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

In the matter of **Docket # 50-293**
Entergy Corporation
Pilgrim Nuclear Power Station
License Renewal Application

TESTIMONY OF ARNOLD GUNDERSEN SUPPORTING PILGRIM WATCH'S CONTENTION 1

March 6, 2008

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TESTIMONY OF ARNOLD GUNDERSEN ON PILGRIM WATCH'S CONTENTION 1 REGARDING THE ADEQUACY OF THE AGING MANAGEMENT PROGRAM FOR BURIED PIPES AND TANKS

WITNESS BACKGROUND

Q1. Please state your name.

A. Arnold Gundersen

Q2. Please state your residential address.

A. 376 Appletree Point Road, Burlington, VT 05408

Q3. Please summarize your educational and professional experience.

A. My CV is attached. I have a bachelor's and a Master's Degree in Nuclear Engineering from Rensselaer Polytechnic Institute (RPI) cum laude; and began my career as a reactor operator and instructor in 1971 and progressed to the position of Senior Vice President for a nuclear licensee. My more than 35 years of professional nuclear experience include and are not limited to: Nuclear Plant Operation, Nuclear Management, Nuclear Safety Assessments, Reliability Engineering, In-service Inspection, Criticality Analysis, Licensing, Engineering Management, Thermohydraulics, Radioactive Waste Processes, Decommissioning, Waste Disposal, Structural Engineering Assessments, Cooling Tower Operation, Cooling Tower Plumes, Nuclear Fuel Rack Design and Manufacturing, Nuclear Equipment Design and Manufacturing, Prudency Defense, Employee Awareness Programs, Public Relations, Contract Administration, Technical Patents, Archival

Storage and Document Control.

Q4. What is the purpose of your testimony?

A. My testimony is in support of Pilgrim Watch's Contention 1 that the programs and procedures Entergy uses for the Aging Management of the Pilgrim Nuclear Power Plant's buried pipes are insufficient. Moreover, in my review of the record, the Order has changed significantly during the course of these proceedings.

OVERVIEW

Q5. What buried pipes and tanks within the "revised scope" contain or may contain radioactive liquid?

A. The buried pipes connected to the following systems: Condensate Storage System (CSS); Salt Water Service System (SSW), discharge piping; and the Standby Gas Treatment System (SGTS).

Entergy's Testimony and the questions issued by the ASLB have focused solely on the CSS and SSW Discharge piping; however both are silent on the SGTS (Standby Gas Treatment System) piping. The SGTS piping may indeed have radioactive liquids, perhaps not in the same quantity as the CSS, however, in my review of the evidence, the volume of contaminated water was not specified in the Order.

The SGTS is used to improve the performance of the condenser by enabling it to "draw" more steam through the turbine. The condenser is maintained at a pressure that is as low as possible below atmospheric pressure. The Standby Gas Treatment System must extract air from the condenser in order to maintain it at a lower pressure than the outside air pressure. Furthermore, since part of this system includes a re-combiner to combine hydrogen and oxygen atoms to form water molecules, the non-condensable isotopes (xenon, krypton, iodine, etc) are transmitted via piping from the AOG Building to charcoal beds and then released from the main stack vent.

This stream of non-condensable gases is contaminated with radioactive isotopes from neutron activation of the reactor water and from leaks in the fuel. While the preponderant gaseous activation product is Nitrogen-16, it has a very short half life and therefore is not a concern for this analysis. *However,* leaking fuel contributes gaseous fission products and their decay related daughter products, which is of great concern to this analysis. For instance, the short lived Krypton-90 is a gaseous fission product that decays to the long lived isotope Strontium-90. Therefore the Standby Gas Treatment System Piping contains many isotopes beyond the original noble gases that it is designed to contain including Strontium-90 which is a known bone seeking carcinogen with a known 30-year half-life.

According to industry documentation, Pilgrim, like many reactors around the country, has used fuel assemblies with defective cladding. Therefore, when the plant shuts down during an outage, or at any other time of shutdown, radioactive water might collect Standby Gas Treatment System and potentially leak from the SGTS piping.

Q6. From an engineering viewpoint, what is the basic function of a pipe?

A. The basic function of a pipe is to carry or transmit the contents inside the pipe to another location while also protecting the environment by keeping its contents from seeping out into the environment, or in other words, pipes must not leak any contents into the environment. Pipes must also keep the liquid inside the pipe, and not let it travel into the ground. A pipe cannot deliver water as designed if it has holes or cracks. Leaks or breaks are not part of the design. At a nuclear power plant like Entergy Nuclear Pilgrim, pipe leakage is especially critical given that many pipes are contaminated with radioactivity that might leach into water tables and Pilgrim's surrounding fragile estuaries.

REQUIREMENTS

Q7. 10 C.F.R. § 54.21(a)(3) requires that Entergy's license renewal application show that for these pipes, "…the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation." Based on your professional experience, what does "adequately managed" mean?

A. Based upon my professional experience of more than 35-years as a nuclear engineer, "adequately managed" means that the licensee has demonstrated with "reasonable assurance" at approximately a 95% level of certainty that the effects of aging will be managed so that the intended function of the pipes will be maintained consistent with the Current Licensing Basis (CLB) during the license extension and that the pipes in question will perform their respective safety functions. It does not mean a requirement to demonstrate absolute assurance that structures or components will not fail.

The 95 percent confidence standard was accepted and applied by the NRC as the measure of "reasonable assurance" [Transcript of ACRS Meeting (Sept. 6, 2001), Citizens' Ex. 62 at 3].

