weld areas, and not the nozzles, were routinely inspected on the premise that cracks, if they were going to occur, would occur there first (NRC, 2001).

- On January 9, 2002, operators shut down Quad Cities Unit 1 in Illinois following indication that one of the jet pumps inside the reactor vessel had failed. Subsequent investigation determined that the hold-down beam for jet pump #20 had cracked apart and pieces had damaged the impeller of the recirculation pump, causing it to shut off. The jet pump hold-down beam was routinely inspected for cracks, but only at its two ends. The hold-down beam for jet pump #20 cracked in the middle. Workers also discovered two other hold-down beams with cracks in their middle regions (Grobe, 2002).

- On October 7, 2000, workers at the Summer nuclear plant in South Carolina found boric acid on the containment floor. This led to the discovery of a through-wall crack where a major pipe was welded to the reactor vessel nozzle. This location was specifically examined during the 10-year in-service inspection in 1993, but the crack, which was present at the time, was missed because an air gap between the pipe weld area and the inspection detector, a sonar-like device, created "noisy" output. This noise masked the indications of a crack and prevented workers from noticing the problem (Casto, 2001).

- On February 15, 2000, a steam generator tube broke at Indian Point Unit 2 in New York and caused the uncontrolled release of radioactivity into the atmosphere. Under its revamped oversight process, the NRC issued its first red finding—a failing grade—to Indian Point for this event because the near-miss was avoidable. The NRC cited the plant's owner for having detected signs of degradation exceeding federal regulations during the steam generator tube inspections in 1997 but failing to do anything about it (Miller, 2000).

These examples illustrate two fundamental flaws in current aging management programs: (1) looking in the wrong spots with the right inspection techniques (as happened with the Oconee and Quad Cities plants), and (2) looking in the right spots with the wrong inspection techniques (as happened with the Summer and Indian Point plants). Aging management programs should find these problems before they become self-revealing, but they are not. As problems in Region C have the potential to be much more severe than problems in Region B, strong aging management programs must be in place to help prevent these failures from occurring.

Reactor License Renewal: Ignoring the Generation Gap

Nuclear plants were originally licensed for 40-year operating lifetimes. Several plant owners have already sought and obtained 20-year license extensions from the NRC, and many more owners are queuing up to do so. The NRC's license renewal process is based on an assumption that all U.S. nuclear plants conform to their current licensing basis, the industry term for the set of federal safety regulations that apply to a specific nuclear power plant,[5] and a determination that plant owners have effective aging management programs for all equipment and structures with an important safety function. However, this assumption and determination, even if valid, may not be enough to adequately ensure that nuclear reactors can operate safely in Region C.

The current licensing basis varies from plant to plant. Nuclear plants licensed in the same year have different current licensing bases due to varying exemptions and license conditions. New regulations are constantly being generated and existing regulations revised so that, for example, the applicable regulations in 1985 differ significantly from the applicable regulations in 1975. The NRC cannot issue or revise its regulations unless it determines the regulatory changes either maintain or increase safety levels. Therefore, today's regulations are as good as, or better than, the 1975 or 1985 regulations from a safety perspective.

If a new nuclear power plant were to be built and operated today, it would have to meet the federal safety regulations in effect today. But the NRC's license renewal process fails to define the generation gap between today's safety requirements and the current licensing basis for an existing nuclear power plant, making it difficult—if not impossible—to determine whether an aging plant will operate safely for 20 more years. A prudent regulator would want to know just how far away from today's safety standards an aging nuclear plant seeking license renewal is and why it is acceptable for that plant *not* to meet today's safety standards for two more decades. The NRC's license renewal process fails to ask and answer that crucial question. This shortfall must be fixed if aging reactors are to operate for 20 more years.

Recommendations

The NRC's license renewal process questions whether plant owners have effective aging management programs, and the answer has always been "yes" despite considerable evidence to the contrary. It is well known that "two wrongs don't make a right," but it takes two rights to make a right in aging management—looking in the right spots with the right techniques. If today's existing nuclear reactors are to be in service for another 20 years, there needs to be strong aging management programs at all reactors to ensure failures are found before it is too late. UCS recommends the following reforms:

1. The NRC must overhaul how it assesses problem identification and resolution programs.
Diverse inspection methods lessen the chances of overlooking problems when looking in the right spots.

2. The NRC must require periodic inspections of areas considered less vulnerable to degradation and deemed outside the inspection scope.
Out-of-scope inspections increase the chances of

5 Code of Federal Regulations. "Definitions." Title 10, §54.3.

finding problems that would have otherwise been overlooked.

3. The NRC must formally review all differences between today's safety regulations and the regulations applicable to an aging reactor before granting license renewals.

It is unacceptable to grant license extensions to reactors that lag woefully behind in regulations. The NRC must confirm that adequate safety margins exist for reactors up for license renewal and require safety and regulatory upgrades as necessary to remedy any shortfalls.

Actually, the best way to prevent recurrent problems at aging nuclear plants would be for the NRC to suspend the issuance of license renewals until the nuclear industry has demonstrated that it takes plant safety seriously. Plant owners will continue to follow lax aging management programs and allow failures to reveal themselves unless the NRC imposes stronger standards. If the NRC required truly effective aging management programs as a condition for license renewal, plant owners would have no choice but to adhere to stronger safety regulations, regardless of cost. Right now, they have no incentive to do so.

CHAPTER 5

Conclusion

The risk profile for nuclear power reactors varies from cradle to rocking chair just as it does for people. Because the risk is never zero, it must be properly managed at all times to protect against undue risk. The best way to manage nuclear reactor risk is to have an aggressive regulator consistently enforcing federal safety regulations.

At least this is what UCS considers to be the best way; we've never actually observed such NRC performance. We have observed, all too often, the consequences that arise from a lack of enforcement of federal safety regulations. When this happens, safety margins drop unnecessarily low and the risk to people living near the reactors climbs unacceptably high.

The late Henry Kendall, Nobel laureate and former chairman of the UCS board of directors, once said, "You can't have one end of a ship sink." This quote is fitting for U.S. nuclear reactors, which are essentially in this very ship. A serious accident at any U.S. reactor, at any point in its lifetime, would likely dim the future for all reactors. To prevent unwarranted risk to the American public, Congress must reform the NRC into a consistently effective enforcer of federal safety regulations.

The suggested reforms outlined in this report would lay the proper foundation for the NRC to resolve long-standing safety problems at the more than 100 nuclear plants operating nationwide. Congress must sustain the NRC reform effort through completion of this entire process, to provide the American public with the protection they expect and deserve.

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APPENDIX

Selected Examples of NRC Generic Communications

Manufacturing Defects

- BL-74-06: Defective Westinghouse Type W-2 Control Switch Component. Bulletin. May 22, 1974.
- CR-80-17: Fuel Pin Damage Due to Water Jet from Baffle Plate Corner. Circular. July 23, 1980.
- IN-80-40: Excessive Nitrogen Supply Pressure Actuates Safety-Relief Valve Operation to Cause Reactor Depressurization. Information Notice. November 7, 1980.
- CR-81-01: Design Problems Involving Indicating Pushbutton Switches Manufactured by Honeywell Incorporated. Circular. January 23, 1981.
- GL81011: BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking (NUREG-0619). Generic Letter. February 28, 1981.
- IN-82-43: Deficiencies in LWR Air Filtration/Ventilation Systems. Information Notice. November 16, 1982.
- BL-86-03: Potential Failure of Multiple ECCS Pumps Due to Single Failure of Air-Operated Valve in Minimum Flow Recirculation Line. Bulletin. October 8, 1986.
- IN-88-76: Recent Discovery of a Phenomenon Not Previously Considered in the Design of Secondary Containment Pressure Control. Information Notice. September 19, 1988.
- IN-89-44: Hydrogen Storage on the Roof of the Control Room. Information Notice. April 27, 1989.

Material Imperfections

- BL-79-26: Boron Loss from BWR Control Blades. Bulletin. November 20, 1979.
- GL85022: Potential for Loss of Post-LOCA Recirculation Capability Due to Insulation Debris Blockage. Generic Letter. December 3, 1985.
- GL88005: Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants. Generic Letter. March 17, 1988.
- GL89008: Erosion/Corrosion-Induced Pipe Wall Thinning. Generic Letter. May 2, 1989.
- GL91015: Operating Experience Feedback Report, Solenoid-Operated Valve Problems at U.S. Reactors. Generic Letter. September 23, 1991.
- IN-97-84: Rupture in Extraction Steam Piping as a Result of Flow-Accelerated Corrosion. Information Notice. December 11, 1997.

Poor Workmanship

- BL-73-06: Inadvertent Criticality in a Boiling Water Reactor. Bulletin. November 27, 1973.
- BL-77-04: Calculational Error Affecting the Design Performance of a System for Controlling pH of Containment Sump Water Following a LOCA. Bulletin. November 4, 1977.
- CR-78-04: Installation Error That Could Prevent Closing of Fire Doors. Circular. May 15, 1978.
- CR-79-18: Proper Installation of Target Rock Safety-Relief Valves. Circular. September 6, 1979.
- IN-85-96: Temporary Strainers Left Installed in Pump Suction Piping. Information Notice. December 23, 1985.
- IN-90-77: Inadvertent Removal of Fuel Assemblies from the Reactor Core. Information Notice. December 12, 1990.
- IN-2001-06: Centrifugal Charging Pump Thrust Bearing Damage Not Detected Due to Inadequate Assessment of Oil Analysis Results and Selection of Pump Surveillance Points. Information Notice. May 11, 2001.

NOTE: The generic communications cited herein, and hundreds like them, are available through the NRC's Electronic Reading Room. Online at www.nrc.gov/reading-rm/doc-collections/gen-comm/.

U.S. Nuclear Plants in the 21st Century

THE RISK OF A LIFETIME

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Nuclear power in the United States has, throughout the industry's history, been less safe and more expensive than necessary because of ineffective oversight. The Nuclear Regulatory Commission's (NRC) poor regulatory performance has contributed to several major disasters and countless close calls at nuclear plants.

Nuclear plants are at highest risk for failure when they begin operation and when they approach the end of their useful life. With new reactor designs proposed for construction, and more than 100 aging U.S. nuclear plants seeking extensions to their operating licenses, the need for an effective regulator has never been greater.

In this report, the Union of Concerned Scientists describes nuclear plant risks from cradle to grave and makes recommendations on how to reform the NRC into a consistently effective enforcer of federal safety regulations. With strong regulatory standards and enforcement measures in place, the NRC can provide the American public with the protection they expect and deserve.

EXHIBIT 11

DECLARATION ALAN COX

June 5, 2007

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

Before the Atomic Safety and Licensing Board

In the Matter of	)	
	)	
Entergy Nuclear Generation Company and	)	Docket No. 50-293-LR
Entergy Nuclear Operations, Inc.	)	ASLBP No. 06-848-02-LR
	)	
(Pilgrim Nuclear Power Station)	)	

DECLARATION OF ALAN COX IN SUPPORT OF ENTERGY'S MOTION FOR SUMMARY DISPOSITION OF PILGRIM WATCH CONTENTION 1

Alan Cox states as follows under penalties of perjury:

---

[6] The inlet SSW carbon steel piping that was replaced with titanium piping in order to prevent interior corrosion was never removed from the ground so the exterior coatings and surface of the original carbon steel SSW inlet piping were not examined.

EXHIBIT 12

Union of Concerned Scientists Issue Paper
Help Wanted: Dutch Boy at Byron
October 25, 2007

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

Before The Atomic Safety And Licensing Board

In the Matter of
Entergy Corporation
Pilgrim Nuclear Power Station
License Renewal Application

Docket # 50-293-LR

January 24, 2008

DECLARATION OF DAVID LOCHBAUM

I, David Lochbaum, prepared the attached reports: "U.S. Nuclear Plants in the 21st Century: The Risk of a Lifetime," (Union Concerned Scientists, May 2004) *and* Union of Concerned Scientists Issue Brief, "Help Wanted: Dutch Boy at Byron" (Union of Concerned Scientists, October 25, 2007).

I stand by the contents of the reports today.

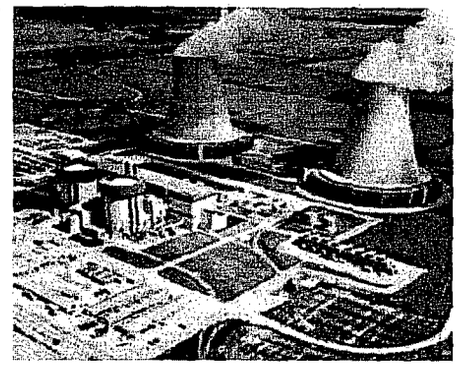
I declare that under penalty of perjury that the foregoing is true and correct.

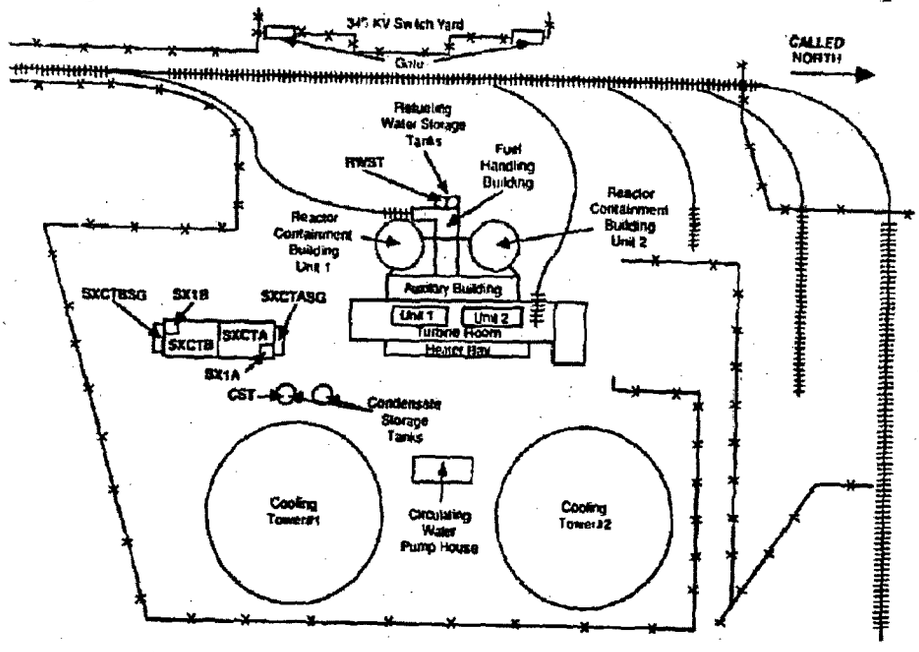
David Lochbaum

Union of Concerned Scientists
Citizens and Scientists for Environmental Solutions | issue brief

HELP WANTED: DUTCH BOY AT BYRON

On October 19, 2007, operators at the Byron nuclear plant in Illinois began shutting down both reactors after a leak was found in essential service water (ESW) system piping. In event of an accident, the ESW system supplies cooling water to emergency equipment like the emergency diesel generators, the containment fan coolers, the component cooling system heat exchangers, and the lube oil and room coolers for the auxiliary feedwater, safety injection, residual heat removal, and charging pumps. In addition, the ESW system provides a source of water for the auxiliary feedwater system pumps. The heat picked up by the ESW system water in cooling these components is dissipated to the atmosphere via cooling towers. But the cooling towers are not the tall, concrete chimneys making clouds in the aerial photograph of the Byron plant. The ESW cooling towers are the low, mechanical draft cooling towers in the foreground of the concrete cooling tower on the right. The concrete cooling towers remove the waste heat produced by the reactors in making electricity. The circulating water pumps, located in the building between the concrete cooling towers, moves water from the cooling tower basins through each unit's condenser and then through the cooling towers.



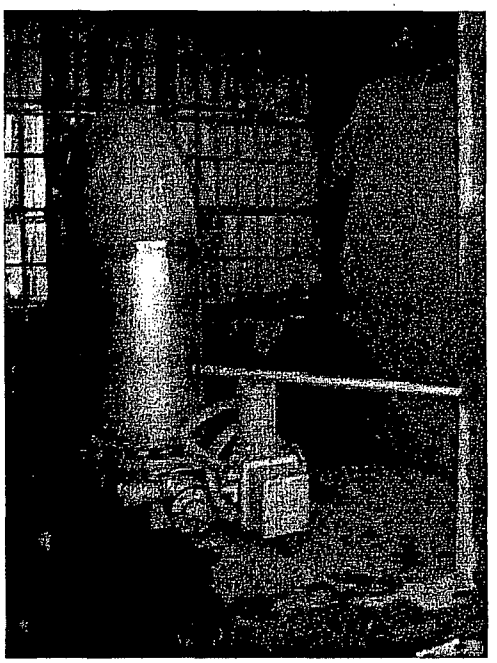


Washington Office: 1707 H Street NW Suite 600 • Washington DC 20006-3919 • 202-223-6133 • FAX: 202-223-6162
Cambridge Headquarters: Two Brattle Square • Cambridge MA 02238-9105 • 617-547-5552 • FAX: 617-864-9405
California Office: 2397 Shattuck Avenue Suite 203 • Berkeley CA 94704-1567 • 510-843-1872 • FAX: 510-843-3785

The ESW piping runs underground from the mechanical draft cooling towers to the two reactor units and back. The ESW system piping became heavily corroded. As the metal walls of the piping rusted, the water flowing through the piping eroded away some of the rust flakes. This erosion/corrosion process thinned the pipe walls below the minimum acceptable level (0.375 inches) in some places. Workers measured the thickness of some of the pipe walls using ultrasonic devices as little as 0.047 inches. As workers scraped away the rust flakes from the outside surface of the piping, a leak developed.

Because the erosion/corrosion mechanism commonly affected all of the ESW system piping and the condition of the buried portions was uncertain, Exelon conservatively assumed that piping in the ESW systems for both reactors had degraded below the condition needed for the systems to function properly in event of an accident. Consequently, they declared the ESW systems inoperable and had to shut down both reactors as a result. If the ESW system cannot function during an accident, the ability of the plant to avoid a reactor core meltdown with concurrent loss of containment is severely impaired if not entirely prevented. In other words, the accident is likely to become a catastrophe.

▲ *The leak occurred as workers scraped rust from the heavily corroded ESW pipe. The pipe, which is specified to have a minimum wall thickness of 0.375 inches, had a measured wall thickness of 0.047 inches – before rust removal took that thickness to zero.*



The ESW piping runs underground and emerges vertically to connect with the cooling tower. The leak occurred just above the concrete floor where the ESW piping emerges from an underground run. ▶

The time needed to correct the problem can not be estimated until workers examine the condition of the entire run of ESW system piping, including the underground portions. The NRC has dispatched a special inspection team to Byron to investigate what happened and why.

Prepared by: David Lochbaum
Director, Nuclear Safety Project
Union of Concerned Scientists

Additional Photographs of the Corroded ESW System Piping

PRELIMINARY NOTIFICATION- REGION III

October 23, 2007

PRELIMINARY NOTIFICATION OF EVENT OR UNUSUAL OCCURRENCE - PNO-III-07-012

This preliminary notification constitutes EARLY notice of events of POSSIBLE safety or public interest significance. The information is as initially received without verification or evaluation, and is basically all that is known by the Region III staff on this date.

Facility	**Licensee Emergency Classification**
Byron Station Unit 1 and 2	__ Notification of Unusual Event
Exelon Generation Company, LLC	__ Alert
Byron, Illinois	__ Site Area Emergency
Docket: 50-454/50-455	__ General Emergency
License: NPF-37/NPF-66	x Not Applicable

SUBJECT: BOTH UNITS AT BYRON SHUT DOWN DUE TO A LEAK IN PIPE

DESCRIPTION:

On October 19, 2007, at 7:55 PM, Exelon Nuclear Company notified the NRC that operators at the Byron Station began to shut down both reactors due to a leak in an essential service water pipe.

The discovery of the leak led to declaring the essential service water system inoperable. According to the plant's Technical Specifications, both reactors had to be shut down.

The essential service water system draws water from the river to the cooling basins. Water from the basins would be used to cool important plant safety components required to safely shut down the reactor in an emergency.

Plant systems performed their functions as designed. The plant was shut down safely and is in a stable shutdown condition. There is no threat to public health and safety.

The leak occurred while plant workers were inspecting essential service water system pipes. The inspections were performed to follow up on indications of external corrosion that had been previously identified on all eight similar essential service water pipes.

These pipes go from the basins into the ground. Rust was found on sections of piping located between the basins and the ground.

The utility is investigating the cause of the leak and evaluating what repairs need to be completed prior to restarting both units.

The NRC resident inspectors and region-based inspectors have been monitoring these issues associated with the essential service water system degradation prior to and since the shutdown.

The duration of the dual unit shutdown is expected to exceed 72 hours. There has been media coverage of the issue.

The State of Illinois has been notified.

The information in this preliminary notification is current as of 4:30 p.m. on October 22, 2007.

This information has been reviewed with plant management.

CONTACTS:

Richard Skokowski	Bruce Bartlett
630-829-9620	815-234-5451

PRELIMINARY NOTIFICATION- REGION III

October 31, 2007

PRELIMINARY NOTIFICATION OF EVENT OR UNUSUAL OCCURRENCE - PNO-III-07-012A

This preliminary notification constitutes EARLY notice of events of POSSIBLE safety or public interest significance. The information is as initially received without verification or evaluation, and is basically all that is known by the Region III staff on this date.

Facility	**Licensee Emergency Classification**
Byron Station Unit 1 and 2	___ Notification of Unusual Event
Exelon Generation Company, LLC	___ Alert
Byron, Illinois	___ Site Area Emergency
Docket: 50-454/50-455	___ General Emergency
License: NPF-37/NPF-66	x Not Applicable

SUBJECT: UPDATE TO DUAL UNIT SHUTDOWN

DESCRIPTION:

This preliminary notification supplements information in PNO-III-07-012, which documented the shutdown of the Byron Station Unit 1 and Unit 2 reactors on October 19, 2007, due to a leak in an essential service water pipe.

During the shutdown, the utility investigated the cause of the leak and made necessary repairs in the essential service water system to support start-up. Additional repairs are in progress.

Byron Unit 1 and Unit 2 restarted on October 30, 2007. Full power is expected to be achieved on or about November 2, 2007.

