UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of	)	
	)	
ENTERGY NUCLEAR OPERATIONS, INC.	)	Docket Nos. 50-247-LR/ 50-286-LR
	)	
(Indian Point Nuclear Generating	)	
Units 2 and 3)	)	

NRC STAFF'S REVISED PROPOSED FINDINGS OF FACT
AND CONCLUSIONS OF LAW
PART 2: CONTENTION NYS-5 (BURIED PIPING AND TANKS)

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March 22, 2013
As Revised 04/22/2013

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In accordance with 10 C.F.R. § 2.1209 and the Atomic Safety and Licensing Board's Orders,[1] the NRC Staff ("Staff") hereby submits its proposed findings of fact and conclusions of law ("Proposed Findings" or "PFF") regarding the nine contested "Track I" contentions in this proceeding. The Staff's Proposed Findings are set forth in ten separate filings, as follows:

Part 1: Overview and Regulatory Standards;

Part 2: Contention NYS-5 (Buried Piping and Tanks);

Part 3: Contention NYS-6/7 (Non-EQ Inaccessible Medium and Low Voltage Cables);

Part 4: Contention NYS-8 (Transformers);

Part 5: Contention NYS-12C (Severe Accident Mitigation Alternatives ("SAMA") Analysis Decontamination and Cleanup Costs);

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[1] *See* (1) Scheduling Order (July 1, 2010), at 19; (2) Order (Scheduling Post-Hearing Matters and Ruling on Motions to File Additional Exhibits) (Jan. 15, 2013) at 1; and (3) Order (Granting Parties Joint Motion for Alteration of Filing Schedule) (Feb. 28, 2013).

Part 6: Contention NYS-16B (SAMA Analysis Population Estimates);

Part 7: Contention NYS-17B (Real Estate Values);

Part 8: Contention NYS-37 (No-Action Alternative);

Part 9: Contention RK-TC-2 (Flow Accelerated Corrosion); and

Part 10: Contention CW-EC-3A (Environmental Justice).[2]

In Part 2 of the Staff's Proposed Findings, set forth below, the Staff addresses the issues raised in Contention NYS-5 (buried piping and tanks). For the reasons set forth herein, the Staff submits that Contention NYS-5 should be resolved in favor of license renewal for Indian Point Nuclear Generating Units 2 and 3.

I. BACKGROUND AND INTRODUCTION

2.1 These findings and rulings address all outstanding issues with respect to Contention NYS-5, filed by the State of New York ("New York"), concerning the treatment of buried piping and tanks in the license renewal application ("LRA") filed on April 23, 2007, by Entergy Nuclear Operations, Inc. ("Entergy" or "Applicant") for Indian Point Nuclear Generating Units 2 and 3 ("Indian Point" or "IP2" and "IP3"). An overview of this proceeding and the regulatory standards that govern consideration of the IP2 and IP3 LRA are set forth in Part 1 of

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[2] The Staff utilized a unique number designator for each separate Part of its Proposed Findings, whereby all paragraphs in Part 1 are consecutively numbered "1.__"; all paragraphs in Part 2 are consecutively numbered "2.__", etc. Accordingly, paragraph numbers in this Part commence with the number 2.1.

the Staff's Proposed Findings, submitted simultaneously herewith. To avoid unnecessary duplication, the Staff hereby incorporates Part 1 of its Proposed Findings by reference herein.

2.2. On November 30, 2007, New York filed a petition to intervene in this matter, in which it raised a number of contentions including Contention NYS-5. As filed by New York, Contention NYS-5 asserted as follows:

> <u>NYS-5</u>
> The aging management plan contained in the license renewal application violates 10 C.F.R. §§ 54.21 and 54.29(a) because it does not provide adequate inspection and monitoring for corrosion or leaks in all buried systems, structures, and components that may convey or contain radioactively-contaminated water or other fluids and/or may be important to plant safety.[3]

2.3. This contention was restated by the Atomic Safety and Licensing Board ("Board") in its "Memorandum and Order (Ruling on Petitions to Intervene and Requests for Hearing)" ("Order"), LBP-08-13, 68 NRC 43 (July 31, 2008); as restated by the Board, Contention NYS-5 asserts as follows:

> <u>NYS-5</u>
> The LRA does not provide [an] adequate AMP for buried pipes, tanks, and transfer canals that contain radioactive fluid that meet 10 C.F.R. § 54.4(a) criteria. In addition, the LRA is not clear whether an AMP for IP1 buried SSCs that are being used by IP2 and IP3 exists and whether the LRA is adequate if it does exist.

LBP-08-13, 68 NRC at 218.

2.4. The bases for Contention NYS-5 were set forth in New York's Petition at pages 80-92. As set forth therein, and as summarized by the Board in LBP-08-13, New York generally asserted that the buried piping and tank AMP for IP2 and IP3 is inadequate in that (a) there is

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[3] "New York State Notice of Intention to Participate and Petition to Intervene" (Nov. 30, 2007) ("NY Petition"), at 80.

no adequate program to replace buried structures, systems and components ("SSCs") that convey or contain radioactively-contaminated water and/or other fluids (including underground pipes, tanks and transfer canals), before a leak occurs; (b) there is no adequate inspection or monitoring program to determine if and when leakage occurs; and (c) buried SSCs at Indian Point Unit 1 ("IP1") that will be used for IP2 and IP3 during the period of extended operation ("PEO") are subject to the same inadequacies.[4] *See* LBP-08-13, 68 NRC at 78. In sum, Contention NYS-5 asserted that the AMP fails to provide adequate programs for leak prevention and the inspection, replacement, and monitoring of buried piping and tanks that convey or contain radioactively contaminated fluids.

2.5. In support of this contention, New York asserted that buried SSCs are exposed to possible corrosion which jeopardizes the integrity of these SSCs and their ability to perform their intended safety function (LBP-08-13, 68 NRC at 78). According to New York, the "Buried Piping and Tanks Inspection Program" ("BPTIP") located in LRA Appendix B.1.6, is inadequate, in that (a) the inspection period specified in the LRA and AMP will not prevent or provide early detection of potential leaks; and (b) the LRA and AMP fail to provide an evaluation of the baseline conditions of the buried systems or their welded joints, and do not specify potential corrosion rates. New York further asserted that the buried SSCs of concern here, *i.e.,* the buried SSCs which "may contain radioactive water," "whether by design or a structural or system failure" are the (1) safety injection system, (2) service water system, (3) fire protection

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[4] Indian Point Units 2 and 3 share the Indian Point Energy Center ("IPEC") site with Indian Point Unit 1 ("IP1"); that reactor was permanently shut down on October 31, 1974, and has been placed in a safe storage condition (SAFSTOR) until Unit 2 is ready for decommissioning. LRA (Ex. ENT00015A) at 1-7.

system, (4) fuel oil system, (5) security generator system, (6) city water system, (7) plant drain systems, (8) auxiliary feedwater system, and (9) heating system. NY Petition at 81-82.

2.6. In its Memorandum and Order admitting this contention, the Board limited the contention "to the extent that it pertains to the adequacy of Entergy's AMP for buried pipes, tanks, and transfer canals that contain radioactive fluid which meets 10 C.F.R. § 54.4(a) criteria" -- stating that the issues for hearing "include, *inter alia*, whether, and to what extent, inspections of buried SSCs containing radioactive fluids, a leak prevention program, and monitoring to detect future excursions are needed as part of Entergy's AMP for these components," including "the adequacy of the AMP for IP1-buried SSCs that are being used by IP2 and IP3" during the license renewal period." LBP-08-13, 68 NRC at 81.

2.7. Subsequent to the Board's admission of Contention NYS-5, New York withdrew its assertions regarding (a) spent fuel pool transfer canals, and (b) internal corrosion of buried pipes and tanks; this limitation of the issues is set forth in a "Joint Stipulation" filed by the parties on January 23, 2012.[5] Accordingly, those issues are now outside the scope of this contention.

2.8. In accordance with scheduling Orders issued by the Board on July 1, 2010, October 18, 2011 and February 16, 2012, initial testimony and exhibits on Contention NYS-5 were filed by New York on December 22, 2011, by Entergy on March 30, 2012 (as subsequently revised), and by the Staff on March 29, 2012 (as subsequently revised); New York then filed rebuttal testimony and exhibits on June 29, 2012 (as subsequently revised). In these Proposed Findings, we consider all of the parties' admitted exhibits, including the initial testimony

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[5] *See* "State of New York, Entergy Nuclear Operations, Inc., and NRC Staff Joint Stipulation" (Jan. 23, 2012), at 1-2, ¶¶ 1-2.

submitted by New York;[6] revised testimony submitted by Entergy;[7] revised testimony submitted by the Staff,[8] and New York's revised rebuttal testimony.[9] Earlier versions of the parties' final testimony were reviewed but are not addressed herein.[10]

2.9. An evidentiary hearing on all admitted contentions was held in Tarrytown, New York, on October 15 through 18, October 22 through 24, and December 10 through 13, 2012. Contention NYS-5 was heard on December 10-11, 2012 (Tr. at 3274 – 3979). Witnesses appeared on behalf of Entergy, the Staff, and New York, with regard to Contention NYS-5, as summarized below.

2.10. These proposed findings of fact and conclusions of law present the Board's findings of fact with respect to the evidence presented at the hearings on December 10-11, 2012, concerning Contention NYS-5, and the Board's conclusions of law with respect thereto.

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[6] "Pre-Filed Written Testimony of Dr. David J. Duquette, Ph.D Regarding Contention NYS-5" (dated Dec. 16, 2011, filed Dec. 22, 2011) ("New York Testimony on NYS-5") (Ex. NYS000164). New York also filed a written report by Dr. Duquette. *See* "Report of Dr. David J. Duquette, Ph.D in Support of Contention NYS-5" (Dec. 16, 2011) ("Duquette Report") (Ex. NYS000165).

[7] "Testimony of Entergy Witnesses Alan Cox, Ted Ivy, Nelson Azevedo, Robert Lee, Stephen Biagiotti, and Jon Cavallo Concerning Contention NYS-5 (Buried Piping and Tanks))" (Dec. 6, 2012) ("Entergy Testimony on NYS-5") (Ex. ENTR30373).

[8] "NRC Staff's Testimony of Kimberly J. Green and William C. Holston Concerning Contention NYS-5 (Buried Pipes and Tanks)" (Dec. 7, 2012) ("Staff Testimony on NYS-5") (Ex. NRCR20016).

[9] "Pre-Filed Written Rebuttal Testimony of Dr. David J. Duquette Regarding Contention NYS-5" (dated Oct. 5, 2012, filed Oct. 16, 2012) ("New York Rebuttal") (Ex. NYSR20399).

[10] Entergy had filed three previous versions of its testimony, on March 30, May 9, and October 9, 2012 (Exs. ENT000373, ENTR00373, and ENTR20373); the Staff had filed two previous versions of its testimony, on March 29 and August 23, 2012 (Exs. NRC000016 and NRCR00016); New York had filed one previous version of its rebuttal testimony (dated June 5, 2012), on June 29 2012 (Ex. NYS000399).

II. FINDINGS OF FACT

A. Regulatory Standards

2.11. The regulatory standards governing license renewal are set forth at length in Part 1 of the Staff's Proposed Findings, filed simultaneously herewith; that discussion is hereby incorporated by reference herein.[11]

2.12. In brief, pursuant to 10 C.F.R. § 54.29(a), the Commission may issue a renewed license upon finding that actions have been identified, and have been or will be taken, to manage the age-related degradation of structures and components that are within the scope of license renewal pursuant to 10 C.F.R. § 54.4(a) and identified as requiring aging management review ("AMR") in 10 C.F.R. § 54.21(a)(1), "such that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the CLB [current licensing basis], and that any changes made to the plant's CLB . . . are in accord with the [Atomic Energy] Act and the Commission's regulations." 10 C.F.R. § 54.29(a). In this regard, the Commission has explained that the license renewal process "is not intended to demonstrate absolute assurance that structures or components will not fail, but rather that there is reasonable assurance that they will perform such that the intended functions . . . are maintained consistent with the CLB."[12]

2.13. As stated in Part 1 of these Proposed Findings (at 12-14), 10 C.F.R. § 54.4(a) defines plant systems, structures and components ("SSCs") within the scope of the license

[11] See "NRC Staff's Proposed Findings of Fact and Conclusions of Law / Part 1: Overview And Regulatory Standards" (Mar. 22, 2013) ("Part 1" of these Proposed Findings), at 8-22.

[12] Statement of Consideration, "Nuclear Power Plant License Renewal; Revisions," 60 Fed. Reg. 22,461, 22,479 (May 8, 1995) ("1995 Statement of Consideration") (Ex. NYS000016).

renewal review to include (1) SSCs that are "safety-related,"[13] (2) SSCs that are non-safety related but whose failure could prevent satisfactory accomplishment of any of the safety functions identified in 10 C.F.R. § 54.4(a)(1)(i), (ii) or (iii), or (3) SSCs that are relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with Commission 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). 10 C.F.R. § 54.4(a)(3).

2.14. As further stated in Part 1 of these Proposed Findings (at 17-19), 10 C.F.R. § 54.21(a)(1)(i) provides that, for structures and components within the scope of license renewal, an AMR must be accorded to structures and components "that perform an intended function, as described in § 54.4, without moving parts or without a change in configuration or properties." In 10 C.F.R. § 54.21(a)(3), the Commission required license renewal applicants to demonstrate, for structures and components within the scope of license renewal, that "the effects of aging will be adequately managed so that the intended function(s) [of those structures and components] will be maintained consistent with the CLB for the period of extended operation."[14] If a structure or component performs no intended function as defined in § 54.4(a),

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[13] "Safety-related" SSCs are those SSCs that are "relied upon to remain functional during and following design-basis events (as defined in 10 CFR 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 shutdown 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 [ ] as applicable." 10 C.F.R. § 54.4(a); *cf.* 10 C.F.R. § 50.2 (defining "safety-related" SSCs under 10 C.F.R. Part 50).

[14] 10 C.F.R. § 54.21(a)(3); *see Entergy Nuclear Generation Co. and Entergy Nuclear Operations, Inc.* (Pilgrim Nuclear Power Station), CLI-10-14, 71 NRC 449, 453 (*citing* the License Renewal SOC (Ex. NYS000016), 60 Fed. Reg. at 22,464.

it is not within the scope of license renewal, and therefore is not subject to an AMR.

2.15. The Commission has issued detailed regulatory guidance regarding the submittal and review of license renewal applications, as set forth in (a) NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants" ("SRP-LR") (Sept. 2005) (Ex. NYS000195),[15] (b) NUREG-1801, "Generic Aging Lessons Learned (GALL) Report" (Sept. 2005) ("GALL Report, Rev. 1") (Ex. NYS000146A-C),[16] and (c) NRC Regulatory Guide ("RG") 1.188, "Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Licenses" (June 2005) ("RG 1.188") (Ex. ENT000099).[17]

2.16. The GALL Report is a technical basis document to the SRP-LR, and provides specific guidance to a license renewal applicant on how it may demonstrate that its aging management programs ("AMPs") satisfy the requirements in 10 C.F.R. Part 54. GALL Report, Rev. 1 (Ex. NYS000146A), at 3-4. The GALL Report contains the NRC's approved set of recommendations which the agency would find to be acceptable for license renewal. *Id.*[18]

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[15] In December 2010, the Staff issued Revision 2 to the SRP-LR. *See* NUREG-1800, Revision 2, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants" ("SRP-LR, Rev. 2") (Dec. 2010) (Ex. NYS000161).

[16] In December 2010, the Staff issued GALL Report Revision 2. *See* NUREG-1801, Revision 2, "Generic Aging Lessons Learned (GALL) Report" (Dec. 2010) ("GALL Report, Rev. 3") (Ex. NYS000147A-D).

[17] Regulatory Guide 1.188, in turn, endorses the regulatory guidance provided in a Nuclear Energy Institute ("NEI") guidance document, NEI-95-10, Rev. 6, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule" (June 2005) (Ex. ENT000098). *See* SER (Ex. NYS000326A), at 1-5; GALL Report Rev. 1 (Ex. NYS000146A), at 1.

[18] The GALL Report summarizes staff-approved aging management programs for many SCs subject to an AMR. If an applicant commits to implementing these staff-approved AMPs, the time, effort, and resources for LRA review can be greatly reduced, improving the efficiency and effectiveness of the license renewal review process. The GALL Report summarizes the aging management evaluations, programs, and activities credited for managing aging for most of the SCs used by nuclear power plants. The report is also a quick reference for both applicants and staff reviewers with respect to AMPs and activities that can manage aging adequately during the period of extended operation. SER (Ex. NYS000326A), at 1-5.

These approved recommendations relate to (a) "preventive actions", (b) "mitigative actions", (c) "condition monitoring", and (d) "performance monitoring,"[19] as applicable to the component and material type, the environment to which the items are exposed (*e.g.,* raw water, soil, outdoor air), and the aging effect which is being managed. This is documented in a series of NRC-approved AMPs described in the GALL Report (*e.g.,* AMP XI.M20, "Open-Cycle Cooling Water System"; AMP XI.M30, "Fuel Oil Chemistry"; and AMP XI.M34, "Buried Piping and Tanks Inspection"). For example, in GALL Report Rev. 1 (Ex. NYS000146A-C), AMP XI.M34 contains "preventive actions" (e.g., coatings) and "condition monitoring" recommendations. Staff's Testimony on Contention NYS-5 (Ex. NRCR20016) at 11-13.

2.17. Further, the GALL Report establishes one acceptable way for an applicant to manage the aging effects for license renewal. Thus, an applicant may reference NUREG-1801 in its LRA to demonstrate that the programs at its facility correspond to those reviewed and approved in the GALL Report. *Id.* GALL Report Rev. 1 (Ex. NYS000146A) at 3-4. To demonstrate the adequate management of aging effects, license renewal applicants may use AMPs that are consistent with GALL Report Rev. 1 (Ex. NYS000146A-C), or (for more recent license renewal applications) GALL Report Rev. 2 (Dec. 2010) (Ex. NYS000147A-D). *See NextEra Energy Seabrook, LLC* (Seabrook Station, Unit 1), CLI-12-05, __ NRC __ (Mar. 8, 2012) (slip op. at 4, 18), *petition for review denied sub nom Beyond Nuclear v. NRC*, 704 F.3d 12 (1st Cir., Jan. 4, 2013).

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[19] "Mitigative actions" (*i.e.,* actions that slow the effects of aging) are included in some aging management programs, such as those associated with controlling the fuel oil chemistry to minimize internal corrosion in the buried fuel oil lines; "performance monitoring" consists of testing the ability of an SSC to perform its intended function; "condition monitoring" recommendations consist of piping and tank inspections. Staff Testimony on Contention NYS-5 (Ex. NRCR20016), at 12.

2.18. If an applicant commits to implement the AMP that is consistent with the GALL Report, that commitment will be found to be an adequate demonstration of reasonable assurance under section 54.29(a). *NextEra Energy Seabrook, LLC* (Seabrook Station, Unit 1), CLI-12-05, 75 NRC __, __ (Mar. 8, 2012) (sip op. at 4), *petition for review denied sub nom Beyond Nuclear v. NRC*, 704 F.3d 12 (1st Cir., Jan. 4, 2013); *Amergen Energy Co, LLC* (Oyster Creek Nuclear Generating Station), CLI-08-23, 68 NRC 461, 468 (2008). *Accord, Entergy Nuclear Vermont Yankee, LLC* (Vermont Yankee Nuclear Power Station), CLI-10-17, 72 NRC 1, 36-37 (2010) (noting that the NRC does not just rely on a commitment; rather, the commitment is subject to Staff verification, prior to issuance of the license, that the AMP is in fact, consistent with the GALL Report).

2.19. As noted above, the Staff issued GALL Report, Revision 2, in December 2010. Therein, the Staff added AMP XI.M41 for "Buried and Underground Piping and Tanks" (Ex. NYS000147A-D).[20] As discussed *infra*, this portion of GALL Report Revision 2 was later "replaced in its entirety" and "supersede[d]" by an interim staff guidance ("ISG") document, LR-ISG-2011-03, "Changes to the Generic Aging Lessons Learned (GALL) Report Aging Management Program XI.M41 'Buried and Underground Piping and Tanks'" (Ex. NRC000162),

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[20] As described in GALL Report Rev. 2, Section XI.M41, as revised in LR-ISG-2011-03, "buried" piping and tanks are those in direct contact with soil or concrete (e.g., a wall penetration); in contrast, "underground" piping and tanks are below grade but are contained within a tunnel or vault such that they are in contact with air and are located where access for inspection is restricted. LR-ISG-2011-03 (Ex. NRC000162), App. A, at A-1; Tr. at 3306.

issued on August 2, 2012. LR-ISG-2011-03 (Ex. NRC000162) at 10; Tr. at 3971.[21]

2.20. The GALL Report is treated in the same manner as an NRC-approved topical report that is generically applicable. GALL Report, Rev. 1 (Ex. NYS000146A) at 3; Tr. at 3376, 3408. As the Staff explained, an applicant for license renewal can take credit for a program described in the GALL Report such that its AMP would be found acceptable, in one of three ways:

> 1) It may establish a program that is completely consistent with all the recommendations in the GALL Report, or
>
> 2) It may establish a program that is consistent with the GALL Report with exception(s) to certain portion(s) of the GALL Report that the applicant does not intend to implement, and/or it may state enhancements, revisions or additions to existing aging management programs that the applicant commits to implement prior to the period of extended operation to ensure that its AMP is consistent with the GALL Report AMP. Enhancements may expand, but not reduce the scope of an AMP, or
>
> 3) If an applicant's facility has specific materials, environments, aging effects and/or plant-specific operating experience for which aging cannot be effectively managed by any of the GALL Report AMPs, the applicant may develop a plant-specific program that meets the recommended format and content of an AMP as set forth in Section A.1.2.2, Aging Management Program for License

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[21] *See* LR-ISG-2011-03 (Ex. NRC000162) at 10 ("The guidance described in this final LR-ISG supersedes the affected sections of the SRP-LR and GALL Report and is approved for use by the NRC staff and stakeholders"). Inasmuch as GALL Report Rev. 2, AMP XI.M41, was issued after Entergy submitted its LRA, the Staff did not apply this AMP to the IP2/IP3 LRA; nonetheless, the Staff evaluated the Applicant's AMP against the "key elements" of AMP XI.M41. Staff Testimony on Contention NYS-5 (Ex. NRCR20016) at 12 n.3; Tr. at 3923-24. Following publication of SER Supplement 1, the Staff published a draft interim staff guidance document for public comment, concerning AMP XI.M41 (Ex. NRC000019), which was followed by publication of Final LR-ISG-2011-03, "Changes to the Generic Aging Lessons Learned (GALL) Report Aging Management Program XI.M41 'Buried and Underground Piping and Tanks'" (Ex. NRC000162). The Staff considered this ISG in its testimony, addressing, for example, the number of inspections, soil sampling, and use of plant specific operating experience. *See* Staff Testimony on Contention NYS-5 (Ex. NRCR20016), at 12 n.3, 36, 40, 52-53, 58, 60, and 67. In effect, the Staff's review consisted of a "hybrid" evaluation, under GALL Report Rev. 1, GALL Report Rev. 2, and LR-ISG-2011-03. Tr. at 3938. *See* n.59, *infra.*

> Renewal, NUREG-1800, Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants.

Staff Testimony on NYS-5 (Ex. NRCR20016), at 12-13; see GALL Report Rev. 1 (Ex. NYS000146A) at 3-4; Tr. at 3408-09.

2.21. During its review of a license renewal application, the Staff evaluates the applicant's AMPs and its applicable exceptions and enhancements to ensure they provide reasonable assurance that the effects of aging will be adequately managed so that the in-scope system, structure or component's intended function(s) will be maintained consistent with the current licensing basis ("CLB") for the period of extended operation. *Id.* at 13.

B. Witnesses Presented

2.22. As stated above, evidentiary hearings on Contention NYS-5 were held in Tarrytown, New York, on December 10 – 11, 2012 (Tr. at 3274 – 3979). Nine witnesses appeared on behalf of Entergy, the Staff and New York with regard to this contention, as summarized below. We find all of the witnesses presented by Entergy, the Staff, and New York to be qualified to present testimony on the areas they addressed.

1. Applicant's Witnesses

2.23. Entergy presented a panel of six witnesses in support of its LRA, on the issues raised in Contention NYS-5. These were: Alan B. Cox, Ted S. Ivy, Nelson F. Azevedo, Robert C. Lee, Stephen F. Biagiotti, Jr., and Jon R. Cavallo.[22]

2.24. Applicant witness Alan B. Cox is employed by Entergy as Technical Manager, License Renewal; his office is located at Entergy's Arkansas Nuclear One ("ANO") facility in

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[22] Testimony of Entergy Witnesses Alan Cox, Ted Ivy, Nelson Azevedo, Robert Lee, Stephen Biagiotti, and Jon Cavallo Concerning Contention NYS-5 (Buried Piping and Tanks))" (Dec. 6, 2012) ("Entergy Testimony on NYS-5") (Ex. ENTR30373).

