RAS J-31

January 8, 2008

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

DOCKETED
USNRC

April 15, 2008 (10:00am)

OFFICE OF SECRETARY
RULEMAKINGS AND
ADJUDICATIONS STAFF

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

U.S. NUCLEAR REGULATORY COMMISSION
In the Matter of Entergy (Pilgrim Nuclear Power Station
Docket No. 50-293-LR Official Exhibit No. 1
OFFERED by Applicant/Licensee Intervenor Entergy Exh. A
NRC Staff Other
IDENTIFIED on 4-10-08 Witness/Panel
Action Taken: ADMITTED REJECTED WITHDRAWN
Reporter/Clerk Thibault

Temp = SECY-028

DS03

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I. WITNESS BACKGROUND

Alan B. Cox ("ABC")

Q1. Please state your full name.

A1. (ABC) My name is Alan B. Cox.

Q2. By whom are you employed and what is your position?

A2. (ABC) I am the Technical Manager, License Renewal with Entergy Nuclear ("Entergy"). In that capacity, I was involved in preparing the license renewal application and developing aging management programs for the Pilgrim Nuclear Power Station ("PNPS" or "Pilgrim") license renewal project.

Q3. Please summarize your educational and professional qualifications.

A3. (ABC) My professional and educational experience is summarized in my *curriculum vitae*, which is attached to my declaration supporting this testimony. Briefly summarized, I hold a Bachelors degree in nuclear engineering from the University of Oklahoma and a Masters of Business Administration from the University of Arkansas at Little Rock. I have 30 years of experience in the nuclear power industry, having served in various positions related to engineering and operations of nuclear power plants. I have held reactor operator and senior reactor operator licenses issued by the NRC for the operation of Arkansas Nuclear One, Unit 1. I have been licensed as a registered professional engineer in the State of Arkansas.

Since 2001, I have worked full-time on license renewal supporting the integrated plant assessment and license renewal application development for Entergy license renewal projects, as well as projects for other utilities. I am a member of the Nuclear Energy Institute ("NEI") License Renewal Task Force and have been a representative on the NEI License Renewal Mechanical Working Group and the NEI License Renewal Electrical Working Group. As a member of the Entergy license renewal team, I have participated in the development of seven license renewal applications. In addition, I have participated in industry peer reviews of at least eleven additional license renewal applications.

Brian R. Sullivan ("BRS")

Q4. Please state your full name.

A4. (BRS) My name is Brian R. Sullivan.

Q5. By whom are you employed and what is your position?

A5. (BRS) Since April 2007, I have held the position of Engineering Director for PNPS. In this capacity, I am responsible for providing engineering support at PNPS. My specific duties include maintaining the PNPS design bases; maintaining plant systems through predictive programs and system monitoring; maintaining equipment reliability through preventive maintenance optimization; resolving plant system issues through troubleshooting and problem solving support; providing modifications in support of plant needs; overseeing procedures and documentation which govern and control plant engineering activities; developing and implementing department procedures and corporate level policies; and developing, planning and coordinating or implementing special projects, corrective action plans, or improvement programs to address particular plant or regulatory issues.

During the preparation of the PNPS license renewal application I was the Manager, Engineering Programs and Components for PNPS. In this position I was knowledgeable of the development of the aging management programs credited for buried pipes and tanks.

Q6. Please summarize your educational and professional qualifications.

A6. (BRS) My professional and educational experience is summarized in my *curriculum vitae,* which is attached to my declaration supporting this testimony. Briefly summarized, I hold a Bachelor of Science Degree in Marine Engineering from the Massachusetts Maritime Academy. I have over 24 years of experience in the nuclear power industry, 19 of which have been at PNPS where I have served in various positions since 1988, including Senior Engineer, Control Room Supervisor, Shift Manager, AOM Shift, Outage Manager, AOM Support, Programs and Components Manager, Systems Engineering Manager, and now Engineering Director. I was a licensed Senior Reactor Operator and held a United States Coast Guard License as a Second Assistant Engineer.

Steven P. Woods ("SPW")

Q7. Please state your full name.

A7. (SPW) My name is Steven P. Woods.

Q8. By whom are you employed and what is your position?

A8. (SPW) I am the Manager, Engineering Programs and Components for PNPS. In that position, I am responsible for developing and maintaining engineering programs and standards as well as monitoring plant components and replacement parts. My specific duties include overseeing code programs, plant programs, predictive maintenance and valve programs; maintaining equipment reliability through preventive maintenance; ensuring replacement parts and components meet safety standards and technical specifications; managing and coordinating engineering work activities; overseeing procedures and documentation which govern and control plant programs, components, and engineering activities; and interfacing with regulatory and industry representatives on behalf of station activities.

Q9. Please summarize your educational and professional qualifications.

A9. (SPW) My professional and educational experience is summarized in my *curriculum vitae*, which is attached to my declaration supporting this testimony. Briefly summarized, I hold a Bachelor of Science Degree in Marine Engineering from the Massachusetts Maritime Academy. I have over 26 years of experience applying engineering methods and capabilities to various projects and engineering disciplines, including repairing and maintaining marine and nuclear facilities, designing and preparing modifications for new and existing systems, implementing effective and efficient nuclear power plant procedures, and analyzing mechanical components and piping systems.

I have been employed by Entergy at PNPS since May 2000 and previously held the position of Supervisor Code Programs, Engineering Programs & Components. Prior to that position, I was the Senior Engineer, Design Engineering for the Mechanical/Civil/Structural group, where I performed all facets of design engineering, including nuclear changes and field support.

Prior to joining Entergy, I worked for several industry contractors providing engineering services at nuclear power plants throughout the country. I worked at PNPS on several occasions prior to joining Entergy. Specifically, and relevant to my testimony here today, from May 1992 to July 1993, I was the Site Mechanical Project Engineer dedicated to the "Salt Service Water Pipe Replacement" project. In that role, I was responsible for the site engineering and installation of the titanium piping for the salt service water inlet line, including excavation, shoring of the trenches, interferences, construction of concrete vaults, installation and assembly of pipe, and backfilling of excavation.

William H. Spataro ("WHS")

Q10. Please state your full name

A10. (WHS) My name is William H. Spataro.

Q11. By whom are you employed and what is your position?

A11. (WHS) Until December 31, 2007 (at which time I retired), I was the Senior Staff Engineer-Corporate Metallurgist with Entergy Nuclear ("Entergy"). In that capacity, I provided technical support in metallurgy, corrosion, welding, and forensic investigation in support of Entergy's operation of its nuclear power plants. Prior to Entergy's purchase of the Fitzpatrick and Indian Point Unit 3 plants, I was Director of Materials Engineering – Consulting Metallurgist for the New York Power Authority ("NYPA"). In that capacity I managed metallurgical and chemical engineers supporting the operation of NYPA's nuclear, fossil fueled, pumped storage, and hydroelectric power projects and its transmission lines and under-water cables.

Q12. Please summarize your educational and professional qualifications.

A12. (WHS) My professional and educational experience is summarized in my *curriculum vitae*, which is attached to my declaration supporting this testimony. Briefly summarized, I hold a Bachelor of Engineering (in Metallurgy) degree from New York University. I have nearly 40 years of experience in the fields of metallurgy, welding, corrosion, and forensic investigation; including 27 years of service with Entergy and the NYPA. I am a Registered Professional Engineer in Connecticut and New York, an American Welding Society Certified Welding Inspector and Certified Welding Educator, as well as a National Board Registered Certified Nuclear Safety Related Coating Engineer.

Q13. Please explain the requirements for becoming a National Board Registered Certified Nuclear Safety Related Coating Engineer.

A13. (WHS) To become a National Board Registered Certified Nuclear Safety Related Coating Engineer one must: 1) have at least 10 years experience with nuclear related coatings; 2) pass an eight hour written exam; 3) pass a practical evaluation exam; 4) complete a one week course; and 5) be a registered professional engineer.

II. OVERVIEW

Q14. What is the purpose of your testimony?

A14. (ABC, WHS, BRS, SPW) The purpose of our testimony is to address, on behalf of Entergy, Contention 1 submitted by Pilgrim Watch ("PW") in this proceeding. As admitted by the Atomic Safety and Licensing Board ("Board"), PW Contention 1 reads:

> "[t]he 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."

Memorandum and Order, LBP-06-23, 64 N.R.C. 257, 315 (2006). In addition, the scope of PW Contention 1 has been clarified recently by the Board, which has ruled 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 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."

Memorandum and Order, LBP-07-12, 66 N.R.C. __, slip op. at 17 (Oct. 17, 2007).

Q15. What has been your role in the PNPS license renewal project as it relates to PW Contention 1?

A15. (ABC) In my capacity as Technical Manager, License Renewal, I am knowledgeable of the function and purpose of the aging management programs ("AMPs") that are described in the PNPS license renewal application. I have been the manager of the technical staff responsible for preparing the license renewal application. In that capacity, I have reviewed and provided input to aging management reviews and AMP development for PNPS.

(BRS) In my capacity as Engineering Director, I am knowledgeable of the AMPs that are described in the PNPS license renewal application.

(SPW) In my capacity as the PNPS Manager, Engineering Programs and Components, I am knowledgeable of the AMPs that are described in the PNPS license renewal application, and I will support development of new procedures to ensure that aging management programs are properly implemented.

(WHS) I am knowledgeable of the technical requirements in my fields of expertise that are attendant to the aging management programs that are described in the PNPS license renewal application ("LRA"). Also, in my capacity as Senior Staff Engineer-Corporate Metallurgist, I was the primary author of the Buried Piping and Tanks Inspection Monitoring Program Procedure, EN-DC-343, Rev. 0, an Entergy fleet-wide procedure for the inspection of buried piping at Entergy's nuclear power plants that will be used for implementing the AMP for buried piping and tanks at PNPS.

Q16. What will your testimony cover?

A16. (ABC) I will testify on the function and purpose of license renewal AMPs, the buried piping and tanks at PNPS that potentially contain radioactive liquids which are within the scope of PNPS license renewal, and the adequacy of the PNPS AMPs to assure the performance of the intended functions of in-scope buried piping and tanks through the license renewal period of extended operation. My testimony will encompass the conformance of those AMPs to the programs described in NUREG 1801, Generic Aging Lessons Learned ("GALL") Report, Rev. 1 (Sept. 2005), and discussion of applicable operating experience supporting the adequacy of those programs.

(BRS) I will testify on (1) the license renewal intended functions and the design and operation of the condensate storage system ("CSS") buried piping, which include the reactor core isolation cooling ("RCIC"), high pressure coolant injection ("HPCI"), and fire protection safe shutdown functions; (2) the license renewal intended functions and the design and operation of the salt service water ("SSW") system; (3) the design features that preclude radioactive liquids from entering the SSW system and the high degree of assurance that the SSW will not contain radioactive liquids; (4) the license renewal intended functions and design and operation of the standby gas system treatment ("SGTS"); and (5) the differentiation between the SGTS and the condenser off-gas system. In addition, my testimony will describe (1) periodic surveillance tests and regularly documented observations to ensure that the CSS and SSW system are capable of performing their intended functions (including discussion of tests and observations ensuring the HPCI, RCIC, and fire protection functions of the CSS); and (2) the capability of these systems to perform their intended functions even if some leakage occurs.

(SPW) I will testify on (1) the specifications for the protective coating and wrapping of buried piping and tanks used at PNPS to protect against external degradation, (2) the installation of buried piping in accordance with these specifications and other measures taken at PNPS to protect against the external degradation of buried piping and tanks, (3) the operating experience at PNPS with buried coated piping, (4) the Service Water Integrity Program, and the demonstrated capability of that program to identify SSW system degradation prior to the loss of its intended function, and (5) the replacement and upgrading of the buried piping for the SSW system.

(WHS) I will testify on (1) the corrosion resistance of the materials used for the buried CSS and SSW system piping at PNPS, (2) the general industry practice for protective coating and wrapping of buried piping and tanks to protect against external degradation, (3) the general industry practice for the installation of buried piping and the examination of protective coatings prior to burial, (4) the industry operating experience concerning the use of buried coated piping, (5) compatibility of the corrosion controls with soil conditions at PNPS, and (6) the Buried Piping and Tanks Inspection Program and the capability of that program to manage the effects of aging on buried piping to prevent the loss of intended function.

Q17. Do you agree with the assertion in PW Contention 1 that the "[t]he 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?"

A17. (ABC, BRS, SPW, WHS) No.

Q18. What is the basis for your disagreement?

A18. (ABC, WHS, BRS, SPW) Only six systems contain buried pipes and tanks within the scope of the PNPS license renewal. Only two of those six systems contain or could contain radioactive liquid: (1) the CSS, which contains radioactive liquid, and (2) the SSW system, which, although highly unlikely, could contain radioactive liquid. For both the CSS and SSW system, Pilgrim has developed aging management programs ("AMPs") that will maintain the pressure boundary of the buried pipes and tanks in those systems to provide reasonable assurance that the CSS and SSW system will perform their system intended functions. The AMPs will protect against the loss of material due to corrosion and other aging effects in a manner sufficient to provide reasonable assurance that the buried pipes in those systems will remain capable of performing their intended functions.

In addition, Pilgrim employs surveillance testing for the CSS and SSW system. These surveillance tests periodically demonstrate that the systems are capable of performing their intended functions. Therefore, monitoring wells are not necessary to ensure that the CSS and SSW system do not develop leaks that would impair the performance of their intended functions. Indeed, monitoring wells to detect leakage would not be nearly as effective as the AMPs and the surveillance programs in place and credited under the plant's technical specifications for ensuring that the CSS and the SSW system will perform their intended functions.