Therefore, it is my professional opinion that the Applicant must be held to the same reasonable assurance standard of proof by the ASLB that the NRC presented to support its assertion that its programs and procedures for managing the aging of these pipes *does in fact* provide reasonable assurance to relicense Entergy Nuclear Pilgrim Station. Neither the Applicant nor the NRC may simply rely upon "engineering judgment", unless that judgment is grounded in facts that provide the 95% level of certainty. If a factual analysis is unavailable, the Applicant's judgment may be driven by convenience and/or economics. Assuring a 95% confidence level for license extension upon a 40-year-old reactor is critical, especially given that NRC has loosened regulations to make them less prescriptive by allowing for voluntary initiatives rather than promulgating measurable regulations.

Q8. Besides, 10 C.F.R. § 54.21(a)(3) requires that Entergy's license renewal application show that for these pipes, "…the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation." What does consistent with the CLB (Current Licensing Basis) for the period of extended operation mean?

A. In my opinion, consistent with the CLB (Current Licensing Basis) for the period of extended operation means that Entergy *is required* to fully comply with its license and all NRC Regulations.

Q9. Therefore, in your professional experience, would you list some key NRC regulations that pertain to buried piping that apply to Pilgrim and explain your reasoning why Entergy is required to comply with said regulations?

A. Yes, let me answer this by first listing the regulation and guidance and then discussing the importance of each one.

10 CFR Appendix B to Part 50 – Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants, XVI. Corrective Action that reads:

> "Measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. The identification of the significant condition adverse to quality, the cause of the condition, and the corrective action taken shall be documented and reported to appropriate levels of management."

Appendix C, Article C.12, "Operability Leakage from Class 1, 2, and 3 Components", to NRC Inspection Manual Part 9900, Technical Guidance, Attachment to RIS 2005-20 states:

> "Upon discovery of leakage from a Class 1,2 or 3 pressure boundary component (*pipe wall*, valve body, pump casing, etc), the licensee must declare the component inoperable."

I believe these rules and guidance make sense. Obviously it is important that leakage not occur so that Pilgrim does not unknowingly:

- expose members of the public to excessive doses of radiation by radioactive leaks migrating offsite;
- that workers on site are not exposed via inhalation, especially in the winter or during heavy rains when radioactive contaminated water could rise to the surface and become airborne;
- for decommissioning purposes to reduce Pilgrim becoming an expensive

legacy site;

- and lastly to prevent failures that would impact the safety of the system.

More importantly, the declaration of inoperability assures that a repair will occur in a timely fashion so as to meet the NRC statutory requirements of not jeopardizing public health and safety.

Q10. In your opinion, do the answers Entergy and NRC staff applied to the ASLB's questions regarding leakage from the CSS and SWW discharge pipes incorrectly imply that leaks are acceptable?

A. First, let me summarize what Entergy and the NRC staff has after which I will state my professional opinion.

- According to NRC regulations and guidance leaks are not acceptable. If pipes leak, they must be fixed, as the component is inoperable.
- Since the ASLB questions address an entirely separate issue, it is difficult to determine if in fact Entergy and NRC staff are ignoring NRC regulations and guidance in their answers.
- In my opinion, the NRC, Pilgrim, and the ASLB seem to have turned the issue of underground leakage on its head. If the leaking pipe or tank were above ground, the system would be declared inoperable and fixed, regardless of the size of the leak. I am unaware of any NRC regulations that differentiate between the severity of a leak as opposed to the existence of an underground leak. Let me elaborate.

To begin: The ASLB's question (c) read, "*What is the smallest leakage rate that could reasonably be expected to challenge the ability of the CSS system piping at issue to fail to satisfy its intended function(s) as relevant* *for license renewal? Provide a detailed statement of the basis of and sources for your answer."*

> Entergy responded that, "At the outset, no amount or rate of leakage from the CSS buried piping could challenge the ability of the HPCI and RCIC systems to perform their intended functions. While the CSTs are the preferred source of water for HPCI and RCIC (because of water purity), the assured (i.e. safety-related) source of water is the torus. If the CSS were unable to deliver water to the HPCI and RCIC pumps, for any reason, the HPCI and RCIC suction path would be switched to the torus."
>
> And, "While leakage from the CSS piping would not prevent the HPCI and RCIC functions from being performed, it could affect the ability of the CSTs to serve as the preferred source of water for HPCI and RCIC. Make-up to the CSTs is supplied from the demineralized water storage tank (DWST). The demineralized water transfer system (DWTS), which transfers water from the DWST to either CST, is supplied by two pumps each of which is rated at 110 gallons per minute. Since only one of the two pumps is normally in service, a maximum of 110 gallons per minute of makeup could be provided to either CST to compensate for a leak. If leakage from buried CSS piping were to exceed this rate, the volume of water in the CST could not be maintained, which would eventually impact its ability to provide the preferred source of water to the HPCI and RCIC systems.
>
> The smallest leakage rate that would challenge the ability of a CST to serve as the preferred source for HPCI and RCIC within a 4 hour interval is on the order of 500 gallons per minute. With regard to a leakage rate that would be detected by the 4 hour monitoring, one could hypothesize the following: Assume initial tank level is at the procedural minimum of 30 feet. A leak develops such that the level drops to the alarm setpoint (12.5 feet) just before the next 4

hour observation. In this case, a level reduction of 17.5 feet over a 4 hour period would represent a leakage rate of over 500 gpm. Because this leakage rate exceeds the make-up capability of the DWTS, the capability of the CST to act as the preferred source would not be recovered without corrective action. However, such a large leakage rate would likely cause visible effects, such as water leaking into the building, erosion of exterior ground surfaces, or significant amounts of visible water in exterior areas, that would be noticeable well within the 4-hour observation period.