The NRC had dispatched a Special Inspection team to the plant to review the root causes of the problem, extent of condition, and corrective actions. The team continues the review of the issues associated with the essential service water system. Prior to the reactor restart, the team verified the adequacy of the licensee's repairs to the essential service water system that had necessitated the shutdown.

This information is current as of 7:30 a.m. on October 31, 2007.

The information in this preliminary notification has been reviewed with licensee management.

Richard Skokowski
630-829-9620

Bruce Bartlett
815-234-5451

October 11, 2007

PRELIMINARY NOTIFICATION OF EVENT OR UNUSUAL OCCURRENCE PNO-II-07-012

This preliminary notification constitutes EARLY notice of events of possible safety or public interest significance. The information is as initially received without verification or evaluation, and is basically all that is known by Region II staff (Atlanta, Georgia) on this date.

Facility	Licensee Emergency Classification
Catawba Nuclear Station	Notification of Unusual Event
Units 1 & 2	Alert
York, SC	Site Area Emergency
Dockets/License: 50-413, 50-414	General Emergency
	X Not Applicable

SUBJECT: ONSITE GROUND WATER TRITIUM CONTAMINATION

On October 8, 2007, plant staff at the Catawba Nuclear Station received sample results which indicated the presence of detectable concentrations of tritium (hydrogen-3) in liquids collected from a ground water monitoring well located within the owner controlled area (OCA). The monitoring well is located approximately one half mile inside the property boundary of the facility. The measured level of activity in the sample obtained from this monitoring well was approximately 42,000 pCi/L from a depth of 50 feet. Additional water samples collected from other monitoring well locations onsite within the OCA also had measurable concentrations of tritium with a maximum level of approximately 4,000 pCi/L. This was the initial sampling of 30 new ground water monitoring wells which were recently installed at Catawba Nuclear Station in support of the Nuclear Energy Institute (NEI) ground water initiative.

The licensee has begun implementation of an action plan to monitor and evaluate the extent and potential for movement of detectable tritium in the groundwater based on the tritium detected in the single monitoring well which produced the sample with elevated levels of tritium. This includes taking additional samples from the 35 ground water monitoring wells located within the OCA and analyzing them for tritium and other radionuclides.

Once the licensee determined that tritium levels in excess of the NEI voluntary reporting criteria (greater than 20,000 pCi/L for onsite groundwater) were confirmed to be present in one of the ground water monitoring wells installed onsite, a 10 CFR 50.72 (EN 43703) report was submitted on October 9, 2007, at 9:41 a.m., with this information.

The South Carolina Department of Health and Environmental Control visited the Catawba Nuclear Station site on October 10, 2007, and collected water samples from the only two drinking water wells within the OCA. A split sample from each well was provided to Catawba personnel for confirmatory testing. The site does not use wells to supply potable water for employees at the facility.

Region II continues to monitor and assess the licensee's actions in response to this issue.

South Carolina Department of Health and Environmental Control (SCDHEC) intends to return to Catawba Nuclear Station on October 12, 2007, to begin sampling public and private drinking

water wells in the surrounding area. The licensee will receive split samples from any well that is sampled by SCDHEC.

The SCDHEC Division of Media Relations has issued a news release on this issue dated October 10, 2007. News coverage has been provided by both newspaper and television outlets in North Carolina and South Carolina starting on October 10, 2007.

Additional information on groundwater contamination from tritium can be found at the NRC public web site at the following address: http://www.nrc.gov/reactors/operating/ops-experience/grndwtr-contam-tritium.html

Region II received initial notification of ground water tritium contamination on October 8, 2007, when licensee management informed the Senior Resident Inspector. The information presented herein has been discussed with the licensee and the State, and is current as of 12:00 p.m., on October 11, 2007.

The state of South Carolina Department of Health and Environmental Control has been notified.

CONTACTS:	James H. Moorman (404) 562-4647	George B. Kuzo (404) 562-4658	Brian R. Bonser (404) 562-4653

EXHIBIT 13

FINAL EIS -1972

related to operation of

PILGRIM NUCLEAR POWER STAT

BOSTON EDISON COMPANY

DOCKET No. 50-293

May 1972

UNITED STATES ATOMIC ENERGY COMMISSION

DIVISION OF RADIOLOGICAL AND ENVIRONMENTAL PROTE

DISTRIBUTION OF THIS DOCUME

Station on historic landmarks.[32] The Council concluded "that the probable effect on these properties (Plymouth Rock and Forefathers Faith Monument) cannot be judged to be sufficiently adverse to warrant Council comment." A copy of this correspondence was forwarded to the Massachusetts Historical Commission. The plant stack, about 4.5 miles across Plymouth Bay from the site, can barely be seen from the Plymouth Rock memorial.

The Station buildings are on the offside of Pine Hills south of the Town of Plymouth and Plymouth Rock. There is no evidence that the site has any specific historical significance.

D. ENVIRONMENTAL FEATURES

The Station site is along the rocky western shoreline of Cape Cod Bay. The Station proper is on the Bay side of the northeast end of Pine Hills, a ridge of low hills about four miles long and tending in a north-south direction. These hills reach a maximum height of 395 feet and form the major drainage divide in the area. A portion of the site before clearance and construction is shown in Figure 2. (For comparison of the site with the Station nearly completed, see Figure 7.)

The geology of the site is recognized as primarily surficial glacial deposits.[24] The natural surface stratum in the station area consists of approximately 20 feet of silty and clayey fine sands with scattered boulders. Bedrock is about 30 to 90 feet below mean sea level. NB

Cape Cod Bay has a surface area of about 430 square nautical miles or about 365,000 acres.[7] Depths generally increase rapidly from shore and the greatest depths of about 180 feet occur at the mouth of the Bay. The volume of the Bay is about 1.6×10^{12} cubic feet. The net movement of water at the site is in a southeasterly direction and averages less than 0.1 knot over the entire depth. Currents within 1/2 mile of shore are much slower than those farther out. The counterclockwise circulation of water in the Bay is reduced by the presence of submarine ledges offshore near the plant site. Water of the Bay is exchanged by at least three processes: (1) tidal exchange, (2) the general counterclockwise circulation, and (3) wind-induced motion. The intertidal volume represents about 9% of the mean volume of the Bay. The fractional rate of renewal of the waters of the Bay per day by tidal action is about 4%; the fractional rate of renewal by inflowing currents

is about 9% per day. This action, together with wind induced flows, indicates an approximate circulation rate or renewal of at least 10% per day. This rate would provide a mean residence time for plant discharges of about 10 days. During continuous plant operation the plant's liquid effluents are expected to reach an equilibrium in the Bay. Therefore, no concentration of Station effluents is expected because they will be continually flushed out of the Bay.

Seasonal temperature fluctuations of the water in the vicinity of the Station (as measured at Cape Cod Canal, about 10-miles downcoast from the site) exhibit typical annual cycles. In August, the month of peak water temperatures, the surface water temperatures of record (1955-1962) range from 42°F to 73°F with an average of about 65°F.[33] Low surface water temperatures occur between December and April and range between 30° and 40°F. Daily variations of 7-9°F have been observed and a differential of up to 10°F commonly exists between surface and bottom temperatures during the months of June through October. During this period, a weak thermocline is often present. Temperatures ranges and means as measured from 1955 to 1962 at Cape Cod Canal are shown in Figure 3.

Weekly temperature ranges taken from thermograph records at 2 feet, 10 feet and on the bottom of the Bay off Rocky Point (located about 500 yards NNW of the mouth of the discharge canal) from June 1970 to December 1970 are shown in Figure 4.

Surface topography is such that surface drainage from the Station is seaward and surface water will not leave the Station property otherwise.[7] Subsurface water follows the surface topography, resulting in overall movement of water toward the Bay. NB

The main features of the weather of eastern Massachusetts are variety and changeability since it lies in a transition zone of westerly air currents which encompass the southward movement of polar air masses and northward movement of tropical air masses. The area is frequently situated in or near the tracks of low pressure systems during the fall, winter and spring seasons. As a result, the region has no dry season, with summer precipitation coming in the form of showers or thunderstorms. The coastline location of the site results in seasonal temperatures which are less extreme than inland locations due to onshore winds in the summer (seabreeze) and the presence of relatively warm water in

EXHIBIT 14

Entergy's BPTIMP

Procedure Contains NMM REFLIB Forms: YES ☒ NO ☐

Effective Date	Procedure Owner: Title: Site:	Oscar Limpias VP Engineering HQN	Governance Owner: Title: Site:	Oscar Limpias VP Engineering HQN
11/19/07				

Exception Date*	Site	Site Procedure Champion	Title
	ANO	Jamie McCoy	Mgr, Prog & Comp
N/A	BRP		
	GGNS	William Parman	Mgr, Prog & Comp
	IPEC	Richard Burroni	Mgr, Prog & Comp
	JAF	Joseph Pechacek	Mgr, Prog & Comp
N/A	PLP		
	PNPS	Steven Woods	Mgr, Prog & Comp
	RBS	Chris Forpahl	Mgr, Prog & Comp
	VY	George Wierzbowoski	Mgr, Prog & Comp
	W3	Rex Putnam	Mgr, Prog & Comp
N/A	NP		
	HQN	Karen Tom	Mgr, Prog & Comp

Site and NMM Procedures Canceled or Superseded By This Revision

Process Applicability Exclusion: All Sites: ☐

Specific Sites: ANO ☐ BRP ☐ GGNS ☐ IPEC ☐ JAF ☐ PLP ☐ PNPS ☐ RBS ☐ VY ☐ W3 ☐ NP ☐

Change Statement

Original Issue

*Requires justification for the exception

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1.0 PURPOSE

[1] This procedure provides the requirements, for each site to develop its own site specific Buried Piping and Tanks Inspection and Monitoring Program Section (hereafter referred to as The Program). This procedure specifies the Program content, the scope, ranking methodology, priorities and inspection frequency of the buried piping and tanks. The Program consists of inspection and monitoring of selected operational buried piping and tanks for external corrosion, including crevice, general, microbiologically influenced corrosion (MIC), and pitting corrosion.

2.0 REFERENCES

[1] NUREG-1801, "Generic Aging Lessons Learned (GALL) Report", dated July 2001

[2] NUREG-6876, "Risk-Informed Assessment of Degraded Buried Piping Systems in Nuclear Power Plants", dated June 2005

[3] 10 CFR 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants"

[4] 10 CFR 50, Appendix B "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants"

[5] ANSI N18.7-1976, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants"

[6] NUMARC 93-01 (1996), "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," April 1996

[7] NEI 95-10 (1996), "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 –The License Renewal Rule," March 1996

[8] NEI 07-07, "Industry Ground Water Protection Initiative", June 2007

[9] EPRI Report 1011829, "Condition Assessment of Large-Diameter Buried Piping, Phase 2: Vehicle Design and Construction"

[10] INPO Engineering Program Guide, "Underground Piping Reliability Management", dated June 2006

[11] INPO Operating Experience Digest OED 2007-09, "External Degradation of Buried Piping", dated April 2007

[12] ASM Handbook, Volume 13A, "Corrosion: Fundamentals, Testing and Protection, ASM International", October 2003

[13] ASM Handbook, Volume 13B, "Corrosion: Materials, ASM International", November 2005

[14] "Corrosion Resistance of Stainless Steels in Soils and in Concrete", by Pierre-Jean Cunat. Paper presented at the Plenary Days of the Committee on the Study of Pipe Corrosion and Protection, Ceocor, Biarritz, October 2001

[15] API Standard 570, "Inspection, Repair, Alteration, and Rerating of In-Service Systems Piping Systems", Second edition, Addendum 1, February 2000

3.0 DEFINITIONS

[1] Baseline Inspection – The inspection of a new or replaced component that has not previously been involved in plant operations.

[2] Buried Section – A buried portion of piping or tank in a plant system that is placed below grade either in soil or concrete, (generally categorized by P &ID) which has similar parameters; i.e. similar pressure, temperature and materials.

[3] Concrete Piping - Piping that is manufactured from concrete or cementitious material with or without metallic reinforcement. Concrete piping is generally used for large diameter lines such as the water intake piping from sources of cooling water (e.g., lakes, rivers, and reservoirs).

[4] Corrosion - The chemical or electrochemical reaction between a material, usually a metal, and its environment that produces a deterioration of the material and its properties. A common example is the oxidation of an iron-based alloy exposed to water (rusting).

[5] Crevice Corrosion - Localized corrosion that may occur in areas of stagnant solutions existing in crevices, joints, and contacts between metals or between metals and non-metals.

[6] Erosion - Deterioration of materials by the abrasive action of moving fluids or gases, usually accelerated by the presence of solid particles or gases in suspension. When corrosion occurs simultaneously, the term Erosion/Corrosion is often used.

[7] General (also called Uniform) Corrosion - This type of corrosion attacks the entire un-protected surface in a uniform manner. Of all types of corrosion, this is the least damaging and easiest to determine or quantify the corrosion rate.

[8] Holidays - also known as pinholes, voids, discontinuities.

[9] Initial Operational Inspection - The first inspection of a component that has been in-service and has not been subjected to a baseline inspection.

[10] Inspection Program – A systematic evaluation of all buried components using various techniques [e.g., ultrasonic testing (UT), radiographic testing (RT), visual testing (VT), leak testing (LT), eddy current (ET)].

[11] Licensed Material - Any material for which a permit or license is issued for purposes of monitoring inventory, effluent limits or prevention of release [e.g. State Pollution Discharge Elimination System (SPDES)].

[12] Microbiologically Influenced Corrosion (MIC) - Corrosion caused by the presence and/or activities of microorganisms in biofilms on the surface of the material. Microorganisms have been observed in a variety of environments that include seawater, natural freshwater (lakes, rivers, wells), soils, and sediment. Microbiological organisms include bacteria, fungi, and algae.

[13] Pitting - A form of localized corrosion that results in the formation of small, sharp cavities in a metal.

[14] Quality Assurance Classification – For this purpose of this procedure Safety Class or QA Category used to designate safety classification. Refer to Attachment 9.8 of EN-DC-167 for a summary of the corresponding "legacy" classifications formerly used at each plant and how they are classified as safety related, augmented and non-safety related.

[15] Redox - of or relating to oxidation-reduction.

[16] Resistivity - the longitudinal electrical resistance of a uniform rod of unit length and unit cross-sectional area. The reciprocal of conductivity.

[17] Subsequent Re-inspection – The inspection of a component that has been previously subjected to a Baseline Inspection and/or an Initial Operational Inspection.

[18] Visual Inspection – The inspection of a component accessible for direct observation by inspectors or by the use of remote visual inspection devices.

4.0 RESPONSIBILITIES

4.1 Site Engineering Director is responsible for:

[1] Sponsoring all aspects of this Program at the station.

4.2 Manager Programs & Components is responsible for:

[1] Implementing all aspects of this Program at the station.

[2] Ensuring that all activities associated with this Program are performed in a timely and cost efficient manner commensurate with the risk and safety significance of the issue.

[3] Allocating adequate resources as necessary to implement this Program.

4.3 Supervisor Programs & Components is responsible for:

[1] Assigning a Program Owner to develop, implement and maintain the site's Program in accordance with this procedure.

[2] Ensuring the timely completion of inspections.

4.4 Program Owner is responsible for:

[1] Developing, implementing and maintaining a site specific Program in accordance with the requirements of this procedure and EN-DC-174.

[2] Developing controlled Program and inspection documents.

[3] Reviewing site maintenance records for designated buried piping/tanks to determine if previous maintenance and inspections can be credited for pre-extended period of operation inspection requirements contained in Attachment 9.1, XI.M34 (4) Detection of Aging Effects.

[4] Initiating Condition Reports (CRs) for inspected conditions that fail to meet the acceptance criteria.

[5] Interfacing with other discipline Engineers as required to implement this procedure.

4.5 Site Design Engineering is responsible for:

[1] Supporting Program Owner in developing and maintaining a site specific Program in accordance with this procedure.

[2] Developing Acceptance Criteria for buried piping and tanks.

[3] Supporting the review of inspection results and evaluations.

4.6 Site System Engineering is responsible for:

[1] Ensuring that the site Cathodic Protection System is evaluated for proper operation and that routine maintenance and surveillance testing is being performed. Verifying that proper acceptance criteria have been established for evaluation of the test results. Confirming that the Cathodic Protection System is periodically evaluated by a National Association of Corrosion Engineer certified specialist as recommended by INPO.

5.0 DETAILS

5.1 PRECAUTIONS AND LIMITATIONS

[1] The risk of a failure caused by corrosion, directly or indirectly, is probably the most common hazard associated with buried piping and tanks. The corrosion risk assessment, described herein, is organized into categories reflecting four factors that impact the degree of corrosion risk due to design and environmental conditions. Table 2 contains the elements contributing to each type of environment and the suggested weighting factors.

[2] Building the risk assessment tool requires the following four steps:

(a) Sectioning: dividing a system into smaller sections. The size of each section shall reflect practical considerations of operation, maintenance, and cost of data gathering with respect to the benefit of increased accuracy.

(b) Customizing: deciding on a list of risk contributors and risk reducers and their relative importance.

(c) Data gathering: building a database by completing an evaluation for each section of the system.

(d) Maintenance: identifying when and how risk factors can change and updating these factors accordingly. (Reference 12)

[3] Each Program Owner shall evaluate the site excavating procedures/processes to take advantage of opportunistic inspections.

[4] Be aware that backfilling an excavated area could increase the corrosion susceptibility in that area of the buried piping or tank due to changing soil conditions.

[5] When the inspection of the pipe entails unearthing the pipe, caution should be used so as to not disturb the protective exterior coating or the cathodic protection system, as applicable.

[6] Piping used to convey petroleum products should be inspected by an authorized inspection agency in accordance with the provisions API 570.

[7] Work Orders involving excavation should be routed to the Program Owner.

5.2 Scope of Program

[1] The Program shall include the following piping and tanks described in [2], [3] and [4].

[2] The Program shall include all systems and that have been identified in the License Renewal Aging Management Program consistent with NUREG-1801, "Generic Aging Lessons Learned (GALL) Report" (Ref. 1), Section XI.M34, "Buried Piping and Tanks Inspection" (see Attachment 9.1).

[3] The Program shall include buried or partially buried piping and tanks that, if degraded, could provide a path for radioactive contamination of groundwater (See Reference 8).

Some examples are:

- Underground storage tanks
- Outdoor tanks such as refueling water storage tanks and condensate storage tanks
- Spent fuel pools
- Buried piping containing contaminated or potentially contaminated liquids
- Discharge canals
- Retention ponds or basins

[4] The Program shall include buried piping or tanks not included in [1] through [3] that may present a potential concern as noted in site specific or general industry Operating Experience (OE).

[5] The Program shall at least assess all other buried piping or tanks not included in steps 5.2[2]-5.2[4] for susceptibility and risk as described in this procedure.

[6] A roadmap of the major steps needed for the Program is shown in Attachment 9.2

5.3 Identification of Affected Systems

[1] The affected systems shall be identified in accordance with the requirements stated in Section 5.2. Attachment 9.3 provides a list of affected buried piping systems for those plants that have submitted a License Renewal Application (LRA). The Program shall include these systems and any additional systems as identified in accordance with Section 5.2.

5.4 Identification of Buried Piping and Tanks to be Inspected and Prioritized

[1] The Program Owner shall develop a list of all systems containing buried piping and tanks. The Program Owner shall identify those sections of the affected piping and tanks that are buried, collecting physical drawings, piping/tank installation specifications, piping design tables and other data needed to support inspection activities.

[2] The Program Owner should complete the above design information and input into Attachment 9.4 within 3 months after issuance of this procedure.

[3] The Program Owner shall perform the impact assessment for all buried piping and tanks within 6 months after issuance of this procedure using Table 1 and input into Attachment 9.4

[4] Any buried piping or tank identified by applicable OE is designated High Impact requiring prompt attention until evaluated and dispositioned otherwise.

Table 1 Impact Assessment

	High	Medium	Low
Safety (Class per EN-DC-167)	Safety Related	Augmented QP and Fire Protection	Non-Safety Related
Public Risk	Radioactive Contamination e.g. Tritium	Chemical/Oil Treated System gases	Untreated Water SW, Demin Water
Economics (Cost of buried equipment failure to plant)	>$1M or Potential Shutdown	>$100K<$1M	<$100K

Notes:

1. Any buried section with at least one High Impact rating gets an overall High Impact rating.
2. Any buried section with no High Impact Rating but at least one Medium Impact rating gets an overall Medium Impact rating.
3. Any buried section with all Low Impact ratings is to be rated as Low Impact.

5.5 Preparation of Corrosion Risk Assessment

[1] The Program Owner shall perform the corrosion risk evaluation (Tables 2 and 3) for all High Impact buried sections within 9 months of issuance of this procedure, 12 months for all Medium Impact buried sections and 18 months for all Low Impact buried sections and input the data into Attachment 9.4.

[2] The Corrosion Risk Tabulation (Table 3), must consider the following attributes contained in Table 2 using the following steps but note this is already factored into the table in Attachment 9.4:

(a) Step 1: Using Table 2, take the soil resistivity measurement results to determine the soil resistivity risk weight. This is the first weight number (1-10).

(b) Step 2: Using Table 2, determine the Drainage Risk Weight. This is the second weight number (1- 4)

(c) Step 3: Using Table 2, determine the Material Risk Weight. This is the third weight number (0.5- 2)

(d) Step 4: Using Table 2, determine the Cathodic Protection/Coating Risk Weight by considering the condition of both cathodic protection and coating. This is the fourth weight number (0.5- 2).

(e) Step 5: Next, multiply together all weights from steps 1 thru 4 to determine the final Corrosion Risk Assessment number (0.25 – 160).

[3] The data generated in sections 5.4 and 5.5 shall be input in Attachment 9.4 and included in the Program.

[4] The Program Owner shall develop a long term inspection plan and input the schedule into Attachment 9.5 after completion of the impact assessment (Table 1), corrosion risk tabulation (Table 3) and inspection interval (Table 4). The inspection plan shall include a representative sampling of each section or tank within each of the High, Medium and Low inspection priorities in Table 4.

[5] The determination of the inspection locations may also consider:

- Ease of access to inspection point, especially for buried locations,
- Ability to insert/withdraw inspection tool(s) and/or "pigs",
- Limitations of inspection tools to navigate bends and elbows in piping, and,

Ability to isolate section of piping/tank or to place piping/tank in an out-of-service condition.