III. DISCUSSION

A. Function and Purpose of the PNPS License Renewal AMPs

Q19. Please describe the function and purpose of the PNPS license renewal AMPs.

A19. (ABC) 10 C.F.R. Part 54 governs the matters that must be considered in a license renewal proceeding. 10 C.F.R. §§ 54.21 and 54.29(a) focus on the management of the effects of aging on certain systems, structures, and components defined in the license renewal rule. PNPS has identified AMPs to provide reasonable assurance that the effects of aging during the renewed license term are managed for the systems, structures, and components that are within the scope of license renewal. The purpose of the AMPs identified in the PNPS license renewal application is to manage the effects of aging so that the intended function(s) of systems, structures, and components will be maintained consistent with the current licensing basis for the period of extended operation in accordance with 10 C.F.R. §54.21(a)(3).

The PNPS license renewal AMPs manage the effects of aging on buried piping and tanks that are within the scope of license renewal and subject to aging management review. The objective of the aging management programs as applied to buried pipes and tanks is to maintain the pressure boundary of the buried pipes and tanks so as to provide reasonable assurance that the systems containing the buried pipes and tanks can perform their system intended functions in accordance with 10 C.F.R. §§ 54.4(a)(1), (a)(2) or (a)(3).

Q20. How are the systems, structures, and components within the scope of license renewal identified?

A20. (ABC) The scoping criteria for license renewal set forth in 10 C.F.R. § 54.4(a) dictate the plant systems, structures, and components that are within the scope of 10 C.F.R. part 54. This provision reads in full as follows:

> (a) Plant systems, structures, and components within the scope of this part are –
>
> (1) Safety related systems, structures, and components which are those relied upon to remain functional during and following design-basis events (as defined in 10 C.F.R. 50.49 (b)(1)) to ensure the following functions –
>
> > (i) the integrity of the reactor coolant pressure boundary;
> >
> > (ii) the capability to shut down the reactor and maintain it in a safe shut-down condition; or
> >
> > (iii) the capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to those referred to in § 50.34(a)(1), § 50.67(b)(2), or § 100.11 of this chapter as applicable
>
> (2) All non-safety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of any of the functions identified in paragraphs (a)(1) (i), (ii), or (iii) of this section.

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

Thus, 10 C.F.R. §§ 54.4(a)(1)-(3) define both the safety-related and non-safety-related systems, structures, and components that are within the scope of license renewal and the functions of the systems, structures, and components that are intended to be assured by the AMPs. Of these systems, structures, and components that fall within the scope of license renewal, 10 C.F.R. § 54.21(a)(1) defines the systems, structures, and components that are subject to aging management review as those that (i) perform an intended function, as described in § 54.4, without moving parts or without a change in configuration or properties; and (ii) are not subject to replacement based on a qualified life or specified time period.

Q21. With respect to the systems, structures and components within the scope of the license renewal rule, what must the applicant demonstrate to obtain a renewed license?

A21. (ABC) Pursuant to 10 C.F.R. § 54.21(a)(3), an applicant must demonstrate that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the licensing basis for the period of extended operation. As reflected in 10 C.F.R. § 54.29, these actions to manage aging must provide reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the current licensing basis.

An applicant must also evaluate time-limited aging analyses, but there are no such analyses relevant to PW Contention 1.

Q22. What are "intended functions"?

A22. (ABC) Pursuant to 10 C.F.R. § 54.4(b), intended functions that these systems, structures, and components must be shown to fulfill in § 54.21 are those functions that are the bases for including them within the scope of license renewal as specified in 10 C.F.R. § 54.4(a)(1)-(3).

B. License Renewal Buried Pipes and Tanks That Contain or Potentially Contain Radioactive Liquids and Their Function and Purpose

1. License Renewal Buried Pipes and Tanks Containing or Potentially Containing Radioactive Liquids

Q23. What PNPS systems with buried pipes and tanks are within the scope of license renewal?

A23. (ABC) For PNPS, there are six systems with buried piping or tanks that meet the scoping criteria of 10 C.F.R. § 54.4: (1) the CSS; (2) the fire protection water system; (3) the fuel oil system; (4) the SSW system; (5) the standby gas treatment system ("SGTS"); and (6) the station blackout diesel generator system.

Q24. Of those PNPS buried pipes and tanks within the scope of license renewal, which have the potential for containing radioactive liquids?

A24. (BRS, SPW) The only system within the scope of license renewal with buried pipes or tanks that contain radioactive liquid is the CSS. In a boiling water reactor facility, such as PNPS, the CSS contains radioactively contaminated water. At PNPS, the CSS includes buried piping, but no buried tanks.

Specifically, buried CSS piping made of stainless steel (which is generally resistant to soil induced corrosion) runs from the concrete vault for the two 275,000 gallon condensate storage tanks ("CSTs") to the reactor building auxiliary bay where the piping then supplies water to the reactor core isolation cooling ("RCIC") pumps and the high pressure coolant injection ("HPCI") pumps. One line of piping runs from each CST to the CST concrete vault where the two pipes connect to a header. The header runs from the vault underground to the reactor building auxiliary bay. The buried potion of the piping runs approximately sixty-four feet before entering the reactor building auxiliary bay, and is approximately seven to ten feet below grade. Once inside the reactor building auxiliary bay, the piping connects to a header from which water is supplied to both the HPCI and RCIC systems.

Entergy Exhibit 1-A from Plant Reference Drawing C-8 shows the general PNPS plant layout with the CSTs and the reactor building auxiliary bay. Entergy Exhibit 1-B shows the layout of the buried CSS piping running from the CST concrete vault wall to the reactor building auxiliary bay wall. The CSTs themselves are not buried and, therefore, are not within the scope of the license renewal AMP for buried pipes and tanks.

It is possible, but highly unlikely, that the SSW system cooling water discharged by PNPS through buried SSW discharge piping could contain radioactively contaminated water. There are two loops of buried SSW system discharge piping. Loop A buried discharge piping runs 240 feet from the reactor building auxiliary bay to the discharge canal that runs into Plymouth Bay. Loop B buried discharge piping runs 225 feet from the reactor building auxiliary bay to the discharge canal that runs into the bay. Both loop A and loop B are buried approximately ten feet below grade. Entergy Exhibit 1-A shows both loops of buried discharge piping running from the reactor building auxiliary bay to the discharge canal (as well as the SSW system inlet buried piping running from the intake structure to the reactor building auxiliary bay). There are no buried SSW system tanks.

The SGTS would, during accident conditions, remove particulates and radioactively contaminated gases from the reactor building's ventilation exhaust air system. However, the SGTS is a gas system and does not contain radioactively contaminated water.

The buried pipes and tanks for the Fire Protection water system, the Fuel Oil system, and the Station Blackout Diesel Generator system do not contain radioactive materials; nor do they interact with systems that contain radioactivity.

Thus, only two systems with buried pipes or tanks within the scope of license renewal contain or potentially contain radioactive liquids.

Q25. What is the "off gas system"?

A25. (BRS) The offgas and augmented offgas system removes, processes and disposes of non-condensable gases from the condenser. All such gases from the unit are routed to the main stack for dilution and elevated release to the atmosphere.

Q26. Does the offgas system contain buried pipes and tanks within the scope of license renewal?

A26. (ABC) No. The offgas and augmented offgas system has no intended function under 10 C.F.R. §§ 54.4(a)(1) or (a)(3). The buried piping in this system does not meet the scoping criterion of 10 C.F.R. § 54.4(a)(2) because failure of the buried piping cannot prevent satisfactory accomplishment of any of the functions identified in 10 C.F.R. § 54.4(a)(1)(i), (ii), or (iii).

2. Intended Function of the CSS and SSW System Buried Pipes

a. Intended Function of the CSS Buried Pipes

Q27. What is the intended function of the CSS?

A27. (BRS, ABC) The CSS has two license renewal intended functions. Regarding 10 C.F.R. § 54.4(a)(1), the CSS supplies water to the suction of the RCIC pumps and the HPCI pumps, which is performed by safety-related piping and valves that interface with RCIC and HPCI. Regarding 10 C.F.R. § 54.4(a)(3), the CSS provides a source of water to the HPCI and RCIC systems, which are credited in the 10 C.F.R. 50 Appendix R safe shutdown analysis for fire protection. The buried piping in this system does not meet the scoping criterion of 10 C.F.R. § 54.4(a)(2) because failure of the buried piping cannot prevent satisfactory accomplishment of any of the functions identified in 10 C.F.R. § 54.4(a)(1)(i), (ii), or (iii).

Q28. What do the RCIC and HPCI systems do?

A28. (BRS) The RCIC system provides makeup water to the reactor vessel following reactor vessel isolation in order to prevent the release of radioactive materials to the environment as a result of inadequate core cooling. The RCIC system is capable of delivering 400 gallons per minute ("GPM") to the reactor vessel over a range of reactor pressures. The RCIC system pump is normally lined up to the two 275,000 gallon CSTs. Each CST has a 75,000 gallon reserve dedicated to the HPCI and RCIC systems. In other words, the inlet suction points from other systems that draw water from the CSTs are located sufficiently high in the CSTs so as not to draw on the 75,000 gallon reserve in either CST. The assured supply of cooling water for the RCIC system is the suppression pool (torus). If the water is unavailable from the CST, the safety function of the RCIC system is accomplished by using water from the torus.

The HPCI system is provided to ensure that the reactor core is adequately cooled to limit fuel clad temperature in the event of a small break in the nuclear system which does not result in rapid depressurization of the reactor vessel. The HPCI system is designed to maintain sufficient reactor vessel water inventory until the reactor vessel is depressurized to the point at which the low pressure coolant injection system operation or core spray system operation maintain core cooling. The HPCI system is designed to pump water into the reactor vessel over a wide range of pressures in the reactor vessel. The Pilgrim accident safety analysis requires the HPCI system to deliver 4250 GPM to the reactor vessel over a range of reactor pressures. Like the RCIC system, the HPCI system initially draws from the two 275,000 gallon CSTs. If water is unavailable from the CSTs, the safety function of the HPCI system is accomplished by using water from the torus.

Q29. What is the overall objective of the AMPs with respect to the buried CSS piping?

A29. (ABC) The overall objective of the AMPs with respect to the CSS buried piping is to preserve the piping's capability to provide a source of water to the HPCI and RCIC systems so as to avoid the loss of license renewal intended functions.

b. Intended Function of the SSW System Buried Pipes

Q30. What is the license renewal intended function of the SSW system?

A30. (ABC, BRS) The SSW system has two license renewal intended functions. Regarding 10 C.F.R. § 54.4(a)(1), the SSW provides a heat sink for the reactor building closed cooling water ("RBCCW) system under transient and accident conditions. The same is also credited under 10 C.F.R. § 54.4(a)(3) because the SSW is credited in the 10 C.F.R. Part 50 Appendix R safe shutdown analysis for fire protection (10 C.F.R. § 50.48). The buried piping in this system does not meet the scoping criterion of 10 C.F.R. § 54.4(a)(2) because failure of the buried piping cannot prevent satisfactory accomplishment of any of the functions identified in 10 C.F.R. § 54.4(a)(1)(i), (ii), or (iii).

Q31. How does the SSW system work?

A31. (BRS) The SSW system operates as the ultimate heat sink to transfer heat from safety-related plant equipment and non-safety-related plant equipment. The SSW system cools the RBCCW system, which in turn cools safety-related equipment. The SSW system draws in ocean water from Cape Cod Bay through the intake structure and pumps this water through the RBCCW heat exchangers, which cool the RBCCW system water. The SSW system then discharges the cooling water back into the Bay.

Q32. Please explain why it is possible, but highly unlikely, that the SSW system could contain radioactively contaminated water.

A32. (BRS) The SSW system is designed to function as the ultimate heat sink for all the systems cooled by the RBCCW system in all operating states by continuously providing adequate cooling water flow to the secondary side of the

RBCCW heat exchangers. The RBCCW system provides required cooling to equipment located in the reactor building during normal planned station operations and provides a barrier between the systems containing radioactively contaminated water (e.g., the reactor coolant system) and the SSW system. It is possible, but unlikely, that the RBCCW system could become contaminated by leakage from a system that it cools. It is therefore possible, but even more unlikely, that the SSW system, which cools the RBCCW system, could become contaminated. PNPS conducts weekly sampling of the RBCCW system water to detect any potential radioactivity in the RBCCW system and, furthermore, the interfacing RBCCW system is continuously monitored for radioactivity by radiation detectors. Should the radiation alarms be triggered, the alarm response procedure calls for obtaining a sample of the RBCCW system water and initiating actions to identify and isolate the source of any leak.

Additionally, water from the SSW system is sampled at least once per week to monitor for radioactivity. Further, Pilgrim performs periodic inspection, maintenance, and testing of the RBCCW heat exchangers to prevent potential leakage and cross contamination between the RBCCW and SSW systems. The heat exchanger inspection, maintenance, and testing includes performance testing, visual examinations, eddy current testing, and periodic cleaning.

(ABC) In addition, water chemistry control programs based on EPRI guidelines are in place for the RBCCW system and the radioactive systems that it cools to protect against corrosion and cracking that could cause leakage of radioactive fluid into the SSW system. The EPRI guideline documents have been developed based on plant experience and have been shown effective over time throughout the nuclear power industry.