1. For example, if the leakage rate from a CST were 220 gallons per minute (twice the makeup rate of a DWTS pump), it would take about 20 hours before the CST level would be reduced below the level reserved for HPCI and RCIC. The volume of water that would have to be lost to reduce the water level in the CST from its normal minimum (30 feet) to the level reserved for HPCI and RCIC (10.5 feet) is 136,500 gallons ([30 feet – 10.5 feet] x 7,000 gallons/foot). Assuming a single DWST pump provides makeup at its rated capacity, a leak of 220 gallons per minute would correspond to a net loss rate of 110 gallons per minute (220 gallons per minute leakage rate minus 110 gallons per minute makeup rate). The time it would take for this net loss rate to reduce the volume by 136,500 gallons is: 136,500 gallons ÷ [110 gallons per minute x 60 minutes/hour] ~ 20 hours.

Leakage from the buried piping would not be expected to affect the flow of water through the buried CSS line. The positive pressure in the piping would cause any leakage to flow out of the line, not in, so leakage would not be expected to introduce debris or cause blockage of the piping. Further, the key consideration in system operation is maintaining adequate suction pressure (i.e. net positive suction head) to the pumps. The CST and piping system design, in conjunction with the setpoints for swapping the HPCI and RCIC suction source to the torus, ensure adequate net positive suction head to the pumps. Thus, while some amount of water would be diverted from the piping to the ground which would serve to increase the rate of level decrease in the CST, this would merely accelerate the time at which the suction swap to the torus would be required. HPCI and RCIC functions would be unaffected.

ASLB 2. With Regard to the Salt Service Water ("SSW") system – Explain how any leak in the SSW buried pipes that might carry radioactive water from the plant to the canal that dumps into the bay could challenge the ability of the SSW system to satisfy its intended function(s)? For example, is there any correlation between any potential leak in those pipes and any potential plugs in them that might prevent them from discharging water from the SSW, thereby impeding the ability to remove heat from the RBCCW? Provide a detailed statement of the basis of and sources for your answer.

Entergy Response: The SSW system discharge piping is an open-ended run of unobstructed piping. Leakage is generally not a concern for an open-ended discharge pipe.

The external surface of the carbon steel discharge pipe is protected by either a coal tar wrapping or epoxy coating. The interior of the discharge piping is protected by a ½" thick cured-in-place-pipe (CIPP) lining, consisting of polyester felt material with a resin and catalyst system or an epoxy resin and hardener system, which forms a smooth, hard inner protective surface. These coatings and linings are designed to prevent internal and external corrosion. For leakage to occur, there would have to be a failure of the external coating, a through wall failure of the metal pipe, and a failure of the CIPP liner. The likelihood of these three barriers being breached is remote.

Further, in the unlikely event of leakage from the discharge piping, such leakage would not be expected to have any effect on the SSW system's ability to perform its intended function. Leakage would simply result in some salt water being discharged to the ground rather than to the bay. Further, because there is a positive pressure differential within the discharge piping, in-leakage of dirt or debris that might block the discharge line would not be expected. Indeed, even if dirt were introduced, it would likely be swept away with the discharge flow. Moreover, if dirt or debris were somehow accumulating, any significant diminishment of flow would be detected by the daily monitoring of the heat exchange capability of the SSW system. Thus, only if degradation of the SSW discharge piping were somehow to progress to the point of pipe collapse would the SSW system's ability to satisfy its intended function be challenged. The design and construction of the SSW discharge piping, including external coatings and internal liner, make such a failure mechanism not credible."

<u>NRC Staff Response ASLB Questions Regarding CSS</u>

ASLB Q. *What is the smallest leakage rate that could reasonably be expected to challenge the ability of the CSS system piping at issue to fail to satisfy its intended function(s) as relevant for license renewal? Provide a detailed statement of the basis of the sources for your answer?*

> NRC Staff response at 5: "In sum, there is no CS system leak rate that would challenge HPCI/RCIC performance for purposes of § 54.4(a)(1), and only a very large leak would compromise the performance for purposes of § 54.4(a)(3)."

In addition, according to 10 CFR 50 Appendix B leaks are required to be repaired and Entergy must look for leaks and fix them when found in order to comply with its CLB during the relicensed period. In my opinion, this regulation makes absolute sense because if there are any unidentified leaks in the aforementioned pipes, such leaks may jeopardize the design and intended function of safety related systems and components at the Pilgrim Nuclear Power Station.

Therefore, in my opinion, there are at least <u>three possible scenarios</u>:

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

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

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

Given the newly discovered Tritium leaks, it then becomes quite likely that if a safety function is required, the leak may either divert the required water or reduce the required line pressure, rendering the pipe and tank system "*unable to perform the intended safety function*".

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

2. <u>The second scenario</u> is similar to the first in that a growing leak remains undetected by an inadequate Aging Management System. However, unlike the first scenario, in which a system failure is caused by allowing water to

exit the expanding hole(s), in this scenario rust particles, dirt and other contamination enter the pipe or tank through the hole thereby clogging downstream filters and heat exchangers, or the debris abrades the moving parts thus rendering the system "*unable to perform the intended safety function*"

Under these conditions, the Venturi Effect[1] is the governing scientific principle. For illustrative purposes, let my use the simple example of applying lawn fertilizer to a lawn through a garden hose to explain this phenomena. Even though the hose water is at higher pressure than the fertilizer, the Venturi Effect from the moving water pulls the fertilizer into the moving fluid.

ASLB Question 2 relates to the SSW system. *Regard to the Salt Service Water ("SSW") system – Explain how any leak in the SSW buried pipes that might carry radioactive water from the plant to the canal that dumps into the bay could challenge the ability of the SSW system to satisfy its intended function(s)? For example, is there any correlation between any potential leak in those pipes and any potential plugs in them that might prevent them from discharging water from the SSW, thereby impeding the ability to remove heat from the RBCCW?*

> NRC Staff response, at 5, "The Staff does not believe that there is any credible mechanism for the discharge piping to become plugged. The discharge piping is

[1] **VENTURI EFFECT**—The increase in the velocity of a fluid stream as it passes through a constriction in a channel, pipe, or duct. Calculated by the *Continuity Equation*, or $Q = VA$ Q = VA where Q is the volumetric flow rate, A is the Area of flow, and V is the fluid velocity. Because Q does not change, as A gets smaller then V must increase.