Russellville, Arkansas; as summary of Mr. Cox's professional qualifications is provided in his *curriculum vitae,* admitted into evidence as Ex. ENT000031. In brief, Mr. Cox has a Bachelor of Science degree in Nuclear Engineering from the University of Oklahoma and a Masters of Business Administration (M.B.A.) from the University of Arkansas at Little Rock. He has more than 34 years of experience in the nuclear power industry, having served in various positions related to engineering and operations of nuclear power plants. From 1993 to 1996, he was employed as a Senior Staff Engineer at ANO; from 1996 to 2001, he served as the Supervisor, Design Engineering, at ANO. Mr. Cox was licensed by the NRC in 1981 as a reactor operator and in 1984 as a senior reactor operator for ANO, Unit 1. Entergy Testimony on NYS-5 (Ex. ENTR30373) at 1-2.

2.25. As Technical Manager for license renewal, Mr. Cox was directly involved in preparing the LRA and developing or reviewing AMPs for IP2 and IP3. Those programs include the Buried Piping and Tanks Inspection Program ("BPTIP"), which is the Applicant's AMP for buried piping and tanks that may be susceptible to external corrosion at Indian Point. He was directly involved in developing or reviewing Entergy's responses to NRC Staff requests for additional information ("RAIs") concerning the LRA and various amendments or revisions to the application (principally as they relate to aging management issues). He also supported Entergy at the related Advisory Committee on Reactor Safeguards ("ACRS") Subcommittee and Full Committee meetings for the IPEC LRA, held in March 2009 and September 2009, respectively. Mr. Cox testified that he has personal knowledge of the development and subsequent revision of the LRA, including the BPTIP. *Id.* at 2.

2.26. Applicant witness Ted S. Ivy is employed by Entergy as Manager, License Renewal; his office is located at Entergy's ANO facility in Russellville, Arkansas. A summary of Mr. Ivy's professional qualifications is provided in his *curriculum vitae,* admitted into evidence as Ex. ENT000374. In brief, Mr. Ivy has over 25 years of work experience in the nuclear industry.

He has a Bachelor of Science degree in Mechanical Engineering from the University of Arkansas and a Masters of Business Administration ("MBA") degree from the University of Arkansas at Little Rock. He is a licensed Professional Engineer in the States of Arkansas and Louisiana; he is a member of the American Society of Mechanical Engineers ("ASME"), the National Association for Corrosion Engineers ("NACE International"), and the Electric Power Research Institute ("EPRI") Buried Piping Integrity Group. In addition, he serves as an Entergy representative on the Nuclear Energy Institute ("NEI") License Renewal Mechanical Working Group, and served as Vice Chairman (2009-2010) and Chairman (2010) of that organization. *Id.* at 2-3.

2.27. As a member of Entergy's License Renewal Services team, Mr. Ivy was directly involved in seven license renewal projects, including the Indian Point LRA project. In addition, he served as Responsible Lead for development and maintenance of the web-based License Renewal Information System database that Entergy uses to develop aging management review ("AMR") reports and license renewal applications. Mr. Ivy's principal responsibilities with respect to the Indian Point LRA included: (1) preparation and review of license renewal project guidelines on scoping, screening, mechanical aging management reviews, and time-limited aging analyses; (2) preparation and review of Class 1 and Non-Class 1 mechanical aging management review and aging management program evaluation reports; and (3) review of Class 1 and Non-Class 1 mechanical portions of the LRA and preparation of related responses to NRC Staff RAIs. These responsibilities encompassed review of the license renewal BPTIP and revisions to that program. *Id.* at 3-4.

2.28. Applicant witness Nelson F. Azevedo is employed by Entergy as Supervisor, Code Programs, at the Indian Point facility. A summary of Mr. Azevedo's professional qualifications is provided in his *curriculum vitae,* admitted into evidence as Ex. ENT000032. Mr. Azevedo has a Bachelor of Science in Mechanical and Materials Engineering from the

University of Connecticut, a Master of Science degree in Mechanical Engineering from the Rensselaer Polytechnic Institute ("RPI") in Troy, New York, and an M.B.A. degree from RPI. Mr. Azevedo has over 30 years of professional experience in the nuclear power industry, during which time he held engineering, supervisory, and managerial positions with Northeast Utilities and Entergy. As a Department Manager with Northeast Utilities, Mr. Azevedo managed five engineering sections responsible for implementing numerous engineering programs at Millstone Station. *Id.* at 4.

2.29. Mr. Azevedo oversees the engineering section responsible for implementing a number of programs at the Indian Point Energy Center ("IPEC") where IP2 and IP3 are located, including the inservice inspection ("ISI"), inservice testing, flow-accelerated corrosion, snubber testing, boric acid corrosion control, non-destructive examination ("NDE"), fatigue monitoring, steam generator integrity, buried piping, nickel alloy 600 inspection, reactor vessel surveillance, welding, and 10 C.F.R. Part 50, Appendix J containment leak-rate programs. He is also responsible for ensuring compliance with the ASME Code, Section XI requirements for repair and replacement activities at IPEC, and he represents IPEC before industry organizations, including the Pressurized Water Reactor ("PWR") Owners Group Management Committee. As Supervisor, Code Programs at IPEC, Mr. Azevedo contributed to the development and review of license renewal documentation, including the BPTIP, Entergy's responses to related Staff RAIs, and amendments to the BPTIP. *Id.* at 4-5.

2.30. Applicant witness Robert C. Lee is employed by Entergy as Senior Engineer, Code Programs, at the IPEC facility. A summary of his professional qualifications is provided in his *curriculum vitae*, admitted into evidence as Ex. ENT000375. In brief, Mr. Lee received a Bachelor of Science degree in Mechanical Engineering from the City College of New York. He is a licensed Professional Engineer in the State of New York, and has approximately 30 years of work experience in the nuclear power industry. Mr. Lee's nuclear experience principally has been in the Design/Analysis groups within Combustion Engineering, the New York Power Authority, and Entergy. In the IPEC Code Programs group, Mr. Lee is the lead for the following programs: Inservice testing, Appendix J containment leak-rate, pressure testing, and the Underground Piping and Tanks Inspection and Monitoring Program ("UPTIMP"). *Id.* at 5-6.

2.31 In particular, Mr. Lee is the program engineer for the UPTIMP, which is Entergy's current 10 C.F.R. Part 50-based program for managing IPEC buried and underground piping and tanks. In this capacity, Mr. Lee has been responsible for developing and implementing the UPTIMP, which Entergy also is using to implement its license renewal AMP (*i.e.*, the BPTIP). Mr. Lee is familiar with the AMP described in LRA Section B.1.6; amendments to that program, including license renewal commitments related to buried and underground piping; and specific actions being taken by Entergy to implement both the UPTIMP and the BPTIP. *Id.*

2.32. Applicant witness Stephen F. Biagiotti, Jr., is employed as a Senior Associate at Structural Integrity Associates, Inc. ("SIA") in Centennial, Colorado. SIA is an international consulting firm that provides expert inspection, assessment, and engineering services to the nuclear, fossil, and pipeline industries, with particular focus on analyzing, preventing, and controlling structural and component failures. Mr. Biagiotti was retained by Entergy to provide expert services in connection with the adjudication of Contention NYS-5. *Id.*

2.33. Mr. Biagiotti's professional qualifications are summarized in his *curriculum vitae,* admitted into evidence as Ex. ENT000376. In brief, he holds Bachelor of Science and Master of Science degrees in Metallurgical Engineering from the Colorado School of Mines. He is a Registered Professional Engineer in Colorado, and has over 25 years of work experience focusing on corrosion control at pipeline, production, and refinery operations in the oil and gas industries and at operating nuclear power plants. Mr. Biagiotti has been a member of the NACE International (formerly National Association for Corrosion Engineers) for over 20 years. During that time, he had a lead role in industry implementation of piping integrity management procedures (including American Petroleum Institute ("API") 1160, Pipeline Integrity Management), data integration, high consequences area identification, code interpretation, and risk minimization practices and algorithms. He also has substantial expertise in in-line inspection and direct assessment (*i.e.,* external corrosion direct assessment, internal corrosion direct assessment, stress corrosion cracking direct assessment) of buried piping, failure and root-cause analysis, and material selection. *Id.* at 7.

2.34. During the past five years, Mr. Biagiotti served as the Chairman of NACE Task Group 357, which created Standard Practice ("SP") 0507, External Corrosion Direct Assessment ("ECDA") Integrity Data Exchange ("IDX") Format, and he is an active leader in Task Group 404 on Nuclear Buried Piping. More recently, he served as chairman of Special Technology Group 35, "Pipelines, Tanks and Well Casings," which is responsible for overseeing all standard development and reaffirmations on these topics. Currently, he serves as the Associate Technology Coordinator for the NACE Cross-Industry Technology C2 group, "Corrosion Prevention and Control for Pipelines and Tanks, Industrial Water Treating and Building Systems and Cathodic Protection Technology." He has authored or co-authored approximately three dozen publications relating to corrosion risk assessment and integrity management of pipelines and buried plant piping, and holds several related patents. *Id.* at 7-8.

2.35. Among other positions, Mr. Biagiotti served as Metallurgical Engineer in charge of the Corrosion and Failure Analysis Group for Marathon Oil Company's Petroleum Technology Center, providing technical support to Marathon's domestic and international production, pipeline and refining operations; in that capacity, he supervised all corrosion, failure analysis, and metallurgical testing in three laboratories. From 2003 to 2006, Mr. Biagiotti served as Product Manager, Integrity Services at GE Energy in Houston, Texas, where, he led the development of a new service for identifying external corrosion in pipeline systems that could not be inspected with inline inspection technologies (*i.e.,* "smart pigs"). For the past six years, Mr. Biagiotti has been a Senior Associate at SIA, acting as the technical lead in the development of corrosion engineering solutions, databases, and computer models for the assessment of buried piping to detect the degradation mechanisms of internal and external Corrosion; during that time, he developed for EPRI the new nuclear industry buried piping data model and software application for Version 2 of BPWorks™, and the companion Microsoft Windows-based software application, MAPPro©, which provide risk-based ranking of buried piping systems. *Id.* at 8.[23]

2.36. Mr. Biagiotti testified that he has reviewed numerous documents pertaining to Entergy's buried piping AMP at Indian Point, including the BPTIP; relevant portions of the LRA; relevant portions of the Staff's Safety Evaluation Report ("SER") and Supplemental SER, particularly the portions relating to the BPTIP; Entergy's responses to Staff RAIs; Entergy's license renewal commitments, corrective action/operating experience documents, and fleet engineering procedures relevant to the BPTIP; and SIA digitized information from over 150 pipe drawings, representing more than 400 buried lines, as part of Entergy's buried pipe database population and risk analysis effort (i.e., BPWorks™ 2.0 and MAPPro©). Further, Mr. Biagiotti testified that SIA reviewed, compiled, and discussed with IPEC system engineers information to include in the comprehensive BPWorks™ database, including design specifications, pipe drawings, system descriptions, inspection reports, and soil data. In addition, SIA performed an Area Potential Earth Current ("APEC") survey at the IPEC site in 2010 specifically to evaluate the cathodic protection ("CP") system effectiveness and coating condition of buried piping;

[23] Mr. Biagiotti testified that the MAPPro© software program is being deployed by Entergy at its nuclear units, including IP2 and IP3, to assist in managing aging effects on buried piping and tanks. Entergy Testimony on NYS-5 (Ex. ENTR30373) at 8.

Mr. Biagiotti participated in the evaluation of that survey and has been to the Indian Point site. *Id.* at 8-9.

2.37. Applicant witness Jon R. Cavallo is employed as a Vice President and Senior Consultant by UESI Nuclear Services, in Portsmouth, New Hampshire, specializing in corrosion mitigation and protective coatings. A summary of Mr. Cavallo's professional qualifications is provided in his *curriculum vitae,* which was admitted into evidence as Ex. ENTR00377. In brief, Mr. Cavallo has a Bachelor of Science degree in Engineering Technology from Northeastern University in Boston, Massachusetts. He is a Registered Professional Engineer in three states; he is a NACE-certified Level 3 Coating Inspector (the top certification offered by the NACE International Coating Inspector Program), with Nuclear Facilities Endorsement, and a certified SSPC – The Society for Protective Coatings Protective Coatings Specialist. He holds registrations as (a) a Certified Nuclear Coatings Engineer from the National Board of Registration for Nuclear Safety Related Coating Engineers and Specialists and (b) a Senior Nuclear Coatings Specialist from the Board of International Registration for Nuclear Coatings Specialists. In 2010, Mr. Cavallo received the ASTM International Award of Merit and was designated a Fellow by the American Society for Testing and Materials ("ASTM"). *Id.* at 9-10.

2.38. Mr. Cavallo has approximately 40 years of work experience related to corrosion mitigation and protective coatings. From 1971 to 1983, I worked in the Boston and Denver offices of Stone & Webster Engineering Corporation. During that period, he specified coating systems for a number of new nuclear generating facilities, performed coating system failure analysis, and prepared attendant repair plans for operating nuclear generating facilities. From 1983 to 1986, he worked at Metalweld, Inc., where he served as that company's Northeastern U.S. regional manager and the project manager for all of the protective coatings work performed for the Seabrook Station. From 1986 to 1991, he was a Senior Associate in the consulting engineering firm of S.G. Pinney & Associates, Inc., where he managed various offices and performed protective coating and lining work at a number of nuclear generating facilities. From 1991 to 1998, he worked as an independent professional engineer, providing corrosion engineering consulting services. From 1998 to 2009, he was the Vice President of Corrosion Control Consultant & Labs, Inc., which provides corrosion mitigation professional engineering services in surface preparation, protective coatings, and linings. From 2009 to April 2012, he was a Senior Consultant with Enercon Services, Inc. Mr. Cavallo recently joined UESI Nuclear Services as Vice President and Senior Consultant. *Id.* at 10.

2.39. Mr. Cavallo is active in numerous national technical societies, including SSPC, NACE, and ASTM. He served as Chairman of the Northern New England Chapter of SSPC from 1991 to 1998; has been Chairman of the New England Chapter of SSPC since 2000, and was a member of the SSPC National Strategic Planning Committee. In addition, he was elected Chairman of ASTM Technical Committee D-33 on Protective Coating and Lining Work for Power Generation Facilities, and served as Chairman of the Industry Coating Phenomena Identification and Ranking Table ("PIRT") Panel reviewing the work of Savannah River Technical Center on the NRC Containment Coatings Research Project (NRC Generic Safety Issue 191). Mr. Cavallo served as Editor of EPRI Technical Report ("TR") 1003120 (formerly TR-109937), Revision 1, Guideline on Nuclear Safety-Related Coatings; he assisted in development of, and teaches, an EPRI Comprehensive Coatings Course; and he is the Principal Investigator for Revision 2 to Guideline on Nuclear Safety-Related Coatings, which EPRI published as a final report in December 2009. *Id.* at 11.

2.40. Mr. Cavallo testified that, among numerous other documents, he has reviewed the relevant portions of the Indian Point LRA and the Staff's SER and Supplemental SER, specifically those portions relating to the BPTIP. He also reviewed Entergy's responses to Staff RAIs, as well as its license renewal commitments, corrective action/operating experience documents, coating specifications for IPEC buried piping, and fleet engineering procedures relevant to the BPTIP. *Id.*

2. NRC Staff's Witnesses

2.41. The Staff presented a panel of two witnesses regarding Contention NYS-5. These were: Kimberly J. Green and William C. Holston.[24]

2.42. Staff witness Kimberly J. Green is employed by the NRC as a Senior Mechanical Engineer in the Division of License Renewal ("DLR"), Office of Nuclear Reactor Regulation ("NRR"). A summary of Ms. Green's professional qualifications was provided in her *curriculum vitae*, which was admitted into evidence as Ex. NRC000017. In brief, Ms. Green has a Bachelor of Science degree in Engineering from the University of Maryland, with a Major in Nuclear Engineering and a Minor in Mechanical Engineering. She has over twenty years of experience in safety analysis, design modifications, license renewal, and radiological controls. Her expertise includes regulatory analysis and the evaluation of licensing documentation, particularly in the area of license renewal reviews. Staff Testimony on NYS-5 (Ex. NRCR20016), at 1 and 2; Ex. NRC000017, at 1.

2.43. Ms. Green is currently a senior mechanical engineer responsible for the technical review of aging management programs and aging management review results for auxiliary systems for license renewal applications. She has had substantial experience in conducting technical reviews of aging management programs and aging management review results related to auxiliary and steam and power conversion systems in license renewal applications. From April 2007 until April 2011, Ms. Green was the senior project manager responsible for the

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[24] NRC Staff's Testimony of Kimberly J. Green and William C. Holston Concerning Contention NYS-5 (Buried Pipes and Tanks) (Dec. 7, 2012) ("Staff Testimony on NYS-5") (Ex. NRCR20016).

Staff’s safety review of the IP2/IP3 LRA; more recently, she served as the Staff’s environmental project manager for the IP2/IP3 LRA. Staff Testimony on NYS-5 (Ex. NRCR20016), at 1 and 2; Ex. NRC000017, at 1.

2.44. In her capacity as the Safety Project Manager for the IP2/IP3 LRA, Ms. Green was principally responsible for preparation and issuance of the Staff’s “Safety Evaluation Report with Open Items Related to the License Renewal of IP2 and IP3” issued in January 2009, and the “Safety Evaluation Report Related to the License Renewal of IP2 and IP3,” NUREG-1930 (“SER”), published in November 2009 (Ex. NYS000326A-F). In addition, she was a member of the Staff’s audit teams, which evaluated the Applicant’s scoping and screening methodology, as well as its AMRs and AMPs. Ms. Green served as one of the Staff’s technical reviewers of Entergy’s AMP for buried piping and tanks, and she prepared SER Section 3.0.3.1.2 concerning buried piping and tanks at Indian Point. Among her other responsibilities, Ms. Green reviewed the adequacy of the scoping methodology that Entergy utilized in determining which SSCs should be included within the scope of license renewal for IP2 and IP3, including SSCs at Indian Point Unit 1. Staff Testimony on NYS-5 (Ex. NRCR20016), at 3-4.

2.45. In addition to her Indian Point-related duties at the NRC, Ms. Green served as the NRC Staff’s Senior Project Manager for the safety review of the Diablo Canyon Nuclear Power Plant license renewal application, and was a member of the scoping and screening methodology audit team for the Wolf Creek, Susquehanna, Shearon Harris and Diablo Canyon license renewal applications (where she evaluated the scoping and screening methodology for plant-specific license renewal applications to determine if the applicants’ methodology meets the intent of 10 C.F.R. Part 54. Ex. NRC000017, at 1.

2.46. Ms. Green had 16 years of engineering-related experience prior to joining the NRC. From 2000 to 2006, she was employed at Information Systems Laboratories, Inc. (“ISL”), under contract to the NRC, where she performed license renewal scoping and screening evaluations of various systems and was involved in the Staff's safety review of numerous license renewal applications. Among her other duties, she performed engineering evaluations of the main steam, feedwater, auxiliary feedwater, instrument air, emergency diesel generator, and spent fuel pool cooling systems for five license renewal applications; served as the principal investigator for two license renewal application safety reviews; performed an engineering evaluation of the applicants' severe accident mitigation alternative analyses for 23 nuclear power plants; participated in the onsite scoping and screening methodology audits at two nuclear power plants, and in the AMP/AMR audit for two other plants. From 1990 to 2000, she was successively employed at three other engineering firms, where her duties included preparing safety evaluations under 10 C.F.R. § 50.59, analyzing significant regulatory issues, and performing radiation shielding and dose calculations, risk analysis, and safety analysis. *Id.* at 1-2.

2.47. Staff witness William C. Holston is employed by the NRC as a Senior Mechanical Engineer in the Division of License Renewal ("DLR"), Office of Nuclear Reactor Regulation ("NRR"). A statement of his professional qualifications was admitted into evidence as Ex. NRC000018. In brief, Mr. Holston is a Senior Mechanical Engineer at the NRC, and has had 35 years of experience in the nuclear industry, including work as a design engineer and senior engineering manager at two nuclear power plants, and work in nuclear operations, maintenance, quality assurance, and as a training senior manager. Mr. Holston received a Bachelor of Science degree, *cum laude*, from the U. S. Merchant Marine Academy, with a Major in Marine Engineering and a Minor in Nuclear Engineering. He completed the EPRI Guided Wave and EPRI Cathodic Protection and Survey Techniques courses. Staff Testimony on NYS-5 (Ex. NRCR20016), at 1; Ex. NRC000018, at 1 and 3.

2.48. At the NRC, Mr. Holston is responsible for conducting the Staff's technical reviews of aging management programs (AMPs) and aging management reviews (AMRs) for structures, systems and components ("SSCs") within the scope of license renewal (e.g., pipe, tanks, valves) for a variety of materials, component types and aging effects (e.g., elastomers, polymeric materials, aboveground tanks, and selective leaching of aluminum bronze). He serves as the lead reviewer for buried and underground piping and tank AMPs and related issues, and has conducted reviews of these AMPs and related AMRs for buried and underground SSCs in the license renewal applications for sixteen nuclear power plants. Staff Testimony on NYS-5 (Ex. NRCR20016), at 2.

2.49. Mr. Holston provided peer review input for recent changes to the GALL Report, which resulted in issuance of AMP XI.M41, "Buried and Underground Piping and Tanks" in GALL Report Revision 2 (Ex. NYS000147A-D). Mr. Holston is also the author of draft Interim Staff Guidance ("ISG") LR-ISG-2011-03, "Changes to the Generic Aging Lessons Learned (GALL) Report Aging Management Program XI.M41 'Buried and Underground Piping and Tanks'" (Ex. NRC000019), released for public comment on March 9, 2012 (*see* Ex. NRC000020), as well as the final version of LR-ISG-2011-03 (Ex. NRC000162) issued on August 2, 2012 (*see* Ex. NRC000163); this ISG addresses preventive actions and inspection recommendations for nuclear power plants reviewed under GALL Report Revision 2 that have buried piping and tanks without cathodic protection. Staff Testimony on NYS-5 (Ex. NRCR20016), at 2-3.

2.50. Mr. Holston served as the Staff's principal reviewer of Entergy's AMPs for buried and underground piping and tanks for the IP2/IP3 LRA, from January 2011 to the present. As part of his responsibilities, he prepared two RAIs that were issued by the Staff regarding buried and underground piping and tanks at Indian Point, as a result of recent industry operating experience related to buried and underground piping and tanks; in addition, he served as the Staff's technical reviewer of the Applicant's responses to those RAIs. In addition, he was the author of Section 3.0.3.1.2, "Buried Piping and Tanks Inspection Program," in NUREG-1930, "Safety Evaluation Report Related to the License Renewal of Indian Point Nuclear Generating Units 2 and 3," Supplement 1 (Aug. 2011) ("SER Supplement 1") for the IP2/IP3 LRA (Ex. NYS000160). Staff Testimony on NYS-5 (Ex. NRCR20016), at 4.

2.51. In addition to his work in developing LR-ISG-2011-03 and work related to the Indian Point LRA, Mr. Holston has additional experience regarding (a) the scoping and screening of SSCs for license renewal, and (b) the protection of buried piping and tanks from external corrosion. In this regard, Mr. Holston has served as the Staff's principal reviewer for the buried piping and tanks AMPs in all license renewal applications since December 2009. Also, prior to joining the NRC, he was employed by Constellation Energy Group, including assignments as a design engineer, maintenance and quality assurance manager, and the Site Engineering Director for the Calvert Cliffs and Nine Mile Point nuclear power plants; as Site Engineering Director, his duties included implementation of all site engineering programs, including programs for buried and underground piping and tanks. He has had extensive design engineering experience, in particular evaluating new designs and adverse inspection findings for piping and tanks. *Id.* at 5.

2.52. Mr. Holston has had 18 years of experience working with the ASME Section XI Boiler & Pressure Vessel Code, principally related to ASME Code Section XI, In-Service Inspection, for design, inspection, repair and replacement activities for SSCs including buried piping and tanks. He served as Technical Program Representative for the first NRC/ ASME Symposium on Boiler and Pressure Vessel Code Section XI; is a past member of the ASME Board of Nuclear Codes and Standards; past member of the ASME Boiler and Pressure Vessel Code, Main Committee; past Vice Chairman, ASME Boiler and Pressure Vessel Code, Subcommittee XI, Inservice Inspection; past Chairman, ASME Boiler and Pressure Vessel Code, Section XI, Sub Group Repairs, Replacements and Modifications; and past Chairman, ASME Boiler and Pressure Vessel Code Working Group, Design Reconciliation. He also participated in seven plant evaluations for the Institute for Nuclear Power Operation ("INPO") including overview of the evaluation of engineering programs. *Id.* at 5; Ex. NRC000018, at 3.