[6] The determination of inspection points should consider the results of previous inspections. Prioritization of the inspections should be based on severity of the condition, risk implications, and whether an immediate repair would be required. Following any inspection, the as-found conditions shall be applied to the prioritization standards and determination made of next re-inspection requirement.

Table 2 Corrosion Risk Assessment

Soil Resistivity, Ω-cm (Note 1)	Corrosivity Rating	Soil Resistivity Risk Weight
>20,000	Essentially Non-corrosive	1
10,001-20,000	Mildly Corrosive	2
5,001-10,000	Moderately Corrosive	4
3,001-5,000	Corrosive	5
1,000-3,000	Highly Corrosive	8
<1,000	Extremely Corrosive	10
Drainage		**Drainage Risk Weight**
Poor	Continually Wet	4.0
Fair	Generally Moist	2.0
Good	Generally Dry	1.0
Material (Note 2)		**Material Risk Weight**
Carbon and Low Alloy Steel		2.0
Cast and Ductile Iron		1.5
Stainless Steel		1.5
Copper Alloys		1.0
Concrete		0.5
Cathodic Protection	**Coating**	**CP/Coating Risk Weight**
No CP	No Coating	2.0
No CP	Degraded Coating	2.0
No CP	Sound Coating	1.0
Degraded CP	No Coating	1.0
Degraded CP	Degraded Coating	1.0
Degraded CP	Sound Coating	0.5
Sound CP	No Coating	0.5
Sound CP	Degraded Coating	0.5
Sound CP	Sound Coating	0.5

Notes:

1. Soil resistivity measurements must be taken at least once per 10 years unless areas are excavated and backfilled or if soil conditions are known to have changed for any reason.

2. Attachment 9.6 gives further insight to the corrosion of materials in soils.

Table 3 Corrosion Risk Tabulation

Corrosion Condition		Risk Weight Points
Soil Conditions		
Resistivity	step 5.5 [2] (a)	1-10
Drainage	step 5.5 [2] (b)	1- 4
Materials		
Materials	step 5.5 [2] (c)	0.5 -2
Component Protection		
Cathodic Protection/Coating	step 5.5 [2] (d)	0.5 -2
Final Corrosion Risk Tabulation		
Multiply all weights together in steps 5.5 [2] (a) thru (d)		0.25 -160
High Corrosion Risk, 61-160 pts **Medium Corrosion Risk, 30-60 pts** **Low Corrosion Risk, 0-29 pts**		

Table 4 Inspection Intervals vs. Inspection Priority

Impact-Corrosion Risk	Inspection Priority	Initial Inspection (years)	Inspection Interval (years)
High-High	High	5	8
High-Medium	High	5	8
Medium-High	High	5	8
High-Low	Medium	8	10
Medium-Medium	Medium	8	10
Low-High	Medium	8	10
Medium-Low	Low	10	15
Low-Medium	Low	10	15
Low-Low	Low	10	15

Notes:

1. High priority initial inspections shall be scheduled within 5 years. Subsequent High priority inspections shall be scheduled within 8 years.
2. Medium priority initial inspections shall be scheduled within 8 years. Subsequent Medium priority inspections shall be scheduled within 10 years thereafter.
3. Low priority initial inspections shall be scheduled within 10 years. Subsequent Low priority inspections shall be scheduled for all components within 15 years thereafter.
4. Regardless of the inspection schedule in Table 4 each plant site must ensure it complies with the commitments in License Renewal Application (LRA).
5. Once initial inspections are performed and conditions become known, a re-prioritization may maintain, decrease or increase a component future inspection priority.

5.6 Parameters to be Inspected

- External coating and wrapping condition
- Pipe wall thickness degradation
- Tank plate thickness degradation
- Cathodic Protection System Performance (if applicable)

5.7 Acceptance Criteria

Acceptance criteria for any degradation of external coating, wrapping and pipe wall or tank plate thickness should be based on current plant procedures. If not covered by plant

procedures, new acceptance criteria should be developed based on applicable code and industry requirements. Acceptance criteria shall be developed prior to performing inspections.

5.8 Corrective Actions

A Condition Report (CR) shall be written if acceptance criteria are not met. The corrective actions may include engineering evaluations, scheduled inspections, and change of coating or replacement of corrosion susceptible components. Components that do not meet the acceptance criteria shall be dispositioned by engineering.

5.9 Preventive Actions

Newly installed piping and tanks should be coated as applicable during installation with a protective coating system, such as coal tar enamel with fiberglass wrap and a Kraft paper outer wrap, a polyolefin tape coating, or a fusion bonded epoxy coating to protect the piping and tanks from contacting the aggressive soil environment. As part of preventive measures, the existing Cathodic Protection system may be updated or a new Cathodic Protection system may be installed.

For plants with installed Cathodic Protection systems for buried piping and tanks, verify Preventive Maintenance tasks exist to verify proper operation of these systems at least semi-annually. Verify corrective maintenance tasks for CP system identified deficiencies are corrected on a schedule commensurate with the safety significance of the system/component being protected.

- CP System degradation affecting Safety Related SSC, recommended repair within the Work Week T process
- CP System degradation affecting Non-Safety Related SSC, recommended for repair within 6 months of identification.

5.10 Monitoring, Trending and Frequency of Inspections

The Program Owner shall prepare and implement a long-term inspection plan per Table 4 and Attachment 9.5.

5.11 Administrative Controls

[1] This procedure dictates how to develop the Program, what design information must be obtained, how to evaluate the overall scope and inspection frequency and the format for the Program.

[2] The Program Owner shall develop the Program per EN-DC-174 and the template in Attachment 9.7 of this procedure. The Program (which is actually a site engineering procedure (SEP) program section number) shall use the nomenclature of SEP-CBT-XXX where the site will assign a unique number for XXX. The Program includes all

the site specific references, commitments, scope of program and long term inspection plan with tables in Attachment 9.4 and 9.5 filled in for each buried section.

[3] The Program Owner shall document all inspection results, associated data, inspection testing and analysis results and any engineering evaluations performed, in an Engineering Report per EN-DC-147. The Program Owner shall maintain the record of all inspection results in an Engineering Report.

5.12 Inspection Methods and Technologies/Techniques

[1] Visual Inspection

Buried piping and tanks: Visually inspect the "as-found" conditions and document as necessary. Personnel performing inspections shall be qualified as applicable per ANSI/ANS 3.1-1978, "Selection and Training of Nuclear Power Plant Personnel" or equivalent. Pictures should be taken to visually compare with the previous inspections. These picture files are to be maintained for future reference in a Program notebook.

(a) Any time a buried section is opened or removed; it should be examined to quantify deposit accumulation, corrosion mode and localized wall loss and those results documented.

(b) Perform general visual inspection of exterior surface coatings for cracking, peeling, blistering, holidays (pinholes) or other coating failures. Look for signs of damaged coatings or wrapping defects such as coating perforation, holidays, or other damage that indicates possible corrosion damage to the external surface of the piping.

(c) The interior of piping may be examined using divers, remote cameras, robots or moles when appropriate.

(d) Use holiday tester to check excavated areas of piping for coating defects.

(e) If the visual inspection shows that the coatings or wrappings are intact, no further inspection is required. However, if any evidence of coating/wrapping damage is observed or if the component is uncoated, the components will be further inspected for evidence of degradation/loss of material due to corrosion (e.g., crevice, general, MIC, and pitting corrosion) and determination made as to repair.

(f) Inspect inaccessible below-grade concrete for indications of cracking, loss of material, and change in material properties (rust discoloration or white chalky deposits).

(g) A CR shall be initiated if the acceptance criteria are not met.

[2] Non-Destructive Testing (NDT)

There are several NDT methods that are applicable to buried piping inspections. These are:

(a) Ultrasonic Testing (UT) – Automatic Scanning: Automated Scanning UT measures thickness variations in the scanned area for reliable wall loss sampling.

(b) Electromagnetic (ET) – Automated Scanning: This technique provides a "map" of thickness variations in the scanned area of the piping.

(c) Radiographic Testing (RT): This involves creating an image by use of x-rays or gamma-rays. The image is recorded on film or viewed on a monitor.

(d) Torsional Guided Wave: The torsional guided wave (T-wave, G-scan) technique is a non-destructive technique performing a volumetric inspection, suitable for use on buried piping.

(e) Ultrasonic C-Scan: The UT C-scan is used to detect and locate anomalies in the external coating of a buried pipe. Anomalies as small as 1 sq. mm are detectable.

(f) Instant Off Close Interval Survey – monitors for proper operation and coverage of Cathodic Protection Systems

(g) Direct Current Voltage Gradient – indirect monitoring of pipeline for degradation to external pipe wrap/coatings similar to C-Scan.

(h) Pressure Testing – direct method of monitoring an isolable section of piping for the presence of active leakage.

(i) Leak Testing (LT) – A method for detection, locating, and measuring leakage. LT includes but is not limited to pressure testing, vacuum testing, and tracer gas detection (ASME Section V).

6.0 INTERFACES

[1] Entergy Quality Assurance Program Manual (QAPM)

[2] Engineering Standard PS-S-001 "Localized Pipe Wall Thinning and Crack-Like Flaw Evaluation"

[3] Engineering Standard ENN-CS-S-008 "Piping Wall Thinning Structural Evaluation"

[4] CEP-NDE-0112, "Certification of Visual Examination Personnel"

[5] EN-AD-103, "Document Control and Record Management Activities"

[6] EN-DC-115, "Engineering Change Development"

[7] EN-DC-141, "Design Inputs"

[8] EN-DC-147, "Engineering Reports"

[9] EN-DC-167, "Classification of Systems Structures and Components"

[10] EN-DC-174, "Engineering Program Sections"

[11] EN-TQ-104, "Engineering Support Personnel Training"

[12] EN-QV-111, "Training and Certification of Inspection/Verification and Examination Personnel"

[13] EN-NDE-2.12, "Certification of Visual Testing (VT) Personnel"

[14] EN-WM-101, "On-Line Work Management Process"

7.0 RECORDS

[1] All data generated during the course of buried piping and tanks inspections should be referenced or retained by the Program Owner in the program notebooks. Follow applicable QA retention requirements.

[2] Records and reports generated as a result of the periodic inspections shall be retained and maintained in accordance with EN-AD-103 and as directed in the site Program, as applicable.

[3] Changes to the Program based on the periodic review shall be performed in accordance with EN-DC-174, Engineering Program Sections.

8.0 OBLIGATIONS AND COMMITMENTS IMPLEMENTED BY THE PROCEDURE

8.1 OBLIGATIONS AND COMMITMENTS IMPLEMENTED OVERALL

Step	Document	Commitment Number
5.2[2]	NUREG-1801,	none
All	NUMARC 93-01	none
5.2[3]	NEI 95-10	none
5.2[3]	NEI 07-07	none

8.2 SECTION/STEP SPECIFIC OBLIGATIONS AND COMMITMENTS

Step	Document	Document Section/Step	Commitment Number
5.2[2]	NUREG-1801	XI.M34	none

8.3 SITE SPECIFIC COMMITMENTS

Step	Site	Document	Commitment Number or Reference

9.0 ATTACHMENTS

9.1 XI.M34 Buried Piping and Tanks Inspection

9.2 Roadmap for Buried Piping and Tanks Inspection and Monitoring Program

9.3 List of Affected Buried Piping Systems as per License Renewal Application

9.4 Sample Data Table

9.5 Sample Long Term Inspection Plan

9.6 Corrosion of Materials in Soils

9.7 Buried Piping and Tanks Inspection Program Section Template

XI.M34 BURIED PIPING AND TANKS INSPECTION

Program Description

The program includes (a) preventive measures to mitigate corrosion, and (b) periodic inspection to manage the effects of corrosion on the pressure-retaining capacity of buried steel piping and tanks. Gray cast iron, which is included under the definition of steel, is also subject to a loss of material due to selective leaching, which is an aging effect managed under Chapter XI.M33, "Selective Leaching of Materials."

Preventive measures are in accordance with standard industry practice for maintaining external coatings and wrappings. Buried piping and tanks are inspected when they are excavated during maintenance and when a pipe is dug up and inspected for any reason.

This program is an acceptable option to manage buried piping and tanks, except further evaluation is required for the program element/attributes of detection of aging effects (regarding inspection frequency) and operating experience.

Evaluation and Technical Basis

1. ***Scope of Program:*** The program relies on preventive measures such as coating, wrapping and periodic inspection for loss of material caused by corrosion of the external surface of buried steel piping and tanks. Loss of material in these components, which may be exposed to aggressive soil environment, is caused by general, pitting, and crevice corrosion, and microbiologically-influenced corrosion (MIC). Periodic inspections are performed when the components are excavated for maintenance or for any other reason. The scope of the program covers buried components that are within the scope of license renewal for the plant.

2. ***Preventive Actions:*** In accordance with industry practice, underground piping and tanks are coated during installation with a protective coating system, such as coal tar enamel with a fiberglass wrap and a kraft paper outer wrap, a polyolifin tape coating, or a fusion bonded epoxy coating to protect the piping from contacting the aggressive soil environment.

3. ***Parameters Monitored/Inspected:*** The program monitors parameters such as coating and wrapping integrity that are directly related to corrosion damage of the external surface of buried steel piping and tanks. Coatings and wrappings are inspected by visual techniques. Any evidence of damaged wrapping or coating defects, such as coating perforation, holidays, or other damage, is an indicator of possible corrosion damage to the external surface of piping and tanks.

4. ***Detection of Aging Effects:*** Inspections performed to confirm that coating and wrapping are intact are an effective method to ensure that corrosion of external surfaces has not occurred and the intended function is maintained. Buried piping and tanks are opportunistically inspected whenever they are excavated during maintenance. When opportunistic, the inspections are performed in areas with the highest likelihood of corrosion problems, and in areas with a history of corrosion problems, within the areas made accessible to support the maintenance activity.

The applicant's program is to be evaluated for the extended period of operation. It is anticipated that one or more opportunistic inspections may occur within a ten-year period. Prior to entering the period of extended operation, the applicant is to verify that there is at least one opportunistic or focused inspection is performed within the past ten years. Upon entering the period of extended operation, the applicant is to perform a focused inspection within ten years, unless an opportunistic inspection occurred within this ten-year period. Any credited inspection should be performed in areas with the highest likelihood of corrosion problems, and in areas with a history of corrosion problems.

5. ***Monitoring and Trending:*** Results of previous inspections are used to identify susceptible locations.

6. ***Acceptance Criteria:*** Any coating and wrapping degradations are reported and evaluated according to site corrective actions procedures.

7. ***Corrective Actions:*** The site corrective actions program, quality assurance (QA) procedures, site review and approval process, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. The staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions, confirmation process, and administrative controls.

8. ***Confirmation Process:*** See Item 7, above.

9. ***Administrative Controls:*** See Item 7, above.

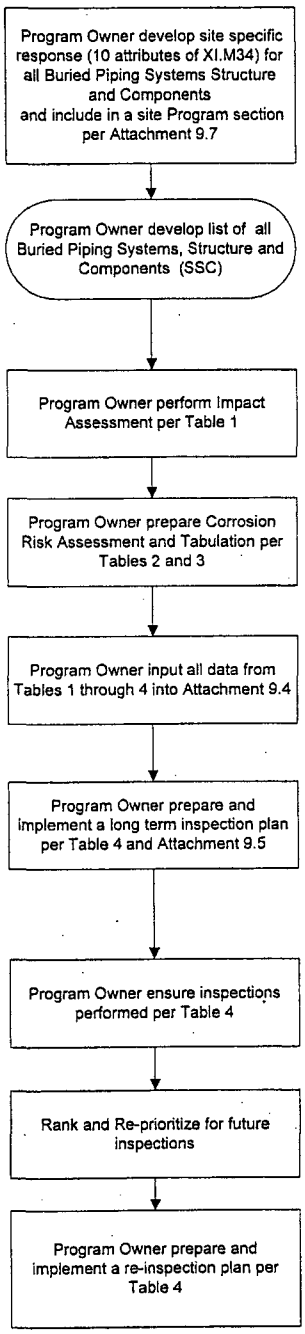
10. ***Operating Experience:*** Operating experience shows that the program described here is effective in managing corrosion of external surfaces of buried steel piping and tanks. However, because the inspection frequency is plant-specific and depends on the plant operating experience, the applicant's plant-specific operating experience is further evaluated for the extended period of operation.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

ATTACHMENT 9.2 ROADMAP FOR BURIED PIPING AND TANKS INSPECTION AND MONITORING PROGRAM

Sheet 1 of 1



ATTACHMENT 9.3 LIST OF AFFECTED BURIED PIPING SYSTEMS AS PER LRA

Sheet 1 of 2

Station	System
ANO	Unit 1 Service Water System
	Unit 2 Service Water System
	The plant's Joint Fire Protection Loop
	Fuel Oil
GGNS	TBD
IPEC	City Water
	Containment Spray
	Fire Protection - Water System
	Fuel Oil
	Plant Drains
	Safety Injection
	Security Generator
	Service Water
JAF	Condensate Storage
	Fire Protection - Water System
	Fuel Oil
	HPCI
	RCIC
	Radwaste and Plant Drains
	Security Generator
	Standby Gas Treatment
PNPS	Condensate Storage
	Fire Protection - Water System
	Fuel Oil
	Salt Service Water
	Standby Gas Treatment
	Station Blackout DG

ATTACHMENT 9.3 LIST OF AFFECTED BURIED PIPING SYSTEMS AS PER LRA

Sheet 2 of 2

Station	System
PLP/BRP	Condensate System
	Demineralized Water System
	Diesel Fuel Oil System
	Feedwater System
	Fire Protection System
	Miscellaneous Gas System
	Service Water System
RBS	TBD
VY	Fire Protection - Water System
	Fuel Oil
	Service Water
	Standby Gas Treatment
W3	TBD

ATTACHMENT 9.4 SAMPLE DATA TABLE

Sheet 1 of 1

System	X		
Section #	X-01	X-02	X-03
Drawing	IP2-YY		
Material	CDI		
O.D. (inches)	10		
Schedule	40		
Nominal Thickness (inches)	0.365		
Cathodic Protection (N, D, S)	N		
Coating Type (N, D, S)	N		
Safety Class (H, M, L)	H		
Public Risk (H, M, L)	L		
Economics (H, M, L)	L		
Overall Impact (H, M, L)	H		
Soil Resisitivity	999		
Soil Resisitivity Risk Weight	**10**		
Drainage (P, F, G)	P		
Drainage Risk Weight (4.0, 2.0, 1.0)	4		
Drainage Risk Weight	**4**		
Material			
Carbon and Low Alloy Steel (CS)	FALSE		
Cast and Ductile Iron (CDI)	1.5		
Stainless Steel (SS)	FALSE		
Copper Alloy (Cu)	FALSE		
Concrete (CO)	FALSE		
Material Risk Weight	**1.5**		
Cathodic Protection/Coating			
No CP, No Coating (N, N)	2		
No CP, Degraded Coating (N, D)	FALSE		
No CP, Sound Coating (N, S)	FALSE		
Degraded CP, No Coating (D, N)	FALSE		
Degraded CP, Degraded Coating (D, D)	FALSE		
Degraded CP, Sound Coating (D, S)	FALSE		
Sound CP, No Coating (S, N)	FALSE		
Sound CP, Degraded Coating (S, D)	FALSE		
Sound CP, Sound Coating (S, S)	FALSE		
CP/Coating Risk Weight	**2**		
Corrosion Risk Tabulation	120		
Corrosion Risk	H		
Impact-Corrosion Risk	H-H		
Inspection Priority	H		

H = High, M = Medium, L=Low, P=Poor, F=Fair, G=Good, S=Sound, D=Degraded, N=None

ATTACHMENT 9.5 **SAMPLE LONG TERM INSPECTION PLAN**

Sheet 1 of 1

Long Term Inspection Plan

System	Section #	Line #	Impact	Corrosion Risk	Inspection Priority	Required Initial Inspection Date	Actual Initial Inspection Date	Required Re-Inspection Date	Actual Re-Inspection Date	Notes
			H	H	H					
			H	M	H					
			M	H	H					
			H	L	M					
			M	M	M					
			L	H	M					
			M	L	L					
			L	M	L					
			L	L	L					

Put this table in order of impact and corrosion risk and inspection priority as shown above so all the systems with sections rated H–H are first and H-M second etc.

Corrosion of Materials in Soils

The corrosion of metals in soils can be divided into two broad categories: corrosion in undisturbed soils and corrosion in disturbed soils. Corrosion in undisturbed soils is always low, regardless of soil conditions, and is limited only by the availability of the oxygen necessary for the cathodic reaction.

Corrosion of metals in disturbed soils is strongly affected by soil conditions, electrical resistivity, mineral composition, dissolved salts, moisture content, total acidity or alkalinity (pH), redox potentials, microbiological activity, and concentration of oxygen. Any metal buried by backfilling is in a disturbed soil and is subject to corrosion attack, depending on the characteristics of the soil, Reference 12, page 497.

The supply of oxygen is comparatively large above the groundwater table but is considerably less below it and is influenced by the type of soil. It is high in sand but low in clay. The different aeration characteristics may lead to significant corrosion problems due to the creation of oxygen concentration cells, Reference 13, page 8.

Cast and Ductile Irons

Neither metal-matrix nor graphite morphology has an important influence on the corrosion of cast irons in soil. Corrosion of cast irons in soils is a function of soil porosity, drainage and dissolved constituents in the soil. Irregular soil contact can cause pitting, and poor drainage increases corrosion rates substantially above the rates in well-drained soils, Reference 13, page 48.

Carbon and Low-Alloy Steels

The corrosion rate of carbon and low alloy steels in soil depends primarily on the nature of the soil and certain other environmental factors, such as the availability of moisture and oxygen. The water content, together with the oxygen and carbon dioxide contents are major corrosion-determining factors. The redox potential in the soil becomes nobler with the increase of oxygen concentration in the soil.

In the pH range of 5 to 8, factors other than pH have greater influence on the corrosion of steel. The risk of localized corrosion (pitting) is high if the soil resistivity is lower than 1000 ohm-cm.

Sulfate-reducing bacteria, which occur under anaerobic conditions such as in deep soil layers, form iron sulfide as a corrosion product. Anaerobic bacterial corrosion is more serious

when it is combined with a differential aeration cell, in which the anaerobic cell works as a local anode.

Steel buried in the ground provides a better electrical conductor than the soil for stray return currents from electrical systems such as electrical grounding equipment and cathodic protection systems on nearby buried metal. Accelerating corrosion occurs at the point where the current leaves the steel to the earth, Reference 13, pages 8-9.