> constructed using carbon steel which is ductile and would deform before it would rupture. In addition, the pressure from the water inside the pipe would keep it from collapsing. But, even if it did become plugged, the second loop is still available to return the water to the bay."

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

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

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

   Holes that reduce the structural integrity of pipes are particularly worrisome at elbows and flanges (similar to the aforementioned Byron incident) and would render the pipe or tank "*unable to perform the intended safety function*" in the event of a Safe Shutdown Earthquake (SSE). As the nuclear industry well knows, the small earthquake at the Perry Nuclear Power Plant in Ohio did cause leaks in plant piping, and this mild earthquake was not at all comparable to a SSE.

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

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

Q11. In your professional opinion, explain how pre-existing holes in underground piping might cause a failure during a design basis event, such as an SSE?

A. To begin, let me give you an analogy. If the existence of holes appreciably increases the likelihood of failure, then essentially the plant has a similar condition to permanent removal of an emergency diesel generator. After all, the EDG might fail, the single failure criterion assumes a single failure, so the EDG is removed and it's the designated single failure.

In addition, let me address the core question of whether or not the existence of holes will appreciably increase the likelihood of failure? That answer depends upon the cause and nature of the holes. A thousand pinhole leaks distributed uniformly over the length of a 1,000-foot buried piping run is unlikely to cause its failure rate to rise. But the same area of through-wall leakage concentrated in one region - such as in a circumferential weld - might create an entirely different outcome. If Entergy knows that buried underground piping is leaking (for example by observing small, slow level drop in the CST), how would Entergy distinguish from that fact the cause and nature of the leakage? Entergy certainly could excavate the piping and eyeball whether or not the leak has been created by a series of pinhole leaks or a gaggle of weld defects. However, no licensee would excavate piping, determine the cause and nature of said holes and leaks, and not fix them, as such degradation would negatively impact performance and earnings. Besides, there is a federal regulation (10 CFR 50 Appendix B) that requires licensees to repair any degradation. Thus, by regulation, a licensee is not allowed to know about piping degradation and ignore it.

<u>CORROSION</u>

Q12. From your professional experience, please review for us some basic facts about pipe corrosion so that we can better evaluate the sufficiency of Entergy's aging management program and procedures.

A. Yes, some key points follow.

a. The older the pipe is, the more likely it is that corrosion and leaks will occur. Engineers explain the aging phenomenon by using what is known as the "Bathtub Curve." The curve is a graph of failure rate according to age. The failure rate due to unidentified leaks is relatively high in the beginning when "kinks" are being worked out; it flattens out during the middle life phase; and it rises again sharply in the end-of-life or at the "wear-out phase." On average, 30 years usually marks the beginning of the wear-out phase. I would expect that most of Pilgrim Station's pipes, wraps and coatings would be in this "wear out phase" during the relicensed period. This adjudication process must flush out the precise age of each part of the pipes, wraps and coatings and provide documents from the manufacturer certifying their life expectancy. In my professional opinion, and the standard applied to aging management of systems, inspections at Pilgrim must increase as any component ages. Piping, coatings and wraps age, and just like human beings, require more doctor visits. Clearly, the rate of corrosion is not linear over time. Even the most meticulously maintained system, like the Space Shuttles, which are a much newer engineered technology than Pilgrim, are reaching the end of their useful life due to the aging phenomena of the Bathtub Curve.

b. Corrosion is not even across the pipe; it is hard to predict. Corrosion occurs more frequently at welds, elbows and dead spots. Therefore inspections cannot avoid the most susceptible locations; instead special attention must be given to examining these areas.

c. Holes or cracks do not fix themselves; and once started, they grow. For example, this is self evident if one imagines a small hole in the Hoover Dam. After the initial pinhole, water begins to exit the tank or pipe, at an ever-accelerating rate as the hole expands. In fact, mathematically speaking, the leak rate growth is proportional to the square of the hole's radius. And not only will a hole let the fluid out, it will also allow dirt and debris in which will foul or clog the system. Corrosion may not be assumed to be a gradual process, and corrosion is non-linear.

d. *Nuclear power plants rely upon buried piping*. Unfortunately, when a pipe is buried, its condition is not readily apparent. Therefore pipes must be inspected. Just as the ESW piping at Byron Station had to be fixed, the piping underground must be fixed and that requires looking via an Aging Management Program with frequent and comprehensive inspections. Furthermore because the CSS, SWS, SGTS piping are buried in the soil, these buried pipes are by definition in a more corrosive environment than any aboveground piping. For instance, oxygen, moisture, chloride, acidity, or microbes found in the soil, in one degree or another, corrode all piping materials. More specifically, because Pilgrim Station is located adjacent to Cape Cod Bay and at a low elevation, it is readily apparent that the soil surrounding the piping is not "friendly." No metal is immune to corrosion. Moreover, piping located near salt water or in salty soil is more easily corroded.

e. Human error either in manufacturing or installation may never be discounted. Over time movement of the soil creates unanticipated stress on underground pipes.

In conclusion, a most important basic fact to keep in mind is that corrosion rates are hard to predict and cannot be assumed to be either linear or gradual.

Q13. In your professional opinion, is Pilgrim Station's environment more or less conducive to the probability of the plant's buried piping corroding?