3. New York's Witness

2.53. New York presented one witness in support of Contention NYS-5: Dr. David J. Duquette, who filed written initial testimony and a report in support thereof, as well as written rebuttal testimony.[25]

2.54. New York witness Dr. David J. Duquette is the John Tod Horton Professor of Engineering in the Materials Science and Engineering Department at Rensselaer Polytechnic Institute ("RPI"); he also has an active consulting practice, primarily in the area of corrosion and mechanical failures. A statement of his professional qualifications was admitted into evidence as Ex. NYS000166. Dr. Duquette has been a member of the RPI faculty since 1970, having successively served as Assistant Professor; Associate Professor; Professor; Associate Director of the Center for Advanced Interconnects Science and Technology; and Department Head prior to his current appointment. He received a Bachelor of Science degree from the U. S. Coast Guard Academy, and a Ph.D. from the Massachusetts Institute of Technology ("MIT"), where his doctoral thesis addressed "The Effect of Environment and Potential on Corrosion Fatigue of Low Carbon Steels." Dr. Duquette performed graduate work at the MIT Corrosion Laboratory, and spent two years as a Research Associate at the Advanced Materials Research and Development Laboratory at Pratt and Whitney Aircraft prior to joining the faculty at RPI. New York Testimony on NYS-5 (Ex. NYS000164), at 1-3; Ex. NYS000166 at 1, 22.

[25] *See* (1) "Pre-Filed Written Testimony of Dr. David J. Duquette, Ph.D Regarding Contention NYS-5" (dated Dec. 16, 2011, filed Dec. 22, 2011) ("New York Testimony on NYS-5") (Ex. NYS000164); (2) "Report of Dr. David J. Duquette, Ph.D in Support of Contention NYS-5" (Dec. 16, 2011) ("Duquette Report") (Ex. NYS000165); and (3) "Pre-Filed Written Rebuttal Testimony of Dr. David J. Duquette Regarding Contention NYS-5" (dated Oct. 5, 2012, filed Oct. 16, 2012) ("New York Rebuttal") (Ex. NYSR20399).

2.55. Dr. Duquette's research and professional experience has focused on corrosion science and engineering. He has supervised more than 50 graduate research dissertations in corrosion and related sciences, and is the author or co-author of more than 230 publications and 20 book chapters. Dr. Duquette has presented numerous lectures both nationally and internationally, and has served for nine years, since 2002, on the U. S. Nuclear Waste Technical Review Board. He is a Fellow of ASM International ("ASMI") (formerly the American Society of Metals), NACE (formerly known as the National Association of Corrosion Engineers) and the Electrochemical Society ("ECS"); and is a member, past committee member, and past officer of the American Institute of Metallurgical Engineers. Dr. Duquette is the recipient of the NACE Whitney Award for outstanding corrosion research, an A. v. Humboldt Senior Scientist Award from the German government, and various other honors and awards from the scientific community. New York Testimony on NYS-5 (Ex. NYS000164), at 2-3; Ex. NYS000166 at 1- 22.

C. <u>SSCs within the Scope of the IP2/IP3 Buried Piping and Tank AMP</u>

1. <u>Overview of the Buried Piping and Tank AMP</u>

2.56. Entergy's witnesses testified that Entergy used the guidance in the GALL Report, Rev. 1 (NUREG-1801) (Ex. NYS000146A-C) in preparing the LRA for IP2 and IP3. In this regard, they cited LRA Section B.1.6, which states that the BPTIP described in the LRA, as submitted in April 2007, was consistent with the program attributes described in GALL Report, Rev. 1, Section XI.M34, "Buried Piping and Tanks Inspection," without exception. Entergy Testimony on NYS-5 (Ex. ENTR30373) at 23, *citing* LRA, Appendix B at B-27 (Ex. ENT00015B); GALL Report Rev. 1 at XI M-111 to XI M-112 (Ex. NYS000146C).

2.57. Following the submission of Entergy's LRA in April 2007, the Staff issued Revision 2 of the GALL Report – and later issued LR-ISG-2011-03; in each instance, issuance of the additional or revised regulatory guidance led to the Staff's issuance of RAIs to the Applicant. *See* Staff Testimony on Contention NYS-5 (Ex. NRCR20016), at 38 & 60-61.

2.58. The additional guidance issued by the Staff, set forth in GALL Report Revision 2 and LR-ISG-2011-03, was not inconsequential. Revision 2 of the GALL Report contains revisions to various AMPs in GALL Report Revision 1. As it relates to contention NYS-5, Revision 2 of the GALL Report combines the previous Buried Piping and Tanks Surveillance Program (Section XI.M28) and the Buried Piping and Tanks Inspection Program (Section XI.M34) to create a new program, Section XI.M41, Buried and Underground Piping and Tanks that incorporates aspects of both prior programs. *See* Entergy Testimony on NYS-5 (Ex. ENTR30373) at 23-24; GALL Report Rev. 2 (Ex. NYS000147D), at XI M41-1 to XI M41-14.

2.59. In particular, the new program for buried piping (AMP XI.M41) in GALL Report Rev. 2, as revised in LR-ISG-2011-03, significantly increases the number of inspections recommended for buried piping for those plants without cathodic protection. Staff Testimony on Contention NYS-5 (Ex. NRCR20016), at 32, 35-36, and 38. Further, Section XI.M41 of GALL Report Rev. 2, as later modified by LR-ISG-2011-03, increases the number of piping materials covered by the program, and calls for both preventive measures and inspections. *See* Entergy Testimony on NYS-5 (Ex. ENTR30373) at 24, *citing* Final LR-ISG- 2011-03 (NRC000162), App. A, revised GALL Report AMP XI.M41 at A-1. Section XI.M41 also provides more specific guidance for inspection and monitoring activities based on plant-specific factors, such as the quality of backfill and the presence or absence of cathodic protection. *Id., citing* Final LR-ISG-2011-03 (NRC000162), at XI M41-1 to XI M41-3. The number of inspections to be performed depends on the piping material and function (e.g., whether it is safety-related or contains hazardous materials) and the available preventive measures. *Id., citing* GALL Report Rev. 2 (NYS000147D), at XI M41-4 to XI M41-10.

2.60. In light of these regulatory initiatives following its April 2007 submittal of the LRA for IP2 and IP3, Entergy substantially revised and augmented the BPTIP (its AMP for buried piping), in response to industry operating experience and the Staff's related RAIs. Entergy Testimony on NYS-5 (Ex. ENTR30373) at 23-24.

2.61. In sum, the AMP for buried piping and tanks that exists now is quite different from the AMP contained in Entergy's LRA as it existed in April 2007. It is this revised AMP that we consider in these Proposed Findings. Based upon the substantial and reliable evidence of record, as more fully discussed below, consistent with 10 C.F.R. § 54.29(a), we conclude that Entergy has satisfactorily demonstrated that the BPTIP provides reasonable assurance that the effects of aging on in-scope buried pipes and tanks potentially containing radioactive fluids will be managed, such that those pipes and tanks remain able to perform their intended functions during the period of extended operation.

2. <u>Identification of SSCs within the Scope of License Renewal</u>

2. 62. As discussed *supra* at 7-9, only certain structures and components at a nuclear power plant are within the scope of 10 C.F.R. Part 54 and are subject to AMR – *i.e*., the structure or component must perform an intended function as defined in 10 C.F.R. § 54.4(a)(1)-(3); it must perform that intended function without moving parts or a change in configuration or properties; and it must not be subject to replacement based on a qualified life or specified time period. *See* 10 C.F.R. §§ 54.4(b) and 54.21(a)(1)(i)-(ii).

2.63. To assure that an LRA satisfies these requirements, an applicant for license renewal typically follows a sequential, two-step process: (1) identification of the SSCs within the scope of the license renewal rule (as defined in 10 C.F.R. § 54.4) (also known as "scoping"), and then (2) from among those in-scope SSCs, identification of the structures and components that are subject to aging management review (also known as "screening"). Screening is part of an applicant's integrated plant assessment, as defined in 10 C.F.R. § 54.21, and is performed to determine which structures and components in the scope of license renewal require AMR. Section 54.21(a)(1)(i) lists examples of structures and components that require an AMR; as pertinent to Contention NYS-5, "piping" appears on the list of components that require an AMR. *See* 10 C.F.R. § 54.21(a)(1)(i); Entergy Testimony on NYS-5 (Ex. ENTR30373) at 21-22.

(a) Entergy's Scoping and Screening Efforts

2.64. Entergy's LRA, Section 2.1, "Scoping and Screening Methodology," describes the method that Entergy used to identify those systems and structures at IPEC that are within the scope of license renewal and those structures and components that are subject to AMR. *See* LRA (Ex. ENT00015A) at 2.1-1 to 2.1-16. In this regard, Entergy followed the guidance in NEI-95-10, Rev. 6, "Industry Guideline for Implementing the Requirements of 10 C.F.R. Part 54 – The License Renewal Rule (June 2005)" (Ex. ENT000098). Entergy Testimony on NYS-5 (Ex. ENTR30373) at 25, *citing* LRA at 2.1-1. Consistent with NEI 95-10, the scoping process consisted of developing a list of plant systems and structures, identifying their intended functions, and determining which functions meet one or more of the criteria in § 54.4(a). *Id.*

2.65. Entergy developed the list of systems using the IPEC component database, which provides component-level information, including the system, component description, quality assurance classification, location, and other relevant information. The database has two parts, one for IP2 (which also includes listings for IP1 systems and components), and another for IP3. IP1 systems and components that support the IP2 or IP3 intended functions were included in the scope of the LRA, regardless of the unit designation of the system or component. Entergy identified mechanical system functions from the IP2 and IP3 safety system function sheets ("SSFSs"), which list functions performed by each system; and it obtained additional information on mechanical system functions from plant layout drawings, the plants' Updated Final Safety Analysis Reports ("UFSARs"), maintenance rule documents, piping flow diagrams, and design basis documents. Entergy Testimony on NYS-5 (Ex. ENTR30373) at 25-26*, citing* LRA (Ex. ENT00015A) at 2.1-1 to 2.1-5.

2.66. Entergy evaluated mechanical systems (which include piping systems) against the criteria of 10 C.F.R. § 54.4(a)(1), (a)(2), and (a)(3). *Id.* at 26, citing LRA at 2.2-1. In the LRA, Section 2.2, "Plant Level Scoping Results," presents the results of the scoping process. In particular, LRA Tables 2.2-1a-IP2 and 2.2-1a-IP3 list mechanical systems for IP2 and IP3 within the scope of license renewal and include references to the LRA sections that describe the systems. *Id., citing* LRA at 2.2-3 to 2.2-11. LRA Tables 2.2-2-IP2 and 2.2-2-IP3 list the mechanical systems that do not meet the criteria specified in 10 C.F.R. § 54.4(a) and, therefore, are excluded from the scope of license renewal. *Id., citing* LRA at 2.2-17 to 2.2-18.[26] For each item on these lists, the table also provides a reference (if applicable) to the section of the UFSAR that describes the system or structure. *Id.*

2.67. Entergy then determined which in-scope buried and underground piping and tanks are subject to AMR. LRA Section 2.1.2.1 discusses the screening process for identifying mechanical components that are subject to AMR. LRA Section 2.3 provides the results of the screening process, which followed NEI 95-10 guidelines. In general, the mechanical systems containing components subject to AMR include the (1) reactor coolant, (2) engineered safety features, (3) auxiliary, and (4) steam and power conversion systems. *Id.* at 27, *citing* LRA at 2.3-2, 2.3-42, 2.3-74, 2.3-318. These systems' supporting subsystems and components are

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[26] Entergy's witnesses observed that various IPEC systems have buried piping and tanks that are not within the scope of license renewal. Only buried piping and tanks that perform one or more of the intended functions identified in 10 C.F.R. § 54.4(a)(1)-(3) are within the scope of license renewal. Entergy Testimony on NYS-5 (Ex. ENTR30373) at 32. *See also* Tr. at 3307-10.

described in LRA Sections 2.3.1 to 2.3.4. The IPEC BPTIP is credited to manage the effects of aging on certain buried piping components that are part of these IP2 and IP3 systems. *Id*.

2.68. Entergy identified the following IP2 and IP3 buried piping that is subject to an AMR under 10 C.F.R. Part 54 and is included within the scope of the BPTIP:

- Safety injection (IP3 only): Approximately 700 feet of stainless steel piping running from the refueling water storage tank ("RWST") to the auxiliary building that supplies borated water to the suction of the safety injection and containment spray pumps.

- Service water: A total of approximately 3800 feet of IP2 and IP3 carbon steel piping that carries service water to and from safety-related cooling loads in two separate parallel trains.

- Fire protection: Approximately 5,000 feet of IP2 and IP3 ductile iron or carbon steel piping that runs from fire water pumps through the fire protection loop that circles the main plant buildings.

- Fuel oil: Approximately 160 feet of carbon steel piping that carries the fuel oil from fuel oil storage tanks to associated diesel engines. Buried piping and tanks provide fuel oil for emergency diesel generators, as well as, the Appendix R diesel generator (IP3 only) and security diesel generator (IP2 only).

- Security generator: Approximately 50 feet of carbon steel piping that provides the propane fuel to operate the IP3 security generator.

- City water: Greater than 4,000 feet of IP2 and IP3 carbon steel, copper alloy and gray cast iron piping that provides a backup source of water for auxiliary feedwater and fire protection systems.

- Plant drains: Greater than 1,000 feet of IP2 and IP3 carbon steel piping that provides a drainage path from floor drains in the lower elevations of certain plant structures to waste holdup tanks.

- Auxiliary feedwater: Approximately 1200 feet of carbon steel piping that serves as the suction line and recirculation line between the auxiliary feedwater pumps and the condensate storage tanks ("CSTs") for each unit. About 1,000 feet of this piping is for IP2, with the remainder of the piping serving IP3.

- Containment isolation support: Approximately 150 feet of carbon steel piping that provides pressurized air to support containment integrity for IP2.

- Circulating Water (IP2 only): Approximately 1,300 feet of carbon steel piping that supplies cooling water from the Hudson River to the IP2 condenser to condense steam exiting the low-pressure and main boiler feed pump turbines.

Entergy Testimony on NYS-5 (Ex. ENTR30373) at 27-28.[27] Each of these systems was shown on a detailed map of the site, in Entergy's testimony. *See id.* at 28 and 30 (Figure 1).[28]

2.69. Prior to issuance of SER Supplement 1, Entergy did not identify any underground piping or tanks as being subject to performance of an AMR; in this regard, Entergy stated, "[i]nscope SSCs that are subject to aging management review at IPEC include no underground piping or tanks."[29] In October 2012, however, Entergy identified approximately 270 feet of piping (including portions of the service water, city water, and fuel oil systems) that meets the definition of underground piping in Section XI.M41 of NUREG-1801, Rev. 2. *Id.* at 28;[30] this

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[27] Entergy stated that portions of the river water system are also within the scope of license renewal. *See* PFF ¶ 2.77, *infra*; Entergy Testimony on NYS-5 (Ex. ENTR30373), at 31-32; Tr. at 3941-42.

[28] Entergy's witnesses rejected New York's assertion that Entergy lacks a comprehensive understanding of IPEC systems containing buried piping components; they stated that Entergy has a comprehensive understanding of those systems, including (a) buried components which support systems performing license renewal intended functions, (b) systems containing, or potentially containing, radioactive fluids, and (c) the specifications that governed installation of IPEC buried piping and its protective coatings. Further, in accordance with EN-DC-343 (Ex. NYS000172), Entergy has developed "as-built" drawings of in-scope buried piping systems (admitted as Exs. ENT000402 & ENT409-422), showing the routes of buried pipes, including their location relative to other buried pipes and aboveground structures. They further observed that Entergy has gained significant insights into the condition of IPEC buried piping and their coatings through numerous direct and indirect (e.g., UT and guided-wave) inspections performed to date, and has incorporated that information into a state-of-the-art computer database (BPWorks™ 2.0) that is and will be used to prioritize inspections based on IPEC design and operating experience information (including, e.g., guided wave tests, visual inspections, UT, leaks), photographs, and drawings. They therefore rejected New York's assertion that Entergy cannot understand existing buried piping conditions absent an excavation of all relevant IPEC buried piping. Entergy Testimony on NYS-5 (Ex. ENTR30373), at 66-67.

[29] Entergy Response (NL-11-032) to Request for Additional Information, Aging Management Programs (Mar. 28, 2011) (Ex. NYS000151), Att. 1, at 8 of 27; *see* Staff Testimony on NYS-5 (Ex. NRCR20016), at 22-23).

[30] Specifically, this piping includes portions of two 24-inch diameter IP3 service water inlet headers (approximate total length of 70 feet) that run over the discharge canal, portions of the Indian Point 2 and 3 fuel oil piping (1 ½-inch, 3-inch and 4-inch in diameter) that supply and run between the fuel oil storage tanks and from the storage tanks to each of the emergency diesel generator ("EDG") rooms (approximate total length of 160 feet) and a portion of the ¾-inch diameter IP3 city water piping (approximate total length of 40 feet) that runs in the EDG pipe trench. Entergy Testimony on NYS-5 (Ex. ENTR30373) at 29. None of that piping contains, or has the potential to contain, radiological fluids. *Id.* at 16.

piping was previously treated as accessible piping (as opposed to restricted-access piping), subject to aging management under the IPEC External Surfaces Monitoring Program. Entergy Testimony on NYS-5 (Ex. ENTR30373) at 28-29.[31]

2.70. In addition, Entergy identified the following buried tanks at IP2 and IP3 as being subject to an AMR and covered by the BPTIP, with their specific identification codes:

- IP2 Fuel Oil Storage Tanks (21/22/23 FOST)
- GT1 Gas Turbine Fuel Oil North/South Storage Tanks (GT1-FOT-11/12)
- IP2 Security Diesel Fuel Tank (SDFT)
- IP3 Appendix R Fuel Oil Storage Tank (EDG-33-FO-STNK)
- IP3 Security Propane Fuel Tanks (SPG-TK-001, SPG-TK-002)
- IP3 Diesel Generator Fuel Oil Storage Tanks (EDG-31/32/33-FO-STNK).

Id. at 31.[32] No "underground" tanks were identified as being within the scope of license renewal and subject to an AMR under 10 C.F.R. § 54.4. *See* PFF ¶¶ 2.122 and 2.133, *infra*.

2.71. New York witness Dr. David J. Duquette testified that New York and he did not disagree with Entergy's identification of the buried and underground piping that is subject to an

[31] Entergy identified this underground piping as being within the scope of license renewal as a result of a conference call with the Staff, in which the Staff clarified that the term "restricted" in the definition of "underground" piping in GALL Report Rev. 2 (*i.e*., pipes that are below grade but are contained within a tunnel or vault such that they are in contact with air and are located where access for inspection is restricted), was intended to refer to piping that is located in vaults for which access requires more than simply opening a locked access cover. Entergy then identified portions of the service water, city water, and fuel oil systems that are located in vaults that require more than unlocking a hatch or cover for access, as "underground" piping within the definition in NUREG-1801, Rev. 2 and Final LR-ISG-2011-03. Entergy Testimony on NYS-5 (Ex. ENTR30373) at 28; Ex. ENT000596. *See* n.20, *supra*.

[32] None of the IP2 or IP3 buried tanks identified in PFF ¶ 2.70 contains, or has the potential to contain, radioactive fluids; those tanks are used only to store hydrocarbon fuels (fuel oil, diesel fuel, propane) and are not connected to systems that contain radioactive materials. Entergy Testimony on NYS-5 (Ex. ENTR30373) at 37.

AMR at Indian Point (although he reserved opinion on Entergy's recent identification of in-scope underground piping, which he had not yet reviewed). *See* Tr. at 3310; *cf.* PFF ¶ 2.89, *infra.*

(b) NRC Staff's Evaluation of Screening and Scoping

2.72. NRC Staff witnesses Kimberly Green and William Holston provided the Staff's views of the adequacy of Entergy's screening and scoping of buried and underground piping and tanks for license renewal purposes.

2.73. As part of its evaluation of the Applicant's screening and scoping methodology, in October 2007, the Staff conducted an on-site audit, as documented in the Staff's "Scoping and Screening Methodology Audit Trip Report" (Ex. NRC000124). Ms. Green's testimony further described the Staff's evaluation of Entergy's scoping and screening of SSCs for license renewal purposes. In this regard, she confirmed, based on the Staff's evaluation, described in Chapter 2 of the SER, that Entergy's screening and scoping of buried and underground piping and tanks for license renewal purposes was adequate. *See* Staff Testimony on NYS-5 (Ex. NRCR20016), at 13-17.

2.74. The Staff's SER presents a detailed description of the Applicant's scoping and screening efforts and the Staff's evaluation thereof. *See* SER (Ex. NYS000326A-B), at 2-1 – 2.232; Staff Testimony on NYS-5 (Ex. NRCR20016), at 3. Thus, in Chapter 2 of the SER ("Structures and Components Subject to Aging Management Review"), the Staff evaluated, *inter alia*, the Applicant's scoping and screening methodology, *Id.,* Vol. 1 § 2.1, at 2-1 – 2-30; the Applicant's plant-level scoping results for IP2 and IP3, *Id.,* Vol. 1 § 2.2, at 2-30 – 2-35; and the Applicant's scoping and screening results for the numerous mechanical systems at IP2 and IP3, *Id.,* Vol. 1 §§ 2.3, 2.3A and 2.3B, at 2-35 – 2-197.[33]

2.75. Based upon a comprehensive evaluation of the Applicant's scoping and screening methodology, described in the SER, the Staff concluded as follows:

> **2.6 Conclusion for Scoping and Screening**
> The staff reviewed the information in LRA Section 2, "Scoping and Screening Methodology for Identifying Structures and Components Subject to Aging Management Review and Implementation Results" and determines that the applicant's scoping and screening methodology is consistent with the requirements of 10 CFR 54.4(a) and 10 CFR 54.21 (a)(1), except as noted above.[34] Accordingly, the staff concludes that the applicant has adequately identified those systems and components within the scope of license renewal, as required by 10 CFR 54.4(a), and those subject to an AMR, as required by 10 CFR 54.21(a)(1).
>
> With regard to these matters, the staff concludes that reasonable assurance exists that the activities authorized by the renewed licenses will continue to be conducted in accordance with the CLB and that any changes made to the CLB, in order to comply with 10 CFR 54.29(a), are in accordance with the Atomic Energy Act of 1954, as amended, and NRC regulations.

SER (Ex. NYS000326B), at 2-231 – 2.232.[35]

3. Unit I Buried Piping and Tanks

2.76. As discussed *supra* at 3- 4, New York contends that the AMP for buried piping and tanks at IP2 and IP3 does not take into account buried piping and tanks of Indian Point

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[33] Within the SER, piping is addressed within the discussions of the specific system that involves that piping, rather than as a category by itself. *See, e.g.*, SER (Ex. NYS000326A), Vol. 1 at 2-42 (IP2 reactor coolant pressure boundary piping), 2-48 (IP2 containment spray system piping), and 2-52 (IP2 safety injection system piping).

[34] No exceptions were noted in the SER on scoping issues. *See*, SER (Ex. NYS000326A), Vol. 1, Section 2, *passim.*

[35] The Staff's evaluation and conclusions regarding Entergy's screening and scoping of SSCs for license renewal purposes were unchanged in SER Supplement 1. *See* SER Supplement 1 (Ex. NYS000160), at 2-1.

Unit 1 that are used by IP2 and/or IP3.

2.77. In this regard, Entergy's witnesses explained that the IPEC license renewal scoping process identified systems containing IP1 components that are in-scope for license renewal (because they support the performance of IP2/IP3 license renewal intended functions). The review of these systems and components identified only the fire protection and city water systems as containing components that are buried and which are included in BPTIP. There are no underground IP1 components in scope and subject to AMR. Subsequently, Entergy amended the LRA to add components for the auxiliary feedwater pump room fire event to the scope of license renewal. Those components include a portion of the IP1 river water system from the pump discharge to the intertie to IP2 service water system; this part of the IP1 river water system piping is buried. *Id.* at 31-32; Ex. ENT000381.

2.78. The Staff agreed with Entergy's view that it had properly included, within the scope of license renewal, the buried piping and tanks at IP1 that may be used or relied upon by SSCs within the scope of license renewal for IP2 and/or IP3, and have an intended function that meet the requirements of 10 C.F.R. § 54.4(a). Staff witness Kimberly Green explained that the Staff had reviewed the adequacy of the AMP for in-scope buried piping and tanks for license renewal of IP2 and IP3, including in-scope IP1 SSCs that are used or relied upon by IP2 and/or IP3. To the extent that SSCs are within the scope of license renewal and are subject to an aging management review, the Staff determined that the Applicant's AMP manages the aging of those SSCs. Based on this review, the Staff determined that the aging management program for in-scope buried piping and tanks, including IP1 buried piping and tanks that are used or relied upon by SSCs at IP2 and IP3, is acceptable. Staff Testimony on NYS-5 (Ex. NRCR20016), at 13-14.

2.79. Further, the Staff found no merit in New York's view that the LRA does not specifically commit to conducting any inspections of buried piping and tanks at IP1 that are used or relied upon by Indian Point Units 2 and 3 SSCs within the scope of license renewal.