(BRS, ABC) In sum, the SSW system is designed to contain only raw, non-radioactive cooling water from the ocean. However, it is possible, although highly unlikely, that radioactive contamination could occur in the SSW system, and therefore possible, although highly unlikely, that SSW system cooling water being discharged into Plymouth Bay through the SSW discharge buried piping could be radioactively contaminated.

Q33. What are the buried piping and/or tanks in the SSW system?

A33. (BRS, SPW) The SSW system does not contain buried tanks. As described above, the SSW system includes two loops of buried discharge piping, loop A and loop B, running from the reactor building auxiliary bay to the discharge canal. This buried discharge piping is made of carbon steel and is coated in accordance with Pilgrim specifications to prevent external degradation of the piping as described later in this testimony.

The two loops of the SSW inlet piping are also buried. The SSW inlet piping is made of titanium and is coated in accordance with Pilgrim specifications. The inlet piping draws water from the bay and therefore does not contain radioactively contaminated water.

Q34. What is the overall objective of the AMPs with respect to the SSW System?

A34. (ABC) The overall objective of the AMPs with respect to the SSW system is to manage the effects of aging to preserve its capability to provide cooling for plant equipment.

C. PNPS License Renewal AMPs

Q35. What are the AMPs for the in-scope buried pipes and tanks containing or potentially containing radioactive liquid?

A35. (ABC) Pilgrim implements multiple programs to manage the effects of aging on buried piping and tanks that are within the scope of license renewal and subject to aging management review. The applicable AMPs for in-scope buried pipes and tanks containing or potentially containing radioactive liquid are (1) the Buried Piping and Tanks Inspection Program ("BPTIP"); (2) the Water Chemistry Control-BWR Program; (3) the Service Water Integrity Program; and (4) the One-Time Inspection Program. These AMPs are set forth in Appendix B 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).

- First, the buried CSS and SSW inlet piping use corrosion resistant metals (stainless steel and titanium, respectively). Further, the SSW discharge liner is protected by a cured in place liner.
- Second, PNPS coats buried piping with a coal-tar or epoxy protective coating to create a barrier between the pipe and the external environment.
- Third, PNPS has in place procedures to make certain that buried piping is installed, excavated, and handled in a manner that does not damage the protective corrosion resistant coatings.

(1) Use of corrosion resistant materials in the CSS and SSW system buried piping

Q38. What materials are used for the buried CSS piping to prevent corrosion?

A38. (SPW) The buried CSS piping is made of stainless steel. Additionally, in accordance with the PNPS specification for buried piping, described below, it has been the practice of PNPS to coat stainless steel piping, although unnecessary.

Q39. Please describe the corrosion resistance properties of stainless steel piping buried in soil.

A39. (WHS) Stainless steels are generally resistant to corrosion in soils. Depending on the grade of stainless steel used, pitting corrosion of stainless steel can occur under certain conditions involving high temperatures, high concentrations of chlorides (generally greater than 500 ppm), and low pH (generally less than 4.5, acidic conditions). However, PNPS has taken steps to prevent soil conditions, discussed below, that could cause corrosion of stainless steel. Further, notwithstanding their corrosion resistance, it has been PNPS practice to apply protective coatings to corrosion resistant piping like the stainless steel CSS piping (and the titanium SSW inlet piping).

Q40. What materials are used in the SSW inlet piping to prevent corrosion?

A40. (SPW) The SSW inlet piping, originally made of wrapped carbon steel, was replaced in 1993 with titanium piping.

Q41. Please describe the corrosion resistance of titanium piping in soil.

A41. (WHS) Titanium is immune to corrosion in soils. Titanium and its alloys are fully resistant to 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. A stable, substantially inert oxide film provides the material with its outstanding resistance to corrosion in a wide range of aggressive media. Whenever titanium is exposed to the atmosphere, or to any environment containing oxygen, including water, it immediately reacts with the oxygen creating a thin film of titanium oxide. It is the presence of this surface film that confers on the material its corrosion resistance.

The protective coatings applied to the buried titanium piping, discussed below, provide additional assurance that the titanium inlet piping will not suffer external degradation by corrosion from the soil.

Q42. What materials are used in the SSW discharge piping to prevent corrosion?

A42. (SPW, BRS) As stated, the SSW discharge piping consists of two loops of buried piping, loop A 240 feet in length and loop B 225 feet in length. This buried discharge piping is made of carbon steel and was wrapped in accordance with PNPS specifications to prevent external degradation. In 1999, PNPS replaced two forty-foot sections of the SSW discharge piping (one from each discharge loop). PNPS applied a protective epoxy coating to both the internal and external surfaces of the replaced pipe.

In addition, in 2001, during refueling outage 13, PNPS lined the entire length of the loop B discharge pipe with Cured-In-Place-Pipe ("CIPP") to protect against internal corrosion of the piping. In 2003, during refueling outage 14, PNPS lined the entire length of the loop A discharge pipe with CIPP liner.

Q43. Please describe the CIPP liner installed in the SSW discharge piping.

A43. (SPW, BRS) The CIPP liner material consists of a nonwoven polyester felt tube that is saturated with a resin and catalyst system in loop A, and an epoxy resin and hardener system in loop B, with a polyurethane or polyethylene inner membrane. The liner has a nominal ½" thickness. The resulting configuration is a rigid resin composite pipe within the original pipe. Based on the service conditions and the design of the CIPP liner, the expected life of the CIPP is approximately thirty-five years.

Q44. Did the carbon steel SSW discharge piping as originally installed have any internal lining of the piping?

A44. (SPW, BRS) Yes. The original SSW discharge piping had an internal rubber liner which was not cured in place with an expected life of about 20 years. The integrity of the SSW system rubber liner was monitored under the Service Water Integrity Program, described below, and the CIPP was installed upon identifying degradation of the internal rubber liner.

Q45. Please describe the corrosion resistance of the CIPP lined SSW carbon steel piping at PNPS.

A45. (WHS) The ½" thick CIPP liner, consisting of polyester felt material with a resin and catalyst system or an epoxy resin and hardener system, forms a smooth, hard surface that resists moisture intrusion and abrasion, and is resistant to most chemicals and all waters. The CIPP liner is superior to the rubber liner since it is an epoxy and polyester thermosetting resin that cures in place with a smooth hard surface that is resistant to biofouling and other forms of degradation. Such an impervious membrane forms an excellent protective barrier protecting the carbon steel from internal corrosion.

(2) External Coatings

Q46. How are the buried CSS and SSW pipes protected from the soil environment?

A46. (SPW) Specification No. 6498-M-306, "Specification for External surface Treatment of Underground Metallic Pipe for Unit No. 1 Pilgrim Station No. 600 Boston Edison Company" (Entergy Exhibit 3) specifies the application of permanent coating to the outside of buried piping. This specification applied to the original SSW buried piping as well as to the CSS buried piping.

In addition, the two forty-foot sections of the SSW discharge piping (one from each discharge loop) that were replaced in 1999 were coated with an epoxy coating applied to the external surface of the piping. Also, although titanium is immune to soil induced corrosion, PNPS applied a coal-tar coating to the replacement SSW system inlet titanium piping installed in 1993.

Q47. How do these external coatings act to protect the piping from the environment?

A47. (WHS) The coatings form a moisture and chemically resistant barrier that is permanently bonded to the outer surface of the pipe creating a waterproof barrier between the soil and the pipe. As long as the protective coating remains in place, the buried piping is protected from external degradation. As discussed below, this is confirmed by extensive industry experience.

Q48. Please describe the content of Specification No. 6498-M-306.

A48. (SPW) Specification No. 6498-M-306 provides procedures for installing and inspecting coatings applied in the shop as well as for coatings applied in the field (e.g., at pipe joints). With respect to coatings applied in the shop, the specification requires the following steps:

- The pipe is cleaned of all dirt, grease, mill scale, or any loose debris using some mechanical means, e.g., impact wheel or wire brush;
- Following cleaning of the pipe, a layer of primer is painted onto the exterior of the cleaned pipe;
- Following application of the primer, a coal-tar enamel coating is applied to the clean dry surface of the pipe at the correct temperature to ensure the primer bonds with the enamel to form a coating which cannot be peeled from the pipe;
- The enamel is then visually inspected for uniformity;

- Before the enamel cools, a fiber-glass pipe wrapping is applied over the enamel in a uniform wrap to cover the entire outside surface of the enamel;

- Thereafter, an additional layer of coal-tar enamel is applied;

- The second layer of enamel is followed by an outerwrap of insulation; and

- A final layer of heavy Kraft paper completes the process.

Q49. Please describe Specification No. 6498-M-306 requirements for the field application of protective coatings used on PNPS buried piping.

A49. (SPW) Specification No. 6498-M-306 provides specific instructions for field applications of coatings, which would occur at the joints where pipe segments are joined. Specification No. 6498-M-306 requires the following steps in-the-field application of coatings:

- Cleaning of the piping by wire brushing to remove and rust, scale, dust, or dirt; oil or grease is removed with a solvent;

- Following cleaning of the pipe, a layer of primer is applied to the exterior of the cleaned pipe and allowed to dry;

- Coal tar tape is applied to the primed surface. The coal tar tape is a 35-millimeter cold-applied tape coating consisting of a 7-millimeter polyethylene film backing and 28 millimeters of adhesive.

Q50. Please describe how the pipe sections are joined together before they are wrapped as you described above.

A50. (SPW) Pipe sections consist of straight length pipe, elbows, and end flanges that are welded together and coated in the shop or in the field. The flanges and elbows are made of the same material as the pipe. In the field, the end flanges of the individual pipe sections are bolted together to create the installed system. Once bolted together, the flange joints are field wrapped as described above, and tested, as described below, for complete coverage prior to back filling the excavation.

Q51. What steps are undertaken to ensure that coatings have been properly applied to ensure that there are no places on the buried pipe exposed to the soil?

A51. (SPW, WHS) In accordance with established industry practices, the coatings are inspected at every stage in the process. Specification No. 6498-M-306 requires that all shop applied coatings be inspected in accordance with Specification AWWA C-203 before shipment. This would involve visual inspection of the coated piping for any misapplication of the coatings followed by an electrical inspection of the pipe coating by a high-voltage "holiday" detector to identify any voids in the coating.

In the field, the pipes are visually inspected upon receipt to ensure that no damage occurred during shipment. Finally, after pipes are fully joined and assembled in place and the field joints are wrapped, and before covering them with soil, the entire pipe is again tested for voids using a high voltage holiday detector to assure the field joints were properly wrapped and that the shop applied coatings were not damaged during installation.

Q52. Please describe the high-voltage "holiday" test of the pipe coating.

A52. (WHS, SPW) An inspector uses a calibrated high-voltage holiday detector to identify any voids or imperfections in the coatings. The inspector drags a coil-spring or brush type electrode along the entire surface of a coated pipe. The electrode is electrically charged at a very high voltage so that if there are any voids in the pipe's coating, electricity will arc from the electrode to the metal pipe surface creating a bright flash and audible noise. If the test finds any defects, they are marked and repaired, then the pipe is retested to assure the repairs are acceptable.

Q53. Please describe the coatings used on the two forty-foot sections of SSW discharge piping that were replaced in 1999.

A53. (SPW, WHS) The coatings used on the two forty-foot section of SSW discharge piping that were replaced in 1999 utilized a aliphatic amine epoxy coating with excellent corrosion resistance properties. A minimum of two coats were applied to each length of piping in the shop to achieve a dry thickness of at least 30 millimeters, and all coated areas were holiday tested after the curing was complete. The joints between two forty-foot sections and the existing pipe were coated in the field.

Q54. Please describe the protective coating applied to the replacement SSW system inlet titanium piping installed in 1993.

A54. (SPW, WHS) The replaced titanium SSW system inlet piping was not coated in the shop, but wrapped in the field with a coal tar tape in accordance with the field application for PNPS coatings as described above.

Q55. Based on your experience, what is the industry standard for protecting buried piping used in nuclear applications?

A55. (WHS) Standard industry practice depends on the metal being buried. Typically, stainless steel and titanium are not coated or wrapped since both are generally resistant to corrosion caused by soil environments. Carbon steel, however, is subject to corrosion from the soil environment and is coated before burial. Standard industry practice for coatings requires that the pipe be cleaned and primed before any coatings are applied. Additional layers of wrapping, such as insulation, epoxy, coal tar, or bonded asbestos wrap paper depend on the pipes function and the soil conditions. Notably, standard industry practice for buried pipes applies to not only the nuclear industry, but the coal, oil, gas industries as well as fossil fueled and hydroelectric power facilities.

Q56. What specifications dictate the industry standard?

A56. (WHS) All industries rely on several common specifications for corrosion resistant coatings that are developed by industry organizations, including: American Water Works Association (AWWA), National Association of Corrosion Engineers (NACE), American National Standards Institute (ANSI), ISO, National Association of Pipe Coating Applicators, (NAPCA), American

Petroleum Institute (API), Society for Protective Coatings (SSPC), and ASTM International.

Q57. How do PNPS coatings for the CSS and SSW systems buried piping compare to industry standards?

A57. (WHS) PNPS coatings exceed industry standards in two major respects. **First,** PNPS has generally double wrapped its buried piping. As described earlier, Specification No. 6498-M-306 provided for double wrapping of buried pipe consisting of a permanent protective coal-tar coating, fiberglass wrapping, another layer of coal-tar, a layer of insulation, and a final layer of heavy Kraft paper. The standard industry practice, as set forth in AWWA C-203, requires a single wrapping for buried piping under normal soil conditions. AWWA C-203 does provide for double wrapping of pipe but only for unusual or severe conditions, such as when pipes are submerged under water. The coal-tar enamel permanent coating and bonded double outerwrap used at PNPS is specifically designed for use on submerged lines, river crossings, or similar installations involving aggressive environments, or where trench conditions are extraordinarily severe, conditions that do not apply at PNPS.