A. Let me answer this question in two (2) parts.

First, the basic problem is that Entergy has not performed any recent and thorough hydro-geologic studies; or if Entergy has performed such studies, the results of those studies have not been shared with the parties or placed them in the public domain. Entergy's own Buried Piping and Tanks Inspection and Monitoring Program [provided in Entergy's Initial Statement as Exhibit 5] states that a corrosion risk evaluation should be performed within 9 months and that it should include soil resistivity measurements etc. and that "soil resistivity measurements must be taken at least every 10 years unless areas are excavated and backfilled or if soil conditions are known to have changed for any reason" [Exhibit 5, at 5.5].

Therefore, I believe that we (the NRC, Entergy, ASLB and the parties) are currently traveling "blind."

Performing a Corrosion Risk Assessment is critical *before* any appraisal or decisions are made regarding Entergy's license application. In my opinion, the ASLB does not have the information in hand to make an adequate assessment of the AMP and meet NRC regulations without knowing either the extent of corrosion risk caused by the local environment and without knowing the corrosion status of the affected components.

Second, my review of the data has shown several concerns. To begin, the piping is mainly made of carbon steel and stainless steel. There is no evidence that Entergy has instituted a thorough Cathodic Protection Program (CPP) for this piping. All metals corrode, and corrosion occurs on both external and internal surfaces. For instance, regarding external corrosion, it is a known fact that water and moisture are needed for corrosion to occur. Pilgrim Station is located in Plymouth, MA, which is a relatively moist environment adjacent to Cape Cod Bay. Plymouth's winter climate is characterized by periods of snow and ground freeze, that thaws in Spring. Periods of rainfall occur throughout the year. Chloride speeds corrosion, and chloride is naturally abundant in seawater. Soil acidity is corrosive. Entergy described procedures to reduce the effects of oxygen from moisture and acidity from decaying organic material – removing vegetation and placing the piping on a bed of sand. However over a period of time vegetation reappears, decays and works its way down to the pipes. Soil above the sand migrates downward mixing with the sand to provide a moist environment. The low pH resulting from decayed organic matter, acid rain and stray electric currents will accelerate corrosion along with the oxygen from water seepage. Pipes corrode both externally and internally. The rate of degradation on interior surfaces is a function of aggressive chemicals, pH level, dissolved oxygen and biological elements at the site. *The recently discovered tritium leaks at Pilgrim, and the nationwide epidemic of tritium leaks from underground pipes clearly prove that these phenomena exist*.

Third, according to a 1990 United States Government Accounting Office Report Pilgrim Station may have received counterfeit or substandard pipefittings and flanges. Therefore, I believe it should be factually established whether or not the CSS, SSW, and SGTS piping has counterfeit and/or substandard pipefittings and flanges. In my opinion, if any parts are counterfeit or substandard, then the probability of failure is increased. Review of the documents and notices regarding counterfeit or substandard pipefittings and flanges, shows that the NRC allowed the continued use of some or all of these components at numerous reactor sites. If this information is indeed accurate, then both Entergy and the NRC should have documentation that would indicate whether the NRC's decision to allow the use of these components was based upon Pilgrim's 40-year license or upon their use for a specific time period or an indefinite timeframe.

Fourth, Plymouth is not immune to soil compaction and seismic activity even though the probability of such an event may be low. Buried pipes and tanks are not flexible and the coatings become brittle with age and therefore are more susceptible to breakage during seismic events.

Fifth, as any entry-level engineer learns, straight piping is less susceptible to failure than welds, elbows and dead spots. What is the precise configuration of the CSS, SSW and SGTS piping? Pilgrim Watch has not been provided this information for review. Prior to commenting further regarding the failure possibility of Pilgrim's piping, I must review the precise configuration of the CSS, SSW, and SGTS piping. I will need this information prior well before my testimony, so that I will have adequate time to review the precise piping configuration. Yes, I did review the Diagrams that were sent to Pilgrim Watch by Entergy Pilgrim, but these were more of a cartoon-style schematic and did not have the accuracy necessary to adequately review the mechanisms required to inspect the CSS, SSW, and SGTS piping.

<u>MANAGING INTERNAL AND EXTERNAL CORROSION</u>

Q14. In your professional opinion, do you think that any leak should be tolerated or that if a pipe within a specific system leaks then that component should be declared inoperable until the leak(s) are repaired?

A. Once again, NRC rules [Appendix B to Part 50--Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants, XVI. Corrective Action] make it clear that any leak is a leak at too great a rate. My response above regarding failure mechanisms explains why this must be so (Answer to Q13).

Q15. What do you believe Entergy Pilgrim Station's Aging Management Plan and Program requires Pilgrim Station to do regarding the detection of leaks when they occur? Is this sufficient?

A. Entergy is required to have a sufficient aging management plan and programs to detect leaks when they occur, and those leaks should be repaired as soon as they are discovered in order to achieve the purpose of their Aging Management Program.

Q16. Earlier in this declaration, in your answer to Q13, you stated that you had difficulty deciphering the cartoon-style schematic for the diagrams pertaining to the inspection of the CSS, SSW, and SGTS piping. In spite of that obstacle,

would you please describe the inspection and Aging Management Programs for underground pipes and tanks at Entergy Nuclear Pilgrim Station?

A. Certainly. The Buried Pipes and Tanks Inspection Program (BPTIP) is described in Appendix A.2.1.2. and B.1.2 of the renewal filing. It consists of three parts.

(1) Appendix A.2.1.2. Buried Pipes and Tanks Inspection Program page A-14 states that buried components are inspected when excavated during maintenance and if "trending" identifies a susceptible location. For example, a specific area with a history of corrosion might have additional inspections, coating or replacement to assure that either no leaks occur or that if leaks do occur the leaks are quickly discovered and the requisite piping is repaired in order to achieve the two goals of protection of the entire system and mitigation of any release of any radioactive isotopes into the environment.

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

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

Q17. In your professional opinion, do you believe that Entergy's BPTIP is sufficient?