Stainless Steels

Generally, buried stainless steels suffer from soil corrosion because of one or more of the following conditions: high moisture content, pH less than 4.5, resistivity less than 1000 ohm-cm, presence of chlorides (> 500ppm), sulfides and bacteria and the presence of stray currents.

Oxygen takes part in the cathodic reaction and a supply of oxygen is therefore, in most circumstances, a prerequisite for corrosion in soil. The supply of oxygen changes with the type of soil and the different oxygen levels may lead to corrosion problems due to the creation of oxygen concentration cells. The oxygen concentration of the soil moisture generally will determine its redox potential. The higher the oxygen content the higher the redox potential. However, low redox values may provide an indication that conditions are conducive to anaerobic microbiological activity.

Another of the most important conditions for corrosion to occur is the chloride ion (Cl^-) concentration in the soil and the moisture, which can contain different dissolved species such as sulfate ions (SO_4^{-2}) and some others e.g.: H^+, HCO_3^-, etc., Reference 14.

Copper Alloys

Copper exhibits high resistance to corrosion by most soils. National Bureau of Standards (NBS) study results indicate that tough pitch coppers, deoxidized coppers, silicon bronzes and low-zinc brasses behave essentially alike. The corrosion rate of copper in quiescent groundwater tends to decrease with time due to the formation of a protective film in which the underlying layer consists of species from the groundwater as well as copper.

For copper and copper alloys, corrosion rate depends strongly on the amount of dissolved oxygen present; deoxygenation results in ground water tests show at least an order of magnitude decrease in the short-term corrosion rate. In aerated solutions, the addition of nickel (90 Cu-10 Ni) decreases the uniform corrosion rate of copper by the formation of a more highly protective surface film.

Soils containing high concentrations of sulfides, chlorides, of hydrogen ions (H+) corrode these materials. Where local soil conditions are unusually corrosive, it may be necessary to use some means of protection, such as cathodic protection, neutralizing backfill (limestone, for example), protective coating or wrapping, Reference 13, pages 132 to 138.

Titanium Alloys

There are no indications in the literature that titanium alloys are susceptible to corrosion in soils; however, some reference to the corrosion resistance of titanium alloys in waters that would be present in soils is beneficial to this understanding.

"Titanium and its alloys are fully resistant to water, all natural waters, and steam to temperatures in excess of 600°F. Titanium alloys exhibit negligible corrosion rates in seawater to temperatures as high as 500°F. Pitting and crevice corrosion will not occur in ambient seawater, even if marine deposits form and biofouling occurs." (Reference 13, page 260).

"Crevice attack of titanium alloys will generally not occur below a temperature of 160°F regardless of solution pH or chloride concentration or when solution pH exceeds 10 regardless of temperature." (Reference 13, page 268).

ATTACHMENT 9.7 BURIED PIPING AND TANKS INSPECTION PROGRAM SECTION TEMPLATE

Sheet 1 of 6

PROGRAM SECTION

for

Buried Piping and Tanks Inspection and Monitoring

ENTERGY NUCLEAR ENGINEERING PROGRAMS

APPLICABLE SITES

All Sites: ☒

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

Safety Related: ☐ **Yes**

☒ **No**

APPLICABLE SITES for Dry Fuel Storage (72.48 Review)

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

Continuous Use ☐ **Reference Use** ☐ **Informational Use** ☒

ATTACHMENT 9.7 BURIED PIPING AND TANKS INSPECTION PROGRAM SECTION TEMPLATE

Sheet 2 of 6

REVIEW AND CONCURRENCE SHEET

Program Section No.:_____

Revision No.:_____

Program Section Title:_____

_____

Prepared By:_____Date:_____

Checked By:_____Date:_____

_____

ANII_____Date:_____

Reviewed By (or N/A)

_____

Concurred:_____Date:_____

Responsible Supervisor

REVISION STATUS SHEET

Program Section No.:_____
Page No.:_____
Revision No.:_____

PROGRAM SECTION REVISION SUMMARY

REVISION	DESCRIPTION OF CHANGES

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1.0 PURPOSE

[1] This Program section (referred to as the Program) provides the scope for the site specific Buried Piping and Tank Inspection and Monitoring Program. The Program contains all the evaluations used to develop the scope, impact evaluation, corrosion risk and the long term inspection plan per EN-DC-343.

2.0 REFERENCES

[1] Don't need to repeat all the references in EN-DC-343 except for the ones applicable to the specific site or site commitments and others such as procedures, reports, etc. that are not already in EN-DC-343

3.0 DEFINITIONS

[1] Only add definitions that specifically apply for this Program. If using any definitions from EN-DC-343 they shall be verbatim from the procedure.

4.0 RESPONSIBILITIES

[1] Program Owner is responsible for preparation and maintenance of the site Program.

[2] Program Owner is responsible for obtaining outside inspection services as needed for the inspection activities.

[3] Maintenance is responsible for excavating as needed to support inspection activities.

5.0 DETAILS

5.1 Precautions and Limitations

Insert any specific precautions and limitations necessary at the site for this Program, can draw upon those already in EN-DC-343

5.2 Scope of Program

The buried piping and tank program developed shall include, as a minimum, piping and tanks described in sections 5.2. [1] through 5.2. [3] of EN-DC-343.

5.3 Program Summary

The design information, impact evaluation and corrosion risk from Tables 1-4 and long term inspection plan in EN-DC-343 shall be input into Attachments 9.4 and 9.5 of EN-DC-343 and included in section 9.0 "Attachments" of the Program section.

6.0 INTERFACES

[1] EN-DC-147, "Engineering Reports"

7.0 RECORDS

Design records consist of Attachments 9.4 and 9.5 in EN-DC-343 and inspection records shall be documented in accordance with EN-AD-103 "Document Control and Records Management Activities".

8.0 OBLIGATIONS AND COMMITMENTS

Insert site specific Program section Obligations and Commitments as applicable

9.0 ATTACHMENTS

Attach tables from Attachment 9.4 and 9.5 from EN-DC-343 as information is completed.

EXHIBIT 15

United States General Accounting Office, Report to the Chairman, Subcommittee on Oversight and Investigations, Committee on Energy and Commerce, House of Representatives, Nuclear Safety and Health Counterfeit and Substandard Products Are A Government Wide Concern,

GAO/RCED-91-6,

October 1990

United States General Accounting Office

GAO

Report to the Chairman, Subcommittee on Oversight and Investigations, Committee on Energy and Commerce, House of Representatives

October 1990

NUCLEAR SAFETY AND HEALTH

Counterfeit and Substandard Products Are a Governmentwide Concern

GAO/RCED-91-6

Table 2.1: Nonconforming Products That Nuclear Power Plants Have Received or Are Suspected of Having Received

Plant	State	Fasteners[a]	Pipe fittings/ flanges[b]	Circuit breakers[a]	Fuses[b]	Other material[c]
Arkansas	AR		X	X		
Beaver Valley	PA	X				X
Bellefonte[d]	AL	X			X	X
Big Rock Point	MI	X				
Braidwood[d]	IL		X	X		
Browns Ferry	AL	X			X	[b]X
Brunswick	NC	X	X	X		
Byron	IL				X	
Callaway	MO	X				X
Calvert Cliffs	MD	X				X
Catawba	SC	X	X	X		
Clinton	IL	X	X	X	X	
Comanche Peak	TX	X				
D. C. Cook	MI	X				X
Cooper	NE					X
Crystal River	FL	X	X	X	X	
Davis-Besse	OH	X	X	X		
Diablo Canyon	CA	X		X	X	X
Dresden	IL	X		X	X	
Duane Arnold	IA	X				X
Farley	AL	X		X		
Fermi	MI	X		X		X
Fitzpatrick	NY	X	X		X	
Fort Calhoun	NE	X	X	X	X	
Fort St. Vrain[e]	CO	X				
Ginna	NY	X	X	X		
Grand Gulf	MS	X	X	X	X	
Haddam Neck	CT				X	
Hatch	GA					X
Hope Creek	NJ		X		X	
Indian Point	NY	X			X	
Kewaunee	WI	X			X	
La Salle	IL	X		X	X	
Limerick	PA	X	X			
Maine Yankee	ME	X			X	
Mcguire	NC	X	X	X		
Millstone	CT	X	X		X	

(continued)

Plant	State	Fasteners[a]	Pipe fittings/ flanges[b]	Circuit breakers[a]	Fuses[b]	Other material[c]
Monticello	MN	X				X
Nine Mile Point	NY	X	X	X	X	
North Anna	VA	X				X
Oconee	SC		X	X		
Oyster Creek	NJ	X				
Palisades	MI	X	X	X		
Palo Verde	AZ	X	X	X		
Peach Bottom	PA	X	X	X		
Perry	OH	X	X			
Pilgrim NB	MA	X	X	X	X	
Point Beach	WI	X				
Prairie Island	MN	X		X		X
Quad Cities	IL	X		X		X
Rancho Seco[e]	CA	X	X	X	X	
River Bend	LA	X	X			
Robinson	SC	X				
Salem	NJ	X	X		X	
San Onofre	CA	X	X	X		
Seabrook	NH	X	X		X	
Sequoyah	TN	X	X		X	
Shearon Harris	NC	X	X	X		
Shoreham[e]	NY	X		X	X	X
South Texas	TX	X	X	X		
St. Lucie	FL	X		X	X	
Summer	SC	X	X			
Surry	VA	X		X	X	
Susquehanna	PA	X	X			
Three Mile Island	PA	X				
Trojan	OR	X				
Turkey Point	FL	X			X	X
Vermont Yankee	VT	X			X	
Vogtle	GA	X	X			
Washington Nuclear	WA	X	X			
Waterford	LA	X		X		X
Watts Bar	TN	X	X		X	
Wolf Creek	KS		X		X	

(continued)

June 5, 2007

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

Before the Atomic Safety and Licensing Board

In the Matter of	)	
	)	
Entergy Nuclear Generation Company and	)	Docket No. 50-293-LR
Entergy Nuclear Operations, Inc.	)	ASLBP No. 06-848-02-LR
	)	
(Pilgrim Nuclear Power Station)	)	

DECLARATION OF ALAN COX IN SUPPORT OF ENTERGY'S MOTION FOR SUMMARY DISPOSITION OF PILGRIM WATCH CONTENTION 1

Alan Cox states as follows under penalties of perjury:

44. Pilgrim Watch erroneously argues that PNPS might be "vulnerable to undetected leaks in its underground pipes and tanks because of nonconforming pipe fittings and flanges." Pilgrim Watch. Pet. at 11. As an initial matter, this is an everyday operational issue, and not an aging management issue, and hence is irrelevant here. Furthermore, the GAO report cited in the Contention makes only a general reference to PNPS, listing PNPS as one of several plants that may have received counterfeit or substandard parts including pipe fittings and flanges, and provides no detail specific to PNPS.[10] Moreover, NRC Bulletin 88-05 (referred to in GAO/RCED-91-6 at 41) alerted utilities about potential counterfeit and substandard pipe fittings and flanges, and Boston Edison, the previous PNPS owner and operator, identified, located and remediated, as appropriate, any counterfeit and substandard pipe fittings and flanges at PNPS. See Boston Edison Company, "Response to NRC Bulletin 88-05 and Supplements 1 & 2, Nonconforming Materials" (Sept. 1988). Therefore, PNPS responded to this issue under the NRC's ongoing oversight, review, and enforcement of operational issues as contemplated by the NRC license renewal rules.

EXHIBIT 16

New England not immune to strong temblors and specialists say that a major event in only a matter of time,

Boston Globe

April 16, 2006

New England not immune to strong temblors
Specialists say major event only a matter of time

By Bryan Bender, Globe Staff | April 16, 2006

RESTON, Va. -- Could a big one hit Boston? It has before.

In 1638, less than a generation after the Pilgrims arrived at Plymouth Rock, a powerful earthquake approaching those that have rocked Los Angeles struck central New Hampshire, shaking homes in Boston and spurring aftershocks for two weeks, according to first-person accounts.

The largest quake ever recorded in the Northeast was estimated to be a magnitude 7.0 on the Richter scale, based on the geological effects. It hit Quebec in 1663, shattering chimneys in Boston, nearly 400 miles away.

The ground opened up in Eastern Massachusetts in 1755 when a quake with its epicenter at Cape Ann formed natural springs and even toppled the grasshopper atop Faneuil Hall.

Major earthquakes are most commonly associated with fault-ridden California. But it is only a matter of time before the Northeast is struck by a major temblor, according to earthquake specialists at the US Geological Survey in Virginia, who have placed Boston on a list of the top 26 risk areas in the nation. Indeed, a major quake has occurred somewhere in the Eastern United States about every 100 years.

Yet Boston and other urban areas, vastly more populated than when the colonists felt the earth shake several centuries ago, are far less prepared than the West Coast, according to earthquake hazard specialists.

Water mains and buildings are not reinforced against collapse, especially masonry structures. And large swaths of Boston that sit on landfill are in heightened danger, subject to what specialists call "liquefaction," when the soil effectively turns into mush. If a quake struck in winter, every gas-heated home would potentially be an ignition source for fires.

"The daily risk of a damaging earthquake in much of the Eastern US is very low, but a repeat of any of these [past] events today would be a disaster on a scale that is difficult to comprehend," declares a soon-to-be-published report by the Geological Survey. "Although the probability that a major earthquake will hit the Eastern US is much lower than in the West, the potential impact is significantly higher."

There is no reliable map of earthquake faults in the Eastern United States, according to researchers. Nevertheless, the rocks transmit earthquake waves more easily than in the West. Therefore, a rupture, brought on by pressure built up over hundreds of years, would be felt over a much larger geographic area.

Two back-to-back quakes in Missouri in the winter of 1810-1811 shook the White House, nearly half a continent away; President James Madison remarked that he thought a burglary was in progress. The tectonic shift that resulted redirected the flow of the Mississippi River, according to geologists.

Smaller earthquakes occur regularly in the Eastern states, including New England. On November 17, a minor quake, measuring 2.5 on the Richter scale, was detected 17 miles southeast of

Whitman. Last March, a moderate quake, measured at 5.4, struck 55 miles north-northwest of Dickey, Maine; nearly 600 residents reported having to hold onto something to avoid falling down.

(For each increase in the Richter scale, a quake's strength grows by an order of magnitude. For example, a 5.0 is 10 times greater than a 4.0. The amount of energy released goes up even more. The 9.0 quake that caused the Asian tsunami in 2004 was a thousand times more powerful than the 7.0 Loma Prieta quake that interrupted the World Series in San Francisco in 1989).

But in the event of a big one, Boston and other East Coast cities like Charleston, S.C. -- almost entirely leveled by a 7.3 quake in 1886 -- are not ready.

"They happen so infrequently that they are not part of people's everyday thinking," said David Applegate, a Massachusetts Institute of Technology-trained geologist who is a senior scientist at the Geological Survey. "But after the [tsunami of 2004] we gave more thought to areas that have infrequent events."

Indeed, the forthcoming government report says "many people are unaware of the potential for a major earthquake to hit the Eastern United States, and fewer still know what to do and what not to do during and immediately after an earthquake."

For geologists in Boston, the biggest concern is those areas built on landfill.

"About two-thirds of Boston is on made land," said John Ebel, a professor of geology and director of the Weston Observatory at Boston College. Walking "from Boston Common to the Public Garden you would have been underwater in the 1700s. The Back Bay is literally a bay that was filled in. Those areas have the potential for greater damage than if you get on to Beacon Hill or the hard rock areas like Brookline." ■

EXHIBIT 17

NUREG-1891

Safety Evaluation Report Related to the License Renewal of Pilgrim Nuclear Power Station

NUREG-1891

Safety Evaluation Report
Related to the License Renewal of Pilgrim Nuclear Power Station

Docket No. 50-293

Entergy Nuclear Operations, Inc.

U.S. Nuclear Regulatory Commission
Office of Nuclear Reactor Regulation
Washington, DC 20555-0001

adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2 AMPs That Are Consistent with the GALL Report with Exceptions and/or Enhancements

In LRA Appendix B, the applicant stated that the following AMPs are, or will be, consistent with the GALL Report with exceptions or enhancements:

- Buried Piping and Tanks Inspection Program
- BWR CRD Return Line Nozzle Program
- BWR Feedwater Nozzle Program
- BWR Penetrations Program
- BWR Stress Corrosion Cracking Program
- BWR Vessel ID Attachment Welds Program
- BWR Vessels Internals Program
- Diesel Fuel Monitoring Program
- Fatigue Monitoring Program
- Fire Protection Program
- Fire Water System Program
- Metal-Enclosed Bus Inspection Program
- Oil Analysis Program
- Reactor Head Closure Studs Program
- Reactor Vessel Surveillance Program
- Service Water Integrity Program
- Structures Monitoring Program
- Water Control Structures Monitoring Program
- Water Chemistry Control - Closed Cooling Water Program

For AMPs that the applicant claimed are consistent with the GALL Report, with exception(s) and/or enhancement(s), the staff performed an audit and review to confirm that those attributes or features of the program for which the applicant claimed consistency were indeed consistent. The staff also reviewed the exception(s) and/or enhancement(s) to the GALL Report to determine whether they were acceptable and adequate. The results of the staff's audits and reviews are documented in the following sections.

3.0.3.2.1 Buried Piping and Tanks Inspection Program

Summary of Technical Information in the Application. LRA Section B.1.2, "Buried Piping and Tanks Inspection," describes the new Buried Piping and Tanks Inspection Program as consistent, with exception, with GALL AMP XI.M34, "Buried Piping and Tanks Inspection."

This program includes (a) preventive measures to mitigate corrosion and (b) inspections to manage the effects of corrosion on the pressure-retaining capability of buried carbon steel, stainless steel, and titanium components. Preventive measures are in accordance with standard industry practice for maintaining external coatings and wrappings. Buried components are

inspected when excavated during maintenance. There will be a focused inspection within the first 10 years of the period of extended operation unless an opportunistic inspection (or an inspection via a method that assesses pipe condition without excavation) occurs within this ten-year period.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report and documented a detailed audit evaluation of this AMP in Audit and Review Report Section 3.0.3.2.1. The staff reviewed the exception to determine whether the AMP remained adequate to manage the aging effects for which it is credited.

The staff reviewed those portions of the Buried Piping and Tanks Inspection Program for which the applicant claims consistency with GALL AMP XI.M34 and finds them consistent. Furthermore, the staff concludes that the applicant's Buried Piping and Tanks Inspection Program provides reasonable assurance of management of the effects of aging so components crediting this program can perform intended functions consistent with the CLB during the period of extended operation. The staff finds the applicant's Buried Piping and Tanks Inspection Program acceptable as consistent with the recommended GALL AMP XI.M34, "Buried Piping and Tanks Inspection," with the exceptions as described:

Exception. The LRA states an exception to the GALL Report program element "detection of aging effects," specifically:

> For cases of excavation solely for the purpose of inspection – methods such as "phased array" UT will be used to determine wall thickness without excavating.

The proposed exception eliminates the possibility of inadvertent excavation related damage during inspection while assessing the component. As the technology becomes available for the nuclear industry, applicants may use this technology to examine the condition of buried piping. On this basis, the staff finds this exception acceptable.

Operating Experience. LRA Section B.1.2 states that there is no operating experience for the new Buried Piping and Tanks Inspection Program.

However, in the past five years, the applicant has had limited experience with the inspection of buried piping, mainly on the fire water underground distribution system. This system, approximately 35 years old, consists of cement-lined malleable iron pipe with mechanical joints and no history of significant leaks other than during two instances in 2001 and 2005. In the first, the 8-inch underground line downstream of 8-L-22 failed, the probable cause induced most likely by minor fabrication anomalies compounded by marginal installation techniques. When examined, this piping was found to be in very good external condition overall except for a small area of surface corrosion attributed to marginal installation techniques. In the second instance, the 8-inch underground pipe failed in the area of the N2 tank adjacent to the emergency diesel generator (EDG) building. Due to congestion and the presence of the tank (installed after the piping), it was not possible to dig up the piping for examination to determine the cause of the failure (possibly related to the tank installation). Apart from these two instances, a number of valves and piping excavated during maintenance were found to be in good condition.

From an additional historical perspective, the SSW system has had leaks on the buried inlet (screenhouse to auxiliary bays) piping due to internal corrosion. The original piping material was

rubber-lined carbon steel wrapped with reinforced fiberglass, coal tar saturated felt, and heavy Kraft paper. The leaks were determined to be results of the rubber lining degrading from contact with sea water. These pipes were replaced in 1995 and 1997 with the same external and internal coatings as for the original pipe.

In addition, the SSW buried discharge piping (also rubber-lined carbon steel with external pipe wrapping) from the auxiliary bays to the discharge canal experienced severe internal corrosion due to failure of the rubber lining. Two 40-foot lengths of 22-inch diameter pipes (one on each loop) were replaced in 1999 with carbon steel coated internally and externally with epoxy. The replaced piping was examined with its wrapping removed and its external surface was found to be in good condition. Since then, the entire length of both SSW buried discharge loops have been lined internally with pipe linings cured in place – "B" Loop in 2001 and "A" Loop in 2003.

The staff reviewed the operating experience presented in the LRA and interviewed the applicant's technical personnel to confirm that the plant-specific operating experience revealed no degradation not bounded by industry experience.

The staff confirmed that the "operating experience" program element satisfies the criterion defined in the GALL Report and in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Section A.2.1.2, the applicant provided the UFSAR supplement for the Buried Piping and Tanks Inspection Program. The staff reviewed this section and determined that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

The LRA states that this program will be implemented before the period of extended operation (Commitment No. 1).

Conclusion. On the basis of its audit and review of the applicant's Buried Piping and Tanks Inspection Program, the staff finds that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exception and its justification and determined that the AMP, with the exception, is adequate to manage the aging effects for which it is credited. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.2 BWR CRD Return Line Nozzle Program

Summary of Technical Information in the Application. LRA Section B.1.3, "BWR CRD Return Line Nozzle," describes the existing BWR CRD Return Line Nozzle Program as consistent, with exceptions, with GALL AMP XI.M6, "BWR Control Rod Drive Return Line Nozzle."