Second, it has been the practice at PNPS to wrap titanium and stainless steel buried piping, although neither is susceptible to corrosion caused by soil conditions. This is not the standard practice for the industry, which typically buries titanium and stainless steel pipe with no protective coatings because of their inherent corrosion resistance.

(3) Precautions taken in burying PNPS piping to prevent corrosion

Q58. Please describe your experience in the field installation of buried piping at PNPS.

A58. (SPW) As stated above, from May 1992 to July 1993, I was the Site Mechanical Project Engineer dedicated to the "Salt Service Water Pipe Replacement" project. In that role, I was responsible for the site engineering and installation of the titanium piping for the SSW inlet line including excavation, shoring of the trenches, interferences, construction of concrete vaults, installation and assembly of pipe, and backfilling of excavation. Also, I am generally knowledgeable of the procedures for the installation of buried piping at PNPS and the industry generally.

Q59. Based on your experience what methods does PNPS use when installing buried piping to ensure that the pipes will not corrode?

A59. (SPW) Several measures are taken at PNPS to ensure that no corrosion occurs on buried piping. These include dig safe measures, safe handling procedures, control of the soil surrounding the pipe, and compaction testing.

Q60. Please describe the dig safe measures.

A60. (SPW) Dig safe measures includes extensive drawing searches and the use of ground detection radar to identify buried components. As an added precaution, once excavation depths near the pipe depths, all digging must occur by hand to avoid damaging piping. All digging requires engineering approval to assure that existing buried systems are not damaged.

Q61. Please describe the safe handling procedures.

A61. (SPW) At all times, coated pipes must be handled with non-abrasive canvas or leather straps or nylon belts. Chains and other abrasive items are prohibited. This is required by Specification No. 6498-M-306.

Q62. Please describe control of the soil and compaction testing.

A62. (SPW) PNPS excavates the soil in layers. Once a layer of soil is excavated, it is stockpiled separately from the other layers. Layers can be as small as six inches. During backfilling, layers are replaced in the order in which they were removed. Generally, soils are replaced and compacted every six inches, and after twelve inches of backfill is added, the soil is tested to ensure the soil is sufficiently compact.

Q63. What other precautions are taken in the installation of buried piping?

A63. (SPW, WHS) The CSS and SSW system buried piping installed at PNPS was buried in a manner to protect the pipe from structural damage and from a corrosive environment. The installation instructions required the pipe to be placed on a bed of sand or specially engineered fill, which consists mostly of fine aggregate sand and specified amounts of fly ash and cement, of approximately 6 inches. The pipe is then covered with sand or specially engineered fill material before being covered by the contaminate-free, controlled soil. The sand and the engineered fill material compared to other forms of soil, such as silt or clay, do not retain water but allow water to percolate through the soil and therefore maintain very high soil resistivity.

Q64. What is the importance of soil resistivity?

A64. (WHS) Soil resistivity is an important property that determines the soil's corrosive nature. Corrosion is largely an electrochemical phenomenon whereby metal is destroyed by electrochemical or chemical reactions. For corrosion to occur, there must be a transfer of electrons between the metal and its soil environment, i.e., there must be an electric current, for which there must be an electrolyte. Soil resistivity measures the degree to which the soil opposes an electric current through it. Highly resistive soil contains minimal water, which limits the electrolytic capabilities of the soil, and inhibits current flow thereby preventing corrosion.

Q65. How do the PNPS installation methods compare to standard industry practice?

A65. (WHS) Standard industry practice for installation requires that the owner take care and precaution in excavating and re-burying piping to assure a defect-free coating or wrap is maintained. PNPS meets or exceeds standard industry practice. AWWA C203 requires that a layer of screened earth or sand, at least three inches in thickness, be placed in the bottom of the trench prior to installation of the pipe. As described above, the PNPS requirements exceed the industry standard because PNPS utilized sand or a special backfill material that is a minimum of 6 inches thick in the bottom of the trench prior to installation of the pipe.

b. Industry experience for buried piping

Q66. Mr. Spataro, what is your experience with industrial coatings used on buried pipes for corrosion resistance?

A66. (WHS) I have extensive experience in industrial coatings used to protect buried piping from corrosion since I began my professional engineering career with Ebasco Services, Inc. in 1968. As an engineer at Ebasco, I worked on projects where I evaluated and compared applied coatings on the market at the time, and I evaluated the coatings' ability to protect the piping's exterior from corrosion. A special assignment occurred during the July to December 1972 time period during which I was assigned to the refurbishment of many miles of a live 600 pound pressure gas transmission line in the countryside surrounding Newburgh, NY. The team inspected excavated piping and evaluated the conditions of the coatings, performed weld sleeve attachment to areas where degradation had occurred because of damage to the coatings, recoated the repaired areas, electrically tested the new and existing coatings, and supervised the backfill operation to assure that the coatings were not damaged.

Since then, I have worked extensively with applied coatings. I have written application procedures used in the power industry, including hydroelectric, nuclear, fossil, oil, and gas facilities as well as transmission towers, and I have evaluated the effectiveness of coatings that have been in service for many years. I have worked on projects requiring the specification of coatings and the excavation, analysis, recoating, and re-burying of piping used in the nuclear industry. I have been involved with the construction of at least 30 nuclear power stations in the United States and overseas where I specified and evaluated corrosion resistant coatings for use on buried piping.

Q67. Does industry experience show that properly wrapped and installed buried piping is sufficient to protect the piping from external corrosion?

A67. (WHS) Yes. Industry experience demonstrates that if, 1) there is a coal tar or epoxy coating on the outer surface, 2) the coating was properly applied, and 3) the coating was not damaged during installation, the protective coating will protect piping from exterior degradation. The consensus standards based on this industry experience have been in existence for many decades with only minor changes. Such durability attests to the validity of the procedures specified in the standard and used in the industry.

Q68. Can you give us some examples of the capability of external coatings to protect buried piping?

A68. (WHS) Yes, I can. As I stated, while a welding engineer at Ebasco Services I assisted in the excavation and analysis of a buried piping gas transmission line which had been coated with coal-tar epoxy in accordance with the industry practice for buried piping as described above. At the time of excavation, the piping had been in service for 25 years. Upon excavation, I personally evaluated the pipe and the coating and found that where the coating had been properly applied and not damaged, not only were there no indications of corrosion, but both the pipe and coatings were essentially in the same condition as when the pipe was buried. Because of the lack of any visible degradation of properly applied coatings over 25 years of service, the coatings as repaired were left in service.

Q69. Can you cite further examples where you have examined coatings that have met or exceeded engineering expectations?

A69. (WHS) Yes. In 1996, as Consulting Metallurgist at NYPA, I assisted in modifications of the 40 ft. wide x 80 ft. tall hydroelectric dam spill gates at the St. Lawrence Seaway Power Project. The spill gates are employed at dams to release the water behind the dam so it can be channeled through the water wheels to produce electricity. Thus, the gates are either completely submerged when closed or partially submerged when open in a flowing river water environment. The gates are coated with the same type of coal-tar that is used on buried pipes to prevent corrosion. In the case of the dam, however, the coating is applied to protect the spillway gates from, not just corrosion, but erosion from the water flow and impact damage caused by solid objects, such as trees and ice floes hitting the gate itself.

The gates had been in service for 40 years when the modifications were planned. Upon my initial inspection, I found the protective coating on the gates to be in substantially original condition. The applicable work procedures, however, required removal of the coating in those areas requiring modification by cutting and welding. After two weeks of vigorous removal efforts with mechanical tools, including chisels and jackhammers, the coating was barely removed from the areas requiring work because it had adhered so tightly to the steel. After inspection and consultation with the coating manufacturer, NYPA elected to leave the original coatings on the remaining gates not requiring modification, and to recoat the modified areas with the same protective coating. Since the gates were in excellent condition and the coating manufacturer stated that the existing coating was good for another 40 years, NYPA put the spill gates back in service with their original protective coating.

Q70. Is other industry data available regarding the capability of properly coated buried piping to resist external degradation?

A70. (WHS, ABC) Yes. NUREG/CR-6876, "Risk-Informed Assessment of Degraded Buried Piping Systems in Nuclear Power Plants" (2005) describes the research performed to assess the effects of age-related degradation of buried piping at nuclear power plants. The report refers to operating experience of buried pipes at 12 nuclear power plants that have undergone license renewal. This experience shows that properly applied coatings will protect the pipe from external corrosion. For example:

- In 1996, portions of four buried pipelines were inspected at the Calvert Cliffs nuclear power plant. The pipe wrap (trade name, "TRU COAT," an extruded polyvinyl coating covered with a black tape) was discovered to have been slightly damaged during construction, but the piping was in pristine condition after 20 years of operation.

- During the 2000 outage of the Catawba Nuclear Power Station, Units 1& 2, the nuclear service water system piping was cleaned to remove fouling buildup. After excavation, an examination of the piping's external coating revealed that the coating had been cut during construction allowing the underground environment to contact the pipe surface. Except for the cut, the external coating was in good shape.

- At North Anna Power Station, Units 1 & 2, a small hole in a branch line pipe was observed. The hole was caused by galvanic or pitting corrosion at a pinhole void. The root cause of the local galvanic cell was due to a void in the protective coating.

NUREG/CR-6876 also refers to NUREG-1522, published in June 1995, which contains descriptions of age-related degradation that were obtained from many different sources, including site visits at six older nuclear plants that had been licensed before 1977. The report stated that internal coating degradation of buried piping had been observed at three of the six plants, but no external degradation was reported.

Q71. What do you conclude after reviewing the operating experience described in NUREG/CR-6876 and NUREG-1522?

A71. (WHS) This operating experience shows that properly applied coatings will protect buried piping from external corrosion for many years. This is in accord with well established industry experience to which I have previously referred. That experience indicates that properly applied coatings will prevent the aging of components buried in the soil for extended periods of time, absent damage to the coatings during installation or maintenance. Thus, I conclude that the external surface of buried piping will not corrode during the life of a nuclear power plant if 1) there is a protective coating on the outer surface, 2) the coating was properly applied, and 3) the coating was not damaged during installation.

My familiarity with the Pilgrim specifications and review of the soil and groundwater chemistry reports, the backfill material composition, and the piping installation records lead me to conclude that the buried piping at PNPS will perform their intended functions for the license renewal period.

Q72. Is this operating experience reflected and confirmed elsewhere?

A72. (ABC) Yes. This operating experience is reflected and confirmed by the "Operating Experience" review for buried piping and tanks in NUREG 1801, Generic Aging Lessons Learned ("GALL") Report, Vol. 2, Rev. 1. The GALL Report states that "[o]perating experience shows" that a program of protective coatings and opportunistic and periodic inspections to confirm that the coatings are intact is effective in managing the "corrosion of external surfaces of buried steel piping and tanks." GALL Report, Section XI.M34, at XI M-112 (excerpts included in Entergy Exhibit 4).

As reflected in the GALL Report in the XI.M34 Operating Experience review at XI M-112, the NRC has determined that the operating experience at nuclear power plants shows that an AMP for the exterior surfaces of buried pipes and tanks consisting of protective coatings (such as those used at PNPS) and opportunistic and periodic inspections (such as those set forth in the PNPS AMP for buried pipes and tanks, discussed below) is effective in managing the corrosion of external surfaces of buried pipes and tanks.

Q73. Please describe the genesis of the GALL Report.

A73. (ABC) The GALL Report is referenced as the technical basis document for NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants." The GALL report identifies AMPs that have been determined by the NRC to be acceptable programs to manage the effects of aging on systems, structures and components within the scope of license renewal as required by 10 C.F.R. Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants." The NRC Staff developed the

GALL report at the direction of the Commission to provide a basis for evaluating the adequacy of aging management programs for license renewal. The GALL report is based on a systematic compilation of plant aging information and evaluation of program attributes for managing the effects of aging on systems, structures and components for license renewal. GALL Report at 1-3, Entergy Exhibit 4.

Q74. Has the effectiveness of the external coatings to protect buried piping been confirmed at PNPS?

A74. (SPW) Yes. The effectiveness of properly applied coatings at PNPS has been confirmed by operating experience at PNPS during the excavation of buried piping for maintenance and modification activities. PNPS had the opportunity to examine external buried piping coatings on the two forty-foot sections of SSW system discharge piping (one from each discharge loop) that were replaced in 1999, more than 25 years after the plant had become operational. The exterior surface of the piping was wrapped with reinforced fiberglass wrapping and coal tar saturated felt and heavy Kraft paper in accordance with the PNPS specification for the external wrapping of pipes that I described previously. The exterior wrappings of the pipes were found to be in good condition and no external corrosion of the pipes was observed. PNPS examined the removed piping after its wrapping was removed and found the outside surface of the piping in original, pristine condition.

(ABC) Thus, evaluation of the PNPS operating experience, as called for by Section XI.M34 of the GALL report, demonstrates the effectiveness of the protective coatings used at PNPS.

c. PNPS periodic and opportunistic inspection program for the aging management of buried piping and tanks

Q75. Please describe the inspections that are part of the PNPS license renewal BPTIP.

A75. (ABC) The PNPS license renewal BPTIP provides for inspection as follows:

- Buried components will be inspected when excavated during maintenance.
- Prior to entering the period of extended operation, plant operating experience will be reviewed to verify that an inspection occurred within the past ten years. If not, an inspection will be performed prior to entering the period of extended operation.
- In addition, 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 an assessment of pipe condition without excavation) occurs within this ten-year period.