Ms. Green took note of the Applicant's statement that IP1 systems and components were considered during the license renewal scoping process, *i.e.*, it considered which IP1 systems have intended functions that satisfy any of the criteria in 10 C.F.R. § 54.4(a) for IP2 and IP3:

> Although the extension of the IP1 license is not a part of this license renewal application, IP1 systems and components interface with and in some cases support the operation of IP2 and IP3. <u>Therefore, IP1 systems and components were considered in the scoping process (see Section 2.1.1).</u> <u>The aging effects of Unit 1 SSCs within the scope of license renewal for IP2 and IP3 will be adequately managed so that the intended functions will be maintained consistent with the current licensing basis throughout the period of extended operation</u>.

Staff Testimony on NYS-5 (Ex. NRCR20016) at 14-15, *citing* LRA (Ex. ENT00015A) at 1-7; emphasis added.

2.80. In addition, in LRA Section 2.1.1, Scoping Methodology, the Applicant stated:

> The component database for IP2 and IP3 was used to develop a list of plant systems. The database provides component level information, including the system, component name and identification, quality assurance (QA) classification, location, and other relevant information. The database is in two parts, one for IP2, which includes listings for Indian Point Unit 1 (IP1) systems and components, and a second part for IP3. <u>Although the extension of the IP1 license is not a part of this license renewal application, IP1 systems and components interface with and in some cases support the operation of IP2 and IP3. The systems and components needed to support the intended functions for IP2 and IP3 are included in the scope of this license renewal application, regardless of the unit designation of the system or component.</u>

Id. at 14-15, *citing* LRA (Ex. ENT00015A) at 2.1-2; emphasis added. Ms. Green noted that other portions of the LRA provide further information about the IP1 SSCs that are included within the scope of license renewal, and the LRA (as amended by Entergy's responses to Staff

RAIs)[36] identified the specific IP2 and IP3 systems that IP1 systems provide support to, or interface with, as well as the portion of the IP1 system that is used by or relied upon by IP2 and/or IP3. *Id.* at 15-16.

2.81. Based upon a thorough review of the LRA (and in particular, the IP2 and IP3 systems that were identified as having an interface with, or being supported by, IP1 systems), as well as the UFSARs, plant drawings and other relevant documents, the Staff concluded that there are no buried tanks at IP1 that are within the scope of license renewal, and that the only buried piping at IP1 that is within the scope of license renewal is included in the city water, river water, and firewater systems. *Id.* at 16-17.

2.82. Further, based on its review, the Staff confirmed that the Applicant's defined scoping boundary (*i.e.,* the portion of the system that supports the intended functions of a system within the scope of license renewal under 10 C.F.R. § 54.4(a)(1)-(3)) is adequate. The Staff concluded, for each system, that the Applicant had appropriately identified the components that are within the scope of license renewal, as required by 10 C.F.R. § 54.4(a), and those components that are subject to an aging management review (AMR), as required by 10 C.F.R. § 54.21(a)(1). *Id.* at 17; SER § 2.3A.3.17 (Ex. /NYS000326A), at 2-103. This determination included consideration of the IP1 SSCs that are included or relied upon by SSCs at IP2 and/or IP3 and are within the scope of license renewal. Accordingly, the Staff concluded that the IP2/IP3 SSCs that are within the scope of license renewal appropriately include the IP1 buried

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[36] For example, on January 30, 2012, subsequent to the Staff's issuance of SER Supplement 1, the Applicant corrected the LRA to include a buried portion of the IP1 river water system within the scope of IP2/IP3 license renewal. This correction was duly noted by the Staff. *See* Staff Testimony (Ex. NRCR20016) at 16; Ex. NRC000021,

piping that is used or relied upon by IP2 and/or IP3 and is within the scope of license renewal. Staff Testimony on NYS-5 (Ex. NRCR20016) at 17.[37]

2.83. Entergy witness Mr. Azevedo testified that Entergy is confident it has identified all piping within the scope of license renewal. It had identified its in-scope buried piping at the time the LRA was submitted; later, Entergy did an extended review of piping at the site, and did not find any omissions; if any additional piping is found to be within scope, it will be identified. Tr. at 3490-91. Staff witness Kimberly Green provided the Staff's view, stating that the Staff is reasonably confident that Entergy has identified all of the in-scope buried piping at Indian Point Units 1, 2 and 3. Tr. at 3489.

4. Piping and Tanks That May Contain Radioactive Fluids

2.84. As further noted *supra* at 3-4, New York contends that Entergy's AMP does not adequately address buried piping and tanks that may contain radioactive fluids. In this regard, Entergy's witnesses explained that of all the IP1, IP2, and IP3 buried or underground piping systems included in the scope of the BPTIP, only the IP3 safety injection system contains radioactive fluids during normal operations, because it contains borated water with radioactive constituents from the RWST; these buried components are made of stainless steel, which has low susceptibility to corrosion. Entergy Testimony on NYS-5 (Ex. ENTR30373) at 32; LRA (Ex. ENT00015A), at 2.3-55 to 2.3-56.

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[37] In addition, Ms. Green explained that the summary of aging management review tables in Section 3 of the LRA identify, by system, the component, material, environment, aging effect, and aging management program for each component type that is within the scope of license renewal and subject to an AMR. As defined in LRA table 3.0.1, the service environment for "soil" is defined as "external environment for components buried in the soil, including groundwater in the soil for component." The types of components listed in the summary of aging management review tables in Section 3 of the LRA whose external environment is stated as "soil" are considered to be buried components. Staff Testimony on NYS-5 (Ex. NRCR20016), at 17.

2.85. Buried piping in the (a) auxiliary feedwater ("AFW"), (b) service water, and (c) floor drain systems for IP2 and IP3 have the potential to contain radioactivity. The AFW systems' normal suction source of water is the condensate storage tanks ("CSTs"), which do not contain radioactive water under normal operation; however, in the event of a steam generator tube leak, the CSTs and, therefore, the AFW systems, could possibly contain trace amounts of tritiated water. Buried service water piping has the potential to contain radioactivity via its interfaces with the component cooling water ("CCW") system heat exchangers and the containment ventilation cooling units. Floor drains can potentially contain radionuclides due to drainage from nearby radioactive systems; however, drainage from these radioactive systems is not normal, and leaks, if any, are repaired such that the floor drains do not normally contain radioactively contaminated fluids. Entergy Testimony on NYS-5 (Ex. ENTR30373) at 32-33; *see* Tr. at 3696-90.

2.86. Each of the buried piping systems that are subject to an AMR and that contain or have the potential to contain radioactive fluids was shown on a detailed map of the Indian Point site, submitted as part of Entergy's testimony on this contention. *Id.* at 33, 34 (Figure 2).[38] None of the piping in the other systems identified above (*i.e*., fuel oil, security generator, containment isolation support, fire protection and city water, river water, circulating water) has the potential to contain radioactive fluids, because the piping is not connected to systems containing or potentially containing radioactive materials or fluids. *Id.* at 33.

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[38] A description of each of the buried piping systems that contain, or has the potential to contain, radioactive fluids was provided in the LRA, along with description of surveillance and testing activities relevant to those systems, as summarized in Entergy's testimony. Entergy's witnesses testified that such activities are not credited in the BPTIP, but nonetheless provide further assurance that in-scope buried piping potentially containing radioactive fluids will not develop leaks that might impact its license renewal intended functions or adversely affect public health and safety. Entergy Testimony on NYS-5 (Ex. ENTR30373), at 35-37.

2.87. Staff witness William C. Holston presented the Staff's views regarding the adequacy of the Applicant's AMP for buried piping and tanks, including the systems that are within the scope of Contention NYS-5. As pertinent here, Mr. Holston presented the Staff's views regarding the IP2/IP3 systems that "may contain radioactive fluid," which is of principal concern in Contention NYS-5. *Id.* at 18.

2.88. With regard to the nine systems listed by New York in Contention NYS-5 as systems which "may contain radioactive water," "whether by design or a structural or system failure,"[39] Mr. Holston found that these may properly be categorized as either (a) systems that contain radioactive fluid, (b) systems that could potentially contain radioactive fluid in abnormal operations, or (c) systems that are unlikely to contain radioactive fluid. Based on his review of the LRA and other pertinent documents, Mr. Holston identified these systems as follows:

- *Systems containing radioactive fluids during normal operations*: (1) the safety injection system, and (2) the IP2 auxiliary feedwater system ("AFWS");[40]
- *Systems that could contain radioactive fluids in abnormal operations* (due to their interfaces with other plant systems that contain radioactive fluids): (1) the service water system, (2) the city water system, and (3) the plant drain system;[41] and
- *Systems that are unlikely to contain radioactive fluids* (due to the lack of interfaces with systems that contain radioactive fluids)*:* All other systems listed in the

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[39] As noted *supra* at 4-5, these are the (1) safety injection system, (2) service water system, (3) fire protection system, (4) fuel oil system, (5) security generator system, (6) city water system, (7) plant drain systems, (8) auxiliary feedwater system, and (9) heating system.

[40] The Staff included the IP2 AFWS in this category due to tritium leakage from a condensate storage tank ("CWST") return line. Staff Testimony on NYS-5 (Ex. NRCR20016) at 18; Ex. NRC000022.

[41] While Mr. Holston's testimony addressed the IP2 AFWS, it is also possible that the IP3 AFWS could become contaminated; Entergy accordingly included the IP3 AFWS in its list of systems that could become contaminated. *See* Entergy Testimony on NYS-5 (Ex. ENTR30373) at 32-33; PFF ¶ 2.85, *supra*.

> contention (*i.e.,* the fire protection, fuel oil, security generator, and heating systems).[42]

Staff Testimony on NYS-5 (Ex. NRCR20016) at 18-20.

5. New York's Evidence on Scoping Issues

2.89. New York's sole witness on Contention NYS-5, Dr. David J. Duquette, did not contest the Applicant's and Staff's views regarding scoping issues, as set forth above, either in his prefiled testimony, written report, or rebuttal testimony. Indeed, at the evidentiary hearing, Dr. Duquette testified that: (a) New York is reasonably satisfied that all in-scope IP1 piping has been covered, Tr. at 3494; (b) Entergy, with SIA's assistance, has performed a detailed inventory of piping, with which he does not disagree, Tr. at 3706-07; (c) although he has not looked carefully at the Applicant's AMP for buried tanks, "at the present time I have no technical criticism of those programs," Tr. at 3584; and (d) he does not disagree with Entergy's identification of the buried and underground piping that is subject to an AMR at Indian Point (although he had not reviewed Entergy's identification of underground piping that is subject to an AMR), Tr. at 3310. *See* PFF ¶ 2.71, *supra*. Further, New York has not proffered any substantial evidence that effectively calls those assessments into serious question.

6. Conclusion on Scoping Issues Raised in Contention NYS-5

2.90. Based upon our review of the evidence presented, we agree with the conclusion in Section 2.6 of the Staff's SER, as it applies to buried and underground piping and tanks. *See*

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[42] Further, Mr. Holston stated that one of the nine systems listed in the contention (the heating system) is not an "in-scope" system for purposes of license renewal under 10 C.F.R. § 54.4(a), in that it does not perform an intended function which would require it to be within the scope of license renewal. Staff Testimony on NYS-5 (Ex. NRCR20016) at 20.

SER (Ex. NYS000326B), at 2-231 – 2.232. More specifically, we find that the Applicant has adequately identified the underground and buried piping and tanks at the Indian Point site (including IP1 systems and components) that may contain radioactive fluids and are within the scope of license renewal as required by 10 CFR 54.4(a), and those that are subject to an AMR as required by 10 CFR 54.21(a)(1). With regard to these matters, reasonable assurance exists that the activities authorized by the renewed licenses will continue to be conducted in accordance with the CLB and that any changes made to the CLB, in order to comply with 10 CFR 54.29(a), are in accordance with the Atomic Energy Act of 1954, as amended, and NRC regulations.

D. Entergy's AMP for Buried Piping and Tanks

1. Aging Effects

2.91 Entergy identified the materials and principal aging effects and mechanisms of concern for IPEC buried and underground pipes and tanks that are subject to AMR; these include metallic components (i.e., buried carbon steel, ductile or gray cast iron, copper alloy, and stainless steel components). As stated in the LRA, the SER, and NUREG-1801, the aging effect of concern for buried and underground pipes and tanks is loss of material due to various forms of corrosion (*i.e.,* general, pitting, crevice, and microbiologically-induced corrosion.). Entergy Testimony on NYS-5 (Ex. ENTR30373) at 37-38, *citing* LRA (Ex. ENT00015B) at 3.4-8; SER (Ex. NYS000326D) at 3-336, 3-372; and LR-ISG-2011-03 (Ex. NRC000162), App. A, Revised AMP XI.M41 at A-1, A-3 to A-4.

2.92. As Entergy's witnesses explained, loss of material is a potential aging effect for both the internal and external surfaces of buried components, but internal and external losses of material are addressed through different aging management programs. *Id.* at 38.[43] In this proceeding, New York's witness, Dr. Duquette, focused solely on external corrosion of buried pipes and tanks; accordingly, both Entergy and the Staff similarly focused on the loss of material due to external corrosion of buried components and IPEC's related AMP, *i.e.,* the BPTIP. *See, e.g., id.* at 38; Staff Testimony on Contention NYS-5 (Ex. NRCR20016) at 21-24.

2.93. The rate of degradation of buried steel (ferrous materials, *i.e.,* stainless and carbon steels, cast irons) piping is a function of environmental, metallurgical, and hydrodynamic variables. The rate of external degradation may be affected by aggressive chemicals (if present), temperature, oxygen content, pH, and electrochemical potentials between two metals in the soil material and groundwater (if present). A key metallurgical variable is the chemical composition of various elements in the pipe material that impact a stable corrosion resistant surface oxide film (*e.g.,* weight percentage of chromium, nickel, and copper) and the resistance of those elements to further oxidation. Entergy Testimony on NYS-5 (Ex. ENTR30373) at 38-39, *citing* Ex. ENT000384, Ex. ENT000386, Ex. ENT000387, and ENT000598.

2.94. Metal corrosion is largely an electrochemical phenomenon, whereby metals revert to a lower energy state (*e.g.,* an oxide) by electrochemical or chemical reactions. The corrosion process involves the removal of electrons (oxidation) of the metal and the consumption of those electrons by some other reduction reaction, such as oxygen or water reduction. For iron (Fe), the reactions are: $Fe > Fe^{2}+ + 2e^{-}$, $2H_2O + 2e^{-} > H_2 + 2OH^{-}$, respectively. Corrosion of metals occurs at the anode of a corrosion cell. For the reaction to proceed, it must be in equilibrium with another chemical reduction reaction at the cathode. If

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[43] Various aging management programs exist apart from GALL Report AMPs XI.M34 and XI.M41, that address other aging mechanisms, such as AMP II.M20 (internal surfaces), and II.M30 (internal surfaces of buried fuel and above-ground fuel lines). *See* Tr. at 3320-3322.

either reaction is inhibited, then it becomes the rate controlling reaction, thereby controlling corrosion. *Id.* at 39, *citing* Ex. ENT000387, at 90-91.

2.95. For external corrosion to be likely in a buried piping application, a susceptible material (*e.g.,* carbon steel) must be in contact with a corrosive environment (*i.e.,* soil) to support a corrosion reaction. The corrosivity of soil depends on the interaction of multiple parameters, including soil moisture content, soil type, soil pH, and soluble salt content (*e.g.,* Na^+, Cl^-, and SO_4^{2-}). These soil parameters may be observed or measured directly. *Id.* at 39-40, *citing* NACE SP0169-2007, "Standard Practice – Control of External Corrosion on Underground or Submerged Metallic Piping Systems" ("NACE SP0169-2007") (Ex. ENT000388), and Ex. ENT000389.[44]

2.96. Soil resistivity measures the degree to which the soil opposes an electric current passing through it. Highly resistive soil contains minimal water, large fractions of sand (which create discontinuities, *i.e*., voids, in the soil), or rock, which limits the electrolytic capabilities of the soil, thereby inhibiting current flow and impeding corrosion. Soil resistivity values are typically stated in terms of ohm-cm, with values exceeding 10,000 ohm-cm typically considered only mildly corrosive to essentially non-corrosive. As resistivity increases, the ability for anions to leave the anode and recombine at the cathode decreases, thereby slowing the corrosion reaction. A similar yet opposite concern is that as soil resistivity increases, it is more difficult for

[44] Soil corrosivity varies. Thus, not all soils are inherently corrosive; further, the corrosiveness of most soils tends to decrease over time, as the oxygen content in the soil is consumed, resulting in lower metal loss rates over time. Entergy Testimony on NYS-5 (Ex. ENTR30373) at 42-43. The potential for corrosion is accounted for in IPEC Buried Piping Specification 9321-05-248-18 (Ex. ENT000394), which states a calculated required wall thickness for stainless and carbon steel pipe, and includes a corrosion allowance of 12.5% of pipe wall thickness. Considering this required minimum wall thickness, and applying additional margins, Entergy's witnesses stated that once a coating has degraded, one could expect an additional 40-60 years before corrosion would reduce the wall thickness to its design minimum thickness (including various safety factors). *Id.* at 43-44. Notably, Dr. Duquette agreed that the IP2/IP3 buried piping coatings will last a very long time, as Entergy expects. Tr. at 3761.

current generated at cathodic protection ("CP") anodes to migrate through the soil and reach the intended buried components or structures, thereby lowering the effectiveness of applied CP.[45] Resistivity is not the sole indicator of corrosion potential for buried structures and must be integrated into the overall corrosion assessment using the other considerations described above. *Id.* at 40, *citing* NACE SP0169-2007 (Ex. ENT000388) and Ex. ENT000389.

2.97. Different metals have different corrosion resistance properties. Type 304 stainless steel, like that used in the buried IP3 safety injection system piping, is generally resistant to corrosion in soils. Depending on the grade of stainless steel, pitting corrosion can occur under certain conditions involving de-aeration, high temperatures, high concentrations of chlorides (generally greater than 500 ppm), and low pH (generally less than 4.5, *i.e.,* acidic conditions)—conditions that are not present at IPEC. Carbon steel will exhibit some corrosion in most environments. The corrosion rate depends on the conditions to which the carbon steel is exposed. In soil, the corrosion resistance of carbon steel varies depending on the soil conditions, which are largely affected by moisture and oxygen content. As discussed *infra*, protective coatings have been applied to steel piping that is managed under the BPTIP at Indian Point. These coatings provide a barrier between the soil and piping, thereby significantly improving the corrosion resistance of the steel piping at IPEC. Entergy Testimony on NYS-5 (Ex. ENTR30373) at 46.

2.98. Corrosion of buried pipes and tanks can occur when two or more electrochemically dissimilar metals are electrically connected to each other and in physical

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[45] From a corrosion control perspective, it is preferable to have moderate soil resistance so that the corrosion potential of exposed metals in the soil will only be moderately corrosive (without applied CP) and any applied CP current can effectively migrate to exposed metal collection regions (also known as "coating holidays") for corrosion control. Entergy Testimony on NYS-5 (Ex. ENTR30373) at 40.

contact with the same electrolyte, such that a "corrosion cell" is created. The direction of positive current flow is from the metal with the more negative potential through the electrolyte to the metal with the more positive potential. The corroding metal, called an anode, is the metal from which the current leaves to enter the electrolyte. The metal that receives the current is referred to as the cathode. Corrosion thus occurs as a result of "anodic" reactions that take place at the point where the positive current leaves the metal surface. *Id.* at 41.

2.99. Cathodic protection – which is the issue of primary concern in the testimony of New York witness Dr. David Duquette, (*see* discussion *infra*) – prevents corrosion by converting the anodic or active sites on the metal surface of buried pipe to a cathodic or passive state by supplying electrical current via an anode. The anode supplies electrons through the metallic path and metal ions through the electrolyte (aka soil) to create the reduction of soil ions at the exposed steel surfaces, ultimately producing a polarization film at the structure and thereby inhibiting the corrosion process. The anode is always more negative than the buried pipe, such that the return flow of current through the wire connection is from pipe to anode, and the flow of current through the electrolyte (soil) is from the anode to the pipe. *Id.* at 41*; cf.* A.W. Peabody, Peabody's Control of Pipeline Corrosion 21-48 (NACE International 2d ed. 2001) ("Peabody's Control of Pipeline Corrosion") (ENT000390).

2. <u>Entergy's Buried Piping and Tanks Inspection Program (BPTIP)</u>

2.100. Entergy's witnesses testified that the Indian Point BPTIP manages loss of material due to external corrosion of buried and underground piping and tanks, to provide reasonable assurance that the associated systems can perform their intended functions. *Id.* at 45-46, *citing* LRA, App. B at B-27 (Ex. ENT00015B), and Ex. NYS000203). As described in Section B.1.6 of Entergy's April 2007 LRA, the BPTIP includes two key elements: (a) reliance on <u>preventive measures</u> (*i.e.,* protective coatings in the case of buried piping) to mitigate external corrosion, and (b) <u>inspections</u> to manage the effects of corrosion on the pressure-retaining capability of buried carbon steel, gray cast iron, copper alloy, and stainless steel components, which are conducted to assess the condition of coatings and to detect and quantify the potential loss of material due to corrosion. *Id., citing* LRA, App. B at B-27 (Ex. ENT00015B).

(a) <u>Preventive Measures for In-Scope Buried Piping</u>

2.101. Type 304 stainless steel, like that used in the buried IP3 safety injection system piping, is generally resistant to corrosion in soils. Depending on the grade of stainless steel, pitting corrosion can occur under certain conditions involving de-aeration, high temperatures, high concentrations of chlorides (generally greater than 500 ppm), and low pH (generally less than 4.5, *i.e*., acidic conditions)—conditions not present at IPEC. Carbon steel will exhibit some corrosion in most environments. The corrosion rate depends on the conditions to which the carbon steel is exposed. In soil, the corrosion resistance of carbon steel varies depending on the soil conditions, which are largely affected by moisture and oxygen content. Protective coatings have been applied to steel piping that is managed under the BPTIP. These coatings provide a barrier between the soil and piping, thereby significantly improving the corrosion resistance of the steel piping at IPEC. *Id.* at 46.

2.102. The IPEC buried piping systems subject to AMR that are constructed of carbon steel are coated to provide effective corrosion control by isolating the external surfaces of the buried piping from the environment. The IP2 and IP3 coating specifications required that carbon steel buried piping be properly coated in accordance with applicable industry standards, to create a barrier between the piping and external environment. All buried piping within the scope of Contention NYS-5 was coated in accordance with the American Water Works Association ("AWWA") standard, AWWA C-203-62, "AWWA Standard for Coal-Tar Enamel Protective

Coatings for Steel Water Pipe" (Jan. 1962) (Ex. ENT000393).[46] In contrast, the "underground" piping discussed in Entergy's testimony does not include such coatings, because it was not installed in direct contact with soil.[47]

2.103. The protective coating system for buried carbon steel piping at IPEC provide several benefits, which include: (1) serving as a moisture barrier; (2) good adhesion to the piping surfaces; (3) the ability to resist the development of holidays (*i.e.,* voids or imperfections) over time;[48] (4) resistance to corrosive soil conditions; (5) robustness to resist against damage during storage, handling, installation and operation; and (6) resistance to disbondment due to mechanical stresses or cathodic "impressed" current. *Id*. at 47, *citing* NACE SP0169-2007 (2007) (Ex. ENT000388) at 6-7.

2.104. Engineering specifications in place at the time of plant construction contained procedures for installing and inspecting coatings applied by the piping manufacturer and for coatings applied in the field (*e.g.*, at pipe joints). The majority of IPEC buried piping within the scope of the BPTIP is carbon steel piping. Those systems containing or potentially containing radioactive material are made of stainless steel (IP3 safety injection system) or carbon steel (AFW, service water, and floor drain systems). The applicable site piping specifications required that all steel pipe and fittings be cleaned, coated, and wrapped with coal tar enamel

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[46] The coating specification required a coal tar coating covered with a fiber-based wrap saturated with coal tar; this was consistent with nuclear and industry standards for buried piping at the time Indian Point was constructed. Entergy Testimony on NYS-5 (Ex. ENTR30373) at 51, *citing* Ex. ENT000393.

[47] *See* Entergy Testimony on NYS-5 (Ex. ENTR30373) at 47, and exhibits cited therein. Staff witness Mr. Holston confirmed that, to the best of the Staff's knowledge, all in-scope buried piping has protective coatings, based on the Staff's audit. Tr. at 3375.

[48] "Holiday" is defined as "[a] discontinuity in a protective coating that exposes unprotected surface to the environment." NACE SP 0169-2007 (Ex. ENT000388), at 2.

and an asbestos fiber wrap in accordance with AWWA C-203-62, AWWA Standard for Coal-Tar Enamel Protective Coatings for Steel Water Pipe (Jan. 1962) (Ex. ENT000393). *Id.* at 47-48.

2.105. The AWWA standard (AWWA C-203-62) employed at IPEC establishes cleaning, coating, and wrapping requirements, for coatings applied by the manufacturer and/or the installer, as applicable. *See id.* at 48-50. IPEC purchase specifications and established industry practices require that the coatings be inspected to verify the coatings were applied properly and have not been damaged during shipment; further, before covering the fully assembled and wrapped pipe 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. *Id.* at 51, *citing* Ex. ENT000393.