Under this program, the applicant has cut and capped the CRD return line nozzle to mitigate cracking and continued ISI examinations to monitor the effects of crack initiation and growth on intended functions of the CRD return line nozzle and cap. In 2003, a structural weld overlay was

EXHIBIT 18

NUREG-1801 Rev 1

Gall Report

NUREG-1801, Vol.1, Rev. 1

Generic Aging Lessons Learned (GALL) Report

Summary

Manuscript Completed: September 2005
Date Published: September 2005

Division of Regulatory Improvement Programs
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

7. ***Corrective Actions:*** When measured water chemistry parameters are outside the specified range, corrective actions are taken to bring the parameter back within the acceptable range and within the time period specified in the EPRI water chemistry guidelines. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

8. ***Confirmation Process:*** Following corrective actions, additional samples are taken and analyzed to verify that the corrective actions were effective in returning the concentrations of contaminants such as chlorides, fluorides, sulfates, dissolved oxygen, and hydrogen peroxide to within the acceptable ranges. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

9. ***Administrative Controls:*** Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address administrative controls.

10. ***Operating Experience:*** The EPRI guideline documents have been developed based on plant experience and have been shown to be effective over time with their widespread use. The specific examples of operating experience are as follows:

    BWR: Intergranular stress corrosion cracking (IGSCC) has occurred in small- and large-diameter BWR piping made of austenitic stainless steels and nickel-base alloys. Significant cracking has occurred in recirculation, core spray, residual heat removal (RHR) systems, and reactor water cleanup (RWCU) system piping welds. IGSCC has also occurred in a number of vessel internal components, including core shroud, access hole cover, top guide, and core spray spargers (Nuclear Regulatory Commission [NRC] Bulletin 80-13, NRC Information Notice [IN] 95-17, NRC Generic Letter [GL] 94-03, and NUREG-1544). No occurrence of SCC in piping and other components in standby liquid control systems exposed to sodium pentaborate solution has ever been reported (NUREG/CR-6001).

    PWR Primary System: The primary pressure boundary piping of PWRs has generally not been found to be affected by SCC because of low dissolved oxygen levels and control of primary water chemistry. However, the potential for SCC exists due to inadvertent introduction of contaminants into the primary coolant system from unacceptable levels of contaminants in the boric acid, introduction through the free surface of the spent fuel pool (which can be a natural collector of airborne contaminants), or introduction of oxygen during cooldown (NRC IN 84–18). Ingress of demineralizer resins into the primary system has caused IGSCC of Alloy 600 vessel head penetrations (NRC IN 96-11, NRC GL 97-01). Inadvertent introduction of sodium thiosulfate into the primary system has caused IGSCC of steam generator tubes. The SCC has occurred in safety injection lines (NRC INs 97-19 and 84-18), charging pump casing cladding (NRC INs 80-38 and 94-63), instrument nozzles in safety injection tanks (NRC IN 91-05), and safety-related SS piping systems that contain oxygenated, stagnant, or essentially stagnant borated coolant (NRC IN 97-19). Steam generator tubes and plugs and Alloy 600 penetrations have experienced primary water stress corrosion cracking (PWSCC) (NRC INs 89-33, 94-87, 97-88, 90-10, and 96-11; NRC Bulletin 89-01 and its two supplements).

7. ***Corrective Actions:*** The site corrective actions program, quality assurance (QA) procedures, site review and approval process, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions, confirmation process, and administrative controls.

8. ***Confirmation Process:*** See Item 7, above.

9. ***Administrative Controls:*** See Item 7, above.

10. ***Operating Experience:*** Corrosion pits from the outside diameter have been discovered in buried piping with far less than 60 years of operation. Buried pipe that is coated and cathodically protected is unaffected after 60 years of service. Accordingly, operating experience from application of the NACE standards on non-nuclear systems demonstrates the effectiveness of this program.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

NACE Standard RP-0169-96, *Control of External Corrosion on Underground or Submerged Metallic Piping Systems*, 1996.

NACE Standard RP-0285-95, *Corrosion Control of Underground Storage Tank Systems by Cathodic Protection,* Approved March 1985, revised February 1995.

XI.M32 ONE-TIME INSPECTION

Program Description

The program includes measures to verify the effectiveness of an aging management program (AMP) and confirm the insignificance of an aging effect. Situations in which additional confirmation is appropriate include (a) an aging effect is not expected to occur but the data is insufficient to rule it out with reasonable confidence; (b) an aging effect is expected to progress very slowly in the specified environment, but the local environment may be more adverse than that generally expected; or (c) the characteristics of the aging effect include a long incubation period. For these cases, there is to be confirmation that either the aging effect is indeed not occurring, or the aging effect is occurring very slowly so as not to affect the component or structure intended function during the period of extended operation.

A one-time inspection may also be used to provide additional assurance that aging that has not yet manifested itself is not occurring, or that the evidence of aging shows that the aging is so insignificant that an aging management program is not warranted. (Class 1 piping less than or equal to NPS 4 is addressed in Chapter XI.M35, *One Time Inspection of ASME Code Class 1 Small Bore-Piping)*

One-time inspections may also be used to verify the system-wide effectiveness of an AMP that is designed to prevent or minimize aging to the extent that it will not cause the loss of intended function during the period of extended operation. For example, effective control of water chemistry can prevent some aging effects and minimize others. However, there may be locations that are isolated from the flow stream for extended periods and are susceptible to the gradual accumulation or concentration of agents that promote certain aging effects. This program provides inspections that either verifies that unacceptable degradation is not occurring or trigger additional actions that will assure the intended function of affected components will be maintained during the period of extended operation.

The elements of the program include (a) determination of the sample size based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience; (b) identification of the inspection locations in the system or component based on the aging effect; (c) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined; and (d) evaluation of the need for follow-up examinations to monitor the progression of aging if age-related degradation is found that could jeopardize an intended function before the end of the period of extended operation.

When evidence of an aging effect is revealed by a one-time inspection, the routine evaluation of the inspection results would identify appropriate corrective actions.

As set forth below, an acceptable verification program may consist of a one-time inspection of selected components and susceptible locations in the system. An alternative acceptable program may include routine maintenance or a review of repair or inspection records to confirm that these components have been inspected for aging degradation and significant aging degradation has not occurred. One-time inspection, or any other action or program, created to verify the effectiveness of an AMP and confirm the absence of an aging effect, is to be reviewed by the staff on a plant-specific basis.

Evaluation and Technical Basis

1. ***Scope of Program:*** The program includes measures to verify that unacceptable degradation is not occurring, thereby validating the effectiveness of existing AMPs or confirming that there is no need to manage aging-related degradation for the period of extended operation. The structures and components for which one-time inspection is specified to verify the effectiveness of the AMPs (e.g., water chemistry control, etc.) have been identified in the Generic Aging Lessons Learned (GALL) Report. Examples include the feedwater system components in boiling water reactors (BWRs) and pressurized water reactors (PWRs).

2. ***Preventive Actions:*** One-time inspection is an inspection activity independent of methods to mitigate or prevent degradation.

3. ***Parameters Monitored/Inspected:*** The program monitors parameters directly related to the degradation of a component. Inspection is to be performed by qualified personnel following procedures consistent with the requirements of the American Society of Mechanical Engineers (ASME) Code and 10 CFR 50, Appendix B, using a variety of nondestructive examination (NDE) methods, including visual, volumetric, and surface techniques.

4. ***Detection of Aging Effects:*** The inspection includes a representative sample of the system population, and, where practical, focuses on the bounding or lead components most susceptible to aging due to time in service, severity of operating conditions, and lowest design margin.

   The program will rely on established NDE techniques, including visual, ultrasonic, and surface techniques that are performed by qualified personnel following procedures consistent with the ASME Code and 10 CFR Part 50, Appendix B.

   The inspection and test techniques will have a demonstrated history of effectiveness in detecting the aging effect of concern. Typically, the one time inspections should be performed as indicated in the following table.

Examples of Parameters Monitored or Inspected And Aging Effect for Specific Structure or Component[9]			
Aging Effect	**Aging Mechanism**	**Parameter Monitored**	**Inspection Method[10]**
Loss of Material	Crevice Corrosion	Wall Thickness	Visual (VT-1 or equivalent) and/or Volumetric (RT or UT)
Loss of Material	Galvanic Corrosion	Wall Thickness	Visual (VT-3 or equivalent) and/or Volumetric (RT or UT)
Loss of Material	General Corrosion	Wall Thickness	Visual (VT-3 or equivalent) and/or Volumetric (RT or UT)
Loss of Material	MIC	Wall Thickness	Visual (VT-3 or equivalent) and/or Volumetric (RT or UT)
Loss of Material	Pitting Corrosion	Wall Thickness	Visual (VT-1 or equivalent) and/or Volumetric (RT or UT)
Loss of Material	Erosion	Wall Thickness	Visual (VT-3 or equivalent) and/or Volumetric (RT or UT)
Loss of Heat Transfer	Fouling	Tube Fouling	Visual (VT-3 or equivalent) or Enhanced VT-1 for CASS
Cracking	SCC or Cyclic Loading	Cracks	Enhanced Visual (VT-1 or equivalent) and/or Volumetric (RT or UT)
Loss of Preload	Thermal Effects, Gasket Creep and Self-loosening	Loosening of Components	Visual (VT-3 or equivalent)

With respect to inspection timing, the population of components inspected before the end of the current operating term needs to be sufficient to provide reasonable assurance that the aging effect will not compromise any intended function at any time during the period of extended operation. Specifically, inspections need to be completed early enough to ensure that the aging effects that may affect intended functions early in the period of extended operation are appropriately managed. Conversely, inspections need to be timed to allow the inspected components to attain sufficient age to ensure that the aging effects with long incubation periods (i.e., those that may affect intended functions near the end of the period of extended operation) are identified. Within these constraints, the applicant should schedule the inspection no earlier than 10 years prior to the period of extended operation, and in such a way as to minimize the impact on plant operations. As a plant will have accumulated at least 30 years of use before inspections under this program begin, sufficient times will have elapsed for aging effects, if any, to be manifest.

[9] The examples provided in the table may not be appropriate for all relevant situations. If the applicant chooses to use an alternative to the recommendations in this table, a technical justification should be provided as an exception to this AMP. This exception should list the AMR line item component, examination technique, acceptance criteria, evaluation standard and a description of the justification.
[10] Visual inspection may be used only when the inspection methodology examines the surface potentially experiencing the aging effect.

XI.M2 WATER CHEMISTRY

Program Description

The main objective of this program is to mitigate damage caused by corrosion and stress corrosion cracking (SCC). The water chemistry program for boiling water reactors (BWRs) relies on monitoring and control of reactor water chemistry based on industry guidelines such as the boiling water reactor vessel and internals project (BWRVIP)-29 (Electric Power Research Institute [EPRI] TR-103515) or later revisions. The BWRVIP-29 has three sets of guidelines: one for primary water, one for condensate and feedwater, and one for control rod drive (CRD) mechanism cooling water. The water chemistry program for pressurized water reactors (PWRs) relies on monitoring and control of reactor water chemistry based on industry guidelines for primary water and secondary water chemistry such as EPRI TR-105714, Rev. 3 and TR-102134, Rev. 3 or later revisions.

The water chemistry programs are generally effective in removing impurities from intermediate and high flow areas. The Generic Aging Lessons Learned (GALL) report identifies those circumstances in which the water chemistry program is to be augmented to manage the effects of aging for license renewal. For example, the water chemistry program may not be effective in low flow or stagnant flow areas. Accordingly, in certain cases as identified in the GALL Report, verification of the effectiveness of the chemistry control program is undertaken to ensure that significant degradation is not occurring and the component's intended function will be maintained during the extended period of operation. As discussed in the GALL Report for these specific cases, an acceptable verification program is a one-time inspection of selected components at susceptible locations in the system.

Evaluation and Technical Basis

1. ***Scope of Program:*** The program includes periodic monitoring and control of known detrimental contaminants such as chlorides, fluorides (PWRs only), dissolved oxygen, and sulfate concentrations below the levels known to result in loss of material or cracking. Water chemistry control is in accordance with industry guidelines such as BWRVIP-29 (EPRI TR-103515) for water chemistry in BWRs, EPRI TR-105714 for primary water chemistry in PWRs, and EPRI TR-102134 for secondary water chemistry in PWRs.

2. ***Preventive Actions:*** The program includes specifications for chemical species, sampling and analysis frequencies, and corrective actions for control of reactor water chemistry. System water chemistry is controlled to minimize contaminant concentration and mitigate loss of material due to general, crevice and pitting corrosion and cracking caused by SCC. For BWRs, maintaining high water purity reduces susceptibility to SCC.

3. ***Parameters Monitored/Inspected:*** The concentration of corrosive impurities listed in the EPRI guidelines discussed above, which include chlorides, fluorides (PWRs only), sulfates, dissolved oxygen, and hydrogen peroxide, are monitored to mitigate degradation of structural materials. Water quality (pH and conductivity) is also maintained in accordance with the guidance. Chemical species and water quality are monitored by in-process methods or through sampling. The chemical integrity of the samples is maintained and verified to ensure that the method of sampling and storage will not cause a change in the concentration of the chemical species in the samples.

BWR Water Chemistry: The guidelines in BWRVIP-29 (EPRI TR-103515) for BWR reactor water recommend that the concentration of chlorides, sulfates, and dissolved oxygen are monitored and kept below the recommended levels to mitigate corrosion. The two impurities, chlorides and sulfates, determine the coolant conductivity; dissolved oxygen, hydrogen peroxide, and hydrogen determine electrochemical potential (ECP). The EPRI guidelines recommend that the coolant conductivity and ECP are also monitored and kept below the recommended levels to mitigate SCC and corrosion in BWR plants. The EPRI guidelines in BWRVIP-29 (TR-103515) for BWR feedwater, condensate, and control rod drive water recommend that conductivity, dissolved oxygen level, and concentrations of iron and copper (feedwater only) are monitored and kept below the recommended levels to mitigate SCC. The EPRI guidelines in BWRVIP-29 (TR-103515) also include recommendations for controlling water chemistry in auxiliary systems: torus/pressure suppression chamber, condensate storage tank, and spent fuel pool.

PWR Primary Water Chemistry: The EPRI guidelines (EPRI TR-105714), for PWR primary water chemistry recommend that the concentration of chlorides, fluorides, sulfates, lithium, and dissolved oxygen and hydrogen are monitored and kept below the recommended levels to mitigate SCC of austenitic stainless steel, Alloy 600, and Alloy 690 components. TR-105714 provides guidelines for chemistry control in PWR auxiliary systems such as the boric acid storage tank, refueling water storage tank, spent fuel pool, letdown purification systems, and volume control tank.

PWR Secondary Water Chemistry: The EPRI guidelines (EPRI TR-102134), for PWR secondary water chemistry recommend monitoring and control of chemistry parameters (e.g., pH level, cation conductivity, sodium, chloride, sulfate, lead, dissolved oxygen, iron, copper, and hydrazine) to mitigate steam generator tube degradation caused by denting, intergranular attack (IGA), outer diameter stress corrosion cracking (ODSCC), or crevice and pitting corrosion. The monitoring and control of these parameters, especially the pH level, also mitigates general (for steel components), crevice, and pitting corrosion of the steam generator shell and the balance of plant materials of construction (e.g., steel, stainless steel, and copper).

4. ***Detection of Aging Effects:*** This is a mitigation program and does not provide for detection of any aging effects.

   In certain cases as identified in the GALL Report, inspection of select components is to be undertaken to verify the effectiveness of the chemistry control program and to ensure that significant degradation is not occurring and the component intended function will be maintained during the extended period of operation.

5. ***Monitoring and Trending:*** The frequency of sampling water chemistry varies (e.g., continuous, daily, weekly, or as needed) based on plant operating conditions and the EPRI water chemistry guidelines. Whenever corrective actions are taken to address an abnormal chemistry condition, increased sampling is utilized to verify the effectiveness of these actions.

6. ***Acceptance Criteria:*** Maximum levels for various contaminants are maintained below the system specific limits as indicated by the limits specified in the corresponding EPRI water

chemistry guidelines. Any evidence of aging effects or unacceptable water chemistry results is evaluated, the root cause identified, and the condition corrected.

7. ***Corrective Actions:*** When measured water chemistry parameters are outside the specified range, corrective actions are taken to bring the parameter back within the acceptable range and within the time period specified in the EPRI water chemistry guidelines. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

8. ***Confirmation Process:*** Following corrective actions, additional samples are taken and analyzed to verify that the corrective actions were effective in returning the concentrations of contaminants such as chlorides, fluorides, sulfates, dissolved oxygen, and hydrogen peroxide to within the acceptable ranges. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

9. ***Administrative Controls:*** Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address administrative controls.

10. ***Operating Experience:*** The EPRI guideline documents have been developed based on plant experience and have been shown to be effective over time with their widespread use. The specific examples of operating experience are as follows:

    BWR: Intergranular stress corrosion cracking (IGSCC) has occurred in small- and large-diameter BWR piping made of austenitic stainless steels and nickel-base alloys. Significant cracking has occurred in recirculation, core spray, residual heat removal (RHR) systems, and reactor water cleanup (RWCU) system piping welds. IGSCC has also occurred in a number of vessel internal components, including core shroud, access hole cover, top guide, and core spray spargers (Nuclear Regulatory Commission [NRC] Bulletin 80-13, NRC Information Notice [IN] 95-17, NRC Generic Letter [GL] 94-03, and NUREG-1544). No occurrence of SCC in piping and other components in standby liquid control systems exposed to sodium pentaborate solution has ever been reported (NUREG/CR-6001).

    PWR Primary System: The primary pressure boundary piping of PWRs has generally not been found to be affected by SCC because of low dissolved oxygen levels and control of primary water chemistry. However, the potential for SCC exists due to inadvertent introduction of contaminants into the primary coolant system from unacceptable levels of contaminants in the boric acid, introduction through the free surface of the spent fuel pool (which can be a natural collector of airborne contaminants), or introduction of oxygen during cooldown (NRC IN 84–18). Ingress of demineralizer resins into the primary system has caused IGSCC of Alloy 600 vessel head penetrations (NRC IN 96-11, NRC GL 97-01). Inadvertent introduction of sodium thiosulfate into the primary system has caused IGSCC of steam generator tubes. The SCC has occurred in safety injection lines (NRC INs 97-19 and 84-18), charging pump casing cladding (NRC INs 80-38 and 94-63), instrument nozzles in safety injection tanks (NRC IN 91-05), and safety-related SS piping

systems that contain oxygenated, stagnant, or essentially stagnant borated coolant (NRC IN 97-19). Steam generator tubes and plugs and Alloy 600 penetrations have experienced primary water stress corrosion cracking (PWSCC) (NRC INs 89-33, 94-87, 97-88, 90-10, and 96-11; NRC Bulletin 89-01 and its two supplements).

PWR Secondary System: Steam generator tubes have experienced ODSCC, IGA, wastage, and pitting (NRC IN 97-88, NRC GL 95-05). Carbon steel support plates in steam generators have experienced general corrosion. The steam generator shell has experienced pitting and stress corrosion cracking (NRC INs 82-37, 85-65, and 90-04).

Such operating experience has provided feedback to revisions of the EPRI water chemistry guideline documents.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

BWRVIP-29 (EPRI TR-103515), *BWR Water Chemistry Guidelines-1993 Revision, Normal and Hydrogen Water Chemistry*, Electric Power Research Institute, Palo Alto, CA, February 1994.

BWRVIP-79, *BWR Water Chemistry Guidelines,* Electric Power Research Institute, Palo Alto, CA, March 2000.

BWRVIP-130, *BWR Water Chemistry Guidelines,* Electric Power Research Institute, Palo Alto, CA, October 2000.

EPRI TR-102134, *PWR Secondary Water Chemistry Guideline-Revision 3*, Electric Power Research Institute, Palo Alto, CA, May 1993.

EPRI TR-105714, *PWR Primary Water Chemistry Guidelines–Revision 3*, Electric Power Research Institute, Palo Alto, CA, Nov. 1995.

EPRI TR-1002884, *PWR Primary Water Chemistry Guidelines*, Electric Power Research Institute, Palo Alto, CA, October 2003.

NRC Bulletin 80-13, *Cracking in Core Spray Piping*, U.S. Nuclear Regulatory Commission, May 12, 1980.

NRC Bulletin 89-01, *Failure of Westinghouse Steam Generator Tube Mechanical Plugs*, U.S. Nuclear Regulatory Commission, May 15, 1989.

NRC Bulletin 89-01, Supplement 1, *Failure of Westinghouse Steam Generator Tube Mechanical Plugs*, U.S. Nuclear Regulatory Commission, November 14, 1989.

NRC Bulletin 89-01, Supplement 2, *Failure of Westinghouse Steam Generator Tube Mechanical Plugs*, U.S. Nuclear Regulatory Commission, June 28, 1991.

EXHIBIT 19

LRA

Appendix A.2.1.2. and B.1.2

water samples and periodic areal density measurements, and (3) analysis of criticality to assure that the required 5% subcriticality margin is maintained.

A.2.1.2 Buried Piping and Tanks Inspection Program

NB

The Buried Piping and Tanks Inspection Program includes (a) preventive measures to mitigate corrosion and (b) inspections to manage the effects of corrosion on the pressure-retaining capability of buried carbon steel, stainless steel, and titanium components. Preventive measures are in accordance with standard industry practice for maintaining external coatings and wrappings. Buried components are inspected when excavated during maintenance. If trending within the corrective action program identifies susceptible locations, the areas with a history of corrosion problems are evaluated for the need for additional inspection, alternate coating, or replacement.

A focused inspection will be performed within the first 10 years of the period of extended operation, unless an opportunistic inspection (or an inspection via a method that allows assessment of pipe condition without excavation) occurs within this ten-year period.

A.2.1.3 BWR CRD Return Line Nozzle Program

Under the BWR CRD Return Line Nozzle Program, PNPS has cut and capped the CRD return line nozzle to mitigate cracking and continues inservice inspection (ISI) examinations to monitor the effects of crack initiation and growth on the intended function of the control rod drive return line nozzle and cap. ISI examinations include ultrasonic inspection of the nozzle-to-vessel weld and ultrasonic inspection of the dissimilar metal weld overlay at the nozzle.

A.2.1.4 BWR Feedwater Nozzle Program

Under the BWR Feedwater Nozzle Program, PNPS has removed feedwater blend radii flaws, removed feedwater nozzle cladding, and installed a triple-sleeve-double-piston sparger to mitigate cracking. This program continues enhanced inservice inspection (ISI) of the feedwater nozzles in accordance with the requirements of ASME Section XI, Subsection IWB and the recommendation of General Electric (GE) NE-523-A71-0594 to monitor the effects of cracking on the intended function of the feedwater nozzles.