Thus, the PNPS licensing renewal BPTIP requires a <u>minimum</u> of two inspections for buried PNPS pipes and tanks subject to the BPTIP.

Q76. What is the purpose of the inspection program that is employed as part of the PNPS license renewal BPTIP?

A76. (ABC, WHS) The purpose of the inspection program is to confirm continuing integrity of the protective coatings so as to ensure protection of the exterior surface of the piping against degradation. As discussed previously, as long as the protective coatings remain intact, the piping will be protected from external degradation caused by the soil. Therefore, as long as the inspections show that the protective coatings are not degrading and are remaining in place as designed and intended to protect the piping, inspection occurring more frequently would serve no purpose, and in fact would create the potential for damage to the protective coatings on the pipes. If degradation of the coatings is identified, however, then further analysis and evaluation would be required with potentially additional, more frequent inspections of the buried piping.

Q77. In your professional opinion, are the inspections provided for by the BPTIP sufficient to provide reasonable assurance of the continued integrity of the buried piping systems at PNPS to perform their intended functions during the period of extended operation?

A77. (ABC, WHS) Yes. The BPTIP provides for two inspections of the buried piping between 2002 (within ten years prior to entering the period of extended operation) and 2022 (within the first 10 years of the period of extended operation). Both the industry experience and the PNPS experience discussed above shows that properly applied coatings would not be expected to degrade so as to impair the integrity of the buried piping, particularly during the limited time span between inspections as provided for by the PNPS BPTIP inspection regime Thus, the inspections are complimentary and provide additional assurance. As stated, if the inspections were to identify degradation of the coatings, then further analysis and evaluation would be required with potentially additional inspections of the buried piping.

Q78. Have any procedures been developed by which the PNPS license renewal BPTIP will be implemented?

A78. (ABC, WHS) Yes. Entergy has developed a fleet-wide procedure, EN-DC-343, Rev. 0, Buried Piping and Tanks Inspection and Monitoring Program ("BPTIMP Procedure" or "the Procedure"), which is provided as Entergy Exhibit 5. The BPTIMP Procedure implements the PNPS license renewal AMP for the inspection of buried pipes and tanks, but also implements additional inspections beyond the scope of the license renewal rules.

Q79. What are the inspection methods specified in the BPTIMP Procedure?

A79. (WHS, ABC) Section 5.12 of the Procedure specifies the inspection methods by which the inspections of buried pipes are to be accomplished. It provides for visual inspection and holiday testing of the exterior of the pipes for degradation of coatings or corrosion of the pipe as well as for non-destructive testing of the pipes.

Q80. What additional inspections beyond the scope of license renewal rules are provided for by the BPTIMP Procedure?

A80. (ABC, WHS) Additional inspections beyond the scope of the LRA are based on a corrosion risk evaluation that accounts for impact factors such as soil resistivity, pipe materials, coatings, and drainage that affect the susceptibility of the piping to corrosion. The more susceptible the piping is to soil induced corrosion, the greater the frequency of the inspections provided by the BPTIMP Procedure.

Q81. What is known about the susceptibility of the CSS and SSW system buried piping to soil induced corrosion.

A81. (WHS) As already discussed, it is PNPS practice to coat buried piping with permanent protective coatings, which greatly reduce susceptibility to soil induced corrosion. In addition, the stainless steel employed in the buried piping of the CSS and the titanium piping employed for the SSW system intake piping are highly resistant to soil induced corrosion. Finally, as discussed below, based on available information, the corrosivity of the soil at PNPS is low. Therefore, the susceptibility of the CSS and SSW system buried piping to soil induced corrosion is low.

d. PNPS soil chemistry and corrosion environment

Q82. What are the soil factors that affect the susceptibility of corrosion in buried piping?

A82. (WHS) Several factors affect the corrosivity of the soil to buried piping:

- Resistivity – Since corrosion is an electrochemical process, soil resistivity is a direct measurement of the properties of the soil in preventing or accelerating corrosion. Resistivity is a broad indicator the soil's electrolytic strength; high resistivity soil indicates that the soil has low electrolytic capability, thereby inhibiting corrosion. The resistivity of soil is largely a function of the soil's moisture content and ion concentration and it generally decreases with increasing moisture and concentrations of aggressive ions.

- Moisture – Soil moisture is a general indicator of the soil's propensity to carry current in the presence of aggressive ions. Soil with low moisture content provides essentially a non-corrosive environment even for carbon steel.

- pH – Soil pH is the measure of acidity or alkalinity of the soil water. Normal soil pH is in the range of 4.5-8.0 whereas highly acidic soils, which can create an aggressive environment for certain metals if high concentrations of aggressive ions are present, have pH values less than 4.5.

- Ion Concentration – The presence of the chloride ion (Cl^-), in excess of 500 ppm, in the soil can be harmful to stainless steel because it can cause pitting initiation. Other ions, such as sulphates, are considered less aggressive, but do contribute to the pH level of the soil water.

Q83. What is known about the soil environment at PNPS that would affect the corrosion of buried pipes?

A83. (SPW, WHS) Two major precautions have been taken at PNPS to ensure that piping is not buried in an aggressive soil environment. First, as discussed above, piping is placed on a bed of sand or specially engineered fill before it is covered by another layer of fill. The sand or special fill is very porous and allows water to percolate through. Thus, it does not retain moisture and generally has high resistivity to corrosion. Second, during construction of PNPS, the site was excavated for the construction of the various PNPS buildings. During excavation, all rocks over six inches, shrubs, and trees were removed from the soil. Rocks can cause physical damage to buried structures and plants, as they biodegrade, release compounds that may increase soil pH. These two precautions serve to reduce the corrosivity of the soil environment experienced by the buried piping at PNPS. Additionally, as discussed below, the soil's pH of 6.2-6.82 and Cl^- content of 210 - 420 ppm show that neither of these factors creates an aggressive soil environment.

Q84. Since moisture content of the soil affects corrosivity, what other steps, if any, has PNPS undertaken to ensure that the moisture content of the soil surrounding the pipe remains low.

A84. (SPW) In addition to surrounding buried pipe with sand or special fill material, as already described, two other important precautions are taken to prevent high levels of soil moisture from occurring: (1) when PNPS was erected, a storm drain system was installed to prevent the buildup of water; and (2) buried pipes are buried above the water table.

Q85. Please describe the PNPS storm drainage system.

A85. (SPW) The storm drain system not only runs throughout the 90 acre PNPS site, but also along the border of the site. The purpose of the drain system is to carry away excess rainwater on the site and to divert rainwater runoff outside of the site away from the site.

Q86. Please describe the effect of burying pipes above the water table.

A86. (SPW, WHS) When it rains, water naturally percolates down through the soil. Burying pipes above the water table ensures that the water percolates down, past the piping, and is taken away with the flow of the ground water instead of collecting and adding moisture to the soil creating an electrolyte next to the buried pipe. The water table at PNPS where the CSS and SSW system piping is buried is approximately 17 feet below the surface. The CSS and SSW system pipes are buried 7 to 10 feet below the surface, well above the water table. In addition to the sand or special fill material used at PNPS, burying the pipe above the water table ensures that the low moisture content of the soil surrounding the buried piping is maintained.

Q87. Mr. Spataro, have you reviewed any soil analysis reports for PNPS that would enable you to characterize the corrosivity of the soil at PNPS?

A87. (WHS) Yes. I reviewed the 1992 soil analysis taken near SSW system loop A and loop B and I have also reviewed an October 2005 analysis of the groundwater at PNPS which is a good indicator of the soil condition.

Q88. What did you find from your review?

A88. (WHS) The soil pH ranges from 6.2-6.82 which reflects a non-aggressive soil environment. The moisture content of the soil ranged from 5.5% to 8.1%, which is a low moisture content and a non-aggressive environment. The chloride content is 210-420 ppm, which constitutes a low ion concentration, and non-aggressive environment. The low moisture and ion concentration along with the use of sand or specially engineered fill used in burying the pipe yields a high soil resistivity and results in a non-aggressive soil environment.

Q89. Mr. Spataro, based on your experience, how aggressive is the PNPS soil?

A89. (WHS) The soil at PNPS is not aggressively corrosive at all. Considering the pH and high resistivity plus the low chloride concentration and low moisture content, in my expert opinion, at worst the soil is mildly corrosive.

e. Sufficiency of the PNPS BPTIP AMP

Q90. Is the PNPS BPTIP sufficient to meet the requirements of 10 C.F.R. Part 54 for the buried piping systems to which it applies?

A90. (ABC, WHS. SPW) Yes. The PNPS BPTIP is consistent with one exception to the NUREG-1801, Section XI.M34 Buried Piping and Tanks Inspection (which provides NRC guidance on aging management programs for the external surfaces of buried pipes and tanks) and is more than sufficient to meet the requirements of 10 C.F.R. Part 54. The one exception allows flexibility to use a more effective means than visual inspection, if available, to assess pipe condition. An effective method of performing piping assessment without excavation would minimize the potential for damage to the protective coating during excavation. Specifically, the BPTIP incorporates the following features that are consistent with regulatory guidance and meet the requirements of the regulations to provide reasonable assurance that the effects of aging on the external surfaces of the PNPS SSW system and the CSS buried piping will be managed such that the intended functions will be maintained consistent with the current licensing basis throughout the period of extended operation.

- The CCS and SSW system buried piping utilizes corrosion resistant materials, titanium, stainless steel, and wrapped carbon steel with internal cured in place linings.
- The buried piping utilizes coal tar or epoxy coatings that generally exceed industry standards.
- The BPTIP provides for inspections to confirm continuing integrity of the protective coatings.

- Because of the precautions taken at PNPS, the corrosivity of the soil surrounding the buried piping is low.
- The PNPS operating experience demonstrates the sufficiency of the protection provided by the protective coatings used on buried pipes at PNPS, consistent with industry experience, which demonstrates that properly applied coatings will ensure the protection of buried piping from soil induced corrosion.

2. The Water Chemistry Control-BWR Program

Q91. What is the purpose of the Water Chemistry Control BWR Program?

A91. (ABC) The Water Chemistry Control-BWR Program optimizes the water chemistry in the CSS (among other plant systems) to minimize the potential for loss of material and cracking due to internal corrosion of the system.

Q92. How does the Water Chemistry Control BWR Program accomplish its purpose?

A92. (ABC) The Water Chemistry Control BWR Program operates by limiting the levels of contaminants in the CSS that could cause loss of material and cracking.

Q93. Has the effectiveness of the Water Chemistry Control BWR Program been confirmed at PNPS?

A93. (ABC) Yes. This is an existing program at PNPS that has been confirmed effective at managing the effects of aging on the CSS as documented by the operating experience review. See PNPS LRA at Appendix B, Section B.1.32.2, p. B-106-07. The continuous confirmation of water quality and timely corrective actions taken to address water quality issues ensure that the program is effective in managing corrosion for applicable components.

Q94. Does the Water Chemistry Control BWR Program comport with the guidance contained in the GALL Report?

A94. (ABC) Yes. The program uses EPRI BWR water chemistry guidelines, as specified in the GALL Report, which include chemistry recommendations for condensate storage tanks. The program's effectiveness has also been confirmed by industry operating experience as described in the GALL Report. GALL Report at XI M-12, M-13, Entergy Exhibit 4.

3. The Service Water Integrity Program

Q95. What is the purpose of the Service Water Integrity Program?

A95. (SPW) The Service Water Integrity Program includes surveillance and control techniques to manage the effects of aging on the SSW system or structures and components serviced by the SSW system.

Q96. How does the Service Water Integrity Program accomplish its purpose?

A96. (SPW) Under the 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. The inspection program includes provisions for visual inspections, eddy current testing of heat exchanger tubes, ultrasonic testing, radiography, and heat transfer capability testing of the heat exchangers. The periodic inspections include direct visual inspections and video inspections accomplished by inserting a camera-equipped robotic device into the SSW system piping. In addition, chemical treatment using biocides and chlorine and periodic cleaning and flushing of infrequently used loops are methods used under this program.

Q97. Has the effectiveness of the Service Water Integrity Program been confirmed at PNPS?

A97. (SPW) This program has been effective in detecting degradation of the internal rubber lining in the original SSW system carbon steel piping. As a result, the inlet pipes were replaced with titanium pipe, and portions of the discharge pipes were replaced with carbon steel piping coated internally and externally with an epoxy coating, and the entire lengths of the discharge pipes were internally lined with cured-in-place pipe linings. Thus, this program has been successfully implemented at PNPS to manage SSW system degradation from loss of material due to internal corrosion prior to the loss of its intended function. See PNPS LRA at Appendix B, Section B.1.28, p. B-92-93 (Entergy Exhibit 2).

Q98. Please describe how the Service Water Integrity Program was used to identify the internal degradation of the original internal rubber lining in the SSW discharge piping.

A98. (SPW) PNPS monitored the integrity of the original rubber lining as part of the in-service inspection requirements for the SSW developed in response to Generic Letter 89-13. As part of this monitoring, PNPS undertook increasingly intensive inspections as the original rubber lining approached the end of its expected life. In 1995, PNPS visually inspected the rubber liner using a robot crawler fitted with a camera and found minor age related degradation. The rubber liner was re-inspected using this same method in 1997, which identified additional degradation. Consequently, in 1999 PNPS undertook more intensive inspections by sending an inspector into the pipe to do both visual and ultrasonic examinations with the intent to make any necessary replacements or repairs. Based on the findings of this inspection, PNPS replaced the two forty-foot sections of the carbon steel SSW discharge pipe, as discussed above, and made other repairs. This action was then followed up with the installation in 2001 and 2003 of the CIPP throughout the entire length of both discharge loops A and B as discussed above.