2.106. Overall industry experience shows that coatings of the type installed on IP2 and IP3 buried piping during construction are sufficient to protect the piping from external corrosion during the period of extended operation. Coal tar coatings of the type installed at IP2/IP3 have been in service elsewhere for periods exceeding 75 years; further, coal tar enamel has the longest performance record of all pipeline coatings available today and ranks first in such measures as resistance to cathodic disbondment, resistance to water penetration, in-use with a cathodic protection system, low maintenance costs, and resistance to physical change/aging. *Id.* at 51-52.

(b) <u>Inspections</u>

2.107. As stated above (PFF ¶ 2.100), the IP2/IP3 BPTIP includes a second element in addition to the preventive measures discussed above: The conduct of inspections, which are conducted to assess the condition of coatings and to detect and quantify the potential loss of material due to corrosion. In this regard, the BPTIP initially included inspections only for buried piping; however, after Entergy determined that certain underground piping is within the scope of license renewal (*see* PFF ¶ 2.69), it revised the BPTIP to include inspections for those components. The following discussion addresses planned inspections for both types of piping.

2.108. The BPTIP inspection program assesses the integrity of the protective coatings on buried piping, to ensure that the exterior surfaces of buried piping are protected against degradation. As long as the protective coatings remain intact, the buried piping will be isolated from potentially corrosive environments and protected from external degradation. Entergy Testimony on NYS-5 (Ex. ENTR30373) at 52, *citing* NACE SP0169-2007 (Ex. ENT000388) and Ex. ENT000389. If degradation of the coatings is identified, then further analysis and evaluation is required, potentially resulting in repair or replacement of the coating and piping or additional and more frequent inspections. *Id.*

2.109. As discussed below, following the submittal of Entergy's LRA in April 2007, information came to light regarding industry operating experience with buried pipes; this operating experience was addressed in various industry initiatives,[49] as well as revised regulatory guidance (*e.g.,* GALL Report Rev. 2, and LR-ISG-2011-03). In light of this operating experience, as well as IPEC plant-specific operating experience, Entergy revised the IPEC BPTIP to include a significantly greater number of buried piping inspections than had been

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[49] These initiatives have resulted in the issuance of various industry guidance documents, including: (a) NEI Nuclear Strategic Issues Advisory Committee ("NSIAC") approval of the "Proposed Buried Piping Integrity Initiative" (Nov. 18, 2009) (Ex. ENT000406); (b) revision of the Buried Piping Integrity Initiative to include underground piping and components, "Underground Piping and Tanks Integrity Initiative" (Sept. 2010) (Ex. ENT000407); (c) NEI 09-14, Rev. 0, "Guideline for the Management of Buried Piping Integrity" (Jan. 2010), and Revision 1 thereof (Dec. 2010) (Ex. NYS000168); (d) EPRI 1016456, "Recommendations for an Effective Program to Control the Degradation of Buried Pipe" (Dec. 2008) (Ex. NYS000167); (e) NEI Buried Piping Integrity Task Force, "Industry Guidance for the Development of Inspection Plans for Buried Piping, Final Draft" (April 2011) (Ex. NYS000169); and (f) Revision 2 of NEI 09-14, entitled "Guideline for the Management of Underground Piping and Tank Integrity" (Nov. 2012) (Ex. ENT000601) (incorporating the final version of the NEI Buried Piping Inspection Plan Guidance (Ex. NYS000169). *See* Entergy Testimony on NYS-5 (Ex. ENTR30373) at 54-57. Entergy reported that <u>all</u> of its nuclear plants have adopted the NEI Buried Piping Integrity Initiative, and are complying with the implementation deadlines for buried and underground piping set out in NEI-09-14. *Id.* at 54, 56.

provided for in its April 2007 LRA. *See* Entergy Testimony on NYS-5 (Ex. ENTR30373) at 52-53; Staff Testimony on NYS-5 (Ex. NRCR20016), at 32-34, and 37-41.

2.110. The BPTIP contained in Entergy's April 2007 LRA, § B.1.6, relied entirely on opportunistic inspections, consistent with GALL Report Rev. 1, Section XI.M34. Thus, as then written, the BPTIP specified one focused (direct visual) inspection before the period of extended operation, and one focused inspection during the first ten years of the period of extended operation (assuming opportunistic inspections did not occur during those periods). Entergy Testimony on NYS-5 (Ex. ENTR30373) at 53, *citing* LRA, App. B (Ex. ENT00015B) at B-27.

2.111. In 2009, as a result of recent industry and IPEC operating experience, related industry initiatives, Entergy fleet initiatives, and Staff RAIs, Entergy significantly increased the number of in-scope IPEC buried piping inspections that it will perform before and during the period of extended operation ("PEO"). In 2011, Entergy revised LRA Sections A.2.1.5 and A.3.1.5 (the UFSAR Supplement) to reflect this increased number and frequency of piping inspections as well as additional soil testing. *Id.*

2.112. More recently, Entergy committed under the BPTIP to visually inspect in-scope IPEC underground piping prior to the PEO, and then on a frequency of at least once every two years during the PEO if that piping is not subsequently coated. Entergy also revised the UFSAR Supplements in LRA Sections A.2.1.5 and A.3.1.5, and the BPTIP description in LRA Section B.1.6, to expressly include this new commitment (Commitment 48). *Id.* at 54.

2.113. Entergy developed its inspection program for buried and underground piping and tanks in accordance with industry guidance, to meet the NEI 09-14 industry initiative for its entire fleet, including IPEC. That program is the Underground Piping and Tanks Inspection and Monitoring Program, or "UPTIMP", and is governed by Entergy fleet procedure EN-DC-343, "Underground Piping and Tanks Inspection and Monitoring Program," Rev. 4 (May 16, 2011) (Ex. NYS000172). EN-DC-343, Rev. 4, adheres to the guidelines of EPRI 106456, Rev. 1, and is implemented, in large part, by Entergy's Program Section No. CEP-UPT-0100, Rev. 0, "Underground Piping and Tanks Inspection and Monitoring Program" (Oct. 31, 2011) (Ex. NYS000173). Entergy also has issued EN- EP-S-002-MULTI, Rev. 0, "Buried Piping and Tanks General Visual Inspection" (Oct. 30, 2009) (Ex. ENT000408), which specifies requirements for buried piping general visual inspections. *Id*. at 58. The BPTIP includes all in-scope buried piping for license renewal; it is a subset of the UPTIMP, which includes all onsite piping, including piping that is not within the scope of license renewal. Tr. at 3479.

2.114. After filing its initial testimony in March 2012, Entergy revised the three fleet-wide procedures identified *supra* in PFF ¶ 2.113, by issuing (a) EN-DC-343, Rev. 5 (Ex. ENT000578) and Rev. 6 (Ex. ENT000599); (b) CEP-UPT-0100, Rev. 1 (Ex. ENT000598); and (c) EN-EP-S-002- MULTI, Rev. 1 (Ex. ENT000600). These Entergy procedures are being used to implement the UPTIMP at IPEC and address the various technical procedures recommended in the NEI 09-14 and EPRI 1016456 guidance documents. Those procedures relate to risk ranking methods; soil analysis; cathodic protection (maintenance, monitoring and surveys); excavation, shoring, and backfilling; pipe and tank inspection techniques; implementation of inspections; scope expansion; interface to fitness-for-service assessment and trending; storage and retrieval of results; coating and lining inspections; fitness-for-service calculation methods and margins; determination of degradation rates and re-inspection interval; repairs (for coatings, linings, piping, tanks, tunnels, trenches, and vaults); prevention methods; and rehabilitation and leak detection techniques. *Id.* at 58-59. All of the NEI recommendations have been incorporated into the BPTIP. Tr. at 3483.

2.115. Entergy has completed its initial risk ranking and prioritization of IPEC buried piping. It is using the NEI Buried Piping Inspection Plan Guidance (Ex. NYS000169), now incorporated in final form as Appendix C to NEI 09-14, Rev. 2 (Ex. ENT000601) and related fleet procedures to implement the UPTIMP and BPTIP at IPEC. *Id.*, at 59.

2.116. The Indian Point BPTIP is essentially implemented by four sets of procedures: EN-DC-343 (Ex. NYS000172), CEP-UPT-0100 (Ex. NYS000173), SEP-UIP-IPEC (Ex. NYS000174), and EN-EP-S-002-MUL TI (Ex. ENT000408), or subsequent revisions thereof.[50] *Id.* at 58-59; Tr. at 3412-13, 3601-02, 3666, 3669-70.

2.117. Entergy's UPTIMP, as implemented, includes all buried and underground SSCs, including those that are not in scope and subject to AMR for license renewal; the BPTIP, in contrast, includes only buried and underground components that are in scope and subject to AMR under 10 C.F.R. Part 54 – i.e., the BPTIP (which is the program challenged in Contention NYS-5) addresses a discrete subset of the buried and underground components covered by the UPTIMP. Entergy Testimony on NYS-5 (Ex. ENTR30373) at 59. In the event that adverse conditions are found during inspections of buried piping that is not in-scope for license renewal, those inspection results will be factored into the inspection program for in-scope buried piping. *See, e.g.,* Tr. at 3864.

2.118. Since submitting its LRA in April 2007, Entergy substantially revised the IPEC BPTIP for inspection of buried piping. These revisions, made in July 2009, August 2009, and March 2011, were submitted in response to industry operating experience and initiatives, as well as the Staff's RAIs concerning the IP2/IP3 buried piping AMP. In a nutshell, Entergy:

- increased the number of planned inspections of buried piping and tanks prior to entering, and during, the IP2 and IP3 periods of extended operation;
- revised LRA Commitment 3 for implementation of the BPTIP, to include a risk assessment of in-scope buried piping and tanks that includes consideration of the impacts of buried piping or tank leakage and of conditions affecting the risk for corrosion;

[50] *See, e.g.*, CEP-UPT-0100, Rev. 1 (Nov. 30, 2012) (Ex. ENT000598); EN-DC-343, Rev. 6 (Nov. 30, 2012) (Ex. ENT000599); and EN-EP-S-002-MULTI, Rev. 1 (Nov. 30, 2012) (Ex. ENT000600).

- committed to perform periodic (instead of opportunistic) inspections and to establish the inspection priorities and frequencies based, in part, on the results of the inspections performed before the PEO and industry and plant-specific operating experience; and

- included additional details on its buried piping inspections, including the number of inspections planned for each unit before and during the PEO, the number of excavated direct visual inspections of external surfaces, the piping length to be excavated for direct visual inspections, the type of material to be inspected (*i.e.*, carbon or stainless steel), and the piping category to be inspected (*i.e.,* "code/safety-related" or "hazmat").

Id. at 60-63. These revisions to the BPTIP, through March 2011, were evaluated by the Staff and approved in SER Supplement 1, issued in August 2011. *Id.* at 61; *see* SER Supp. 1 (Ex. NYS000160), at 3-1 to 3-2.[51]

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[51] On March 15, 2013, Entergy filed a Board Notification, informing the Board and parties that it had revised its March 28, 2011 response to the Staff's RAIs, to indicate, *inter alia*, (a) that "hazmat" buried piping is no longer being treated as a separate category of inspection, and is instead included in the total number of inspections to be conducted prior to and during the PEO, and (b) all 20 of the 20 pre-PEO IP2 inspections have been completed. Entergy then filed an unopposed motion for leave to admit two additional exhibits reflecting these changes: (a) a letter from Entergy to the NRC dated March 5, 2013 (NL-13-037), amending its responses to the Staff's RAIs (Ex. ENT000606), and (b) a Joint Declaration by Entergy witnesses Nelson Azevedo, Alan Cox and Ted Ivy, amending their testimony (Ex. ENT000607) ("Joint Declaration"). Earlier today, the Board admitted these two exhibits in its "Order (Granting Entergy's Motion for Leave to File Two Hearing Exhibits)" (Mar. 22, 2013).

In their Joint Declaration, the witnesses stated, *inter alia,* that "the revised RAI responses do not affect the [BPTIP] descriptions provided in the [UFSAR] Supplements for [IP2 and IP3], [and] do not affect any related Entergy commitments (Commitment Nos. 3 and 48) . . . . There also is no change to the total number of excavated direct visual inspections that Entergy has committed to perform before and during the [PEO], or to Entergy's use of the risk-ranking process described in the UFSAR Supplements (NL-12-174, Attach. 2 (ENT000597)) and CEP-UPT-0100, Rev. 1 [(Nov. 30, 2012) (Ex. ENT000598)]. There also is no effect on the Staff's conclusion in [SER] Supplement 1 (NYS000160) that Entergy is performing a sufficient number of risk-informed inspections." *Id.* at 3-4. They further stated that these developments require "~~modern~~ "modest updates" to their testimony in the proceeding. *Id.* at 4.

The Staff did not oppose Entergy's Motion, but stated that it "reserves the right to make any necessary updates or corrections to its testimony that may arise from Entergy's submittal of [Ex. ENT000606 and Ex. ENT000607]." Entergy's Unopposed Motion for Leave to File, and Request the Admission of, Two New Hearing Exhibits Related to Contention NYS-5 (Buried Piping)" (Mar. 20, 2013), at 1 n.1. The Staff ~~notes~~ noted that it has not yet had an opportunity to consider this new evidence, to address it in revised Staff testimony, or to address it in its Proposed Findings ; accordingly, the Staff indicated it may seek leave to file a revision to these Proposed Findings of Fact, if necessary, to address this newly admitted evidence. On April 22, 2013, the Staff filed an unopposed motion for leave to file a new exhibit (Ex. NRC000167) and to revise these Proposed Findings to address the new information.

2.119. As revised (and approved in SER Supplement 1), the BPTIP provides for inspections of buried piping at IP2 and IP3 that is subject to AMR during the ten-year period prior to entering the PEO for each plant, including 20 direct visual buried piping inspections at IP2 and 14 direct visual buried piping inspections at IP3. These include inspections of buried piping that is (a) code/safety-related or (b) has the potential to release materials detrimental to the environment ("Hazmat"),[52] and consists of both excavated direct visual inspections and inspections using indirect methods; as subsequently revised in Exhibit ENT000606, these are as follows:

IP2/IP3 Pre-PEO Inspections			
Piping Material	**Piping Category**	**Number of IP2 Pre-PEO Inspections (Total/Direct Visual)**	**Number of IP3 Pre-PEO Inspections (Total/Direct Visual)**
Carbon steel	Code/safety related/Hazmat	~~13/9~~ 26/20	~~14/8~~ 19/11
~~Carbon steel~~	~~Hazmat~~	~~13/11~~	~~5/3~~
Stainless steel	Code/safety related/Hazmat	N/A	6/3

The total number of inspections includes both excavated direct visual inspections and inspections performed using indirect methods. Of these, Entergy had completed 24 total inspections (including 13 excavated direct visual inspections) of piping within the scope of the BPTIP, at the time it filed its revised testimony in December 2012. *Id.* at 61-62.[53]

[52] Hazmat piping is piping that, during normal operations, contains material in excess of specified concentrations that, if released, could be detrimental to the environment; it includes chemical substances such as diesel fuel and radioisotopes. Entergy Testimony on NYS-5 (Ex. ENTR30373) at 62 n. 4.

[53] The number of completed inspections increased prior to the hearing on this issue, such that Entergy had completed 14 of the 20 committed pre-PEO inspections for Unit 2, and 4 of 14 pre-PEO inspections for Unit 3. Tr. at 3869. Subsequent to the close of hearings, Entergy completed all 20 of the committed pre-PEO inspections for IP2. *See* n.51, *supra.*

2.120. In addition, Entergy will perform an increased number of direct visual inspections of buried piping at IP2 and IP3 during the PEO; these include 28 IP2 inspections and 32 IP3 inspections; as subsequently revised in Exhibit ENT000606, these are as follows:

IP2/IP3 Excavated Direct Visual Inspections To Be Performed During the PEO			
Piping Material	**Piping Category**	**IP2 Inspections for Each 10-Year Interval of the PEO**	**IP3 Inspections for Each 10-Year Interval of the PEO**
Carbon steel	Code/safety related/Hazmat	~~6~~ 14	~~6~~ 14
~~Carbon steel~~	~~Hazmat~~	~~8~~	~~8~~
Stainless steel	Code/safety related/Hazmat	N/A	2

Id. at 62-63.[54] In accordance with the risk-ranking methodology provided in CEP-UPT-0100, all IPEC piping that is safety-related or that contains radioactive fluids is rated as being of "high" risk in Entergy's risk-ranking of the buried piping to be inspected. Tr. at 3457-59.[55]

2.120A. In March 2013, Entergy submitted two additional exhibits relating to the BPTIP. These were (a) a letter from Fred R. Dacimo (Entergy) to the NRC Document Control Desk, dated March 5, 2013 (NL-13-037), revising Entergy's answers to the Staff's RAIs on buried piping and tanks (Ex. ENT000606), and (b) a Joint Declaration by Entergy witnesses Nelson Azevedo, Alan Cox and Ted Ivy, describing certain revisions Entergy had made to the BPTIP and explaining that those changes did not affect the IP2 and IP3 UFSAR Supplements, the commitments it had made, or the Staff's conclusions regarding the adequacy of the BPTIP (Ex. ENT000607). The Board admitted those exhibits by Order of March 22, 2013.

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[54] The number of hazmat and steel code/safety related piping were later combined, following evidentiary hearings. *See* n.51, *supra*.

[55] The 10-year inspection periods reflected in the BPTIP are consistent with GALL Report AMP XI.M41, and industry practice. *See* Tr. at 3687-88, 3689; Ex. ENT000447.

2.120B. On April 22, 2013, the Staff submitted an unopposed motion for leave to file a new exhibit (Ex. NRC000167) and to revise its proposed findings of fact on Contention NYS-5, to address the new information recited in n. 51 and PFF ¶¶ 2.119-2.120A, *supra*. Exhibit NRC000167, a Declaration by Staff witness William C. Holston, provided the Staff's views regarding the information contained in Exs. ENT000606 and ENT000607. Therein, Mr. Holston described a revision that should be made to one paragraph in Answer 32 of his prefiled written testimony (Ex. NRC000167 at 3 ¶ 6), and stated that no other changes to his written or oral testimony are required (*id.* at 4 ¶ 7). Further, he agreed with Entergy's witnesses, (a) that the new information does not affect the BPTIP descriptions provided in the IP2 and IP3 UFSAR Supplements, or Entergy's Commitments 3 and 48; (b) that no change has been made to the total number of excavated direct visual inspections of this piping to be conducted prior to and during the PEO, or to Entergy's use of the risk-ranking process described in the Supplements to the IP2 and IP3 UFSARs; (c) that the revisions are consistent with Staff guidance in LR-ISG-2011-03 (Ex. NRC000162); and (d) that the revisions have no effect on the conclusion in SER Supplement 1 that Entergy is performing a sufficient number of risk-informed inspections. *Id.* at 4 ¶ 8, *citing* Ex. ENT000607 at 3 & 4.

2.121. In addition, Entergy plans to conduct additional soil testing at IPEC. Although its review of available data did not find that soil surrounding in-scope buried piping at IPEC is corrosive, Entergy will collect and analyze additional soil samples prior to the beginning of the PEO and at least once every 10 years thereafter to confirm that the soil conditions in the vicinity of in-scope buried pipes are non-aggressive. Soil samples will be taken at a minimum of two locations at near in-scope piping to obtain representative soil conditions for each system. The parameters monitored will include soil moisture, pH, chlorides, sulfates, and resistivity. *Id.* at 63; SER Supp. 1 (Ex. NYS000160), at 3-1 to 3-3. The number of inspections performed during the PEO will depend on the results of the soil samples; if soil sample results indicate that the soil is corrosive, the number of inspections for carbon steel code/safety-related~~ piping shown above will be increased to eight, and the number of inspections for carbon steel ~~/hazmat piping will be increased to ~~twelve~~ twenty. Entergy Testimony on NYS-5 (Ex. ENTR30373) at 63; Ex. NYS000151; Ex. ENT000606, Attachment 1 at 1.

2.122. Finally, based on its recent (August 2012) determination that certain underground piping has "restricted" access as defined by the Staff, Entergy committed to visually inspect, under the BPTIP, approximately 270 feet of in-scope IPEC underground service water, fuel oil, and city water piping before and during the PEO. LRA Commitment 48 specifies the inspection frequency and methods of inspection for this in-scope underground piping, as well as Entergy's plan to enter any indications of significant loss of material into the plants' corrective action program, consistent with GALL Report Rev. 1 Section XI.M41. *Id.* at 61, *citing* Ex. ENT000597. LRA Appendices A and B have been revised to expressly include this commitment. *Id., citing* Ex. NYS000203.[56]

2.123. Entergy's witnesses concluded that implementation of the BPTIP will manage aging effects due to external corrosion, and provide reasonable assurance that in-scope IPEC

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[56] Entergy's corrective action program applies to all IP2/IP3 aging management programs. Tr. at 3385. In this regard, LRA Appendix B (Ex. ENT00015B), § B.0.3, states as follows:

> **Corrective Actions**
> Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. Conditions adverse to quality, such as failures, malfunctions, deviations, defective material and equipment, and nonconformances, are promptly identified and corrected. In the case of significant conditions adverse to quality, measures are implemented to ensure that the cause of the nonconformance is determined and that corrective action is taken to preclude recurrence. In addition, the root cause of the significant condition adverse to quality and the corrective action implemented are documented and reported to appropriate levels of management. The corrective action controls of the Entergy (10 CFR Part 50, Appendix B) Quality Assurance Program are applicable to all aging management programs and activities during the period of extended operation.

buried and underground piping will continue to perform its intended functions during extended operation. In this regard, they cited (a) the significant number of inspections to which Entergy has committed in the BPTIP (including 51 pre-PEO inspections, of which 34 are direct visual excavated inspections, and 30 direct visual excavated inspections during each 10-year interval of the PEO), (b) an inspection focus on the most susceptible buried piping during the PEO, (c) inspection of in-scope underground piping prior to the PEO and at least once every two years during the PEO if that piping is not subsequently coated, (d) a continuing review of operating experience, including inspection results, and other relevant site data, to confirm the adequacy of the inspection plan and make any necessary adjustments thereto (*e.g.,* increased inspections due to soil analysis results). Accordingly, they concluded that the BPTIP provides a high level of confidence (*i.e.,* reasonable assurance) that the structural and leak integrity of in-scope buried and underground piping components at IPEC will be maintained during the period of extended operation. *Id.* at 64-65.

2.124. Further, Entergy's witnesses cited the Staff's findings in SER Supplement 1, in which the Staff concluded, *inter alia*, (a) that Entergy had demonstrated that the effects of aging will be adequately managed through the BPTIP so that the intended function(s) of in-scope buried piping will be maintained consistent with the CLB for the period of extended operation, as required by 10 C.F.R. § 54.21(a)(3), and (b) that the UFSAR supplement for the BPTIP provides an adequate summary description of the program, as required by 10 C.F.R § 54.21(d). *Id.* at 65, *citing* SER Supp. 1 (Ex. NYS000160) at 3-5 and 3-3.

3. <u>NRC Staff's Evaluation of Entergy's AMP for Buried Piping and Tanks</u>

2.125. NRC Staff witness William C. Holston presented the Staff's views regarding the adequacy of Entergy's AMP for buried piping and tanks, as it relates to Contention NYS-5.

2.126. Section 3.0.3.1.2 of the SER (Ex. NYS000326B) and SER Supplement 1 (Ex. NYS000160) present the Staff's determination that the Applicant's AMP for buried piping and tanks is adequate to manage the effects of aging such that the in-scope buried SSC functions will be maintained consistent with the CLB for the period of extended operation.[57] In this regard, the Staff concluded that Entergy's aging management program for buried piping and tanks fulfills applicable regulatory criteria, including requirements, among others, that (a) in-scope SSC functions will be maintained consistent with the CLB for the period of extended operation, and (b) actions have been identified and have been or will be taken such that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the CLB. Staff Testimony on NYS-5 (Ex. NRCR20016) at 20-21, *citing* SER (Ex. NYS000326B) and SER Supplement 1 (Ex. NYS000160), Section 3.0.3.1.2.[58]

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[57] As discussed *infra* at PFF ¶ 133, prior to issuance of the SER and SER Supplement 1, Entergy had not identified any in-scope underground piping and tanks as part of its LRA; the SER and SER Supplement 1 therefore only addressed buried piping and tanks.