A.2.1.5 BWR Penetrations Program

The BWR Penetrations Program includes (a) inspection and flaw evaluation in conformance with the guidelines of staff-approved boiling water reactor vessel and internals project (BWRVIP) documents BWRVIP-27 and BWRVIP-49 and (b) monitoring and control of reactor coolant water chemistry in accordance with the guidelines of BWRVIP-130 to ensure the long-term integrity of vessel penetrations and nozzles.

B.1.2 BURIED PIPING AND TANKS INSPECTION

Program Description

The Buried Piping and Tanks Inspection Program at PNPS is comparable to the program described in NUREG-1801, Section XI.M34, Buried Piping and Tanks Inspection.

This program includes (a) preventive measures to mitigate corrosion and (b) inspections to manage the effects of corrosion on the pressure-retaining capability of buried carbon steel, stainless steel, and titanium components. Preventive measures are in accordance with standard industry practice for maintaining external coatings and wrappings. Buried components are inspected when excavated during maintenance.

A focused inspection will be performed within the first 10 years of the period of extended operation, unless an opportunistic inspection (or an inspection via a method that allows assessment of pipe condition without excavation) occurs within this ten-year period.

NUREG-1801 Consistency

The Buried Piping and Tanks Inspection Program at PNPS will be consistent with program attributes described in NUREG-1801, Section XI.M34, Buried Piping and Tanks Inspection, with one exception.

Exceptions to NUREG-1801

The Buried Piping and Tanks Inspection Program at PNPS will be consistent with program attributes described in NUREG-1801, Section XI.M34, Buried Piping and Tanks Inspection, with the following exception.

Attributes Affected	Exception
4. Detection of Aging Effects	Inspections via methods that allow assessment of pipe condition without excavation may be substituted for inspections requiring excavation solely for the purpose of inspection.[1]

Exception Note

1. Methods such as phased array UT technology provide indication of wall thickness for buried piping without excavation. Use of such methods to identify the effects of aging is preferable to excavation for visual inspection, which could result in damage to coating or wrappings.

Enhancements

None

Operating Experience

The Buried Piping and Tanks Inspection Program at PNPS is a new program for which there is no operating experience.

Conclusion

Implementation of the Buried Piping and Tanks Inspection Program will provide reasonable assurance that effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

EXHIBIT 20

Cox Decl. at ¶¶ 23-24

January 8, 2008

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

Before the Atomic Safety and Licensing Board Panel

In the Matter of	)	
	)	
Entergy Nuclear Generation Company and	)	Docket No. 50-293-LR
Entergy Nuclear Operations, Inc.	)	ASLBP No. 06-848-02-LR
	)	
(Pilgrim Nuclear Power Station)	)	

Testimony of Alan Cox, Brian Sullivan, Steve Woods, and William Spataro on Pilgrim Watch Contention 1, Regarding Adequacy of Aging Management Program for Buried Pipes and Tanks and Potential Need for Monitoring Wells to Supplement Program

to the LRA and are provided in Entergy Exhibit 2, which contains relevant excerpts from the LRA.

The objective of the AMPs as applied to buried pipes and tanks is to maintain the pressure boundary of the buried pipes and tanks in a manner providing reasonable assurance that the associated systems can perform their system intended functions. The BPTIP manages loss of material due to external corrosion of buried pipes, while the other AMPs manage loss of material due to internal corrosion of buried pipes.

1. PNPS BPTIP

Q36. Please describe the BPTIP.

A36. (ABC) The Buried Piping and Tanks Inspection Program ("BPTIP") manages the effects of aging on the external surfaces of buried components, specifically, the potential loss of material (i.e., the effect of aging caused by corrosion) from the external surfaces of components buried in soil. As explained in the PNPS LRA, it includes (1) preventive measures to inhibit the corrosion of external surfaces of buried pipes and tanks exposed to soil, such as selection of corrosion resistant materials and/or application of protective coatings, and (2) inspections to manage the effects of external surface corrosion on the pressure-retaining capability of buried carbon steel, stainless steel, and titanium components. See PNPS LRA at Appendix B, Section B.1.2, p. B-17-18 (Entergy Exhibit 2).

a. Preventive Measures for CSS and SSW Buried Piping

Q37. What preventive measures does PNPS employ for in-scope buried pipes for the CSS and the SSW system?

A37. (SPW) PNPS employs several preventive measures to protect against the degradation of buried pipes in the CSS and SSW system (which do not contain buried tanks).

EXHIBIT 21

Affidavit Dr. James Davis

June 28, 2007

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of	)	
	)	
Entergy Nuclear Operations, Inc.	)	Docket No. 50-293-LR
	)	
(License Renewal for Pilgrim	)	
Nuclear Power Station)	)	

AFFIDAVIT OF DR. JAMES A. DAVIS CONCERNING ENTERGY'S MOTION
FOR SUMMARY DISPOSITION OF PILGRIM WATCH CONTENTION 1

16. Material fact 21 states that industry practice has shown that properly applied coatings will prevent corrosion of the piping as long as the soil is not extremely aggressive (as Entergy states is not the case at Pilgrim) or unless there is damage during application of the coating and handling of the pipe. During my many years working in the pipeline industry and working on many pipeline coating standards committees, I have found this to be an accurate statement.

EXHIBIT 22

NRC Office of Inspector General (OIG), Office of Inspector General's Audit of NRC's License Renewal Program

AUDIT REPORT

Audit of NRC's License Renewal Program

OIG-07-A-15 September 6, 2007

All publicly available OIG reports (including this report) are accessible through NRC's Web site at:
http:/www.nrc.gov/reading-rm/doc-collections/insp-gen/

I. EXECUTIVE SUMMARY

BACKGROUND

U.S. Nuclear Regulatory Commission (NRC) regulations limit the term of an initial nuclear reactor operating license to 40 years. However, the regulations also allow a license to be renewed for an additional 20 years given that the initial term was based on economic and anti-trust considerations, not technical limitations. Through technical research, NRC concluded that many aging phenomena are readily managed and therefore should not preclude renewal of a reactor license.

NRC published requirements for license renewal in the *Code of Federal Regulations* (CFR). 10 CFR Part 54[1] addresses operating safety issues – the main focus of this Office of the Inspector General (OIG) report. Part 54 was amended in 1995 to concentrate NRC's reviews on how licensees manage adverse effects of aging to provide reasonable assurance that plants will continue to operate in accordance with their current licensing basis for the period of extended operations.

PURPOSE

The purpose of OIG's audit was to determine the effectiveness of NRC's license renewal safety reviews.

RESULTS IN BRIEF

Overall, NRC has developed a comprehensive license renewal process to evaluate applications for extended periods of operation. However, OIG identified areas where improvements would enhance program operations. Specifically,

[1] 10 CFR Part 54, *Requirements for Renewal of Operating Licenses for Nuclear Power Plants.*

- License renewal reporting efforts need improvements
  - Reporting issues exist because the agency has not fully established report-writing standards or a report quality assurance process. As a result, those who read the reports could conclude that regulatory decisions are not adequately reviewed and documented.
- Guidance for removing licensee documents from audit sites could be clarified
  - Inconsistencies regarding removal of documents result from audit teams being prohibited by their management from removing licensee-supplied documents from audit sites, whereas the inspectors do keep such documents to assist in report writing. As a result, it is more difficult for audit team members to write their reports without using workaround tools.
- Consistent evaluation of operating experience would improve NRC reviews
  - Although expected to, audit team members do not consistently review or independently verify licensee-supplied operating experience information because program managers have not established requirements and controls to standardize the conduct and depth of such reviews. Consequently, license renewal auditors may not have adequate assurances that relevant operating experience was captured in the licensee's renewal application for NRC's consideration.
- More attention is needed to planning for post-renewal inspections
  - Post-renewal inspections are considered vital to ensure that licensees adhered to commitments made for license renewal. However, the agency has only recently focused its attention on developing and overseeing details associated with these inspections. Inadequate planning increases the risk that: licensees could enter into the extended period of operation without being in full compliance with license renewal terms; inspections will

be inconsistently implemented; and inspection and technical support resources will be unavailable when needed.

- License renewal issues need evaluation for backfit application
  - When NRC imposes new staff positions resulting in new review standards, a documented justification is required pursuant to the backfit rule. However, new license renewal review standards have not followed NRC's backfit policy because NRC does not have a mechanism or methodology to trigger such a backfit review. Consequently, the use of different review standards without a backfit justification may result in several management challenges.

RECOMMENDATIONS

This report makes eight recommendations to help NRC improve the effectiveness of its License Renewal Program. Seven of the recommendations are addressed to the Executive Director for Operations. In consideration of the agency's formal comments concerning the applicability of the backfit rule to license renewal applicants, the last recommendation is directed to the Commission. A Consolidated List of Recommendations appears in Section IV.

OIG ANALYSIS OF AGENCY COMMENTS

On May 8, 2007, OIG issued its draft report to the Executive Director for Operations. On July 6, 2007, the Deputy Executive Director for Reactor Programs provided a formal response to this report in which the agency disagreed with OIG's finding regarding applicability of the backfit rule to license renewal applicants. The agency's transmittal letter and specific comments on this report are included in their entirety as Appendix E.

This final report incorporates revisions made, where appropriate, as a result of the subsequent meetings with staff and the agency's written comments. Appendix F contains OIG's analysis of the agency's formal response.

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I. BACKGROUND

The Atomic Energy Act of 1954, as amended, and U.S. Nuclear Regulatory Commission (NRC) regulations limit the term of an initial nuclear reactor operating license to 40 years. The regulations also allow a license to be renewed for an additional 20 years given that the initial term was based on economic and anti-trust considerations, not technical limitations. Nonetheless, NRC recognizes that some plant systems, structures, and components (SSC) may have been engineered with the expectation of a limited 40-year service life. Through technical research, NRC concluded that many aging phenomena are readily managed and therefore should not preclude renewal of a reactor license.

In the early 1990s, NRC published requirements for license renewal in the *Code of Federal Regulations* (CFR). 10 CFR Part 51 addresses environmental issues.[2] 10 CFR Part 54[3] addresses operating safety issues — the main focus of this Office of the Inspector General (OIG) report. Part 54 was amended in 1995 to concentrate NRC's reviews on how licensees manage adverse effects of aging to provide reasonable assurance that plants will continue to operate in accordance with their current licensing basis for the period of extended operations.

In July 2001, NRC issued NUREG-1801, *Generic Aging Lessons Learned (GALL) Report*, as the agency's primary technical basis document for NRC-approved programs for managing the aging of a large number of structures and components that are subject to aging management reviews.

Agency Assumptions

The two key principles of license renewal are: 1) NRC's existing regulatory process adequately ensures that currently operating plants will continue to maintain adequate levels of safety during extended operation, with the possible exception of detrimental

[2] In response to the National Environmental Policy Act, NRC also pursued an environmental rule, 10 CFR Part 51, *Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions*, revised 1996.

[3] 10 CFR Part 54, *Requirements for Renewal of Operating Licenses for Nuclear Power Plants.*

effects of aging on certain SSCs, and a few other issues that may arise during the period of extended operation; and 2) each plant's licensing basis is required to be maintained during the renewal term in the same manner and extent as during the original licensing term. NRC incorporates the following assumptions into its reviews of license renewal applications:

- an applicant should rely on the plant's current licensing basis,[4] actual plant-specific experience, applicable industry-wide operating experience, and existing engineering evaluations to determine which plant SSCs are the initial focus of a license renewal review; and

- a plant's "active" components[5] do not require additional review during license renewal because aging effects of active components are more readily detected and corrected through routine surveillance and maintenance. Therefore, the license renewal process limits its reviews to "passive and long-lived" plant structures and components,[6] time-limited aging analyses,[7] and aging management programs for renewal-related components.

Review Process and Program Responsibilities

In order to assess the reliability of its assumptions about aging, NRC uses a review process that proceeds along two parallel tracks:

---

[4] "Current licensing basis" is the set of NRC requirements applicable to a specific plant and a licensee's written regulatory commitments for ensuring compliance and operation within applicable NRC requirements and the plant-specific design basis that are docketed and in effect.

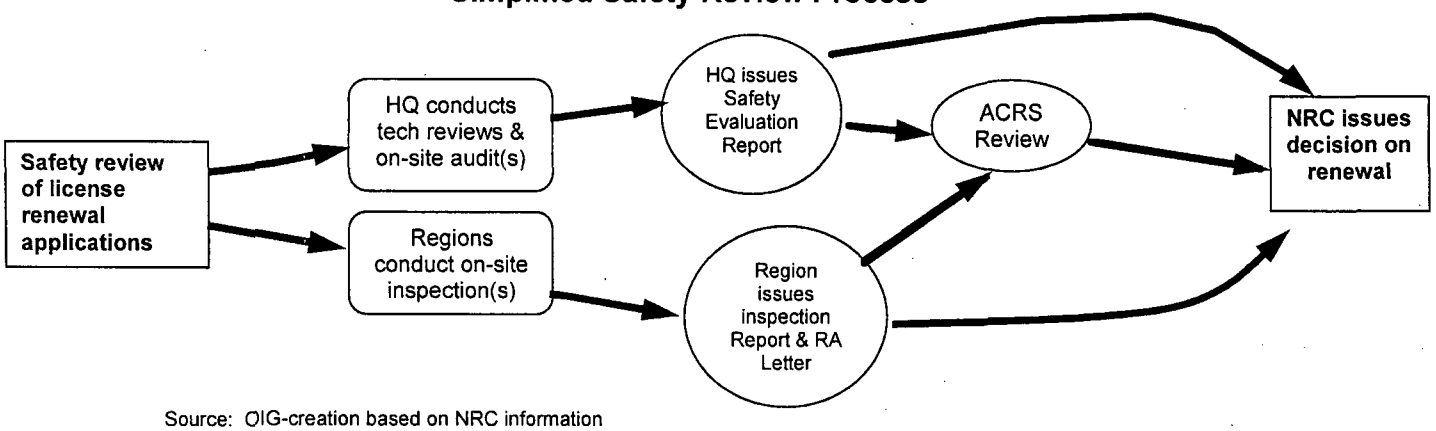
[5] "Active" components include motors, diesel generators, cooling fans, batteries, relays, and switches.

[6] "Passive" and "long-lived" structures and components are those that perform an intended function without moving parts or a change in properties, and those not subject to replacement based on qualified life or specified time period, respectively. Passive and long-lived SSCs include reactor vessels, reactor coolant system piping, steam generators, pressurizers, pump casings, and valve bodies.

[7] "Time-limited aging analyses" are licensee calculations and analyses that: involve SSCs within the scope of license renewal; consider aging effects; involve assumptions defined by the current 40-year operating term; are relevant for making a safety decision; involve basis for decision that SSCs are capable of performing their intended functions; and are contained in or referenced in the current license basis.

a safety review (Part 54) and an environmental review (Part 51). Figure 1 reflects a simplified license renewal safety review process. (See Appendix B for the NRC's dual-track license renewal review process.)

Figure 1
Simplified Safety Review Process



Source: OIG-creation based on NRC information

As reflected in Figure 1, the safety review process consists of headquarters-based technical reviews, on-site audits, and region-based inspections. Primary responsibility for the license renewal program lies within NRC's Office of Nuclear Reactor Regulation (NRR), Division of License Renewal (DLR). DLR project teams, consisting of technical auditors and engineer consultants, perform on-site audits to review the supporting documentation for those aging management programs and aging management reviews cited in the licensee's application as consistent with the *GALL Report* or based on NRC-accepted past precedence. Concurrently, NRR's headquarters-based engineering divisions review scoping and screening of SSCs, plant-specific aging management programs and aging management reviews, and other items not addressed in the *GALL Report* (e.g., unresolved or emergent issues). The results of the NRC staff's review are documented in a safety evaluation report.

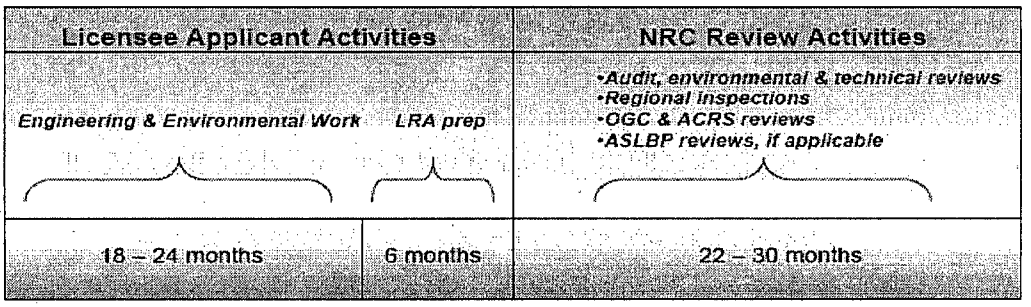
Additionally, teams of specialized inspectors from NRC's four region offices travel to the reactor sites to verify the licensees' claims that current or proposed aging management programs will be effective.

The Advisory Committee on Reactor Safeguards (ACRS) acts as an independent third-party oversight group who reviews safety evaluation report findings as well as inspection report findings and makes recommendations on the renewal application to the Commission. Throughout the process, NRC's Office of the General Counsel (OGC) provides legal and regulatory interpretations as needed and formally reviews and concurs on the safety evaluation reports. When applicable, the Atomic Safety and Licensing Board rules on stakeholders' requests for license renewal hearings.

Application Review Timelines and Costs [8]

As shown in Figure 2, renewal application processing can take more than 4 years — approximately 2 years and $20 million is spent by licensees to research, document, and prepare a license renewal application for submission. For NRC's review and decision on an application, it typically takes 22 months and $4 million without a hearing, and a projected 30 months[9] with a hearing.

Figure 2
Application Preparation and Review Process



[8] Regulations allow for renewal applications to be submitted as early as 20 years before expiration of a current license, but licensees technically have until the end of their 40-year license to apply for an extension. However, NRC notes that if a "sufficient" application is not submitted at least 5 years prior to license expiration, a plant may have to cease operations until the renewal decision is made.

[9] OIG notes that NRC's projected 30-month schedule, including a hearing, has not yet been tested because none of the license renewals granted to date went through a hearing process.

Status of License Renewals

The agency's extensive experience with license renewal issues began in 1982. As of April 2007, approximately one-half of the Nation's licensed reactors have either received renewed licenses or are currently under review. Specifically, license extension requests for 48 of the 104 licensed power reactor units in the U.S. have been reviewed and approved. Additionally, eight renewal applications are currently under review while licensees representing an additional 23 plants have announced intentions to submit renewal applications through 2013.

Proactive License Renewal Program Features

NRC incorporated several features into the license renewal program that correspond to the agency's Principles of Good Regulation. For example,

- Several facets of openness are built into the process for public involvement, including open meetings and opportunities to request an adjudicatory hearing.

- For a more efficient license renewal review process:

  - the *GALL Report* was developed to document the basis for determining whether existing programs are adequate and for identifying those programs that warrant particular attention during NRC's review of a license renewal application,

  - NRC Regulatory Guide 1.188[10] helps standardize the format and content of license renewal applications, and

  - the audit function enables NRC staff to review more applications simultaneously by reducing the need for requests for additional information.

[10] Regulatory Guide 1.188, *Standard Format and Content For Applications to Renew Nuclear Power Plant Operating Licenses.*

- Some NRC staff and industry representatives made favorable comments to OIG about the clarity of NRC's guidance regarding the expected content for a renewal application and NRC's adherence to its established review schedule, which provides reliable planning assistance to NRC technical engineering divisions and future license renewal applicants.

II. PURPOSE

The purpose of OIG's audit was to determine the effectiveness of NRC's license renewal safety reviews. Appendix A provides a detailed description of the audit's scope and methodology.

III. FINDINGS

Overall, NRC has developed a comprehensive license renewal process to evaluate applications for extended periods of operation. However, OIG identified areas where improvements would enhance program operations. Specifically,

A. license renewal reporting efforts need improvements,

B. guidance for removing licensee documents from audit sites could be clarified,

C. consistent evaluation of operating experience would improve NRC reviews,

D. more attention is needed to planning for post-renewal inspections, and

E. license renewal issues need evaluation for backfit application.

A. NRC's License Renewal Reporting Efforts Need Improvements

Improvements to the staff's reporting efforts could provide necessary support for NRC's license renewal decisions. Adequate documentation of review methodologies and support for staff conclusions in license renewal reports is important for supporting the sufficiency and rigor of NRC's review process. However, the NRC staff does not consistently provide adequate descriptions of audit methodology or support for conclusions in license renewal reports. This is because DLR has not fully established report-writing standards and does not have a report quality assurance process to ensure adequate documentation. As a result, stakeholders and others who read the reports could conclude that regulatory decisions are not adequately reviewed and documented.

Review Documentation Standards and Current Guidance

NRC's license renewal reviews must be supported to demonstrate the adequacy and rigor of NRC's review process. One way to accomplish this is to have documentation to support conclusions in NRC's license renewal reports, which include the license renewal

audit, inspection, and safety evaluation reports. DLR's audit guidance also acknowledges the importance of documentation for reaching conclusions in the audit reports.

DLR is responsible for conducting on-site audits of the license renewal applications. The license renewal auditors, referred to internally as the project team, use a handbook titled, *Project Team Guidance for License Renewal Application Safety Reviews,* to guide the conduct of the audit. A peer review checklist in the *Project Team Guidance* reminds the reviewer to make sure the conclusions in the audit report are supported by adequate technical bases.

Review Methodology and Conclusions are Not Fully Described in Reports

License renewal audit, inspection, and safety evaluation reports do not provide full descriptions of the methodology the staff used to review an aging management program or provide full support for the staff's conclusions. In some cases, the language presented in the audit and safety evaluation reports mirrors the language provided by the licensee in its license renewal application, which, according to NRC, may have been taken by the licensee out of the *GALL Report* and placed in the application.

OIG performed a content analysis of audit, inspection, and safety evaluation reports for a judgmental sample[11] of license renewal applications submitted between September 2000 and January 2006.[12] For its analysis, OIG focused on narrative passages in the applications and reports that addressed the operating experience program element for a selection of aging management programs.[13] OIG's analysis resulted in 458 report narrative samples.