Similarly, the Service Water Integrity Program will be used to monitor the newly installed CIPP. As the CIPP approaches the end of its expected life, increased inspections will be undertaken of the CIPP. The in-service inspection program for the SSW currently requires PNPS to undertake a complete ultrasonic or visual examination of the CIPP, analogous to those undertaken for the original rubber lining, after the CIPP has been in service for 20 years, well before the end of its expected 35 year life.

Q99. Does the Service Water Integrity Program comport with the guidance contained in the GALL Report?

A99. (ABC, SPW) Yes. The Service Water Integrity Program is consistent with the program described in NUREG-1801 with two minor exceptions. One is that not all of the PNPS SSW components are coated internally (e.g., the titanium inlet piping) while the NUREG-1801 program states that system components are lined or coated. In practice, systems are lined or coated based on whether the coating is necessary to protect specific materials in the service water environment. This practice is standard throughout the industry. PNPS conservatively identified this as an exception because for some component materials, such as the titanium inlet piping, internal linings or coatings are not necessary and were not provided. (As discussed above, all of the carbon steel discharge piping is lined with CIPP.) The second exception is an exception to the frequency specified for tests and inspections. NUREG-1801 specifies testing and inspections annually and during refueling outages. Since some inspections and tests are not feasible during plant operation, the PNPS program entails inspections and testing during refueling outages, not annually. Since aging effects are manifest over several years, the difference in inspection and testing frequency is insignificant.

4. The One-Time Inspection Program

Q100. What is the purpose of the One-Time Inspection Program?

A100. (ABC) The One-Time Inspection Program includes activities to confirm the absence of significant aging effects for the internal surfaces of piping. In essence, the One-Time Inspection Program ensures the effectiveness of the Water Chemistry Control-BWR Program, which minimizes the potential for loss of material due to internal corrosion of the CSS, by "verify[ing] the effectiveness of the water chemistry control [AMPs] by confirming that unacceptable cracking, loss of material, and fouling is not occurring." PNPS LRA at Appendix B, Section B.1.23, p. B-76 (Entergy Exhibit 2).

Q101. How does the One-Time Inspection Program accomplish its purpose?

A101. (ABC) The One-Time Inspection Program is an inspection of a representative sample (based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience) of the interior piping surface, which will be performed prior to the period of extended operation. The inspection locations will be chosen based on identifying locations most susceptible to aging degradation.

Q102. Does the One-Time Inspection Program comport with the guidance contained in the GALL Report?

A102. (ABC) Yes. The PNPS One-Time Inspection Program comports with the NRC Staff guidance set forth in the GALL Report for such inspection programs. See GALL Report at XI M-105 (Entergy Exhibit 4).

5. Summary of the AMPs

Q103. Is it your opinion that the AMPs described above will provide reasonable assurance that the CSS and SSW system will perform their intended safety function during the license renewal term?

A103. (ABC, WHS, BRS, SPW) Yes.

Q104. Please summarize the basis for your opinion.

A104. (ABC, WHS, BRS, SPW) These AMPs will provide reasonable assurance that the effects of aging on the PNPS SSW system and the CSS will be managed such that the intended functions will be maintained consistent with the current licensing basis throughout the period of extended operation. The AMPs described above are either (i) programs proven effective through industry operating experience or (ii) new programs that rely on proven methods to effectively manage the effects of aging.

D. Additional Surveillance Programs for the CSS and SSW System

Q105. In addition to the AMPs described above, does PNPS undertake any additional surveillance or otherwise monitor the integrity and functioning of the CSS and SSW system?

A105. (BRS, SPW) Yes, PNPS employs surveillance and other monitoring programs to ensure the integrity and capability of the CSS and the SSW system to perform their intended functions. The monitoring and surveillance programs consist of frequent monitoring of plant indicators and testing of plant systems.

1. Monitoring of the Integrity of the CSS

Q106. Please describe the additional surveillance and other monitoring that PNPS undertakes to ensure the integrity and functioning of the CSS.

A106. (BRS) PNPS ensures the continuing integrity and functioning of the CSS in two ways. First, a water level indicator in each of the two condensate storage tanks ("CST") is monitored every four hours. Second, the water flow rates from the HPCI and RCIC pumps are tested on a quarterly basis which serves to confirm adequate flow rates through the buried CSS piping.

a. CST Monitoring

Q107. Regarding the monitoring of the water level in the CSTs, how are those tanks related to the in-scope CSS system buried piping?

A107. (BRS) The CSS system buried pipes draw water from the CST tanks and carry that water to the HPCI and RCIC system pumps.

Q108. How does monitoring the water level of the CSTs assist PNPS in verifying the integrity of the CSS system buried piping?

A108. (BRS) A significant change (i.e., outside the normal parameters) in the water level in the CSTs would indicate that there was a significant leak in one of the components of the CSS.

Q109. Why would a significant change in the water level in the CSS tanks indicate that there was a significant leak somewhere in the system?

A109. (BRS) Condensate water is part of the overall condensate and feedwater system. PNPS monitors the water level in the CSTs to ensure that the system is operating within normal parameters. If there were a significant drop in the level of water in the CSTs, we would know that there was a significant leak in the system, and would take appropriate action to identify and fix the leak.

Q110. Please describe the CSS tanks and the measures for monitoring the water level of the tanks.

A110. (BRS) Each of the two CSS tanks holds 275,000 gallons of water. The water level in each tank is maintained such that the level of the water in the tanks does not drop below 30 feet. The control room personnel monitor and record the water level in each tank every four hours to ensure that the water level in the CSTs is maintained.

Q111. What, if any, corrective action would be taken if the water level went below that normal range?

A111. (BRS) Any abnormal usage of water by the plant would require corrective action. Due to normal usage, personnel have to periodically add water to the CSTs. The need for excessive amounts of added water would indicate that there was a leak and would require corrective action. If there was no visible leak in the CSTs and connected systems, we would know that the leak is in the CSS buried piping connected to the CST which provide water to the HPCI and RCIC systems and would take the action necessary to fix the leak.

Q112. Assuming the CST water level was dropping below the normal level, is there a CST water level at which the HPCI and RCIC systems would no longer work?

A112. (BRS) As long as the water levels in the CSTs remain at or above 11 feet, the HPCI and RCIC systems would be able to draw sufficient water from the CSTs to perform their intended functions. (As I noted previously, each CST has a 75,000 gallon reserve dedicated to the HPCI and RCIC systems which equates to 11 feet of water in the CSTs.) Moreover, the HPCI and RCIC intended functions can be accomplished using water from the torus. Thus, even if the CST water level drops below 11 feet, the HPCI and RCIC systems are able to perform their intended functions.

Q113. Is it correct that you would have to lose roughly 20 feet of water from the CSTs before the capability of the HPCI and RCIC to perform their system functions using water solely from the CSTs would be impaired?

A113. (BRS) That is correct.

Q114. Would you notice and respond to such a drop in the CST water level?

A114. (BRS) Yes. Such a large drop in the CST water level would indicate a major leak in the CSS and prompt corrective action would taken to identify and remedy the source of the leak.

Q115. Can the plant still operate without the HPCI and RCIC systems?

A115. (BRS) Based on the plant's technical specifications, if one of the two systems is inoperable, you have 14 days to fix the system before you have to shut the plant down. If both systems are inoperable, you would have to shut down the plant within 24 hours.

Q116. Would a monitoring well be more effective in detecting a leak in the CSS buried piping than the CST water level monitoring program?

A116. (BRS) No. The CST water level check is performed every four hours, which is substantially more frequent than a sampling program for monitoring wells. Further, depending on the location of the leak, it might take additional time for the radioactivity to reach and be detectible in a monitoring well. In addition, the CST water level check would directly detect any leak significant enough to impair the intended functions of the CSS. It is a check on the water that flows into the precise buried piping system that is within the scope of license renewal.

b. HPCI and RCIC system pump water flow monitoring

Q117. How does monitoring the water flow from the HPCI and RCIC system pumps assist PNPS in verifying the integrity of the CSS system buried piping providing water to the HPCI and RCIC systems?

A117. (BRS) The pumps must meet a minimum flow rate in order to perform their intended functions. If, when tested, the required minimum water flow rate out of the HPCI and RCIC system pumps is not met, we would declare the affected systems inoperable. If one or both systems are inoperable, we would take corrective action because, as I previously testified, we would have to shut down within 14 days if one system was inoperable, or within 24 hours if both systems are inoperable.

Q118. Please describe the measures for monitoring the water flow rate from the HPCI and RCIC system pumps.

A118. (BRS) The Pilgrim plant safety analysis requires that the HPCI system maintain a water flow rate of 4,250 ("GPM"). The Pilgrim plant safety analysis requires that the RCIC system maintain a water flow rate of 400 gallons per minute. Pursuant to 10 C.F.R. §§ 50.55a(f)-(g) and the technical specification surveillance requirements, PNPS undertakes in-service testing of the HPCI and RCIC systems to confirm the system capability to deliver the minimum required water flows. Specifically, the HPCI and RCIC systems are tested quarterly to prove operability in accordance with the PNPS Technical Specifications and the ASME Code. In other words, these quarterly tests ensure that the required water flow rates of 4,250 gallons per minute and 400 gallons per minute, respectively, are met.

In addition, the flow rates for the HPCI and RCIC systems are confirmed during system testing once every operating cycle following each refueling outage. The

HPCI and RCIC systems are also tested once every two years to verify the capability to operate the systems from the Alternate Shutdown Panel ("ASP"). These tests are in addition to the quarterly tests.

Q119. What consequences result, if any, should the specified flow rates not be achieved?

A119. (BRS) If any of the acceptance criteria for the flow rate tests are not met, corrective actions will be taken.

Q120. Would these quarterly flow rate inspections detect a leak in the CSS system piping large enough to prevent the HPCI or RCIC systems from performing their intended function?

A120. (BRS) Yes. A sufficiently large leak in the buried piping would cause the acceptance criteria not to be met. In other words, a potential cause of a failure to meet either the required 4,250 GPM or 400 GPM flow rates could be a leak in the buried pipe from the CSTs. As long as the quarterly testing meets the required flow rates, the HPCI or RCIC systems will perform their intended functions. However, a leak that could prevent satisfactory accomplishment of the flow tests is much larger than the size of a leak that will be readily detected through routine monitoring of the CST levels.

Q121. Would a monitoring well be more effective in detecting a leak in the CSS buried piping running to the HPCI and RCIC system pumps than the quarterly flow rate tests?

A121. (BRS) No. The flow rate tests on the HPCI and RCIC system pumps occur once every quarter, once per operating cycle, and once every two years. Therefore, the RCIC and HPCI pumps would be checked at least as frequently as ground water in a monitoring well program. In addition, a monitoring well program could not distinguish a leak in the CSS buried piping leading to the HPCI and RCIC pumps from any other underground leak. Conversely, the quarterly flow rate tests check the water flow from the HPCI and RCIC system pumps connected to the CSS buried piping. It is a check on the water flow rate through the precise buried piping system within the scope of license renewal.

2. Monitoring the Integrity of the SSW System Buried Piping

Q122. Does PNPS monitor the integrity and functioning of the SSW system buried piping?

A122. (BRS) Yes. PNPS performs, on a monthly basis, a flow rate test of the seawater flow through the SSW system.

Q123. Please describe the program for monitoring the water flow rate.

A123. (BRS) Each month, PNPS tests the flow rate of the SSW system through the RBCCW heat exchanger. The minimum required flow for the test is 4500 GPM.

Q124. What does this test show?

A124. (BRS) The test is performed to make sure that there is adequate water flow through the heat exchangers and piping. It confirms that a leak, if any, from the buried piping is not large enough to prevent the system from satisfactorily performing its intended function.

Q125. What consequences result should the specified flow rates not be achieved?

A125. (BRS) If the acceptance criteria for the flow rate test are not met, corrective action will be taken – the problem will be investigated and fixed.

Q126. Are small leaks in the SSW system discharge lines a concern to the operability of the SSW system?

A126. (BRS, SPW) No. A small leak in the SSW system discharge line would not impair the operability of the SSW system. After all, the discharge line discharges the water into the bay. Therefore, a leak in and of itself does not impair the operability of the system. Only if the flow through the discharge system were impaired would system operability be affected. Should that occur, the SSW flow would decrease and pump discharge pressure would increase. These parameters are continuously monitored in the control room by plant operators.

Q127. Would a monitoring well be more effective in detecting a leak in the SSW system buried piping than the monthly flow rate tests of the SSW system?

A127. (BRS) No. The flow rate tests on the SSW system occur every month, which is more frequent than sampling from a monitoring well. In addition, the SSW system does not normally and would be very unlikely to contain radioactivity, so monitoring groundwater wells for radioactivity would not be expected to provide any indication of a leak in the SSW piping. Indeed, the only indicator would be salt water, but the SSW runs near the intake embayment and into the discharge canal, both of which contain salt water, so it would be difficult to discern whether salt levels in a monitoring well are attributable to a leak rather than the influences of the adjacent water bodies. In addition, the SSW discharge lines are each over 200 feet long, and attempting to use monitoring wells to detect leakage from this span would be difficult and inefficient. Further, sampling from a monitoring well could not distinguish a leak in the SSW system buried piping from any other leak. Conversely, the monthly SSW system flow rate tests check the water flow through the SSW buried piping. It is a check on the water that flows through the precise buried piping system within the scope of license renewal.