A. My short answer is "No." And, in my opinion, it is apparent that Entergy agrees with me. In its prefiled testimony, Entergy included a new framework for a company-wide Buried Pipes and Tanks Inspection Program [Entergy's, Exhibit 5]. Yet, Pilgrim Watch has not received any information noting how or when this new framework for a company-wide Buried Pipes and Tanks Inspection Program will be implemented at Pilgrim Station.

Q18. Briefly, please describe Entergy's BPTIP and indicate how it is insufficient?

A. Let me respond to this question by first describing the program and then explaining what I see wrong with it.

<u>Part (1)</u> of the program notes that pipes are inspected if they are excavated during maintenance. The problem is that this leaves inspections and safety to happenstance and does not meet Pilgrim Station's Aging Management goals.

<u>Part (2)</u> of the program requires a one-time inspection during the first 10-years of the license renewal period by either a visual or an as yet untested UT inspection.. The problem here is that the program lacks specificity and provides merely a general framework. By allowing total flexibility for the licensee, this loose framework once again neglects the very specific requirements of Aging Management Programs in general and, in my opinion, certainly neglects the very

goals developed by Entergy for its Pilgrim Station Aging Management Program.

For example, the BPTIP allows: "A determination of the sample size based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience." [NUREG-1801, Rev.1, X I M32].

My review of the evidence provided by Entergy Pilgrim Station finds four problems with Entergy's alleged plan.

- The first problem is that operating experience at Pilgrim Station is limited according to the SER. From the evidence I have reviewed, I believe that Entergy Pilgrim Station has not performed a thorough baseline examination of the pipes, which of course should be a prerequisite to any license extension program.
- The second problem, as I see it, is that Pilgrim Station does not have a monitoring-well program that meets design standards, see Dr. Ahlfeld's declaration.
- In my opinion, the third problem is that Entergy's assessment of materials and the environment provided in Entergy's Initial Statement does not seem accurate. For instance Entergy's statements ignored the facts that all metals corrode, that Pilgrim's specific environment is conducive to corrosion, and that no recent hydrological and geological studies have been performed.
- Fourth and quite simply, there is no new hard data to review, as it seems that Entergy Pilgrim Station has only conducted cursory reviews of old studies via walkabouts on the property.

"Identification of the inspection locations in the system or component based on the aging effect; determination of examination technique; evaluation of the need for follow- up examinations if aging related degradation is found." The problem with this portion of the Entergy Nuclear Pilgrim Station plan is that there is no requirement concerning the number of sample inspections or the location of said sample inspections.

In the statement "An evaluation of the need for follow-up examination", no mention is made regarding who will evaluate the need for follow-up examinations, and no statement as to the NRC's role is articulated. Furthermore, and more critical, is that there are no criteria whatsoever with which to determine when there must be "follow-up examination(s)."

In NUREG-1801, the BPTIP states: "The inspection includes a representative sample of the system population, *where practical*, focuses on the bounding or lead components most susceptible to aging due to time in service, severity of operating conditions, and lowest design margin." In my opinion, the obvious flaw here is the word, "Where practical." Such loose terminology does not meet any engineering standards and allows licensee convenience and profit margins to be the driving force for inspection rather than "public health and safety" as required by federal statute.

Lastly, in the BPTIP it is stated: "The one-time inspection, *or any other action or program*, created to verify the effectiveness of the AMP and confirm the absence of an aging effect, is to be reviewed by the staff on a plant-specific basis." In my opinion the inference presupposes that only on a plant specific basis will a "*one time inspection, or any other action or* *program"*… occur depending upon the effectiveness of the AMP as determined and reviewed by the Pilgrim Station staff. Once again, this is not a commitment to an inspection with formal criteria and trigger points by which to deepen an inspection should specific triggers be uncovered, instead this loose wording simply suggests that the inspection may not occur if Pilgrim Station staff determine such an inspection is not warranted.

Part (3) of the BPTIP says that, "Prior to entering the period of extended operation, the applicant is to verify that there is at least one opportunistic or focused inspection performed during the past ten years." The issue that I see is that any inspections prior to license renewal have all the weaknesses described above. Entergy has not stated when these inspection might occur or if they may have already occurred. Of additional concern is the fact that if Entergy plans to count inspections that occurred early in 2000 as part of this process, and is allowed to do so, than conceivably at least 19 years might lapse between inspections. The critical nature of these pipes requires more than one inspection over the entire period of license renewal.

NUREG-1801, Rev 1, XI M-107, September 2005 states that, " …the applicant should schedule the inspection no earlier than 10 years prior to the period of extended operation…as a plant will have accumulated at least 30 years of use before inspections under this program begin, sufficient times will have elapsed for aging effects, if any, to be manifest." Again the wording here is problematic in that there does not appear to be any requirement that the specific component areas sampled be at least 30-years-old.

To summarize my key points: There is not a requirement for a through baseline inspection prior to license renewal so that the NRC and Entergy know the condition of each component in order to make a rational Aging Management Plan for the renewal period. The required inspections are too infrequent. I explained that corrosion is not gradual, and that as components age they wear out at a greater frequency as predicted by the Bathtub Curve. Therefore they need to be inspected more frequently as time goes forward. Entergy's AMP has no specificity in the program delineating what must be inspected. Engineering experience shows that certain areas of piping are more susceptible than others to corrosion, like welds, elbows, and dead spots. Lastly, there are no clear requirements for reporting, repair or replacement of degraded piping.

Q19. In addition to the BPTIP the Applicant has claimed in its Initial Statement that other more routine programs are effective in preventing corrosion, like the Water Chemistry & the Service Water Integrity Program. Since these two programs address internal corrosion, in your professional opinion, do you believe that these two programs provide adequate assurance in combination with the other programs the Applicant has outlined?