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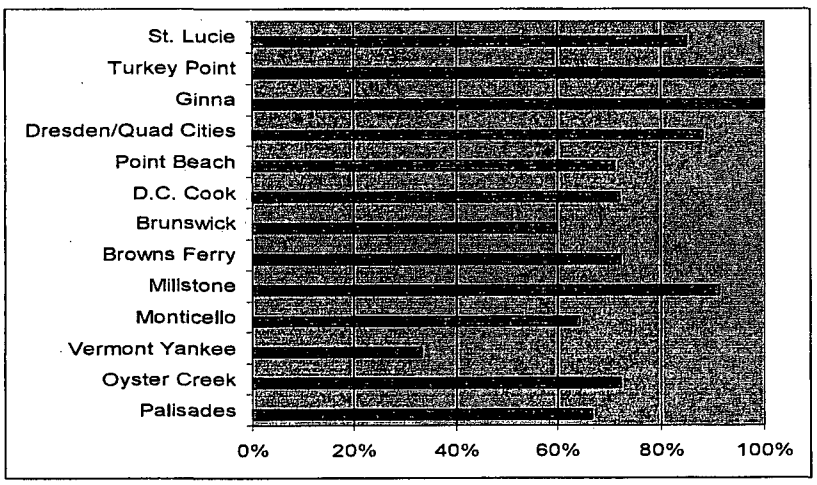
[11] Results of this judgmental sample are limited to the population of license renewal applications sampled.

[12] The judgmental sample of applications represents a cross-section of plant ages, technologies, year of renewal, NRC application review process used, and NRC region. A detailed description of OIG's content analysis methodology is presented in Appendix C.

[13] Operating experience is one of ten GALL program elements that a licensee's aging management program must satisfy in order to secure approval from NRC.

OIG found that approximately 76 percent of the audit, inspection, and safety evaluation report samples did not provide substantive NRC comments about operating experience. Operating experience is a critical facet of the review process. For its analysis, OIG defined non-substantive samples as those that 1) did not describe *any* review methodology for operating experience or provide *any* specific support for the staff's conclusions; or 2) provided information that was identical or nearly identical to the information provided in the licensee's renewal application. Figure 3 depicts, by plant license renewal application, the percent of report samples that did not provide substantive NRC comments about operating experience.

Figure 3
Percent of Report Samples Lacking Substantive Operating Experience Comments, by Plant



Source: OIG analysis of NRC license renewal audit, inspection, and safety evaluation reports; and of license renewal applications.

In some cases, the identical or nearly identical word-for-word repetition of renewal application text found in the audit, inspection, or safety evaluation reports are not offset or otherwise marked to indicate the text is identical to that found in the license renewal application. The lack of precision in differentiating quoted and unquoted text makes it difficult for the reader to distinguish between the licensee-provided data and NRC staff's independent assessment methodology and conclusion. A reader could conclude that they were reading NRC's independent analysis and conclusions when, in fact, it was the licensee's conclusions. While

NRC reviewers may have actually performed such an independent review, a comparison between the license renewal application and the audit report may cast doubt as to what, exactly, NRC did to independently review the licensee's program other than restate what was provided in the renewal application.

For example, NRC's narrative description of operating experience for Millstone's flow-accelerated corrosion program is nearly identical to the description provided in the licensee's renewal application. NRC's Millstone audit report, shown on the right side of Table 1 below, presents information about the trending successes in the Millstone flow-accelerated corrosion program and gives the appearance of the audit team's independent review and analysis. In fact, this passage is nearly identical to that presented in the license renewal application, shown in the left column of the table. Moreover, while NRC states that the project team reviewed operating experience, there is no discussion of what precisely was reviewed.

Table 1
Sample Comparison of Licensee and NRC Report Narrative[14]

Millstone Unit 2 renewal application	NRC's Millstone renewal audit report
The number of planned and unplanned replacements has generally trended downward over the past several years due to the establishment of the Flow-Accelerated Corrosion program and following the recommendations identified in NSAC-202L. (p. B-42)	*The project team reviewed operating experience for the applicant's Flow-Accelerated Corrosion program. The number of planned and unplanned replacements has generally trended downward over the past several years due to the establishment of the Flow-Accelerated Corrosion program and following the recommendations identified in NSAC-202L. (p. 67-8)*

Source: OIG analysis

[14] Additional examples are provided in Appendix D.

NRC staff stated that when the licensee claims an aging management program is consistent with the *GALL Report*, the licensee may copy the operating experience from the *GALL Report,* and the safety evaluation report may copy the application. However, OIG's analysis shows that—for the audit, inspection, and safety evaluation reports sampled—the staff's description of the methods used and the support they provided for their conclusions often lack substance.

Staff Report-Writing Standards Are Not Fully Established

DLR management has not fully established report-writing standards for describing the license renewal review methodology and providing support for conclusions in NRC license renewal audit, inspection, and safety evaluation reports. DLR managers said that they expected license renewal staff to use their own language and avoid copying directly from the license renewal application when writing renewal reports. The managers said they are aware of the importance of demonstrating NRC's independence in the license renewal reviews. DLR managers also said that they have verbally communicated and stressed their expectations to the staff. Yet, the *Project Team Guidance* does not reiterate these expectations or provide any report-writing standards that would support management's expectations. The *Project Team Guidance* instead focuses on the process of compiling the audit and safety evaluation reports and not on the quality of information presented in these reports.

DLR management pointed to some report quality assurance tools that involved audit team leader, peer group, and branch chief reviews of the audit and safety evaluation reports. DLR places the greatest emphasis on the audit team leader review to control report quality. DLR management and staff said that the peer review, conducted near the end of the report-writing process, is not a page-by-page review of the audit and safety evaluation reports but is primarily a spot review seeking to correct major mistakes in the reports. However, these tools have not ensured that the reports contain substantive documentation of NRC's application review methodology and independent support for staff conclusions.

Essentially, DLR lacks a complete report quality assurance process to ensure documentation of the staff's aging management program review methodology and substantive support for staff conclusions.

While the team leader and peer review tools currently in place could form the basis of a report quality assurance process, DLR does not currently have any way to measure or determine the effectiveness of these team leader and peer reviews. Nor does the Division have procedures that would specify additional report quality assurance steps to take, given a pattern or trend in discovered problems. Such procedures would help DLR management refine the report quality assurance process to meet the quality assurance needs of the audit teams and division directors, as well as those—like ACRS members—who depend on the audit and safety evaluation reports for their review responsibilities.

NRC Basis for Conclusions Important to Stakeholders

The basis for conclusions reached by NRC license renewal review staff is important to stakeholders and others who read NRC's reports. The lack of an effective report quality assurance process to ensure that review methodology and support for conclusions are provided in the license renewal reports could lead readers to conclude that regulatory decisions are not adequately reviewed and documented. Furthermore, providing more substantive analysis and conclusions would help NRC better meet its strategic goal of transparency.

NRC internal users—such as members of the ACRS—benefit from more substantive discussions of license renewal review methodologies and support for conclusions. ACRS members said that they rely on information in all of the license renewal reports, and pointed specifically to the value of the level of detail in the audit reports.

RECOMMENDATIONS:

OIG recommends that the Executive Director for Operations:

1. Establish report-writing standards in the *Project Team Guidance* for describing the license renewal review methodology and providing support for conclusions in the license renewal reports.

2. Revise the report quality assurance process for license renewal report review to include:

   - establishing management controls for NRR and DLR management to gauge the effectiveness of team leader and peer group report reviews, and

   - implementing procedures that would specify additional report quality assurance steps to be taken in the event that the team leader and peer group report reviews fail to ensure report quality to management's expectations.

B. Guidance for Removing Licensee Documents from Audit Sites Could Be Clarified

OIG found inconsistencies in the guidance provided to license renewal auditors with regard to removing licensee documents obtained at audit sites. License renewal audit teams should collect and document the information they review during site visits. However, audit teams are prohibited by DLR from removing licensee documents from the audit site, which makes it more difficult for audit team members to write their reports without using workaround tools. DLR's policy also creates document handling inconsistencies with inspectors, who do keep documents obtained from the licensee's site.

Information Collection Guidance

As noted earlier, the license renewal audit team uses the *Project Team Guidance,* to guide the conduct of the audit. With regard to documentation, the *Project Team Guidance* exhorts auditors to "properly collect and document the information they review during site visits," especially for information used as a basis for reaching a conclusion regarding the audit and safety evaluation reports.

Audit Teams Prohibited from Removing Licensee Documents from Audit Site

License renewal audit teams, as a matter of DLR policy, are prohibited by their management from removing copies of licensee-provided documents from the audit site. The licensee provides an extensive amount of bases and technical documents for DLR auditors. DLR auditors review these documents for information that may answer their questions about the license renewal application. Licensee staff may exert great effort to make multiple copies of documents available, both in hard copy and on compact disc. Because DLR management prohibits auditors from removing licensee-provided documents, auditors use the time available on-site to peruse the documents and interview licensee staff.

License renewal auditors said that being allowed to take documents offsite would aid them in writing and supporting their audit and safety evaluation report inputs. They thus resorted to removing documents provided by the licensee in violation of the Division's policy.

DLR management's policy to prohibit license renewal auditors from removing licensee-provided documents from the audit site is also contrary to the policy and practice for license renewal inspectors. For example, NRC region-based license renewal inspectors said that the renewal inspection teams can and do take documents from the site. The inspectors said it is standard procedure to dispose of licensee documents once their report is written.

Guidance for Removing Licensee Documents from Audit Sites is Inconsistent

OIG found inconsistencies in the guidance provided to license renewal auditors with regard to removing copies of licensee-provided documents from audit sites. DLR management provides the audit teams with verbal guidance to never remove licensee documents obtained from the audit site. However, DLR's *Project Team Guidance* appears to permit some removal of licensee documents from an audit site, as indicated on page 26:

> *"The project team shall not take documents from an applicant's site for in-office review, unless the documents are either already in ADAMS or the applicant agrees that the NRC can put the document in ADAMS."*[15]

Elsewhere, the *Project Team Guidance* states that "if the documentation cannot go on the docket or into ADAMS then it cannot be taken off site." A more permissive document removal policy is provided to inspectors through Inspection Manual Chapter 0620.[16] It provides a number of acceptable practices for obtaining licensee documents, including sending an inspector to the site or using the licensee's equipment to make copies of relevant materials. The guidance states that copies of licensee records and documents may be reviewed offsite with the licensee's permission.

When asked the reason for the more restrictive verbal removal policy, DLR managers echoed the rationale provided by the *Project Team Guidance*. They said that most documents provided by the

[15] ADAMS is NRC's Agencywide Documents Access and Management System.

[16] Inspection Manual Chapter 0620, *Inspection Documents and Records*, dated January 27, 2006.

licensee at the audit site have not been docketed by NRC and, therefore, DLR does not want license renewal auditors to bring the undocketed items back to headquarters. According to DLR management, OGC told NRR staff that all documents that NRC auditors bring back "must be docketed."

A senior attorney involved with the License Renewal Program said that OGC warned NRR management not to take documents unless they are willing to "give them up" through a Freedom of Information Act request or via a mandatory disclosure requirement for a hearing. The OGC attorney could not identify any specific guidance that required NRC to put licensee documents on the docket, and admitted that NRC's criteria regarding what licensee documents must be docketed by the agency is unclear.

The OGC attorney also said that the practice among region-based inspectors to remove licensee-provided documents from a license renewal site is acceptable. However, the attorney expressed concern about the inconsistent practices of the license renewal audit and inspection staffs regarding the removal of documents from license renewal sites.

Consequences of DLR's Documentation Policies and Practices

DLR's prohibition on its audit staff from removing documents provided by the licensee at license renewal sites makes it more difficult for the auditors to write their inputs to the audit and safety evaluation reports. Instead, the audit staff has to rely on notes and memory, and use other source document workarounds—such as worksheets and the licensee-managed database of questions and answers—to construct input for the audit and safety evaluation reports. Given the Division's greater reliance on the staff to perform audits with fewer contractors, any effort to provide auditors with source documents may contribute to review efficiencies.

Furthermore, NRR's policy also leads to document handling inconsistencies between the license renewal audit and inspection teams. The same blanket prohibition on removal of licensee documents from the licensee's site does not extend to license renewal inspectors.

RECOMMENDATION:

OIG recommends that the Executive Director for Operations:

3. Clarify guidance and adjust procedures for auditors' and inspectors' removal of licensee-provided documents from license renewal sites

C. Consistent Evaluation of Operating Experience Would Improve NRC Reviews

License renewal audit teams have a unique opportunity to improve the NRC license renewal review with a deeper and more consistent approach to reviewing operating experience. Operating experience plays an important role in license renewal, and the license renewal staff is expected to review plant-specific operating experience, including corrective actions. Yet, audit team members do not review operating experience consistently. Furthermore, most audit team members do not conduct independent verification of operating experience, instead relying on licensee-supplied information. This is because program managers have not established requirements and controls to standardize the conduct and depth of such reviews. In the absence of conducting independent verification of plant-specific operating experience, license renewal auditors may not have adequate assurances that relevant operating experience was captured in the licensee's renewal application for NRC's consideration.

The Importance of Operating Experience to License Renewal

Operating experience plays an important role in license renewal and figures prominently in a licensee's renewal application. NRC's *Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants* (Standard Review Plan) instructs NRC staff to assess 10 program elements for each aging management program submitted in a licensee's renewal application. Operating experience is listed as one of these 10 elements, and defined in brief in the *Generic Aging Lessons Learned (GALL) Report* summary as follows:

> *"Operating experience involving the aging management program, including past corrective actions resulting in program enhancements or additional programs, should provide objective evidence to support a determination that the effects of aging will be adequately managed so that the structure and component intended functions will be maintained during the period of extended operation." (p. 2)*

Operating experience is also an important part of two other aging management program elements: specifically, detection of aging effects, and monitoring and trending. The Standard Review Plan

also calls attention to the importance of the licensee's plant-specific operating experience in relation to scoping and screening, aging management review, and time-limited aging analyses activities. DLR management also said that it expects its license renewal staff to review plant-specific operating experience, including corrective actions. Given the Standard Review Plan's emphasis on operating experience and on management's expectations, OIG concludes there is ample reason for the licensee to provide—and NRC to review—sufficient amounts of operating experience information and data.

Operating Experience Is Not Consistently Reviewed or Independently Verified

When reviewing aging management programs, license renewal audit team members do not approach their reviews of operating experience consistently and, furthermore, most team members do not conduct independent verification of operating experience. Team members are assigned aging management programs to review based on their areas of expertise. A more experienced reviewer or auditor may look more in-depth at, or conduct independent spot checks of, licensee-submitted information provided in the license renewal application.

OIG asked license renewal auditors and management about the appropriateness of conducting independent searches of licensee operating experience. Such searches might examine the licensees' corrective actions, system health reports, and inspection results. NRR managers said that they expect the audit teams to review plant-specific operating experience. Some managers said they expected license renewal auditors to perform their own searches of corrective actions rather than rely solely on information provided by the licensee.

However, license renewal auditors said that they generally do not conduct independent searches of licensee corrective action databases and that auditors would not normally review a plant's corrective action program for each aging management program because the industry-wide experience is already known. One reviewer said that it is the licensee's responsibility to provide NRC with plant-specific operating experience that is different from industry-wide operating experience. The auditor reviews only what the licensee provided in its application. Another reviewer said

that capturing plant-specific operating experience is time-consuming or that it is too difficult to learn how to use the licensees' corrective action program databases.

With the assistance of an OIG technical advisor having a general engineering background, OIG sought to learn how difficult it would be to generate a useful database report of corrective actions. OIG staff visited two separate plants owned by large utility companies and, using computers attached to the respective owners' local area networks, performed keyword searches of the corrective action databases.[17] OIG's technical advisor searched the available network data for the host plant and for several other already renewed plants in their respective fleets.[18]

From these searches, OIG was able to identify a number of areas for each plant that would warrant follow-up questions for licensees regarding past performance of license renewal aging management programs. Given the time to conduct and analyze the database searches, OIG concluded that accessing the corrective action databases was relatively easy and provided access to a good deal of information of potential value to license renewal audit teams. OIG does not believe that the results of such a search would necessarily validate an entire aging management program, but the endeavor does identify a relatively easy way for license renewal auditors to conduct an independent check of the information provided by the licensee.

Requirements to Independently Verify Operating Experience Have Not Been Established

License renewal program managers have not established requirements or controls to standardize the conduct of independent verifications and depth of probes of plant-specific operating experience during audit reviews of licensee applications. That is not to suggest that DLR management has failed to mention the importance of reviewing operating experience to audit teams. On

[17] Keywords included "corrosion," "cracking," "fatigue," "leak," "pitting," "drywell," "HPCI," "primary containment," "secondary containment," and "Torus."

[18] It is important to note that OIG staff had no previous experience or familiarity using these databases. At both plant sites, OIG staff needed approximately 5 hours total to learn basic search mechanisms for the corrective action databases, and then perform the keyword search for three plants in each fleet.

the contrary, OIG observed DLR management discussing the importance of plant-specific operating experience with license renewal auditors at a team meeting.

DLR management has not set any formal requirements that license renewal audit teams independently verify plant-specific operating experience as a standard part of their reviews. The *Project Team Guidance* handbook instructs reviewers to compare program elements for the plant's aging management programs to the corresponding program elements for GALL-identified aging management programs. But the *Project Team Guidance* handbook does not include any specific direction about how this should be accomplished. Essentially, the guidance leaves a lot of leeway to individual auditors to review operating experience as they see fit.

DLR also has no controls to monitor and enforce operating experience verification, which incorporate independent searches of corrective action databases. One manager said that more management controls to bring consistency to the reviews would be welcomed. The manager pointed out that DLR management can require audit teams to perform deeper probes of operating experience, but has no way of determining whether the auditors follow through.

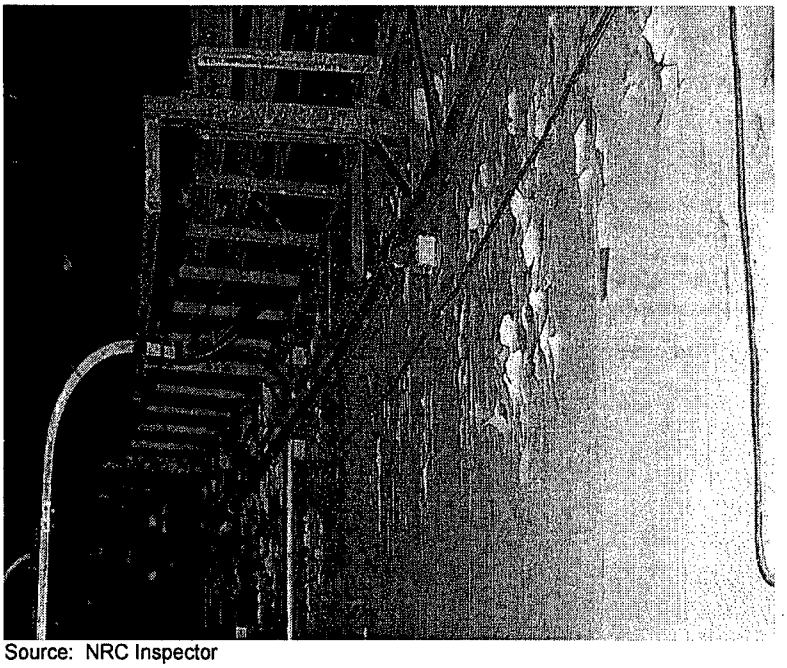
Auditors May Not Be Aware of All Relevant Operating Experience

In the absence of conducting independent verification of plant-specific operating experience, license renewal auditors may not have adequate assurances that all relevant operating experience was captured in the licensee's renewal application. As reported above, OIG was able to identify a number of areas for each plant that would warrant follow-up questions for licensees regarding past performance of license renewal aging management programs.

OIG's work in this area was, in part, informed by a discrepancy noted while reviewing the Oconee license renewal application. NRC received the Oconee plant's license renewal application in July 1998, whereupon the application remained under review until renewal was granted in May 2000. The application stated that minor local containment coatings failures had been observed and

repaired. Yet, the Oconee corrective action program contained 20 entries for degraded coatings from 1995-2003.[19] OIG's analysis of this corrective action program indicates that the coatings aging management program had not been implemented consistent with the statements in the Oconee license renewal application. In fact, coatings degradation was a continuing problem at the Oconee Nuclear Station as of Spring 2004, the date of the photograph presented in Figure 4 below, casting doubt on the efficacy of Oconee's aging management program for coatings.

Figure 4
Example of Coatings Degradation at Oconee



Source: NRC Inspector

NRC license renewal reports do not indicate that NRC reviewers independently verified Oconee's operating experience for coatings. The license renewal inspection report states that the inspection included a review of the program description documents and discussion of the program with a site engineer. The inspection report concluded, based on the program document review and the

[19] Six of the entries were made prior to the submittal of the license renewal application in 1998. Two of the entries were made after the renewal application was submitted, but prior to the granting of the renewed license in May of 2000.

discussion, that the "team verified that this previously existing program was implemented as described in the [license renewal application]." The license renewal safety evaluation report for Oconee quotes or paraphrases passages from the Oconee renewal application, including the licensee's conclusion that the program is based on well-established industry standards and has been revised as necessary on the basis of plant experience. The staff acknowledged in the safety evaluation report that the licensee did not provide coatings program operating experience in its application, yet the staff did not offer any indication of having conducted an independent look at coatings operating experience.

OIG contends that a quickly-performed, independent search of the Oconee corrective action database would have revealed discrepancies with the information and assessment provided by the licensee in the renewal application. Such a search would have generated the corrective action reports that described continuing coatings problems and raised questions about the licensee's contention that minor local containment coatings failures have been observed and repaired. Moreover, performing and documenting this type of search helps NRC prevent the appearance that license renewal reviewers trust information provided by the licensee in the renewal application without verification.

RECOMMENDATION:

OIG recommends that the Executive Director for Operations:

4. Establish requirements and management controls to standardize the conduct and depth of license renewal operating experience reviews.