E. Monitoring Wells are Not Necessary to Detect Leakage Sufficiently Large Enough to Prevent the CSS Buried Piping and the SSW System Buried Discharge Piping from Performing their Intended Safety Functions

Q128. Is it your opinion that monitoring wells, through which sampling would monitor the radiation levels in the ground water in and around the Pilgrim site, are necessary in order to detect a leak in the buried CSS piping or the SSW system discharge piping?

A128. (ABC, WHS, BRS, SPW) No.

Q129. Why not?

A129. (ABC, WHS, BRS, SPW) Monitoring wells would not be as effective at detecting significant leaks from either the CSS or SSW system as the periodic surveillance tests summarized above. Sampling for radioactivity in the monitoring wells would not likely detect a leak from the SSW system because it is highly unlikely that the discharge piping would contain any radioactive water. In addition, the flow rate testing for the SSW system confirms on a monthly basis that that system is capable of performing its intended function.

For the CSS, which does contain radioactive liquid, monitoring confirms every four hours that the water level in the two CSTs is within the normal operating range. CST water level within normal range indicates that there is no leak in CSS system piping large enough to compromise the ability of those pipes to perform their intended function of providing water to the HPCI and RCIC systems.

Furthermore, the HPCI and RCIC system pump flow rate tests confirm on a quarterly basis that the HPCI and RCIC system pumps, which are fed by the in-scope CSS buried piping, are performing at the water flow rates required under the technical specifications. The daily monitoring and quarterly testing of the systems using in-scope buried piping provide a more precise indication of whether the in scope buried piping is leaking sufficient liquid such that the piping could not perform its intended function than monitoring wells.

Even if monitoring wells detected radioactivity, such a measurement could not indicate, with anywhere near as much precision, the origin of the leak. Furthermore, monitoring wells would likely not be monitored more than once every quarter. This is no more frequent than the quarterly surveillance program for the HPCI and RCIC system piping and less frequent than the monthly program for the SSW system piping, and is significantly less frequent than the daily monitoring of the CST water level.

IV. CONCLUSION

Q130. What is your conclusion regarding the sufficiency of the AMPs discussed above to provide reasonable assurance that components within the scope of license renewal containing radioactive liquids at PNPS will continue to perform their intended functions during the period of extended operation?

A130. (ABC, BRS, SPW, WHS) The AMPs for those buried components within the scope of license renewal containing radioactive liquids at PNPS are programs that have been shown to be effective by PNPS operating experience and the GALL Report, and thus provide reasonable assurance that such components will continue to perform their intended functions during the period of extended operation. Further, these AMPs are in addition to regular monitoring and surveillances that continually confirm the ability of the components to perform their intended functions.

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)	)	

DECLARATION OF ALAN B. COX IN SUPPORT OF ENTERGY'S PRE-FILED TESTIMONY ON PILGRIM WATCH CONTENTION 1

I, Alan B. Cox, do hereby state the following:

I am the Technical Manager, License Renewal for Entergy Nuclear. My business address is 1448 State Road 333, Russelville, AR 72801. I was involved in preparing the license renewal application and developing aging management programs for the Pilgrim Nuclear Power Station license renewal project and have extensive experience and knowledge in the preparation of license renewal applications. A statement of my professional qualifications is attached.

I provide this declaration in support of Entergy's pre-filed testimony on Pilgrim Watch Contention 1 pursuant to the December 19, 2007 Atomic Safety and Licensing Board Order.

I attest to the accuracy of those statements attributed to me (that material marked by my initials in Entergy's pre-filed testimony), support them as my own, and endorse their introduction into the record of this proceeding. I declare under penalty of perjury that those statements, and my statements in this declaration, are true and correct to the best of my knowledge, information, and belief.

Executed on January 8, 2008

Alan B. Cox

Entergy

RESUME

Alan B. Cox

EDUCATION	B.S., Nuclear Engineering, University of Oklahoma, 1977 M.B.A., University of Arkansas at Little Rock, 1999
EXPERIENCE	
June 2001 - Present	<u>Entergy License Renewal Team – Manager, License Renewal</u> Project manager and technical lead for license renewal services supporting both Entergy and non-Entergy license renewal projects. Entergy representative on various license renewal related industry groups.
1996-2001	<u>Entergy Operations – Supervisor, Design Engineering</u> Responsible for NSSS systems including supervision of engineers responsible for ANO-1 license renewal project. Served as member of expert panel responsible for review of license renewal application. Also provided design engineering support for plant modifications, corrective action tasks, major projects and plant operations associated with Arkansas Nuclear One.
1993-1996	<u>Entergy Operations – Senior Staff Engineer</u> Provided design engineering support for plant modifications, corrective action tasks, major projects and plant operations associated with Arkansas Nuclear One. Principal mechanical engineering reviewer for improved Technical Specifications for ANO-1.
1990-1993	<u>Entergy Operations – Technical Assistant to Plant Manager</u> Provided technical support associated with management of Arkansas Nuclear One, Unit 1. Served as Entergy representative on the B&W Owners Group steering committee.
1986-1989	<u>Arkansas Power & Light Company – Manager, Operations</u> Responsible for the day to day operations of Arkansas Nuclear One, Unit 1.
1977-1986	<u>Arkansas Power & Light Company – Engineer</u> At Arkansas Nuclear One, served in various capacities associated with the operation of Unit 1 and the startup and operation of Unit 2. Included assignments in plant performance monitoring, outage planning and scheduling, reactor engineering, and operations technical support. Qualified as shift technical advisor for both units of Arkansas Nuclear One.
CERTIFICATIONS	• Professional Engineer; Registered in Arkansas (currently inactive) • Previously held RO and SRO licenses at Arkansas Nuclear One, Unit 1
PROFESSIONAL AFFILIATIONS	• Member, American Nuclear Society (ANS)

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)	)	

DECLARATION OF BRIAN R. SULLIVAN IN SUPPORT OF ENTERGY'S PRE-FILED TESTIMONY ON PILGRIM WATCH CONTENTION 1

I, Brian R. Sullivan, do hereby state the following:

I am the Engineering Director for Pilgrim Nuclear Power Station ("PNPS"). My business address is 600 Rocky Hill Road, Plymouth, MA 02360. I am currently responsible for engineering support at PNPS and I am knowledgeable of the intended functions for license renewal components and of the aging management programs credited for buried pipes and tanks for PNPS license renewal. A statement of my professional qualifications is attached.

I provide this declaration in support of Entergy's pre-filed testimony on Pilgrim Watch Contention 1 pursuant to the December 19, 2007 Atomic Safety and Licensing Board Order.

I attest to the accuracy of those statements attributed to me (that material marked by my initials in Entergy's pre-filed testimony), support them as my own, and endorse their introduction into the record of this proceeding. I declare under penalty of perjury that those statements, and my statements in this declaration, are true and correct to the best of my knowledge, information, and belief.

Executed on January 8, 2008

Brian R. Sullivan

Brian R. Sullivan
Pilgrim Nuclear Power Station
600 Rocky Hill Road
Plymouth, MA 02360

EDUCATION

1980 – BSME – Massachusetts Maritime Academy
Senior Operator License Number 11780
Operator Docket Number 55-62007
2nd Assistant Engineers License – USCG

EXPERIENCE

<u>1988 – Present</u>

Various positions of increased responsibility at Pilgrim Nuclear Power Station

- Senior Engineer
- Control Room Supervisor
- Shift Manager
- AOM Shift
- Outage Manager
- AOM Support
- Programs and Components Manager
- Systems Engineering Manager
- Engineering Director

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DECLARATION OF STEVEN P. WOODS IN SUPPORT OF ENTERGY'S PRE-FILED TESTIMONY ON PILGRIM WATCH CONTENTION 1

I, Steven P. Woods, do hereby state the following:

I am the Manager, Programs & Engineering Components for Pilgrim Nuclear Power Station ("PNPS"). My business address is 600 Rocky Hill Road, Plymouth, MA 02360. I knowledgeable of the PNPS aging management program for buried pipes and tanks and was responsible for site engineering to install buried salt service water inlet piping at PNPS in 1993. A statement of my professional qualifications is attached.

I provide this declaration in support of Entergy's pre-filed testimony on Pilgrim Watch Contention 1 pursuant to the December 19, 2007 Atomic Safety and Licensing Board Order.

I attest to the accuracy of those statements attributed to me (that material marked by my initials in Entergy's pre-filed testimony), support them as my own, and endorse their introduction into the record of this proceeding. I declare under penalty of perjury that those statements, and my statements in this declaration, are true and correct to the best of my knowledge, information, and belief.

Executed on January 8, 2008

Steven P. Woods

STEVEN P. WOODS **RESUME OF QUALIFICATIONS**

SUMMARY OF QUALIFICATIONS

EXPERIENCE	Over twenty six years experience applying engineering methods and capabilities to various projects and engineering disciplines ... employing management and supervisory skills ... repairing and maintaining marine and nuclear facilities ... identifying technical discrepancies ... solving engineering problems ... designing and preparing modifications for new and existing systems ... implementing effective and efficient nuclear power plant procedures...designing and developing specifications for various equipment and systems ... analyzing mechanical components and piping systems to ASME, AWS, ANSI and AISC codes utilizing conventional methods and computer programs including MATHCAD, SUPERPIPE, GT Strudl and CDC Baseplate II, ... highly motivated and capable of working independently or as a member of an integrated team.

EMPLOYMENT HISTORY

	ENTERGY CORP. - PILGRIM NUCLEAR POWER STATION, Plymouth, Massachusetts
7/07 To Present	Manager, Engineering Programs & Components. Responsible for budgets, schedules, resource allocation for emergent activities as well as long term plans including outages and license renewal.
1/06 To 7/07	Supervisor Code Programs, Eng. Programs & Components. Responsible for code program activities such as budgets, schedules, resource allocation, long term plans, and license renewal. Acting EP&C manager.
5/00 To 1/06	Senior Engineer, Design Engineering – Mechanical / Civil / Structural group. Performing all facets of design engineering including nuclear changes and field support.
9/99 To 5/2000	**ALTRAN CORPORATION,** Boston, Massachusetts Engineering Consultant, Indian Point Unit 2 and Pilgrim Nuclear Power Stations Project Manager / Engineer to resolve design problems via generic modifications / component replacements to support IP2's outage. Staff augmentation to Mechanical / Structural Engineering Group at Entergy's PNPS for plant design changes.
3/96 To 9/99	**PROTO-POWER CORPORATION,** Groton, Connecticut Senior Engineer, Structural / Applied Mechanics Group, Millstone Unit 2 Nuclear Power Station Engineering Consultant assigned to lead the mechanical section of the Rapid Response Group in resolving "hot items" critical to plant operations. Performed analysis of structural and mechanical components initiated by Non-Conformance Reports, Condition Reports and Plant Design Changes. Provide Motor Operated Valve (MOV) engineering support to MOV Group.
8/93 To 2/96	**ALTRAN CORPORATION,** Boston, Massachusetts Engineering Consultant, Millstone Units 1, 2, 3 & Connecticut Yankee Nuclear Power Stations and Fitzpatrick Nuclear Plant Lead Project Engineer performing Weaklink structural analysis of components for MOV's in accordance with the NRC's GL89-10 program. Developing design modifications for overstressed MOV's to return valves to original design basis.
5/92 - 7/93	**CYGNA ENERGY SERVICES,** Boston, Massachusetts Engineering Consultant, Boston Edision's Pilgrim Nuclear Power Station Mechanical Project Engineer dedicated to the "Salt Service Water Pipe Replacement" project. Generated calculations to qualify design modifications during each phase of the project including excavation, underground concrete vault construction, titanium pipe fabrication and installation.
1/92 - 3/92	**ALTRAN CORPORATION,** Boston, Massachusetts Engineering Consultant, Millstone Units 1, 2, 3 & Connecticut Yankee Nuclear Power Stations

Performed Erosion / Corrosion analysis for operability of piping systems enabling plant restart.

12/88 - 12/91 <u>ABB IMPELL CORPORATION,</u> Framingham, Massachusetts
Lead Senior Engineer, Engineering Mechanics Division
Mechanical Engineering Consultant for Nine Mile Units 1 & 2 and Pilgrim Nuclear Station. Performed pipe stress analysis and calculations. Mechanical Maintenance Project Engineer for Reactor Recirc Pumps Replacement and Modification controlling part replacements, rebuilding; identified and procured vendor specialty services; identified and designed special tools to facilitate field conditions. Resolved critical path engineering discrepancies in preparation for plant restart. Develop program and staff for material availability / substitution.

6/88 - 11/88 <u>IMPELL CORPORATION,</u> Fort Worth, Texas
Senior Engineer Consultant, Structural Mechanics Division, Comanche Peak Nuclear Plant.
Lead Engineer for the Post Construction Hardware Validation Program. Evaluated and controlled critical path items; verified support calculations for structural integrity.

1/88 - 5/88 <u>GILBERT/COMMONWEALTH,</u> Chattanooga, Tennessee
Senior Engineer Consultant, Hixson Office.
Verifier, Checker and Originator of calculations for analysis of pipe supports on Sequoyah Nuclear Plant Calculation Regeneration Program.

12/85 - 9/87 <u>IMPELL CORPORATION,</u> Knoxville, Tennessee
Principal Engineer, Watts Bar Nuclear Plant.
The Design Engineering Department interface for system modifications and special tasks per request by the client. Field verified and analyzed structural and mechanical components, including load generation and support qualification, utilizing conventional methods and computer programs. Performed constructability reviews.