[58] As stated in n.21, supra, GALL Report, Revision 2, AMP XI.M41, was issued after Entergy submitted its LRA, and the Staff therefore did not directly apply that AMP to the IP2/IP3 LRA; nonetheless, the Staff, through a series of RAIs issued after publication of SER Supplement 1, evaluated the Applicant's AMP against the key elements of GALL Report Rev. 2, AMP XI.M41. In addition, the Staff compared the Applicant's BPTIP to the guidance in the Draft and Final versions of LR-ISG-2011-03 (Exs. NRC000019 and NRC000162) (*e.g.,* number of inspections, soil sampling, and use of plant specific operating experience). The Staff concluded that Entergy's AMP (as revised through its responses to the Staff's RAIs) is adequate to manage the applicable aging effects to ensure that buried piping and tanks will perform their current licensing basis functions. *See* Staff Testimony on Contention NYS-5 at 12 n.3, 20-21, 36, 39-41, 52-53, 58-60, 65, 67, and 72. Further, the Staff found that the Applicant's AMP is consistent with Final LR-ISG-2011-03. Tr. at 3972. As stated in n.21, *supra*, the Staff's review effectively consisted of a "hybrid" evaluation, under GALL Report Rev. 1, GALL Report Rev. 2, and LR-ISG-2011-03. Tr. at 3938.

These determinations were based upon the Staff's review of Entergy's AMP as well as on-site audits of its screening and scoping methodology and of the AMP itself.[59]

2.127. In this regard, the Staff made the following specific findings in Section 3.0.3.1.2 of the SER and SER Supplement 1:

> *Original SER:*
>
> On the basis of its audit and review of the applicant's Buried Piping and Tanks Inspection Program, the staff finds that all program elements are consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).
>
> *SER Supplement 1:*
>
> On the basis of its review of the applicant's response to RAIs 3.0.3.1.2-1, 3.0.3.1.2-2, and 3.0.3.1.2-3, the staff finds that those program elements for which the applicant claimed consistency with the GALL Report are consistent. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be

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[59] The Staff conducted an extensive audit of the Applicant's AMPs in August, October, and November 2007, and February 2008. The results of that audit were reported in the Staff's "Audit Report for Plant Aging Management Programs and Reviews" ("Audit Report") (Ex. ENT000041), which considered numerous AMPs including LRA AMP B.1.6, "Buried Piping and Tanks Inspection." The Audit Report noted that the LRA had indicated that "the [BPTIP] is a new program that will be consistent with GALL AMP XI.M34, "Buried Piping and Tanks Inspection." The Audit Report described the Staff's audit of this AMP, and reported that the AMP elements reviewed during the audit "are consistent with the GALL Report AMP elements." *Id.* at 8, 9. The BPTIP procedures were not reviewed at that time, as they had not yet been developed, Tr. at 3679-80; those procedures will be (and have been) reviewed during the Staff's pre-PEO inspections, conducted under Inspection Procedure 71003 or TI-2516, in which the Staff verifies that procedures have been developed consistent with the approved AMP. *See* Tr. at 3686-87. The Staff's witnesses described the Staff's on-site AMP audit process, in which it examines the applicant's procedures to confirm whether its AMP is consistent with the GALL Report. *See, e.g.,* Tr. at 3323-25, 3331-32. For example, during its on-site audits at Indian Point, the Staff reviewed extensive documentation to verify whether the applicant's process of risk-ranking buried piping is consistent with the GALL AMP Tr. at 3668, 3686-87.

> maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

See Staff Testimony on NYS-5 (Ex. NRCR20016) at 21.[60]

2.128. Mr. Holston disputed the assertion in Contention NYS-5 that Entergy's AMP for buried piping and tanks does not provide an adequate AMP for in-scope buried pipes and tanks that contain radioactive fluid. As he explained, the Staff's conclusion that Entergy's AMP will adequately manage the effects of aging for in-scope buried components during the PEO, took into account the following considerations:

- In regard to preventive actions to mitigate potential corrosion, all steel piping has been coated in accordance with standard industry practices. Recent excavated direct visual examinations of buried pipe have demonstrated that the coatings are in acceptable condition and the backfill in the vicinity of the pipe has not damaged the coatings.

- The Applicant has committed to sample the soil for corrosivity prior to and during the period of extended operation, using standard industry methodologies to determine soil corrosivity, and will increase the number of inspections if the soil is found to be corrosive.

- The Applicant is risk informing its piping inspection locations to select those with the greatest potential for leakage or consequence of leakage.

- The Applicant is conducting a sufficient number of inspections to establish a basis for the Staff to conclude that there is a reasonable assurance that the CLB function(s) of buried systems within the scope of license renewal will be maintained throughout the period of extended operation.

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[60] Pursuant to 10 C.F.R. § 54.37, license renewal applicants are required to "retain in auditable and retrievable form for the term of the renewed operating license . . . all information and documentation required by, or otherwise necessary to document compliance with, the provisions of this part [Part 54]." This requirement affords the basis for the Staff's audits and subsequent inspections. *See* Tr. at 3409.

Id. at 22, *citing* SER Supp. 1, Section 3.0.3.1.2 (Ex. NYS000160).

2.129. Mr. Holston then provided a detailed description of the considerations supporting the Staff's evaluation and conclusions regarding the adequacy of Entergy's AMP for buried piping and tanks. *See* Staff Testimony on NYS-5 (Ex. NRCR20016), at 29-44.

2.130. Mr. Holston explained that the Applicant's Buried Piping and Tanks Inspection Program (BPTIP) manages aging effects for buried piping and tanks, as described in LRA Sections A.2.1.5 and B.2.1.6, and Entergy's responses to Staff RAIs of July 27, 2009 (NYS Ex. 000203), March 28, 2011 (Ex. NYS000151), July 14, 2011 (Ex. NYS000152), and July 27, 2011 (Ex. NYS000153). He observed that this AMP is both a preventive action and condition monitoring based program. The program's preventive actions include coatings and wrappings on buried piping. The program's condition monitoring feature includes an extensive number of excavated direct visual inspections of buried piping, which are used to validate the condition of the backfill, coatings and the pipe's external surface. Inspection locations are selected based on risk (*i.e.,* potential for failure and consequence of failure). Inspection results are trended to identify portions of buried piping systems with a history of corrosion problems, which will need to be evaluated for additional inspection, alternate coating, or replacement. The Staff's evaluation of this AMP is set forth in SER (Ex. NYS000326B) and SER Supplement 1 (Ex. NYS000160), Section 3.0.3.1.2. Staff Testimony on NYS-5 (Ex. NRCR20016) at 29-30.

2.131. As Mr. Holston testified, the Staff determined that (1) the Applicant's plant-specific <u>operating experience</u> for in-scope buried piping has been properly factored into in the Applicant's AMP, providing insights into a proper balance of preventive actions and condition monitoring inspections;[61] (2) the AMP appropriately addresses preventive actions as necessary to minimize the potential for external surface corrosion on buried piping and tanks that could lead to leakage;[62] (3) the AMP specifies that the selection of inspection locations be risk informed, thus ensuring that the scheduled inspections are conducted in the areas that will have the highest consequence as a result of potential leakage and/or the highest risk of corrosion;[63]

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[61] The Staff observed that the Applicant had considered its plant-specific operating experience for in-scope buried piping, including (a) leakage of a buried (out-of-scope) auxiliary steam line in 2007 due to the use of an inappropriate insulation material, (b) buried piping excavated inspections in 2008, which identified two areas that required coating repairs and two areas with minor coating defects, and (c) leakage from an IP2 condensate storage tank return line in 2009 (attributed to damage to coatings due to the presence of deleterious backfill materials). Other buried piping inspections have found no coating defects and no potentially damaging materials in the backfill. This information was accounted for by the Applicant in developing its AMP for buried piping and tanks. Staff Testimony on NYS-5 (Ex. NRCR20016) at 32-33.

[62] The Staff concluded that the Applicant's AMP appropriately addresses preventive actions as necessary to minimize the potential for external surface corrosion on buried piping and tanks, and is generally consistent with related industry standards. *Id.* at 31-32 and 34. In particular, the Staff's review led it to conclude that the Applicant's AMP addresses the three preventive actions for buried components listed in NACE SP0169-2007, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems" (Ex. NRC000027), *i.e.,* cathodic protection, protective coatings, and backfill quality. Although the Applicant does not utilize cathodic protection for IPEC buried piping and tanks (except for city water lines), it has committed (a) to increase the number of inspections that will be conducted prior to and during the PEO, and (b) to conduct soil sampling to determine soil corrosivity and to further increase inspections if the soil is found to be corrosive; these alternatives compensate for its lack of cathodic protection, consistent with GALL Report Rev. 2 (Ex. NYS000147A-D). Staff Testimony on NYS-5 (Ex. NRCR20016) at 34-37. With regard to backfill quality, the Applicant had satisfactorily addressed its discovery of coating damage due to deleterious backfill materials by increasing the number of planned inspections, consistent with GALL Report, Rev. 2, AMP XI.M41, and Final LR-ISG-2011-03 (Ex. NRC000162). *Id.* at 35-36; SER Supp 1 (Ex. NYS000160), at 3-4.

[63] The Staff found that the Applicant's AMP requires that the selection of inspection locations be risk informed, thus ensuring that scheduled inspections are conducted in the areas that will have the highest consequence in the event of leakage and/or the highest risk of corrosion. In this regard, the Applicant committed to classify pipe segments and tanks as having a high, medium or low impact of leakage based on the item's safety class, the hazard posed by fluid contained in the piping, and the impact of leakage on reliable plant operation. The risk ranking will also include a determination of corrosion risk through consideration of piping or tank material, soil resistivity, drainage, the presence of cathodic protection and the type of coating. In addition, the AMP provides that the Applicant will establish the inspection priority and frequency for periodic inspections of the in-scope piping and tanks based on the results of its risk assessment. The Staff found that this risk informed inspection approach provides assurance that the inspections are conducted in the areas that have the highest consequence due to potential leakage and the highest risk of corrosion, in the event of leakage. Staff Testimony on NYS-5 (Ex. NRCR20016) at 37.

and (4) the AMP ensures that the Applicant will conduct a significant and sufficient number of inspections prior to and during the period of extended operation, providing reasonable assurance that the CLB function(s) of the buried systems within the scope of license renewal will be maintained throughout the period of extended operation.[64] *Id.* at 31-32, and 32-41.[65]

2.132. In sum, based on its review of Entergy's AMP and related submittals, the Staff concluded that the aging management program for buried and underground piping and buried tanks for license renewal of IP2 and IP3 is acceptable, and there is no merit in the contention's assertion that the LRA does not provide an adequate AMP for in-scope buried and underground piping and tanks that contain radioactive fluid. *Id.* at 24.[66]

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[64] As discussed above, the Applicant significantly revised the BPTIP in the period since New York filed this contention. These revisions were documented in a series of revisions (a) on July 27, 2009 (Ex. NYS000203) (evaluated in the Staff's SER (Nov. 2009) (Ex. NYS000326A-F)), and (b) March 28, July 14 and July 27, 2011 (Exs. NYS000151, NYS000152, and NYS000153) (evaluated in SER Supp. 1 (Aug. 2011) (Ex. NYS000160). Staff Testimony on NYS-5 (Ex. NRCR20016) at 38-39. In sum, the Applicant has committed to conduct at least 94 excavated direct visual inspections of in scope buried piping, including 34 inspections prior to the PEO and 30 inspections during each 10-year interval of the PEO, each of which will include a full circumferential inspection of at least ten feet of pipe; the inspection locations will be risk-ranked, based on the potential for corrosion and the consequences of leakage. *Id.* at 39, 41. In addition, the Applicant has committed to conduct soil sampling and testing to determine soil corrosivity prior to and during the PEO (using industry standard soil testing parameters and corrosivity determination guidance), and will conduct an additional 24 inspections if the soil is found to be corrosive, consistent with ISG-LR-ISG-2011-03 (Ex. NRC000162). *Id.* at 39, 40. Further, the eight in-scope buried fuel oil tanks will be inspected prior to and during the PEO (a total of 24 inspections), by conducting thickness measurements on the bottom of the tanks, consistent with GALL Report AMP XI.M30, "Fuel Oil Chemistry" (Ex. NYS000147A-D). *Id.* at 40. The Staff found that these provisions, along with the Applicant's Corrective Action program, provide reasonable assurance that in scope buried components which contain radioactive fluids or other hazardous material will meet their intended CLB functions during the period of extended operation. *Id*. at 40-41; Tr. at 3972-74.

[65] Mr. Holston testified that the Applicant's specified number of inspections is at the high end of the spectrum of the four other plants Mr. Holston has evaluated, that have little or no cathodic protection. Tr. at 3871-72.

[66] As compared to the other buried piping programs he has reviewed, Mr. Holston stated that the Indian Point AMP is more robust than the programs at other plants that have only partial or no cathodic protection. Tr. at 3974.

4. In-Scope Underground SSCs

2.133. With respect to the issue of *underground* piping and tanks, Mr. Holston explained that SER Supplement 1, Section 3.0.3.1.2 (Ex. NYS000160) pertains only to buried piping and tanks, inasmuch as Entergy had previously stated that it does not have any in-scope "underground" piping or tanks. Following a conference call held on October 11, 2012, however, Entergy amended its statements to indicate the presence of in-scope underground piping at IP2/IP3, based on the Staff's clarification of the definition of underground piping and tanks in GALL Report Rev. 2 (Ex. NYS000147A-D).[67] Entergy then revised its AMP and UFSAR Supplement to state, *inter alia*, that the underground piping at IP2/IP3 is not coated; that it will be visually inspected prior to the PEO and at least once every two years during the PEO if that piping is not subsequently coated; and that other specified inspection measures will be taken. Further, Entergy added a new commitment (Commitment No. 48) to reflect the above. Staff Testimony on NYS-5 (Ex. NRCR20016) at 23-24, *citing* Ex. ENT000597. Based on these revisions, the Staff concluded there is reasonable assurance that the intended function of the uncoated underground piping will be met throughout the PEO. *Id.* at 24.

5. Intended Functions

2.134. As discussed *supra* at 3-4, Contention NYS-5 includes assertions that Entergy's AMP for buried piping and tanks must provide for inspection or monitoring to determine "if and when" leakage of radioactive fluids occurs, and for replacement of these buried components

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[67] By letter dated October 18, 2012 (Ex. NYS000450 or ENT000596) Entergy amended its application to state that portions of the in scope service water, city water, and fuel oil systems contain underground piping located in vaults that require more than unlocking a hatch or cover for access. This underground steel piping is exposed to either a condensation or outdoor air environment. Staff Testimony on NYS-5 (Ex. NRCR20016) at 23.

before a leak occurs; in essence, New York asserts that preventing leakage of radioactive fluids from buried piping and tanks constitutes one of their intended functions under 10 C.F.R. Part 54.

2.135. These assertions were supported by New York witness Dr. David Duquette, who stated, "[l]eaking of radioactive fluids, in my opinion constitutes failure of the system in a pipe, that, like all safety related pipes carrying radioactive fluid, was not supposed to fail." New York Rebuttal (Ex. NYSR00399), at 6. Further, he opined, "[t]he function of piping and of tanks is not only to maintain pressure, but to contain the fluids that either flow or are stored in them. Piping systems that contain, or can contain, potentially toxic materials, by definition, fail if the toxic material is released to the environment." *Id.* at 16. In this regard, Dr. Duquette challenged the views of Entergy and the Staff – who, in Dr. Duquette's words, had stated that "the function of the buried piping system is to maintain a pressure barrier [*sic*]" or "pressure boundary." New York Rebuttal (Ex. NYSR00399), at 6, 16.[68] .

2.136. Staff witness William C. Holston responded to these assertions on behalf of the Staff. First, Mr. Holston observed that. 10 C.F.R. § 54.4 does not require that all SSCs that convey or contain radioactively-contaminated fluids be included within the scope of license renewal, or that all the functions of a piping system necessarily be within the scope of license renewal. Staff Testimony on NYS-5 (Ex. NRCR20016) at 24-25. He pointed out that 10 C.F.R. § 54.4(a) describes the scope of the SSCs that are required to be addressed in the LRA. Further, 10 C.F.R. § 54.4(b) states, "The <u>intended functions</u> 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 paragraphs (a)(1)-(3) of this

[68] *See* Staff Testimony on NYS-5 (Ex. NRCR20016), at 25; Entergy Testimony on NYS-5 (Ex. ENTR30373), at 94.

section" (emphasis added). Only functions that are required to meet 10 C.F.R. § 54.4(a) are within the scope of license renewal. *Id.* at 25-26.

2.137. Mr. Holston explained that "in-scope" systems can have multiple functions. Some of these functions fall within the scoping requirements of 10 C.F.R. § 54.4(a) and thus the SSCs that support these functions must be age-managed in accordance with the rule. Other functions of the system may not fall within the scoping requirements of 10 C.F.R. § 54.4(a), and therefore those functions are not within the scope of license renewal. Mr. Holston noted that LRA Section 2, "Scoping and Screening Methodology for Identifying Structures and Components Subject to Aging Management Review and Implementation Results," indicates that the function of these buried piping systems is to provide a pressure boundary. LRA Table 2.0-1 describes this function as, "Provide pressure boundary integrity such that adequate flow and pressure can be delivered. This function includes maintaining structural integrity and preventing leakage or spray for 54.4(a)(2)." This definition of "pressure boundary" is consistent with the definition in the Standard Review Plan, NUREG-1800 (Ex. NYS000195), Table 2.1-4(b), "Typical 'Passive' Component- Intended Functions," and 10 C.F.R. § 54.4(a)(2). Therefore, as long as any leakage from the system does not impact the SSC's ability to deliver flow at an adequate pressure, it is not a safety consideration for license renewal. *Id.* at 26-27.[69]

2.138. Second, Mr. Holston observed that the Commission's regulations in 10 C.F.R. Part 54 do not require an applicant to implement an AMP that will replace a buried SSC before it leaks. *Id.* at 25. For each SSC identified pursuant to § 54.21(a)(3), an applicant must

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[69] Although leaks have occurred to date at Indian Point, there has not been a "failure" of buried piping. In this regard, 10 C.F.R. Part 54 establishes safety requirements, rather than the avoidance of environmental impacts – which are addressed in regulations governing the operating license (including any renewed license), in 10 C.F.R. Parts 20 and 50. Accordingly, an evaluation of the adequacy of an AMP must focus upon the safety function of the SSC under consideration. Staff Testimony on NYS-5 (Ex. NRCR20016), at 27; Tr. at 3569-72.

"demonstrate that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation," as required by § 54.21(a)(3). Given that the function of the buried piping and tanks is to perform its CLB function as a pressure boundary (*i.e*., deliver flow between two points at an acceptable flow rate and pressure), as long as the leakage from an in-scope SSC does not impact its ability to perform its pressure boundary function, preventing said leakage is not an intended function for these systems for license renewal. *Id.* at 27.

2.139. Third, Mr. Holston observed that a release or leak from a piping system, whether radiological or non-radiological, would not degrade the ability of a piping system to perform its CLB pressure boundary function unless the leak was very substantial. The Staff's review of the Applicant's LRA determined that the Applicant's AMP for buried piping and tanks provides reasonable assurance that any leakage or release of fluids from buried piping and tanks within the scope of license renewal will not degrade those SSCs' CLB pressure boundary function, as required by 10 C.F.R. § 54.29. *Id.* at 25.

2.140. In this regard, in the event that a buried pipe or tank were to leak, the intact area of the pipe or tank around the hole or site of leakage can often be demonstrated to meet full structural integrity, notwithstanding the existence of a leak. In other words, unless a leak is substantial, the development of a hole in a pipe or tank would not result in the collapse of the SSC or failure to meet its intended safety function. Accordingly, as long as the piping system meets structural integrity requirements, leaks in piping systems, including buried systems, need not be prevented prior to occurrence. Such leaks are typically discovered and corrected by a licensee before the defect impacts the pipe's pressure boundary function of delivering flow between two points at an acceptable flow rate and pressure. Mr. Holston then provided two examples of leaks that have occurred at Indian Point (a leak in a condensate storage tank return line for IP2, and an internal leak on an IP3 aboveground essential service water line), that did not challenge the structural integrity or the CLB function of the piping; he further stated that he was not aware of a single instance where external corrosion of an in-scope system was so substantial that it resulted in the collapse of the system or the system becoming unable to meet its pressure boundary function as defined in 10 C.F.R. § 54.4(b). *Id.* at 27-28.

2.141. In addition, Mr. Holston testified that both the Staff and the American Society of Mechanical Engineers (ASME) (an international consensus codes and standards body) have recognized that leakage does not necessarily challenge the intended function of an SSC. [70] He therefore concluded that, consistent with these principles, it is acceptable for a license renewal applicant to provide an AMP that focuses on inspections, excavation, and repair of leaks in buried pipes and tanks rather than providing for replacement of the pipe or tank prior to leakage. Staff Testimony on NYS-5 (Ex. NRCR20016) at 28-29 and 30-31.[71]

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[70] For example, the Staff issued Generic Letter 90-05, "Guidance for Performing Temporary Non Code Repairs of ASME Code Class 1, 2, and 3 Piping," to address means to demonstrate structural integrity of piping systems with through-wall defects (Ex. NRC000024). In addition, the ASME issued ASME Nuclear Code Case 513-3, which addresses temporary acceptance of through wall flaws in moderate energy (*i.e.,* not exceeding 200°F and 275 psig) Class 2 or 3 piping (Ex. NRC000025). Further, the ASME Code recognizes that minor leaks can be easily detected prior to challenging the structural integrity of the pressure boundary, as reflected in ASME Nuclear Code Case N-776, which allows an alternative to excavated direct visual examination of piping -- consisting of an inspection for evidence of leakage on ground surfaces in the vicinity of the buried components to validate the structural integrity of the buried piping (Ex. NRC000026). Staff Testimony on NYS-5 (Ex. NRCR20016), at 28-29.

[71] Nonetheless, Entergy's witnesses described ongoing NRC and industry initiatives to address the leakage of radioactive fluids and groundwater contamination from buried piping, tanks, and spent fuel pools at nuclear power plants. *See* Entergy Testimony on NYS-5 (Ex. ENTR30373) at 74-78. In this regard they cited, *inter alia*, (1) the NRC's Liquid Release Task Force Report (Sept. 2006); (2) the NRC's Groundwater Task Force Report (June 2010); (3) NEI 07-07, Industry Ground Water Protection Initiative (GPI) (Aug. 2007) (Ex. ENT000423); (4) NEI 09-14, Rev. 0, Guideline for the Management of Buried Piping Integrity (Jan. 2010) (Ex. ENT000378); (5) NEI 09-14, Rev. 1, Guideline for the Management of Underground Piping and Tank Integrity (Dec. 2010) (Ex. NYS000168); (6) SECY-11-0019, "Senior Management Review to Overall Regulatory Approach to Groundwater Protection" (Feb. 9. 2011) (Ex. ENT000322); (7) "Staff Requirements Memorandum– SECY-11-0019 – Senior Management Review of Overall Regulatory Approach to Groundwater Protection" (Aug. 15, 2011) (Ex. ENT000424); and (8) NRC Inspection Manual Temporary Instruction ("TI") 2515/182, "Review of the Implementation of the Industry Initiative to Control Degradation of Underground Piping and Tanks" (Nov. 17, 2011) (Ex. ENT000425). . *See* Entergy Testimony on NYS-5 (Ex. ENTR30373) at 74-75 and 77.

2.142. Moreover, Mr. Holston testified that 10 C.F.R. Part 54 does not require that in-scope SSCs be managed to prevent leaks, as long as the leakage from an in-scope SSC does not impact its ability to perform its CLB function as a pressure boundary (i.e., deliver flow between two points at an acceptable flow rate and pressure). Therefore, a buried piping and tank AMP need not include an inspection or monitoring program to prevent leaks from occurring. Leak prevention is provided by other means (*e.g.*, protective coatings to prevent external corrosion); if a leak occurs, inspection, monitoring, and corrective action programs are included in the CLB and in a license renewal AMP, so that appropriate actions are taken to detect and repair the leak before it can affect the ability of a SSC to perform its CLB function. *Id.* at 30.[72] Further, Mr. Holston stated that under the NRC's requirements for operating licenses set forth in 10 C.F.R. Part 50, Appendix B, if leaks are discovered, licensees are required to excavate and repair any areas of leakage, and to consider whether any further actions are necessary. *Id.* at 29-30. He further testified that the Applicant's CLB contains acceptable monitoring programs to detect leakage in buried pipes and tanks. *Id.* at 30.[73]

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[72] Mr. Holston observed that other inspection and monitoring programs to detect leakage exist within the Applicant's current licensing basis. For example, 10 C.F.R. § 20.1501(a)(2) requires that a licensee conduct surveys that may be necessary to evaluate (i) the magnitude and extent of radiation levels, (ii) concentrations or quantities of radioactive material, and (iii) the potential radiological hazards. In addition, under 10 C.F.R. § 20.2203, a licensee is required to report, within 30 days, any radiation exposure or dose, radiation level, or concentration of radioactive materials, that exceeds the limits stated therein. Similarly, 10 C.F.R. § 50.36a ("Technical specifications on effluents from nuclear power reactors") requires that licensees file an annual report stating the quantity of each of the principal radionuclides released to unrestricted areas in liquid and in gaseous effluents during the previous 12 months. These requirements would apply to a renewed license. Staff Testimony on NYS-5 (Ex. NRCR20016) at 31.