A. No, the water chemistry program is a mitigation program and does not provide detection for aging effects. More frequent complete inspections as part of the overall program are the only effective assurance that defects created by aging components will be uncovered. Tritium leaks at reactors across the country belie the effectiveness of water chemistry alone to prevent leaks.

In its Prefiled Testimony (Testimony at A93), Entergy stated that the Water Chemistry Program was effective because,

> "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."

In my opinion, Entergy's statement alludes to problems within the water chemistry program, and identifies that it has had problems and has improved the program. However, Entergy never discusses the potential damage caused while operating under the older methodology, nor what remediation steps have been taken regarding any damage that occurred. Furthermore, Entergy provides no factual evidence to validate its verbal assurance that the new program is effective.

The Service Water Integrity Program addresses internal corrosion. In the Applicant's Testimony, A96, in Entergy's Initial Statement, they describe the program as,

> "(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."

At, A97, Entergy's expert says that the program is effective because

> "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."

As I see it, the problem is that the program's effectiveness is ascribed to the fact that there was serious corrosion, which was not identified until after 23 years of operations, and it was identified only as a result of prodding from NRC, Generic Letter 89-13. This leads me to wonder how long there were significant corrosion problems and how long the licensee would have waited if it were not for the generic letter.

According to Entergy, Pilgrim replaced (2) 40' sections of SSW Discharge piping out of 240' in one loop and 225' in the other loop 1999. Once again there is insufficient data to make a valid assessment. The problem here is that there is no indication of the condition of the remainder of these loops.

In 2001, Entergy states that a new liner was placed in loop B and in 2003 a new liner was placed in Loop A. It strikes me as remarkably convenient that the life expectancy of the liners is given as 35-years, yet there is no factual data with which to corroborate that statement.

Last at A98 in Entergy's Initial Statement, it is noted that,

> "the Service Water Integrity Program will be used to monitor the

> newly installed liner (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."

Once again, there is no timeline delineating the "increased inspections" or enumerating how many inspection will occur. Just as importantly, no definition of "complete ultrasonic or visual inspection" is provided nor is it clear whether this would be a stem to stem inspection or only a partial inspection.

Q20. In its Initial Statement Entergy describes additional surveillance programs for the CSS and SSW. In your professional opinion do these additional programs provide the assurance required?

A. <u>First in regard to the additional programs for the CSS</u>, the simple answer is "No." The CST program consists of level indictors in the Condensate Tank and quarterly testing of the water flow from the RCIC pump and the HPIC pump.

Entergy responded to the Board's questions on February 11 and stated in regard to the 4-hour testing of the CST water level that,

> "Under normal operation, the level of the CSTs is dynamic (i.e. the CST levels fluctuate as they provide makeup or receive condensate discharge to maintain appropriate condenser water level). Therefore, under normal operation, there is no specific leakage rate that would be detected by or could be readily correlated with the four-hour test results."

In my opinion, Entergy's response clearly indicates that the monitors cannot predict the level of corrosion in the pipes and whether or not the pipes are leaking.

In response to the same question, the NRC Staff said at 5,

> "there is no CS system leak rate that would challenge HPCI/RCIC performance for purposes of § 54.4(a)(1), and only a very large leak would compromise the performance for purposes of § 54.4(a)(3). And if there were a large drop in water in the CST, it would be noticed and corrective action taken.

While the NRC staff assessment may be interesting and informative, in my opinion, it does not address the core question, which is: whether or not leaks will be identified and will be repaired in order to protect public health and safety.

<u>The second part of the question addresses the surveillance programs for the SSW, and again the simple answer is "No." they do not provide assurance, either.</u>

Entergy Testimony at 17, A30 states that,

> "By the time the cooling water is in the buried discharge piping, it has completed its intended safety function of providing cooling water for the RBCCW. Therefore, if a leak develops in the discharge piping, it will not affect the intended safety function. There is no correlation between any potential leak in the buried discharge piping and any potential plugs in them that might prevent them from discharging water from the SSW. The SSW system is designed so that no active component failure nor any single passive component failure, or any other system, can prevent it from achieving its safety objective. There are two loops of

> discharge piping, so if one were inoperable, the second loop could be used to return the cooling water back to the bay. Each loop can transfer the full heat capacity required for its intended safety objective.

The NRC Staff Exhibit 17 says that,

> "… the system would retain the ability to remove heat from the RBCCW. The Staff does not believe that there is any credible mechanism for the discharge piping to become plugged. The discharge piping is constructed using carbon steel which is ductile and would deform before it would rupture. In addition, the pressure from the water inside the pipe would keep it from collapsing. But, even if it did become plugged, the second loop is still available to return the water to the bay"

Waiting for a leak to grow so big as to effect the intended function of the system would be unthinkable in an above ground portion of the same system. Single failure criteria do not apply when a system is known to be leaking significantly, in which case it should be considered inoperable already. Therefore, in my opinion, a second single failure should be postulated given that Entergy's Pilgrim Station plans to wait an excessive amount of time to repair any leaks.

In my opinion, the central question of identifying leaks, that is leaks of any size, is not addressed so that the responses and questions, although of general interest, do not answer the question at hand, which is the sufficiency of the AMPs to assure leaks will be detected and promptly repaired in order to comply with regulation and thereby protect the public health and safety.

Q21. On November 19, 2007, Entergy announced its initiation of a new program entitled: the *Buried Piping and Tanks Inspection Program and Monitoring Program*, Entergy's Prefiled Testimony, labeled as Exhibit 5. Please describe the program and evaluate its effectiveness.

A. The Program indicates that Entergy agrees with the Petitioners that the programs and procedures are currently in place that would determine whether or not the buried pipes containing radioactive fluids are leaking in such a manner as to be unable to satisfy their respective safety functions.