12/81 - 10/85 <u>TELEDYNE ENGINEERING SERVICES,</u> Waltham, Massachusetts
Project Engineer. Turkey Point Nuclear Plant, Nine Mile Point Nuclear Plant, Fitzpatrick Nuclear Plant, Pilgrim Nuclear Station and Watts Bar Nuclear Plant.
Liaison engineer coordinating uninterrupted construction of all mechanical activities, making on-the-spot decisions for effective work flow. Performed structural and mechanical component analysis on new and existing systems.

1980 - 1981 <u>U.S. MERCHANT MARINES</u>
Third Assistant Engineering Officer aboard cargo vessels.
Engineering Officer-On-Watch. Responsible for power plant operations and maintenance including supervision of extensive repair / testing of power plant components such as turbines, gears, pumps, valves, heat exchangers, boilers, I&C systems and electric motors.

1977 - 1980 <u>MASSACHUSETTS MARITIME ACADEMY</u>
Summer training cruises (3) aboard Academy vessels. Performed all engine room tasks.

CLEARANCES Unescorted access to all nuclear plant sites assigned to.

EDUCATION Bachelor of Science Degree, Marine/Mechanical Engineering,
Massachusetts Maritime Academy, Buzzards Bay, Massachusetts, 1980

U.S. Coast Guard Third Assistant Engineer of Steam and Motor Vessels for Unlimited Horsepower. License No. 513413.

DATE OF BIRTH

CITIZENSHIP USA

REFERENCES Available upon request.

January 8, 2008

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DECLARATION OF WILLIAM H. SPATARO IN SUPPORT OF ENTERGY'S PRE-FILED TESTIMONY ON PILGRIM WATCH CONTENTION 1

I, William H. Spataro, do hereby state the following:

Until December 31, 2007, I was the Senior Staff Engineer-Corporate Metallurgist with Entergy Nuclear. My personal address is 2 Burning Brush Court, Pomona, NY 10970. In that position, I provided technical support in metallurgy, corrosion, welding, and forensic investigation in support of Entergy's operation of its nuclear plants. I am a National Board Registered Certified Nuclear Safety Related Coating Engineer and have extensive experience in the coating and corrosion of buried pipes.. A statement of my professional qualifications is attached.

I provide this declaration in support of Entergy's pre-filed testimony on Pilgrim Watch Contention 1 pursuant to the December 19, 2007 Atomic Safety and Licensing Board Order.

I attest to the accuracy of those statements attributed to me (that material marked by my initials in Entergy's pre-filed testimony), support them as my own, and endorse their introduction into the record of this proceeding. I declare under penalty of perjury that those statements, and my statements in this declaration, are true and correct to the best of my knowledge, information, and belief.

Executed January 8, 2007

William H. Spataro

William H. Spataro

WILLIAM H. SPATARO, P.E.
CONSULTING SPECIALIST
METALLURGY WELDING CORROSION

Professional Engineer – CT, NY
NBR Certified Coatings Engineer
AWS Certified Welding Inspector
AWS Certified Welding Educator

FORENSIC ANALYSIS CONSULTANT

Forty-five years of practical welding experience, thirty-nine years of professional engineering experience in welding, corrosion and metallurgical engineering. Expertise in welding and repair welding specification development, nondestructive examination, corrosion and materials evaluation, root cause determination, forensic failure analysis and supervision of on-site fabrication, installation and repair methods and techniques. Applications performed for nuclear, fossil fuel and hydroelectric power plants, electric transmission systems, steam, water and gas transmission pipelines, wastewater treatment and industrial manufacturing facilities, especially during outages.

Of special note, during steam generator installation, determined the cause of nozzle mock-up weld lack of fusion, developed solution and presentation to plant personnel and NRC; vessels installed without incident of weld defects. Received EPRI Innovators Award for reduction of nondestructive examination requirements for socket welds resulting in $995,000 estimated savings.

Currently hold or have held certifications in shielded metal arc (SMAW), gas tungsten arc (GTAW), gas metal arc (GMAW), flux-cored arc (FCAW) and oxy-acetylene welding, brazing, soldering, plasma and flame spray overlay processes.

COURSE DESIGN AND DELIVERY

Thirty-six years of experience as guest lecturer, course author and presenter at utilities, architect-engineering firms, manufacturing facilities, professional seminars, conferences and symposia.

Entergy Nuclear Northeast (New York Power Authority,) White Plains, NY
Developed and delivered five-day Welding Metallurgy Course, three-day Forensic Metallurgical Failure Root Cause Evaluation Course and two-day Material Science Course. Each course delivered twice yearly. Each presentation saves an estimated $10,000-50,000/presentation over outsourcing. (1980 - Present)

Garlock Sealing Technologies, Palmyra, NY
Guest Lecturer, Regional and on-site Nuclear Applications Seminars. (2004 - Present)

Electric Power Research Institute, Charlotte, NC
Guest Lecturer, Visual Examination and Advance Welding Technology Courses. (1988 - 1991)

American Association of Performance Engineers
New York State Convention - Keynote Speaker, Topic "The Role of Metallurgy in Failure Analysis." (1987.)

ASM, NACE and AWS
Guest lecturer at local chapter meetings (1984-1987.) Guest Lecturer - "Interaction Between Welding and Corrosion Control," NACE Northeast Region Conference September 1988.

Burns & Roe, Incorporated, Paramus and Oradell, NJ
Developed and delivered five-day Practical Metallurgy For Engineers Course at Burns & Roe Corporate Office and at "Washington Public Power Supply System, Hanford, WA"; "Northeast Utilities, Millstone, Waterford, CT"; "General Public Utilities, Toms River, NJ" and "William F. Wyman Fossil Plant, Falmouth, ME." Savings - $20,000/presentation. (1973 -1980)

PROFESSIONAL EXPERIENCE

ENTERGY NUCLEAR NORTHEAST (NEW YORK POWER AUTHORITY)
Director Materials Engineering - Consulting Metallurgist (1980 - Present)

Manage metallurgical and chemical engineers supporting the operation of the company's nuclear, fossil fueled, pumped storage and hydroelectric power projects and its transmission lines and under-water cables. Develop and present engineering support personnel training courses in Material Science, Welding Metallurgy, and Root Cause Forensic Metallurgical Failure Evaluation. Received Employee of the Quarter Award twice, Excellence In Engineering Performance Award twice, and EPRI Innovators Award.

BURNS & ROE, INCORPORATED, ORADELL, NJ
Senior Metallurgist (1973 - 1980)

EBASCO SERVICES, INCORPORATED, NEW YORK, NY
Welding Engineer (1968 - 1973)

EDUCATION AND DEVELOPMENT

B.E. Metallurgy - New York University
Supervisory Development Program - Rutgers University
Maintenance Coatings in Class I Areas of Nuclear Plants – National Bureau of Registration
ASME Section IX Welding Qualifications Course
ASME Section XI Inservice Inspection Course

PROFESSIONAL AFFILIATIONS AND MEMBERSHIPS

Registered Professional Engineer, Connecticut and New York
AWS: Certified Welding Inspector, Certified Welding Educator
NBR: Certified Nuclear Safety Related Coating Engineer
American Welding Society, Life Member
American Society for Metals International, 41-year member
National Association of Corrosion Engineers, 28-year member
Welding Research Council - Subcommittees on High Nickel Alloys,
Corrosion and Weldability of Stainless Steel
Toastmasters International - Able Toastmaster Bronze Award
Union County Vocational Institute, Scotch Plains, NJ - Advisory Board Member and Guest Lecturer - 1970-1975
Rockland County Board of Cooperative Extension Services, Bardonia, NY - Advisory Board Member and Guest Lecturer - 1969-1976

PUBLICATIONS

<u>Analysis and Monitoring of Heat Transfer Tube Fouling</u>, N.Zelver, J.R.Flandreau, W.H.Spataro, et. al. Presented at ASME Joint Power Generation Conference, Denver, CO, October 1982.

<u>Avoiding SCC Failures in Steam Turbine Blades</u>, W.H.Spataro. Welding Design & Fabrication. October 1989.

WILLIAM H. SPATARO, P.E.
CONSULTING SPECIALIST
METALLURGY WELDING CORROSION

Professional Engineer – CT, NY
NBR Certified Coatings Engineer
AWS Certified Welding Inspector
AWS Certified Welding Educator

MAJOR ACCOMPLISHMENTS

Nuclear Power Plants

Pressure Vessel Shell Weld Failures and Repair Techniques

Analyzed 3-1/2" thick pressure vessel shell weld failures. Determined the cause of failure to be improper post weld heat treatment of original fabrication weld repairs on quench & tempered material. Excessive residual stresses, acting on high hardened weld heat-affected zones, pitted By brackish water contamination, resulted in over 200 individual corrosion assisted fatigue cracks in each of four vessels. Developed repair techniques. Used the lessons learned to develop the specifications used to purchase new, competitively bid steam generators for $30,000,000, a savings of $10,000,000. During steam generator installation, determined the cause of nozzle mock-up weld lack of fusion, developed solution and presentation to plant personnel and NRC.

Low Pressure Turbine Blade Failure Evaluation and Manufacturing Modification

Analyzed blade failures in low-pressure turbines. Determined improper welding caused recurring corrosion failures. The welding technique resulted in a heat-affected zone of extremely high hardness in which stress corrosion cracking initiated. Modified manufacturing sequence to add peening and ultrasonic testing as a crack preventative measure. Spindles operated without further blade cracking. Estimated savings: $850,000.

Condenser Tube/Tubesheet Weld Corrosion Failure Evaluation and Repair

Analyzed condenser tube/tubesheet weld corrosion. Over 1000 welds had experienced pitting corrosion. The attack covered 1/4 -1/3 of the weld circumference. The position of the corrosion around the circumference varied in different areas and suggested the phenomenon was related to the weld procedure. Analysis showed a rapid cooling at the weld start/stop location caused microstructural segregation that was susceptible to intragranular galvanic corrosion and cavitation/erosion degradation. Developed repair procedure to weld rather than plug the tubes. Designed a cathodic protection system to prevent further corrosion. Condenser operated without further corrosion. Deferred condenser replacement for an estimated $10,500,000 savings.

Isophase Bus Installation Procedure Development

Evaluated aluminum isophase bus welds failures and determined that poor welding techniques caused brittle welds that cracked. Developed new installation welding and heat-treating procedures. The bus, installed in half the estimated time, has operated since 1983 without incident of cracking. Estimated savings two weeks outage time $120,000.

Hydroelectric Power Plants

Discharge Tube Cracking Evaluation and Repair

Evaluated cavitation repair failures and determined cause of cracking. The repair welds were made with carbon steel filler metal diluted by a previous stainless steel repair weld deposit resulting in a brittle weld that cracked from residual stress. Developed a repair method for sealing the four-foot long, through-wall (3-1/2") cracks using the back-step, alternate bead placement technique. The remaining fifteen 60MW units were repaired without incident. Estimated savings $210,000/unit.

WILLIAM H. SPATARO, P.E.
CONSULTING SPECIALIST
METALLURGY WELDING CORROSION

Professional Engineer – CT, NY
NBR Certified Coatings Engineer
AWS Certified Welding Inspector
AWS Certified Welding Educator

MAJOR ACCOMPLISHMENTS

Fossil Fueled Power Plants

Metallurgical Analysis of Cracked Low Pressure Turbine Blades

A prior turbine blade weld deposit, susceptible to fatigue failure, was removed and re-welded by the equipment supplier with a different material. The new welds failed. Determined fatigue failure of new welds caused by insufficient removal of prior precipitation hardened material that formed a metallurgical notch. Developed weld repair technique eliminating crack sensitive material. Spindles have operated since 1986 without blade cracking. Estimated savings: $700,000.

Replacement Boiler Tube Process Development

Boiler tube failures were caused by caustic cracking of sensitized and decarburized 304H stainless steel. The tubes, cold worked during bending prior to installation and exposed to 1100°F operating condition developed a susceptibility to corrosion and failed within two years. Developed pre-installation, post-bend heat treatment. The tubes have been in service since 1982 without failure. Estimated savings $150,000.

High VoltageTransmission Towers

Bolted Connection Failure Analysis and Repair

Performed root cause evaluation of bolted connections on 765kV and 345kV weathering alloy steel towers. Corrosion product build-up in the bolted connections exerted a force that deformed the structural members creating a danger of imminent failure. Designed a coating system to prevent intrusion of moisture into the joint and still maintain current transfer across the connection. The program enabled the towers to be repaired without interruption of service. There have been no further incidents of corrosion since 1984. Prevented a potential New York State blackout.

State of the Art Material Utilization

Service Water System Heat Exchanger Failure Analyses and Repair

Evaluated root cause of corrosion failures of copper-nickel material in brackish water after less than one year of service. Determined crevices in weld joint design and susceptible material caused the failures. The material was unsuitable for low flow rate (less than 2 fps) conditions. Anaerobic bacteria under silt deposits rapidly pitted the material. Designed new system utilizing crevice free joints of 904L/AL6X material that has operated successfully since 1981 without failure. Estimated savings of four replacements, one every five years at $5,500,000 each.

Service Water System Piping and Component Failure Analyses and Repair

Utilized latest corrosion resistant materials: 347SS, 904L, Alloy 20, AL6XN, 254SMO and Titanium. Corrosion degradation eliminated in many systems handling brackish water or corrosive media. Evaluated these materials with emphasis on the effect of stagnant or low flow, crevice, galvanic, and microbiologically influenced corrosion mechanisms.