[73] Entergy's witnesses described Entergy's ongoing actions to address the leakage of radioactive fluids into the environment, under the current operating licenses for IP2 and IP3, including its development and ongoing implementation of an extensive groundwater monitoring program to monitor and address radioactive groundwater contamination. Id. at 76-77. These initiatives and actions have been undertaken to assure compliance with public dose limits and CLB requirements in 10 C.F.R. Parts 20 and 50, wholly apart from license renewal requirements. *See* Entergy Testimony on NYS-5 (Ex. ENTR30373) at 74-75 and 77-78. As part of these efforts, Entergy has installed an extensive system of monitoring wells – which should detect the leakage of radioactive fluids. Tr. at 3586-87.

2.143. Having considered the witnesses' testimony, we find no merit in Dr. Duquette's view that the leakage of radioactive fluids from buried piping, in itself, constitutes the failure of an "intended function" within the scope of the license renewal regulations. As discussed in PFF ¶¶ 2.13 – 2.14 *supra* and in Part 1 of these Proposed Findings (at 11-12), 10 C.F.R. § 54.4(a) defines SSCs within the scope of license renewal as SSCs that are (1) "safety-related," (2) non-safety related but whose failure could prevent satisfactory accomplishment of any safety functions identified in 10 C.F.R. § 54.4(a)(1)(i)-(iii), or (3) SSCs that are relied upon in safety analyses or plant evaluations to perform a function required to comply with NRC safety regulations for fire protection, environmental qualification, pressurized thermal shock, anticipated transients without scram, and station blackout.

2.144. Our review of the NRC's license renewal regulations finds no indication that the retention of radioactive fluids in buried piping and tanks is, in itself, an "intended function" within the scope of those regulations. Rather, the license renewal regulations define in-scope "intended functions" as essentially functions related to safety, including (a) SSCs that perform a specified safety function in the event of a design basis event (*i.e.,* preserving the integrity of the reactor coolant pressure boundary, safe shutdown of the reactor, or preventing or mitigating the consequences of accidents which could result in offsite exposures that exceed NRC dose standards), (b) non-safety SSCs whose failure could prevent satisfactory performance of a safety function, or (c) SSCs relied upon to perform a specified safety function required by 10 C.F.R. §§ 50.48, 50.49, 50.61, 50.62, or 50.63. Preventing the leakage of radioactive fluids is thus not an in-scope "intended function" for license renewal purposes, unless it affects an in-scope intended function (*e.g.,* maintenance of the pressure boundary); there was no evidence of such an effect in any of the testimony or exhibits in this proceeding.[74] Moreover, Entergy's witnesses testified that groundwater monitoring is not necessary to ensure that in-scope buried components will maintain their pressure boundaries and perform their license renewal intended functions during extended operations. Entergy Testimony on NYS-5 (Ex. ENTR30373) at 77.

2.145. Our determination that preventing the leakage of radioactive fluids into groundwater is not an intended function under 10 C.F.R. § 54.4 is fully consistent with the Commission's recent ruling in the *Pilgrim* license renewal proceeding.[75] There, the Commission confirmed that § 54.4 defines SSCs to be within the scope of license renewal <u>only</u> if they perform one of the intended safety functions outlined in the rule (*Pilgrim*, CLI-10-14, 71 NRC at 455-46). The Commission further stated as follows:

> Through the regulatory process, which includes plant inspections, notices and guidance to licensees, and enforcement actions, the NRC takes a host of measures to improve the ability to timely detect and correct inadvertent leaks to assure compliance with public dose limits. This is an ongoing operational issue involving existing facilities regardless of whether those facilities are seeking or will seek license renewal.
>
> The question before us here is not the adequacy to date of NRC regulatory actions to address leakage incidents, but <u>whether the key safety functions that are the focus of the license renewal safety review under Part 54 include, as a general matter, preventing inadvertent leaks from buried piping. We agree with the Board that they do no</u>t.

Id. at 461 (emphasis added).

2.146. Accordingly, inasmuch as preventing leakage from any buried or underground

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[74] This is not to say that the leakage of radioactive fluids is condoned by the NRC. Rather, other regulations in 10 C.F.R. Part 20 and Part 50 address this issue, which apply to operations under the plants' current operating license as well as under a renewed license. Tr. at 3569-72. *See* discussion *supra* at PFF ¶¶ 2.142.

[75] Entergy Nuclear Generation Co. and Entergy Nuclear Operations, Inc. (Pilgrim Nuclear Power Station), CLI-10-14, 71 NRC 449 (2010)

piping or tank that may contain radioactive fluids is not an intended function under 10 C.F.R. Part 54, we find that Entergy is not required to provide an AMP for such buried or underground piping and tanks unless they perform an intended function as defined in 10 C.F.R. § 54.4(a). Based upon the undisputed testimony, we find no reason to believe that any such piping and tanks have been improperly excluded from Entergy's AMP.

6. Baseline Inspections and Specification of Corrosion Rates

2.147. As noted *supra* at PFF ¶ 2.5, Contention NYS-5 asserted that the BPTIP and Entergy's LRA are inadequate, in part, in that they fail to provide "an evaluation of the baseline conditions of the buried systems or their welded joints, and do not specify potential corrosion rates." As further noted above, New York filed this contention based upon the AMP as it existed in April 2007. As discussed above, subsequent to New York's filing of the contention, Entergy significantly revised its buried piping and tanks inspection program to reflect site-specific and industry operating experience – and it committed to conduct a large number of inspections both prior to and during the PEO, and to conduct even more inspections if it finds degraded coating or metal conditions or if its soil sampling program reveals the presence of corrosive soil. These inspections were not reflected in the LRA as it existed when the contention was filed.

2.148. We find no inadequacy in Entergy's non-specification of corrosion rates or the lack of a baseline inspection. Our evaluation of the inspection program contained in Entergy's BPTIP, set forth above, based upon a preponderance of the evidence, found that Entergy's buried piping and tank inspection program satisfies the requirements of 10 C.F.R. § 54.21(a), and provides the "reasonable assurance" required by 10 C.F.R § 54.29(a) – despite the lack of a baseline inspection and a specification of corrosion rates. This conclusion is directly supported by the testimony of Staff witness William C. Holston, who provided the Staff's view that the AMP need not provide for a baseline inspection or specification of corrosion rates. *See*

Staff Testimony on NYS-5 (Ex. NRCR20016), at 41-44. We find Mr. Holston's testimony on this issue to be persuasive.

2.149. First, as Mr. Holston explained, the Staff's guidance does not recommend a baseline inspection or the determination of corrosion rates, either in (a) GALL Report, Rev. 1, AMP XI.M34, Buried Piping and Tanks Inspection (Ex. NYS000146A-C), or (b) GALL Report Rev. 2, AMP XI.M41, "Buried and Underground Piping and Tanks" (Ex. NYS000147A-D). *Id.* at 42.

2.150. Second, an applicant is not required to provide absolute assurance that a buried pipe or tank will not leak; rather through a combination of preventive actions and condition monitoring, "reasonable assurance" can be established to effectively manage the aging of buried piping and tanks, <u>without</u> requiring a baseline inspection or identification of piping corrosion rates. The adequacy of an AMP that complies with Staff guidance (such as the GALL Report), that does not contain the additional measures sought by New York, has been recognized by the Staff, the Boards, and the Commission. Moreover, the Applicant's commitment to conduct 34 excavated direct visual inspections of in-scope buried piping prior to the PEO provides significant information as to the condition of the buried piping and establishes reasonable assurance that the effects of aging will be adequately managed – and the AMP's provision of at least 60 additional excavated direct visual examinations of buried piping during the PEO provides additional assurance that significant deleterious conditions affecting the external surfaces of the piping will be detected. *Id.* at 42-43; *see* Tr. at 3857-59.

2.151. Third, the Applicant is required to document any adverse as-found conditions in accordance with 10 C.F.R. Part 50, Appendix B, Criterion XVI ("Corrective Actions"), which requires licensees to identify and document "conditions adverse to quality" and "significant conditions adverse to quality." In accordance with these Part 50 requirements, conditions adverse to quality are required to be corrected, and significant conditions adverse to quality are required to be addressed by determining the cause of the condition and taking corrective actions to preclude repetition. Evidence of the Applicant's effective utilization of its corrective action program as it relates to the Buried Piping and Tanks Inspection program may be seen in its response to the 2008 discovery of degraded coatings on the IP2 CST return line piping, whereby the Applicant replaced the degraded piping, conducted a root cause analysis of the failure, and revised its AMP in July 2009 (Ex. NYS000203) to conduct additional inspections and to risk-rank future inspection locations prior to the period of extended operation. *Id.* at 43-44.

2.152. In sum, notwithstanding the absence of a comprehensive baseline inspection or a determination of corrosion rates, the AMP's combination of preventive actions, plans for extensive condition monitoring and inspection in conjunction with the use of risk- informed inspection locations, along with the Applicant's Corrective Action program, provides reasonable assurance that in-scope buried piping and tanks will meet their intended CLB functions during the period of extended operation. *Id.* at 44.[76]

2.153. New York has not shown any reason to believe that the Applicant's AMP, with its provisions for risk-ranking, piping inspections and soil sampling, will be unable to manage the effects of aging for in-scope buried piping at the site; Dr. Duquette testified that to his

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[76] Mr. Holston also rejected New York's assertion, at page 44 of its Statement of Position (Ex. NYS000163), that the Applicant's AMP cannot be found to be adequate, "absent a thorough inspection, essentially excavation, of virtually all relevant buried pipes at the Indian Point site." In support of this assertion, New York asserted that proper oversight procedures may not have been implemented during construction when coatings were applied, that Entergy did not know improper backfill had been used during construction, and that Entergy did not make available the engineering report supporting the original plant owner's decision to limit the installation of cathodic protection to certain systems. Ex. NYS000163, at 44-45. Mr. Holston testified that, even if these assertions were correct, they fail to take into account the results of inspections that have been conducted to date, the additional inspections that will be conducted prior to and during the PEO, and the extensive amount of soil sampling and testing that will be conducted. Accordingly, he found no reason to require an excavation and inspection "of virtually all relevant buried pipes at the Indian Point site" before the acceptability of Entergy's AMP can be assessed. Staff Testimony on NYS-5 (Ex. NRCR20016), at 70-71.

knowledge, all leaks of buried piping to date have been identified. Tr. at 3553-54.[77] Further, he agreed that a buried piping leak would not cause a failure of the piping's pressure boundary function, and the piping would likely continue to transport fluid from one end to the other. *See* Tr. at 3555-59.[78] Further, Entergy witness Mr. Cavallo testified that coating systems like that in use at Indian Point have been shown to be good for at least 70 years, Tr. 3828. Dr. Duquette agreed with Entergy that the buried piping coatings at Indian Point are "very good," Tr. at 3886 (although they can be damaged), and that the excavation of buried piping significantly increases the potential for damage to the piping; he therefore does not recommend that broad-scale piping excavations be carried out, which he said would be a "foolish engineering exercise." Tr. at 3624.

2.154. Based on the substantial and reliable evidence of record, we find that the Applicant is not required to conduct baseline inspections and to specify the corrosion rates of its buried piping and tanks, to satisfy the license renewal requirements in 10 C.F.R. Part 54.

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[77] Applicant witness Mr. Lee testified that Indian Point's operating experience includes a total of five leaks of buried piping, involving various lines (including piping that is not Code/safety related, hazmat, or within the scope of license renewal). Tr. at 3930-33. Staff witness Mr. Holston testified that the Applicant's operating experience with buried piping leaks is within "the mix" of operating experience at other nuclear plants. Many plants have had no leaks and only minor coating damage, while six (of 104) plants have experienced leaks of buried piping. Tr. at 3909-10, 3921.

[78] While Dr. Duquette believed that any leak of radioactive fluids constitutes the failure of an intended function, he stated that he did not know if such leakage is an issue to be addressed under the plants' current operating licenses, since he is "not an expert on licensing or regulation." Tr. at 3557. Dr.. Duquette's view was refuted by Staff witness Mr. Holston, who pointed out that the leakage of radioactive fluids is addressed in NRC regulations in 10 C.F.R. Parts 20 and 50, which govern the plants' current operating licenses, and which continue to apply to the plants' CLB under a renewed license. Tr. at 3569-71; Staff Testimony on NYS-5 (Ex. NRCR20016) at 27.

7. Cathodic Protection

2.155. Among the bases stated for this contention, New York asserted that "[t]he LRA contains no plan for using cathodic protection or other methods to prevent leaks from occurring"; further, New York asserted that "Entergy makes no commitment to comply with the [NACE] corrosion control standards." NY Petition at 84. These assertions were supported by New York witness Dr. David J. Duquette, whose testimony asserted that the BPTIP is deficient, in large part, because it fails to provide cathodic protection to prevent the corrosion of buried piping and tanks. *See, e,g.,* New York Testimony on NYS-5 (Ex. NYS000164), at 25; Duquette Report (Ex. NYS000165), at 19-22; and New York Rebuttal (Ex. NYSR00399), at 12.

2.156. In our discussion of applicable aging effects in Section D.1, *supra*, we observed that the aging effect of concern for buried piping and tanks is the loss of material due to various forms of corrosion. *See* PFF ¶ 2.91. As we also observed, cathodic protection constitutes an important means of preventing such corrosion from occurring on the external surfaces of buried steel structures and components; Entergy's AMP, however, does not provide cathodic protection for most of the in-scope buried piping and tanks at Indian Point, but relies instead on other preventive measures such as protective coatings and wrappings, as well as inspections of piping and backfill conditions. *See* PFF ¶¶ 2.59, 2.101 – 2.106.

2.157. Entergy's and the Staff's witnesses, in general, did not dispute New York's (or Dr. Duquette's) view that cathodic protection provides an important means for preventing the corrosion of buried steel piping and tanks. *See, e.g.,* Entergy Testimony on NYS-5 (Ex. ENTR30373) at 41-42; Staff Testimony on NYS-5 (Ex. NRCR20016), at 34, 39, 52, and 58-59. They disagreed, however, with Dr. Duquette's views (a) that cathodic protection must be installed prior at a plant that lacks an effective cathodic protection system, where other effective preventive actions provide for such protection, and (b) that both NRC regulatory guidance and industry standards call for cathodic protection to be installed at plants that lack cathodic protection. *See generally,* New York Rebuttal (Ex. NYSR00399), at 9-14; Entergy Testimony on NYS-5 (Ex. ENTR30373) at 41-42; Staff Testimony on NYS-5 (Ex. NRCR20016), at 34-35 & 71.

2.158. Entergy's witnesses testified that while both coatings and cathodic protection prevent external corrosion in buried steel piping systems, coatings provide the *primary* form of corrosion control because they prevent the susceptible material from coming in contact with a potentially corrosive environment, by isolating the material from the environment. *See* Entergy Testimony on NYS-5 (Ex. ENTR30373) at 42, *citing* NACE SP0169-2007 (Ex. ENT000388); NACE Paper 10059 (Ex. ENT000389) at 1-2. In contrast, cathodic protection is a *secondary* corrosion control technique, which inhibits corrosion as bare material becomes exposed to the surrounding soil. *See id*. at 42. If the coatings are still effective, however, CP is not necessary to prevent external corrosion of the piping and offers no additional corrosion control. *Id.* at 42 & 44, *citing* NACE SP0169-2007 (Ex. ENT000388) and NACE Paper 10059 (Ex. ENT000389), at 2. Thus, CP systems are only needed, or effective, when supplemental corrosion protection is needed at localized areas of coating degradation in corrosive soil environments. *Id.*

2.159. In claiming that cathodic protection is required for IP2/IP3 buried piping, New York witness Dr. Duquette asserted that "Entergy's own studies show that the soils at Indian Point are mildly to moderately corrosive, warranting cathodic protection as an objective matter," which he had based on a report prepared for Entergy by PCA Engineering Inc. ("PCA Report") (Ex. NYS000178). Entergy Testimony on NYS-5 (Ex. ENTR30373) at 116, *citing* Duquette Testimony at 22 (Ex. NYS000164). This claim was effectively refuted by Entergy's witnesses. As they explained, in the cited PCA Report, PCA had recorded soil resistivity data for areas above the buried piping running between the IP2 CST and the AFW pump building, and the IP2 city water storage tank to the IP2 pipe tunnel. Soil resistivity was determined at depths of 5, 10 and 15 feet below ground surface ("bgs"), as summarized in Table 7 of the witnesses' testimony.[79] These data were as follows:

Table 7. Summary of Soil Resistivity Measurements Reported in the 2008 PCA Report			
Location	**Soil Depth**		
	5 feet bgs	**10 feet bgs**	**15 feet bgs**
Condensate Piping – Unit 2	**Soil Resistivity Measurement (ohm-cm)**		
• Location #1	30,640	31,598	8,043
• Location #2	63,195	28,725	11,490
City Water Piping	**Soil Resistivity Measurement (ohm-cm)**		
• Upper Parking Lot Near Stairway	30,161	36,385	40,215
• Overlook Road	24,895	21,065	16,660

Entergy Testimony on NYS-5 (Ex. ENTR30373) at 116.[80]

2.160. To put these data in context, Entergy's witnesses cited Table 5.5 in *Peabody's Control of Pipeline Corrosion*, at 88 (Table 5.5) (Ex. ENT000390), as a generally accepted guide. The Peabody reference provides the following summary:

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[79] As discussed above, soil resistivity measures the degree to which the soil opposes an electric current passing through it, thereby inhibiting current flow and impeding corrosion; as resistivity increases, the corrosion reaction is slowed. *See* discussion *supra,* at PFF ¶ 2.96.

[80] The witnesses stated that most of the condensate and the city water piping is approximately 6-7 feet below grade, where the soil resistivity values exceeded 20,000 ohm-cm; further, they stated that historical soil resistivity data described in the FSAR are consistent with these data – *i.e.,* the majority of the readings are above 10,000 ohm-cm. Entergy Testimony on NYS-5 (Ex. ENTR30373) at 116.

Table 5.5	Soil Resistivity vs. Degree of Corrosivity
Soil resistivity (ohm-cm)	Degree of corrosivity
0 – 500	Very corrosive
500 – 1,000	Corrosive
1,000 – 2,000	Moderately corrosive
2,000 – 10,000	Mildly corrosive
Above 10,000	Negligible

Reference: *NACE Corrosion Basics*

Id. at 117. Dr. Duquette agreed with the classifications in this Table (drawn from a NACE publication; further, he stated that only one reading showed “mildly” corrosive soils, and that a reading of more than 10,000 ohm-cm is not very corrosive. Tr. at 3813-14.[81]

2.161. In addition, Entergy’s witnesses provided detailed accounts of buried piping inspections that were conducted at the Indian Point site in 2008, 2009 and 2011, along with the results of those inspections. Entergy Testimony on NYS-5 (Ex. ENTR30373) at 87-100. Further, they described the field surveys of buried piping that have been conducted at the site, including a corrosion/CP study and assessment of underground structures by PCA Engineering,

[81] The PCA Report provided a different table for classifying soil resistivity vs. degree of corrosivity, as follows: (a) 0 to 2,000 ohm/cm – “extremely corrosive”; (b) 2,000 to 10,000 ohm/cm – “moderately corrosive”; (c) 10,000 to 30,000 ohm/cm – “mildly corrosive”; and (d) 30,000 ohm/cm and over – “progressively less corrosive.” Ex. NYS000178, at page 7 of 18; *see* Staff Testimony on NYS-5 (Ex. NRCR20016), at 62-63. Under this classification table, one of the Indian Point soil corrosivity readings would be classified as “moderately corrosive,” while the others would be classified as mildly or negligibly corrosive.

Inc. ("PCA") in October 2008,[82] and an Area Potential Earth Current ("APEC") survey of the site by Structural Integrity Associates, Inc. (SIA) in November 2010.[83] *Id.* at 100-107. Entergy's witnesses provided photographs of the Indian Point site, showing the locations where SIA conducted the APEC survey and the results obtained, *Id.* at 104-106; these were considered in detail during the Board's questioning of witnesses in the evidentiary hearings. The Board is

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[82] PCA's corrosion/CP field survey and assessment of underground structures included buried and underground structures both within and outside the scope of the license renewal rule. The investigation included a review of site drawings and a site survey that included soil resistivity measurements, structure-to-soil potential measurements, electrical isolation testing, and temporary impressed current testing. PCA issued a report on November 10, 2008, as revised on December 2, 2008. See Engineering Report No. IP-RPT-09-00011, Rev. 0, Corrosion/Cathodic Protection Field Survey and Assessment of Underground Structures at Indian Point Energy Center Unit Nos. 2 and 3 During October 2008 (Dec. 2, 2008) ("PCA Report") (Ex. NYS000178). In its Report, PCA made several recommendations regarding cathodic protection, including (a) that Entergy take action to eliminate/minimize the stray current (i.e., current through paths other than the intended circuit) affecting the city water piping where that piping crosses over the Algonquin natural gas pipeline; and (b) that Entergy evaluate additional CP needs, noting that a progressive or multi-phase plan would provide the most effective return. Entergy Testimony on NYS-5 (Ex. ENTR30373) at 100-01.

[83] SIA conducted a site-wide APEC survey within the protected area at IPEC. SIA completed the APEC survey in November 2010; the final technical report was issued in November 2011. See Report No. 0900271, Rev. 0, Indian Point Energy Center APEC Survey (Nov. 17, 2011) ("APEC Survey Report") (Ex. ENT000445). The APEC survey of buried piping systems provided information on the condition of multiple buried pipes in an area. APEC survey used an accepted technique to evaluate the corrosion potential (corrosion cells are observed where coating degradation allows anodes and cathodes to interact through a soil electrolyte) and the cathodic protection effectiveness on buried piping systems. The APEC survey is designed to identify: (1) where minimum polarization levels of 100 millivolt ("mV") or -850 mV Instant Off potentials are present, indicating adequate cathodic protection levels per NACE SP0169-2007, (Ex. ENT000338); (2) where localized changes in the measured potentials exist, relative to surrounding readings, as a means to locate potential areas containing corrosion cells; and (3) localized variations in earth currents, relative to surrounding readings, which would indicate coating degradation. A total of 335 APEC test locations (grids – yellow dots) were monitored throughout the protected area at IPEC. The results, shown in Figure 5A of the witnesses' testimony, indicate that adequate polarization (>100 mV – green dots) was present around IP2 near the CST and intake structure. The remainder of the plant was not similarly polarized due to the absence of cathodic protection systems in the vicinity of IP1 and IP3. As shown in Figure 5B of the witnesses' testimony, the APEC survey did not reveal extensive current flows (red areas) – *i.e.*, conditions that could indicate external corrosion in the absence of cathodic protection. This provides evidence that coating degradation, if present, is limited. SIA recommended that Entergy perform excavations at the few anomalous locations (red areas) identified in Figure 5B to further quantify piping condition. The witnesses stated that this recommendation will be used in the selection of future locations to excavate and to perform direct visual inspections. Entergy Testimony on NYS-5 (Ex. ENTR30373) at 101-03.

satisfied with the explanations provided by Entergy's witnesses regarding the survey results and the significance thereof.[84]

2.162. Entergy has accounted for the results obtained from the PCA and APEC surveys and assessments. Thus, Entergy has factored the APEC survey results and other available data and operating experience into the IPEC BPTIP, for use in selecting locations for future inspections of in-scope buried piping. *Id.* at 107. Further, Entergy has implemented or is in the process of implanting all three of the PCA Report's recommendations. Tr. 3516-17, 3954-55. Thus, it has installed a CP system to resolve the stray current issue and protect the affected portions of the IP2 and IP3 city water lines, Entergy Testimony on NYS-5 (Ex. ENTR30373) at 101; it has installed some cathodic protection and is in the process of installing more, based upon the results of guided wave inspections conducted at the site, Tr. at 3452; and it has implemented an inspection program for high-priority zones, involving excavations and direct visual inspections in many locations. Tr. 3715-16.

2.163. Staff witness William Holston rejected Dr. Duquette's claim that cathodic protection is "required" for buried piping and tanks at the IP2/IP3 site under GALL Report Rev. 2, AMP XI.M41.[85] Mr. Holston explained that this "recommended" AMP was revised in Final

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[84] At the hearing, Dr. Duquette expressed surprise with regard to the some of the results that show a high level of current per unit area, which he believed might indicate the presence of a lot of exposed metal areas, such as would be caused by degraded coatings. Tr. at 3791-93. Entergy witness Mr. Biagiotti refuted this view, stating that there is a lot of buried metal at the Indian Point site, including galvanized conduits and storm sewers that give off current, so it is really a mixed metal environment. Tr. at 3793-94. Further, Entergy has excavated two of the four areas shown to have the highest currents, and found no significant degradation of coatings; it plans to excavate a third area in 2013. Tr. at 3805-06.

[85] As Mr. Holston pointed out, the GALL Report provides NRC Staff recommendations which, if adopted by an applicant, would be found to be sufficient to satisfy the regulations in 10 C.F.R. Part 54; neither the GALL Report nor AMP XI.M41 constitutes a regulatory "requirement." Tr. 3730, 3732.