Section by Section Analysis [extracted from Gundersen Declaration at 12 minus Tables]

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

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

2. Section 5.2, Scope Program subsection [3] at page 8 acknowledges the validity of Pilgrim Watch's initial contention that, "The program shall include buried or partially buried piping and tanks that, if degraded, could provide a path for radioactive contamination of groundwater. Some examples are: Buried piping containing contaminated liquids." Entergy agrees that "radioactive contamination of groundwater" is an important issue and belongs in the Buried Piping and Tanks Inspection and Monitoring Program.

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

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

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

For example:

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

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

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

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

(e) In subsection [5], the determination of inspection locations may also consider the "ease of access to inspection point." However we know that ease of location and lack of corrosion do not necessarily go together. In fact the odds are that a component that is difficult to access has never been inspected – all the more reason to inspect it.

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

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

6. Section 5.7, on page 13, provides vague remarks about **acceptance criteria** for any degradation of external coating, wrapping and pipe wall or tank plate thickness. It says that they should be based on current plant procedures; and if not covered by plant procedures then new procedures need to be developed before the inspections. The pass/fail grade should be clearly defined. For example what precisely constitutes an "unacceptable" from an "acceptable" degraded external wrapping?

The LLTF was very specific that "significant" and other such descriptions need definition.

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

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

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

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

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

Reports are unlikely to be written or, if they are written, to actually say anything as explained directly below.

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

A review of steps (a) through (f) reveal a lack of objective, or even subjective, acceptance criteria that could trigger a condition report:

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

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

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

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

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

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

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

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

Q22. Entergy contends that the standard of reasonable assurance provided is based upon conformance to: NRC Guidance; the GALL Report; industry practices; PNPS operating experience; and the SER review, in your professional opinion do you agree with Entergy's assessment?

A. No, I do not agree at all.

In my opinion, the GALL Report simply represents general guidance and is not a mandate. The NRC has repeatedly stated that plant specific data such as operating experience must be considered. Furthermore, the GALL Report is changed periodically informing us that it is neither plant specific nor a regulatory mandate.

Conformance to NRC Guidance again is not convincing because guidance is simply "guidance not mandate" and like the GALL, NRC Guidance continues to evolve as industry-wide lessons are learned. In my opinion, the proliferation of leaks from buried pipes and tanks at nuclear power plants around the country is a good example of exactly why public health and safety standards are not met by nuclear power plants by simply referring these firms to either NRC Guidance or industry practices.

As I have previously stated, a thorough baseline inspection has not been performed or required, so there is no baseline data by which to judge Pilgrim's past operating experience. Also, there is no industry-wide experience with which to compare corrosion and leakage in buried components at 40 to 60-year-old reactors. More regrettably the NRC did not perform a thorough "autopsy" of the parts from reactors which have been closed and dismantled, like Yankee Atomic and Maine Yankee. Such an analysis and study of the impact of aging on various materials and components would have enabled the entire industry to make predictions based upon sound data. Finally, there is no operating experience for the AMP and the UT examinations are completely untested.

The SER review was recently evaluated by the NRC Office of Inspector General. Since the NRC OIG found serious flaws with the review process, in my opinion, the SER review should not be applied to Pilgrim until the process has been corrected and once again reviewed by the NRC OIG.

Finally I believe, Entergy's own corporate program, the ***Buried Piping and Tanks***

Inspection Program and Monitoring Program (Entergy's Prefiled Testimony, Exhibit 5), which was introduced quite late during the discovery process on November 19, 2007, should be specifically applied to the Pilgrim site prior to anyone drawing any conclusion based upon the adequacy of Pilgrim's proposed solutions to inspecting underground systems. Absent specific implementing procedures to Entergy's elective corporate guidance, the ASLB and the Petitioners are forced to guess, rather than have the requisite 95% assurance in the adequacy of Pilgrim's program.

Q23. From your professional experience, please describe what the aging management program for buried pipes and tanks at Pilgrim Station must look like in order for the public and ASLB to have confidence that public health and safety will be protected during the license extension.

A. Yes, let me answer with Section 18 from my Declaration Supporting Pilgrim Watch's Contention 1, January 26, 2008. At the end of this discussion, I will also add some additional points.

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

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

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

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

18.1.2. Examinations must include inspection both inside and outside.

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

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

18.1.5. Baseline data is critical so that trending is established.

NUREG/CR 6876 states, at 32, "…it is evident that predicting an accurate degradation rate for buried piping systems is difficult to achieve…"

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

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

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

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

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

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

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

<u>18.4. Increase the Monitoring Well Program to actively look for leaks once they have occurred:</u> According to Pilgrim Watch's expert, Dr. David P. Ahlfeld, in order to meet the minimum criteria for an effective monitoring well program at Pilgrim, such a program should made part of the license going forward so that it is enforceable and not simply voluntary and must follow the steps in monitoring network design as outlined in Dr. Ahlfeld's declaration. In the absence of any leaks at the Applicant's Pilgrim Nuclear Power Station, I believe that my recommendations would be necessary to the evaluation of Pilgrim's application for a 20-year extension to its current operating license. However, given the recently discovered Tritium leaks at Entergy's Pilgrim Plant and other reactors around the country, my recommendations are critical to the continued

operation of Pilgrim to the end of its current license, without any consideration of a license extension.

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

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

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

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

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

18.4.6. Therefore in my opinion, and given Pilgrim's proximity to the environmentally sensitive Bay and salt marshes, a rigorous and

> expanded Monitoring Well program should be ordered and immediately undertaken at and around the Pilgrim Nuclear Power Plant Site."

In closing, let me reiterate that in my opinion until Entergy Nuclear Pilgrim Station implements Entergy's corporate guidance concerning inspection of underground pipes and tanks, provides those implementing procedures to the Petitioners for complete review and assessment, and begins implementation of concrete procedures, these proceedings should be halted, and the license extension should not be granted.