EXHIBIT 23

Event No. 43882, Event Notification report, December 11, 2007

Event Notification Report for December 11, 2007

U.S. Nuclear Regulatory Commission
Operations Center

Event Reports For
12/10/2007 - 12/11/2007

** EVENT NUMBERS **

43832

TOP

Power Reactor	Event Number: 43832
Facility: PALISADES Region: 3 State: MI Unit: [1] [ ] [ ] RX Type: [1] CE NRC Notified By: TODD MULFORD HQ OPS Officer: JASON KOZAL	Notification Date: 12/10/2007 Notification Time: 22:21 [ET] Event Date: 12/10/2007 Event Time: 18:30 [EST] Last Update Date: 12/10/2007
Emergency Class: NON EMERGENCY 10 CFR Section: 50.72(b)(2)(xi) - OFFSITE NOTIFICATION	Person (Organization): JOHN MADERA (R3)

Unit	SCRAM Code	RX CRIT	Initial PWR	Initial RX Mode	Current PWR	Current RX Mode
1	N	Y	100	Power Operation	100	Power Operation

Event Text

NOTIFICATION TO OFFSITE AGENCIES DUE TO ELEVATED TRITIUM LEVELS

"Five new ground water monitoring wells were recently installed at Palisades Nuclear Plant in support of the Nuclear Energy institute (NEI) ground water initiative. The initial sampling of one of these wells displayed a level of tritium that triggered the communication protocol of the NEI initiative on ground water protection. On December 10, 2007, at 1830 hours, Entergy confirmed that the tritium concentration for this well was 22,000 picoCuries per liter (pCi/l). The threshold for initiating the communication protocol is 20,000 pCi/l (Offsite Dose Calculation Manual limit for drinking water). This well is located inside the owner controlled area and inside the protected area. This well is not a drinking water source. Entergy is continuing to investigate the source of tritium identified in this well. Samples from the remaining four wells are below minimum detectable activity levels. There is no indication that tritium has migrated off the Palisades site. The licensee plans to notify the State of Michigan, Van Buren County Office of Domestic Preparedness, City of South Haven, Covert Township, and the South Haven Charter Township.

"The licensee has notified the NRC Resident Inspector."

EXHIBIT 24

Proposed Rulemaking to Prevent Legacy Sites

UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON NUCLEAR WASTE AND MATERIALS
WASHINGTON, D.C. 20555-0001

ACNWMR-0272

November 20, 2007

The Honorable Dale E. Klein
Chairman
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

SUBJECT: Proposed Rulemaking to Prevent Legacy Sites[1]

Dear Chairman Klein:

At its 183rd Meeting, the Advisory Committee on Nuclear Waste and Materials (ACNW&M or "the Committee") received a presentation from the NRC staff on the proposed rulemaking approach to prevent legacy sites. The Committee has been following the staff's activities on this subject and related topics and previously provided observations and recommendations to the Commission on several occasions (References 1 through 4).

OBSERVATIONS

The Committee offers the following observations:

- In presentations to the Committee, the NRC staff stressed the importance of adequate financial resources and accurate estimates of decommissioning costs in preventing legacy sites.

- The Committee informed the Commission of the ACNW&M-preferred approach to prevent the creation of legacy sites. Licensees should maintain an environment that needs minimal restoration at the time of decommissioning (References 1 through 4). The Committee believes that legacy sites can be prevented through: (1) prevention of unplanned releases, (2) unplanned release detection, and (3) prompt remediation of unplanned releases rather than delaying remediation until final decommissioning. NB

- In presentations on decommissioning lessons learned, the NRC staff has stressed the importance of similar principles in preventing legacy sites. At the 172nd Committee Meeting, the staff presented preliminary plans for proposed rulemaking to prevent legacy sites. The staff explained that proposed changes for 10 CFR 20.1406, "Minimization of Contamination," would (1) improve unplanned release controls, (2) improve the monitoring if there is an undetected release, and (3) require remediation promptly although not necessarily immediately.[2]

[1] U.S. Nuclear Regulatory Commission, SECY-07-0177, "Proposed Rule: Decommissioning Planning (10 CFR PARTS 20, 30, 40, 50, 70, AND 72; RIN: 3150-AH45)," October 3, 2007.

[2] U.S. Nuclear Regulatory Commission, Transcript from the ACNW&M 172nd Meeting, July 19, 2006, Pages 17 and 18, and Slide Number 7 from Office of Federal and State Materials and Environmental Management Programs Presentation Viewgraphs, included on Page 3 of Attachment 1 to the Transcript.

- The Committee believes that complying with worker dose (5 rem/yr) and fence line dose limits to members of the public (100 mrem/yr) alone are inadequate measures for avoiding legacy sites. The unrestricted release criteria of 10 CFR Part 20.1402, "Radiological Criteria for Unrestricted Use," apply the "as low as reasonably achievable" (ALARA) principle. Early cleanup of unplanned releases before contamination of large surface areas, surface waters, and ground water occurs comports with the ALARA principle. The Committee believes that it is not good practice to defer remediation to final decommissioning, which can be years or decades away.

- The proposed rule does not address the need for prompt remediation or remediation in general. The Committee is concerned that, as a result of this omission, the staff is missing an opportunity to revise the rulemaking to effectively prevent the creation of legacy sites.

- The Committee believes that unplanned releases that could contaminate ground water deserve special attention because large volumes of soil and ground water can be contaminated over time. If large volumes of soil and ground water become contaminated, the NRC may not be able to release sites for unrestricted use.

- Based on previous working groups and the 183rd meeting, the Committee believes that if the rule is revisited there would be significant stakeholder interest in the guidance developed for prompt rather than deferred remediation.

RECOMMENDATIONS

- The Committee believes that legacy sites can be prevented through (1) prevention of unplanned releases, (2) unplanned release detection, and (3) prompt remediation of unplanned releases rather than delaying remediation until final decommissioning. The Committee recommends that the NRC require licensees to promptly assess and remediate unplanned releases. The staff should develop criteria specifying the assessments and actions a licensee should take to characterize and mitigate the impacts of unplanned releases. These criteria should preclude most licensees from deferring action until eventual decommissioning. These criteria should also emphasize the application of the ALARA principle to fully account for the impacts of contamination if remediation is deferred.

- The Committee recommends that the Commission consider gathering additional stakeholder input regarding prevention of legacy sites from a broad range of stakeholders including licensees, advisory or community groups, and State and local governments that participate in decommissioning.

Sincerely,

/RA/

Michael T. Ryan
Chairman

- The Committee believes that complying with worker dose (5 rem/yr) and fence line dose limits to members of the public (100 mrem/yr) alone are inadequate measures for avoiding legacy sites. The unrestricted release criteria of 10 CFR Part 20.1402, "Radiological Criteria for Unrestricted Use," apply the as low as reasonably achievable (ALARA) principle. Early cleanup of unplanned releases before contamination of large surface areas, surface waters, and ground water occurs comports with the ALARA principle. The Committee believes that it is not good practice to defer remediation to final decommissioning, which can be years or decades away.

- The proposed rule does not address the need for prompt remediation or remediation in general. The Committee is concerned that, as a result of this omission, the staff is missing an opportunity to revise the rulemaking to effectively prevent the creation of legacy sites.

- The Committee believes that unplanned releases that could contaminate ground water deserve special attention because large volumes of soil and ground water can be contaminated over time. If large volumes of soil and ground water become contaminated, the NRC may not be able to release sites for unrestricted use.

- Based on previous working groups and the 183rd meeting, the Committee believes that if the rule is revisited there would be significant stakeholder interest in the guidance developed for prompt rather than deferred remediation.

RECOMMENDATIONS

- The Committee believes that legacy sites can be prevented through (1) prevention of unplanned releases, (2) unplanned release detection, and (3) prompt remediation of unplanned releases rather than delaying remediation until final decommissioning. The Committee recommends that the NRC require licensees to promptly assess and remediate unplanned releases. The staff should develop criteria specifying the assessments and actions a licensee should take to characterize and mitigate the impacts of unplanned releases. These criteria should preclude most licensees from deferring action until eventual decommissioning. These criteria should also emphasize the application of the ALARA principle to fully account for the impacts of contamination if remediation is deferred.

- The Committee recommends that the Commission consider gathering additional stakeholder input regarding prevention of legacy sites from a broad range of stakeholders including licensees, advisory or community groups, and State and local governments that participate in decommissioning.

Sincerely,

/RA/

Michael T. Ryan
Chairman

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LETTER TO: The Honorable Dale E. Klein
NRC Chairman

FROM: Michael T. Ryan
ACNW&M Chairman

SUBJECT: Proposed Rulemaking to Prevent Legacy Sites

DATED: November 20, 207

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Federal Register page 3812

NUCLEAR REGULATORY COMMISSION

10 CFR Parts 20, 30, 40, 50, 70 and 72

RIN 3150-AH45

Decommissioning Planning

AGENCY: Nuclear Regulatory Commission.

ACTION: Proposed rule.

SUMMARY: The Nuclear Regulatory Commission (NRC) is proposing to amend its regulations to improve decommissioning planning, and thereby reduce the likelihood that any current operating facility will become a legacy site. The amended regulations would require licensees to conduct their operations to minimize the introduction of residual radioactivity into the site, including subsurface soil and groundwater. Licensees also would be required to survey certain quantities or concentrations of residual radioactivity, including in subsurface areas, and keep records of surveys of subsurface residual radioactivity identified at the site with records important for decommissioning. The amended regulations would require licensees to report additional details in their decommissioning cost estimates, would eliminate two currently approved financial assurance mechanisms, and would modify the parent company guarantee and self-guarantee financial assurance mechanisms to authorize the NRC to require that guaranteed funds be immediately due and payable to a standby trust if the guarantor is in financial distress. Finally, the amended regulations would require decommissioning power reactor licensees to report additional information on the costs of decommissioning and spent fuel management.

EXHIBIT 25

Approximate location Monitoring Wells, Document Provided by Entergy

Approx GPI Well Locations
November 2007

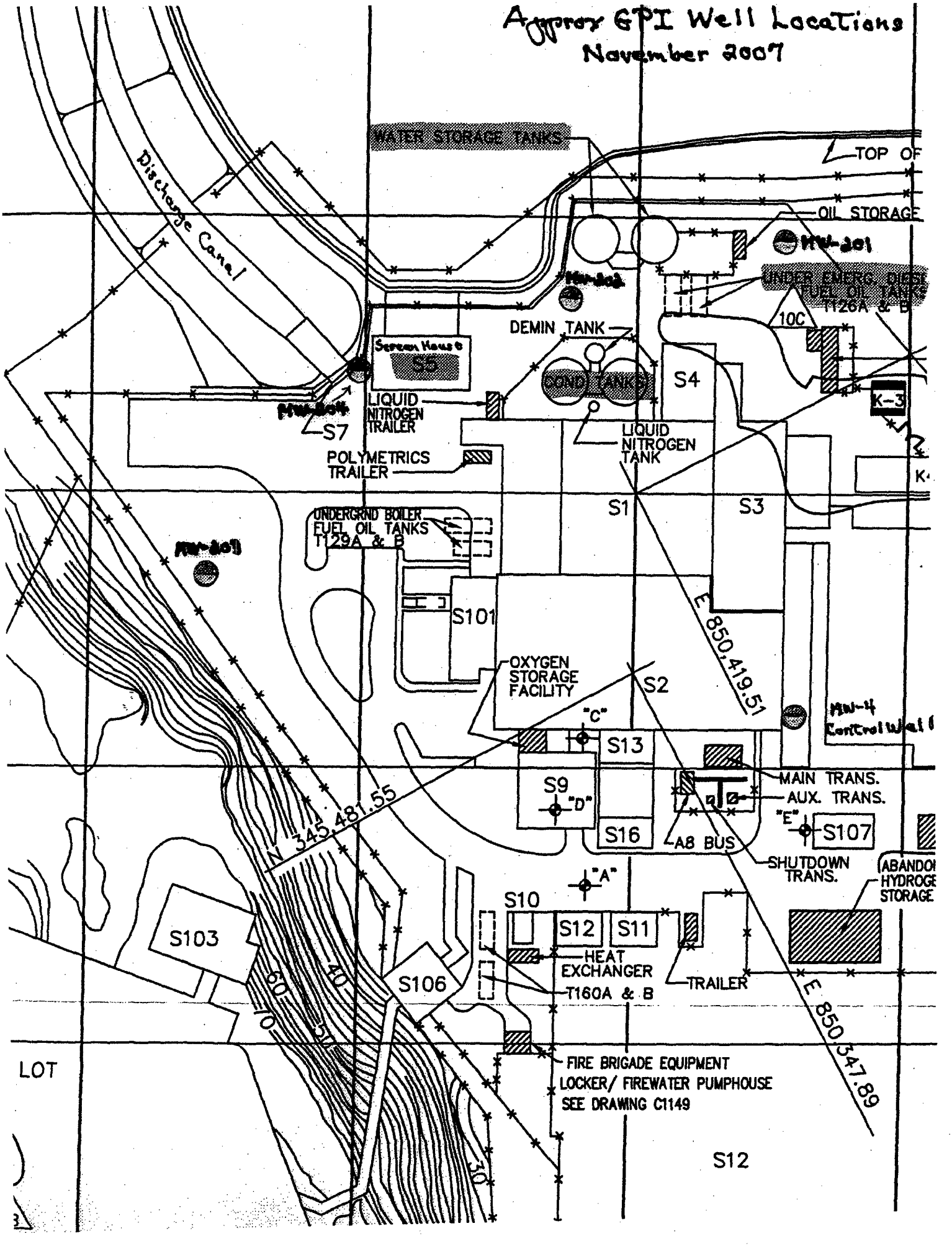

EXHIBIT 26

Reports: Discovery in Pilgrim wells fuels debate, Boston Globe, December 20, 2007; and Analysis Tritium samples for Massachusetts Department of Public Health Split Samples, December 5, 2007.

PLYMOUTH

Discovery in Pilgrim wells fuels debate

The Boston Globe

By Robert Knox, Globe Correspondent | December 20, 2007

The radioactive tritium discovered this month in monitor wells on the grounds of the Pilgrim nuclear power plant in Plymouth was at levels below any reporting requirement, according to federal regulators, and poses no danger to the public.

The tritium was one-seventh the level allowed in drinking water, said Pilgrim spokesman David Tarantino. He also said the finding confirms that the monitoring system is working properly.

But finding a radioactive substance in the ground water demonstrates the need for a more robust monitoring system to protect public safety against leaks from an aging plant, say Pilgrim's critics, who have raised the issue in Pilgrim's license extension review.

Tritium, a hydrogen isotope, is a byproduct of nuclear reactions. But it is also a naturally occurring radioactive form of hydrogen produced in the upper atmosphere, according to the Nuclear Regulatory Commission, and is found in very small amounts in ground water throughout the world. However, since the concentrations found at Pilgrim were above naturally occurring levels, it's logical to assume that some of the tritium was caused by the plant, said Pilgrim spokesman David Tarantino.

The monitor wells were installed at Pilgrim this fall as part of a voluntary program recommended by the Nuclear Energy Institute, an industry group, in the wake of the discovery of tritium at plants in New York, Illinois, and Connecticut, according to NRC spokesman Neil Sheehan and others.

Pilgrim found tritium in the first sampling earlier this month.

The discovery is "an indication that as the reactor ages, things start wearing out," said Mary Lampert of Pilgrim Watch, a regional advocacy group, which has been critical of both the plant and the NRC on the leaks issue.

Last year, in contesting a 20-year license extension for Pilgrim, the Duxbury-based group argued that radiation-contaminated water from buried pipes and tanks that are part of the nuclear reactor's cooling system could end up in coastal waters if a rigorous system for checking on the possibility of underground leaks is not put into place.

An NRC-established panel of nuclear experts agreed this fall that the leaks issue deserved a full hearing, to take place next year as part of Pilgrim's relicensing review process.

Pilgrim Watch also advocates quarterly samplings of the contents of the monitor wells, citing a hydrologist's estimate that leakage could get to Cape Cod Bay in three months or less. And it argues that, to conduct proper monitoring, more than four monitoring wells are needed. Pilgrim Watch recommends wells at "multiple down gradient monitoring points distributed over the area," along with control wells.

But Tarantino defended the number and placement of the plant's four wells, saying the discovery of small amounts of tritium can be looked at as a positive - an indication that more serious contaminants are not present in the ground water and that the wells were properly placed.

"We don't have large amounts of radioactive materials from underground pipes and tanks leaking into the environment. To that extent, it is a good thing," Tarantino said. The placement of the four wells several hundred feet apart within the plant's half-mile of waterfront followed a study by a professional hydrologist, he said.

Sheehan said Pilgrim's owner, the Entergy Corp., reported the finding even though NRC does not require it. "Entergy decided to notify federal, state, and local officials because even though the levels are low, they crossed the informal notification threshold that has been established," he said.

The plant will continue testing, Tarantino said, and send identical samples to the state Department of Public Health.

According to the NRC, the agency has revised its inspection procedures for nuclear power plants to evaluate nuclear facilities' programs to inspect and evaluate the equipment and structures where leaks could occur, following the discovery of tritium at nuclear sites. It has also set up a task force to address unmonitored liquid releases of radioactivity.

Lampert said that along with more wells, Pilgrim needs a thorough and updated study of the ground water flow on its property. New construction, the amount of silt and clay on top of soil, the effects of tidal fluctuations, and seasonal fluctuations can change the direction of the flow, she said. Without a study of these factors, both the number and the placement of the wells are up in the air, Lampert said.

Robert Knox can be contacted at rc.knox@gmail.com. ■

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COMMISSIONER

December 26, 2007

Mr. Robert Walker, Director
MA Department of Public Health
Radiation Control Program
Schrafft Center, Suite 1M2A
529 Main Street
Charlestown, MA 02129

Dear Mr. Walker:

Attached you will find a summary of analysis results for the 4 groundwater samples which were collected at Pilgrim Nuclear Power Station property on November 29, 2007 and submitted to the Massachusetts Environmental Radiation Laboratory (MERL).

MERL performed the gamma spectroscopy analyses of the samples using US EPA Prescribed Procedure Drinking Water for Measurement of Radioactivity in Drinking Water for Gamma Emitting Radionuclides: Method 901.1. Only normal levels of naturally occurring radionuclides were detected. These results are attached in Table 1.

Additionally, tritium analyses were performed on the 4 samples using US EPA Prescribed Procedure Drinking Water for Measurement of Radioactivity in Drinking Water for Tritium: Method 906.0. These results are also considered low in terms of dose. These results are attached in Table 2.

If you have any questions, please do not hesitate to contact me at 617-983-6879.

Sincerely,

Donald J. Buckley
Supervisor, MERL
Radiation Control Program

Attachments (2)

Analysis:

The samples were analyzed with a high purity germanium gamma spectroscopy system utilizing Canberra Genie 2000 software. The detectors were energy and efficiency calibrated for the geometry of the samples. The groundwater samples were transferred to 1 Liter Marinelli beakers and counted for 55,000 seconds. Only normal levels of naturally occurring radionuclides were detected. The attached results (Table 1) are reported in picocuries (pCi) per liter.

All of the analysis results reported reflect the concentration of the radionuclides at the time of sample collection.

The sample analysis results have had background subtracted from the sample plus background counts.

A NDA value reported by MERL can be interpreted to mean that no detectable activity of a radionuclide of interest was found in the sample at the time of analysis.

The following evaluation criteria are used by MERL to report a positive analysis result:

- An analysis result must be three times greater than the one-sigma error value for the radionuclide of interest.

And

- An analysis result must be greater than the detection limit for the radionuclide of interest.

In general, the laboratory's overall uncertainty is ± 15 percent.

Analysis for tritium in the 4 samples followed using a Packard Tri-Carb 2750TR/LL liquid scintillation counter with SpectraGraph Spectrum Analysis Software, luminescence correction on and low level count mode on. The samples were counted for 112 minutes each. The background was 3.22 counts per minute in the 0-18.6 keV region (tritium). The minimum detectable activity for the analysis was less than 300 pCi/Liter.

The attached results (Table 2) are reported in pCi/Liter at 95% confidence (2 sigma error).

Table 1: Massachusetts Environmental Radiation Laboratory Gamma Spectroscopy Analysis Results-4 Groundwater Samples

MERL ID	Sample ID	Sample Date	Analysis Date	Analysis Results ± 1 σ pCi per liter	MDA
07E0610	MW 201	11/29/2007	12/03/2007	*Bi-214 9.19E1 ± 3.65E0	2.13E1
				*Pb-214 9.80E1 ± 3.93E0	1.35E1
07E0611	MW 202	11/29/2007	12/03/2007	*Pb-212 1.51E1 ± 2.84E0	1.03E1
				*Bi-214 1.03E2 ± 7.72E0	4.71E1
				*Pb-214 9.87E1 ± 1.12E1	6.62E1
07E0612	MW 203	11/29/2007	12/04/2007	*Pb-212 1.93E1 ± 3.84E0	9.69E0
07E0613	MW 204	11/29/2007	12/04/2007	*Pb-212 3.24E1 ± 4.62E0	1.30E1
				*Bi-214 1.37E2 ± 1.18E1	6.87E1

* Asterisk denotes radioactivity detected in the sample. Statistically, if the concentration of the radionuclide is greater than three times the standard deviation (1 sigma) of the radionuclide of interest present in the sample and the analysis result is greater than the minimum detectable activity then the radionuclide is present in the sample.

Approved: _____

Date: December 5, 2007

Table 2: Massachusetts Environmental Radiation Laboratory Tritium Analysis Results-4 Groundwater Samples

MERL ID	Sample ID	Sample Date	Analysis Date	Tritium (pCi/Liter) Results ± 2 σ	Minimum Detectable Activity (pCi/Liter)
07E0610	MW 201	11/29/2007	12/19/2007	3014 ± 195	<300
07E0611	MW 202	11/29/2007	12/19/2007	522 ± 131	< 300
07E0612	MW 203	11/29/2007	12/19/2007	371 ± 126	< 300
07E0613	MW 204	11/29/2007	12/19/2007	1277 ± 153	< 300

Tritium Background: 3.22 cpm in the keV region 0-18.6 (tritium) or 0 ± 114 pCi/Liter.

Approved: _____

Date: December 24, 2007

UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the matter of — Docket # 50-293-LR

Entergy Corporation

Pilgrim Nuclear Power Station

License Renewal Application — March 3, 2008

CERTIFICATE OF SERVICE

I hereby certify that Pilgrim Watch's Statements of Position, Direct Testimony and Exhibits under 10 CFR 2.1207, Modified per Request ASLB February 21, 2008, was served March 3, 2008 by electronic mail and by U.S. Mail, First Class to each of the following:

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Washington, DC 20555-0001

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Secretary of the Commission
Attn: Rulemakings and Adjudications Staff
Mail Stop 0-16 C1
United States Nuclear Regulatory Commission [Two Copies]

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