LR-ISG-2011-03 (Ex. NRC000162). [86] Mr. Holston (who served as the author of LR-ISG-2011-03) explained that the GALL Report, Rev. 2, had no provision for plants that lack cathodic protection; the Staff intended to develop such guidance, and then did so with the publication of LR-ISG-2011-03 – which explicitly recognizes that an adequate AMP can be developed in the absence of cathodic protection. Entergy's AMP for IP2 and IP3 is consistent with that guidance. Staff Testimony on NYS-5 (Ex. NRCR20016), at 58; Tr. at 3393-94.

2.164. First, Mr. Holston explained that neither 10 C.F.R. Part 50 nor 10 C.F.R. Part 54 states any requirement for the use of a cathodic protection system – either during the initial license period or the period of extended operation. *Id*.

2.165. Second, an applicant can develop an aging management program that is consistent with the GALL Report, without providing cathodic protection. In this regard, GALL Report AMP XI.M34 (Ex. NYS000146A-C) nowhere recommends cathodic protection; further, GALL Report Rev. 2, AMP XI.M41, as revised in Final LR-ISG-2011-03 (Ex. NRC000162), does not recommend the installation of cathodic protection for all buried piping and tanks that lack CP; rather, it recognizes that reasonable assurance can be established that in-scope buried components will meet their CLB function(s) without cathodic protection, given the applicant's implementation of the ISG's alternative recommendations. Staff Testimony on NYS-5 (Ex.

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[86] Mr. Holston explained that the Staff developed a revision to the GALL Report, establishing AMP XI.M41 to address plants that do not have cathodic protection for buried piping and tanks, based on industry operating experience and the Staff's review of several LRAs for plants that did not have a cathodic protection system. This revision was addressed in the draft ISG for AMP XI.M41, "Buried and Underground Piping and Tanks" (Draft LR-ISG-2011-03) (Ex. NRC000019), as well as in the final version of the ISG. Staff Testimony on NYS-5 (Ex. NRCR20016) at 39.

NRCR20016), at 58-59.[87] Thus, compliance with NRC regulations in accordance with current NRC guidance does not require a nuclear plant to install cathodic protection. *See* Tr. at 3958.

2.166. Third, Indian Point's AMP is consistent with the number of inspections recommended in the Staff's Final ISG for AMP XI.M41 (Ex. NRC000162) for buried piping and tanks that lack cathodic protection. *Id*. at 58 & 59-61. As stated by Mr. Holston (who authored the ISG), the ISG explicitly recognizes that cathodic protection is not available at all plants, and that other measures may be taken to protect buried piping and tanks without cathodic protection and still establish reasonable assurance that in-scope buried components will meet their CLB functions. *Id.* at 59. Mr. Holston quoted the Discussion section of the ISG, which states:

> Table 4a, Inspections of Buried Pipe, <u>was revised to reflect the recommended number of inspections when cathodic protection will not be provided during the period of extended operation for systems or portions of systems within the scope of license renewal</u>. The basis for the number of inspections in the original issuance of AMP XI.M41 was the availability of cathodic protection, quality of backfill, and the presence of coatings. For plants without cathodic protection in use during the period of extended operation, the factors that form the basis for the number of inspections were changed to reflect additional emphasis on plant-specific OE related to backfill, coatings, inspection results, emergent conditions, and soil sampling. These factors were established because, absent cathodic protection, the coatings are the only barrier to corrosion. The staff recognized that non-corrosive soil will result in lower corrosion rates, but not necessarily eliminate corrosion. Backfill that contains objects that can damage the coating can result in a direct challenge to the integrity of the piping system. <u>The inspection quantities were increased because without the preventive action of a cathodic protection system and the ability to trend cathodic protection currents, an indicator of coating degradation, increased</u>

[87] Entergy's witnesses similarly testified that AMP XI.M41, as revised, does not recommend the installation of cathodic protection for plants that lack CP where the alternative recommended measures are taken; and that Entergy's augmented inspection plan meets those recommendations. *See, e.g.,* Entergy Testimony on NYS-5 (Ex. ENTR30373) at 107-109, *citing, inter alia,* Draft LR-ISG-2011-03, Appendix A at 3 (Ex. ENT000379) and Final LR-ISG-2011-03 at 1 & App. A, at A-6 to A-8 (Ex. NRC000162).

> <u>inspections were necessary to provide reasonable assurance that the components will meet their current licensing basis (CLB) functions throughout the period of extended operation.</u> These inspection quantities are the minimum recommended and could possibly need to be higher based on factors such as the plant-specific soil conditions, ground-to-structure potentials and OE.

Id. at 59-60, *quoting* LR-ISG-2011-03 (Ex. NRC000162), at page 3*;* emphasis added.

2.167. Mr. Holston further explained that, under the Final ISG, IP2 and IP3 fall within inspection "Category F" – which would recommend a total of 91 inspections for a two-unit site during years 30 – 60 of the plants' operation. In comparison, the inspection program in the AMP for Indian Point provides for 94 inspections (for soil that is non-corrosive) or 118 inspections (for soil that is corrosive) during that period. Thus, the number of inspections at Indian Point for Category F soils exceeds the number of inspections recommended in LR-ISG-2011-03, and is sufficient to understand the condition of the buried piping at Indian Point. *Id.* at 60.[88]

2.168. Mr. Holston disputed Dr. Duquette's characterization of AMP XI.M41, in which Dr. Duquette claimed that "[f]or carbon steel components[,] NUREG-1801 Section XI.M41 specifies that buried piping should be coated <u>and</u> cathodically protected." *Id.* at 60, *quoting* Duquette Report (Ex. NYS000165) at 24 (emphasis added). Mr. Holston pointed out, *inter alia*, that applicants can propose alternatives to the AMP as long as those alternatives are sufficient to establish reasonable assurance that the buried component's CLB intended functions will be met. Moreover, as documented in the ISG, soil sampling and augmented inspections constitute an <u>acceptable alternative</u> to installing cathodic protection – and the Staff found that Entergy's

[88] As shown in Table 4a of Final LR-ISG-2011-03 (Ex. NRC000162), the Final ISG recommends for a two-unit site without cathodic protection, that has plant-specific operating experience involving debris in the backfill and coating damage, that 23 inspections be conducted in the final 10 years of the initial period of operation, 30 inspections be conducted in years 40-50 of the PEO, and 38 inspections be conducted in years 50-60 of the PEO (91 in total). The quantity of inspections proposed by the Applicant (a total of 94 inspections), is consistent with the recommendations of the Staff's position as documented in the Final ISG. Staff Testimony on NYS-5 (Ex. NRCR20016), at 39-40.

AMP for buried piping and tanks far exceeds the recommendations in GALL AMP XI.M34, and would satisfy AMP XI.M41 in GALL Report Rev. 2, given Entergy's provision for a substantial number of additional inspections, the inclusion of soil testing, and augmented inspection requirements if the soil is found to be corrosive. Staff Testimony on NYS-5 (Ex. NRCR20016), at 60-61.

2.169. The Applicant has adopted GALL Report AMP XI.M41, without exceptions. Tr. at 3732-33.[89] Consistent with AMP XI.M41, as revised in Final LR-ISG-2011-03, which provides that an applicant may provide means other than cathodic protection, to demonstrate reasonable assurance that buried piping will meet its intended function during the period of extended operation, its BPTIP satisfies the requirements in 10 C.F.R. Part 54. Tr. at 3730-33.

2.170. Fourth, based on a review of the plant-specific operating experience at Indian Point, the Staff found that no significant failures (i.e., failure to provide pressure boundary integrity such that adequate flow and pressure cannot be delivered) of in-scope buried piping have occurred, such that the installation of cathodic protection would be warranted. *Id.* at 61. Apart from some minor coating degradation, the only significant degradation of in-scope piping at Indian Point was associated with the leakage from the CST return line in February 2009 – which was found to not constitute an SSC "failure";[90] this conclusion was supported by a

[89] As stated above, Final LR-ISG-2011-03 revised and superseded AMP XI.M41 in GALL Report Rev. 2. The guidance in LR-ISG-2011-03 constitutes a complete reissuance of that AMP, and has the same weight as the GALL Report. Tr. at 3734, 3971.

[90] *See* Entergy's Root Cause Analysis ("RCA") Report, CP-IP2-2009-00666 (Ex. NYS000179). This report found that structural integrity requirements for the piping were met; the through wall leaks could not lead to draining of the CST below minimum inventory requirements; and the loss of inventory returned to the CST if the AFW pumps had been required to operate would have been too small to challenge the minimum inventory requirements in the tank. Thus, the in-scope function of the CST return line was met, and therefore, the CST return line leak did not constitute a "failure". Staff Testimony on NYS-5 (Ex. NRCR20016) at 61.

Structural Integrity Associates ("SIA") Report issued on May 15, 2009 (Ex. NYS000175), which found, *inter alia,* that the corrosion was localized in nature, and the coatings remained largely intact.[91] Entergy's responses to the Staff's RAIs and other documents indicate that the piping excavations to date have shown the coatings are in acceptable condition. Tr. at 3628-29.

2.171. We find no substantial basis for Dr. Duquette's claim that soils at the Indian Point site are "mildly to moderately corrosive." Table 7 in Entergy's testimony shows that the lowest IPEC recorded value is 8,043 ohm-cm, which is well above the 2,000 threshold for "moderately" corrosive soil; moreover, all of the other soil resistivity measurements found values in excess (and generally, well in excess) of 10,000 ohm-cm, for which a "negligible" classification of corrosivity is appropriate. *See id*. Nor do we find any basis for his claim that past corrosion of the discharge canal sheet piling system demonstrates the need for buried piping CP.[92] In sum, having reviewed all the evidence, we find no basis for Dr. Duquette's claim that the levels of soil resistivity found at the Indian Point site warrant the application of cathodic protection.[93] In

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[91] Mr. Holston testified that the SIA Report's findings, a map of the corrosion locations, and the fact that the piping met structural integrity requirements, support a conclusion that damage caused by backfill materials impacting the pipe coatings is most likely limited to discrete locations and would result in localized damage only, such that unaffected portions of the piping that have intact coatings provide adequate structural reinforcement to the degraded areas, and the pipe's intended function would be met. Staff Testimony on NYS-5 (Ex. NRCR20016), at 62.

[92] Leaving aside the question of whether river water and sediments in a brackish tidal estuary like the Hudson River is representative of soils at the Indian Point site, the PCA Report demonstrates that soil conditions at Indian Point have not been found to be so severe as to warrant cathodic protection. Staff Testimony on NYS-5 (Ex. NRCR20016), at 62-63 (*citing, inter alia*, Corrective Action Report CR-IP2-2005-03902 (Ex. NYS000177), p. 5 of 6, which states, "There are no radiological, nuclear [or] industrial safety issues associated with the lack of Cathodic Protection [for specified buried piping systems]").

[93] Entergy's witnesses cited American Petroleum Institute ("API") piping inspection code, API 570; Table 9-1 of API 570 recommends a 10-year inspection frequency for buried piping without effective CP where soil resistivity values are between 2,000 to 10,000 ohm-cm, because these values do not yield high corrosion rates. Entergy Testimony on NYS-5 (Ex. ENTR30373) at 117, citing API 570, "Piping Inspection Code: In-Service Inspection, Rating, Repair, Alteration of Piping Systems," 2d Ed (Oct. 1998) (Ex. ENT000447).

addition, as discussed *supra* at PFF ¶¶ 2.121, Entergy plans to conduct soil testing as part of its AMP prior to the beginning of the PEO and at least once every 10 years thereafter to confirm that the soil conditions in the vicinity of in-scope buried pipes are non-aggressive; if soil sample results indicate that the soil is corrosive, the number of inspections will be increased, and additional preventive measures or corrective actions may be taken. Entergy Testimony on NYS-5 (Ex. ENTR30373) at 63.[94]

2.172. Dr. Duquette stated that the discovery of a leak in the CST return line piping in 2009 (i.e., the same piping that was inspected in the 2008 CST Inlet - 8" Line 1509 inspection), shows that Entergy's inspection process or inspection technique is inadequate. Duquette Report (Ex. NYS000165), at 9 and 23. Indeed, this is the only evidence he offered to support his view that the proposed inspection plan is not sufficient. *See* Tr. at 3634-35. We find no merit in that position. Rather, we agree with Staff witness Mr. Holston, who explained where the inspection and leak occurred, and the proper interpretation of inspection results.[95]

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[94] Entergy has conducted site area corrosion potential mapping, soil testing, and guided wave testing to identify potential areas of concern. It also has committed to collect and analyze additional soil samples before the period of extended operation begins and at least once every 10 years thereafter to confirm that the soil conditions in the vicinity of in-scope buried pipes are non-aggressive. If any areas of concern are identified during future inspections or testing, then they will be input into the corrective action program for evaluation of extent of condition and for determination of appropriate corrective action and preventive measures. Entergy Testimony on NYS-5 (Ex. ENTR30373) at 117.

[95] Mr. Holston pointed out, Entergy's Corrective Action Report LO-IP3L0-2008-00151 (Ex. NYS000180), at 10-11, shows that the 2008 inspections were conducted in locations far removed from the as-found leak that occurred in 2009. He testified that the Applicant's excavation and inspection of a segment of the CST return line piping in 2008 was not intended to verify the condition of the entire length of CST return line piping – nor are any excavations of buried piping, at any site, intended to verify the condition of the entire line of the piping that is being inspected. Rather, the inspections are intended to determine whether any conditions exist that need to be considered or redressed (either at the inspection site or other locations). An adverse inspection finding would point to the need for further inspections or other actions at the inspection site and/or other locations, while a favorable inspection finding would tend to indicate no reason to take further action. Staff Testimony on NYS-5 (Ex. NRCR20016), at 50-51.

2.173. Dr. Duquette's view that industry standards call for cathodic protection to be installed at plants that lack cathodic protection appears to be based primarily on his reading of NACE SP 0169-2007 (Ex. ENT000388). *See* New York Rebuttal (Ex. NYSR00399), at 11-12 & 14-15. Based on our review of the evidence, we find no support for Dr. Duquette's stated view. As Entergy's witnesses explained (PFF ¶ 2.158, *supra)*, NACE SP 0169-2007 recognizes that <u>both</u> coatings and cathodic protection prevent external corrosion in buried steel piping systems; cathodic protection is not required, however, if the coatings are still effective. *See* Entergy Testimony on NYS-5 (Ex. ENTR30373) at 44. For example, section 1.22 of the NACE standard states, "Existing coated piping systems: CP should be provided and maintained, unless investigations indicate CP is not required." NACE SP 0169-2007 (Ex. ENT000388), at 1.

2.174. Dr. Duquette also cited guidance issued by NEI and EPRI in support of his view that cathodic protection must be provided in Entergy's AMP. [96] Dr. Duquette based this view primarily on the following statement that appears in EPRI Report 1016456 (Ex. NYS000167) at 6-1: ""Recommendation Prevention-1, Retrofit. *Where the risk of failure is unacceptable, preventive and mitigative options should be implemented."* Tr. at 3878-81. We find no support for Dr. Duquette's view. Thus, Dr. Duquette overlooks other wording in the same paragraph, which states that "[m]easures to prevent soil-side (OD) degradation include coating, cathodic protection, and special trench fill" – *i.e.*, cathodic protection is only one of the recommended actions. *Id*. at 6-1. Moreover, Dr. Duquette agreed that the EPRI document only recommends

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[96] *See, e.g.*, New York Testimony on NYS-5 (Ex. NYS00164), at 13-15, citing NEI-09-14, Rev. 1, "Guideline for the Management of Underground Piping and Tank Integrity" (Dec. 2010) (Ex. NYS000168) and EPRI Report 1016456, "Recommendations for an Effective Program to Control the Degradation of Buried Pipe" (Ex.NYS000167); Duquette Report at 14-15, 19, & 24; New York Rebuttal Testimony (Ex. NYS000399), at 8. 11-12, & 13-14.

cathodic protection where the “risk of failure is unacceptable – which he would apply to a leak of radioactive fluids. Tr. at 3881.

2.175. Mr. Holston rejected Dr. Duquette’s interpretation of this provision. As Mr. Holston observed, both the NEI and EPRI documents recommend cathodic protection for situations where “the risk of failure is unacceptable” (NEI) or the “risk of failure is unacceptably high” (EPRI); neither organization recommended the use of cathodic protection for all buried piping. As he further pointed out, “failure” means a failure to maintain the pressure boundary integrity such that adequate flow and pressure cannot be delivered, not simply the occurrence of leakage from a piping system. Further, both NEI and EPRI recognize that the absence of cathodic protection may be addressed by other means, such as risk-ranking and the selection of locations to be inspected based on the consequences of failure. See NEI 09-14, Revision 1 (Ex. NYS000168) at pages 6, 7, and 19. Similarly, EPRI 1016456 (Ex. NYS000167) contains numerous statements which acknowledge that cathodic protection is not installed for all buried piping locations at all plants (e.g., pages v, 1-2, 2-9, 2-13, 3-2, A-2), and that the availability of cathodic protection should be considered during risk ranking and selection of inspection locations (page 2-4 and 2 19). Thus, at page 6 1, EPRI provides a similar set of recommendations as the NEI document, for locations where the risk of failure is “unacceptably high” (including coatings, cathodic protection, special fill, pipe replacement with a different material, and prompt leak detection). Staff Testimony on NYS-5 (Ex. NRCR20016), at 72-73.

2.176. Entergy’s witnesses further explained that the NEI and EPRI guidance documents do not recommend that CP be installed for all buried piping systems. Rather, both documents acknowledge that CP systems presently may or may not be installed at a site; and the documents provide guidelines for management of buried piping either with or without cathodic protection. Accordingly, while the cited industry guidance documents include consideration of cathodic protection systems, they do not support the view that new cathodic protection must be installed at Indian Point for Entergy's AMP to be found acceptable. Entergy Testimony on NYS-5 (Ex. ENTR30373) at 107; *see* NEI-09-14 (Ex. NYS000168), at 2, 6, 20, and B-2; EPRI Report 1016456 (Ex.NYS000167), at v, 1-2, 2-8, 2-9, 3-2, 6-1, L-4, and L-7. [97] Further, Mr. Biagiotti testified that industry guidance does not recommend the installation of cathodic protection; rather, the guidance NEI and EPRI documents recommends that where cathodic protection exists, it should be maintained. Tr. at 3882.

2.177. Staff witness William C. Holston found that Entergy's preventive measures for buried piping are consistent with the NACE standard, despite the lack of cathodic protection. In this regard, he cited LRA Section B.1.6, which states, "[p]reventive measures are in accordance with standard industry practice for maintaining external coatings and wrappings." He noted that protective coatings and wrappings were installed on buried piping during construction of Indian Point, in accordance with standard industrial practices; they continue to be installed when replacement or repair activities are conducted, and will be utilized in the period of extended operation. These coatings consist of a coal tar coating covered with a fiber based wrap saturated with coal tar – which is the type of coating used throughout the nuclear industry to isolate the external surfaces of buried components from the soil environment and is consistent with the recommendations in NACE SP0169 (2007). Given that the buried piping at Indian Point has been coated in accordance with standard industry practices, and recent inspections have found the coatings generally to be intact (except in locations where deleterious materials in the

[97] Entergy's witnesses pointed out that NRC guidance likewise does not indicate that new CP must or should be installed and, in fact, provides for increased inspections—as in the IPEC BPTIP—in the absence of CP. In this regard, they cited LR-ISG-2011-03 (Ex. NRC000162), which includes inspection recommendations for plants not utilizing a cathodic protection system during the period of extended operation. Entergy Testimony on NYS-5 (Ex. ENTR30373), at 18-19.

backfill damaged them), the external surfaces of the buried piping should not degrade unless the coatings are penetrated. Staff Testimony on NYS-5 (Ex. NRCR20016) at 34-35.

2.178. In addition, Mr. Holston observed that the Applicant has committed to inspect the condition of its buried piping coatings consistent with the recommendations of NACE, which establishes industry standards applicable to all buried piping systems. In accordance with NACE SP0169-2007, section 5.3.1, the Applicant's AMP specifically states that all direct visual examinations of excavated buried SSCs will include a visual examination of coatings. Further, to account for the lack of cathodic protection and previous instances of coating failure due to deleterious materials in the backfill, the Applicant has committed to conduct a significant number of inspections (34) prior to entering the PEO. *See id*. at 35. In sum, although the LRA does not specifically commit to comply with NACE standards, it did address the three preventive actions discussed in NACE SP 0169-2007 (cathodic protection, protective coatings, and backfill quality), it increased its number of future inspections due to the lack of cathodic protection and its plant-specific operating experience, and it will conduct soil sampling; the AMP is therefore consistent with the Staff's position regarding these three preventive actions. *Id.* at 35-37.[98]

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[98] As Mr. Holston observed, there is no regulatory significance to New York's assertion, at page 19 of its Statement of Position (Ex. NYS000163), that Entergy's buried piping AMP, as revised, fails to meet "the industry standard of care established by [NEI and EPRI] initiatives." Simply stated, the NRC does not require its licensees to satisfy industry guidelines or recommendations, unless those recommendations have been adopted as regulatory or license requirements; similarly, the Staff does not evaluate the adequacy of an applicant's AMP against the recommendations of industry groups. Nonetheless, in the Staff's assessment of the IP2/IP3 LRA, it was apparent that the Applicant's AMP addresses some or all of those NEI and EPRI recommendations. For example, as recommended by EPRI (Ex. NYS000167), at page vi, the Applicant has established an extensive inspection schedule, consistent with the Staff's position in AMP XI.M41 for buried piping without cathodic protection. Further, as recommended by NEI (Exs. NYS000168, at page 6, and NYS000169 at page 5) – and as provided in GALL Report Revision 2, AMP XI.M41 (Ex. NYS000147A-D) and the Staff's Final ISG (Ex. NRC000162) – the Applicant has committed to use risk-ranking to select inspection locations, and its committed number of inspections exceeds those recommended in the NEI Report (NYS000169), at pages 10-16. Staff Testimony on NYS-5 (Ex. NRCR20016), at 71-72.

2.179. We find that Entergy's and the Staff's witnesses have properly interpreted and addressed the NEI and EPRI documents discussed above. We have been presented with no evidence that any of the buried piping and tanks at IP2 and IP3 that lack cathodic protection falls within the "unacceptable risk" category referred to in those documents. Further, we have found no requirement in either the NACE standard or the NEI and EPRI guidance documents, that cathodic protection must be installed for the existing buried piping at Indian Point.

8. Alleged Ambiguities in the AMP

2.180. In his testimony, Dr. Duquette stated his view that Entergy's AMP lacks sufficient specificity in numerous respects. For example, he asserted that the AMP is "ambiguous" or only "conceptual" in nature,[99] and that Entergy's AMP commitments lack sufficient details regarding (a) which past inspections are being credited, (b) the methodology used in performing buried piping risk assessments, (c) soil sample procedures, (d) repair and remediation procedures, (e) and monitoring techniques, acceptance criteria, corrective actions and administrative controls.[100]

2.181. Entergy's witnesses disagreed with Dr. Duquette's view that the buried piping and tanks AMP is ambiguous. In this regard, they stated that IPEC has committed to implement the BPTIP in license renewal Commitment 3, which the NRC Staff has found acceptable in SER Supplement 1 (Ex. NYS000160), App. A, at A-2. They further testified that Commitment 3 is neither ambiguous nor insufficient. It states that IPEC will:

[99] New York Testimony on NYS-5 (NYS000164), at 18.

[100] *See, e.g.*, New York Testimony on NYS-5") (Ex. NYS000164), at 16-21 & 25-26; Duquette Report (Ex. NYS000165), at 18.

> Include in the Buried Piping and Tanks Inspection Program described in LRA Section B.1.6 a risk assessment of in-scope buried piping and tanks that includes consideration of the impacts of buried piping or tank leakage and of conditions affecting the risk for corrosion. Classify pipe segments and tanks as having a high, medium or low impact of leakage based on the safety class, the hazard posed by fluid contained in the piping and the impact of leakage on reliable plant operation. Determine corrosion risk through consideration of piping or tank material, soil resistivity, drainage, the presence of cathodic protection and the type of coating. Establish inspection priority and frequency for periodic inspections of the in-scope piping and tanks based on the results of the risk assessment. Perform inspections using inspection techniques with demonstrated effectiveness.

Entergy Testimony on NYS-5 (Ex. ENTR30373) at 72. Further, they testified that this is precisely the approach that Entergy has taken in implementing the UPTIMP (and BPTIP) in accordance with NEI 09-14 , Rev. 1 and related fleet and site-specific procedures. In this regard, Entergy's witnesses explained that the UPTIMP, as defined by procedures EN-DC-343, CEP-UPT-0100 and SEP-UIP-IPEC (which are used to implement the UPTIP and BPTIP, as discussed above),[101] provides that specific inspections and examinations be based on observed or expected degradation, pipe susceptibility to corrosion, leak consequences, and piping location. These aspects are all part of the risk ranking process (which Entergy completed for IPEC in September 2010) that is used to determine the likelihood and consequence of failure for each piping segment to prioritize inspections. *Id.* at 72-73.

2.182. For example, procedure SEP-UIP-IPEC sets out the inspection plan for buried piping at Indian Point. Tr. at 3412. Mr. Holston testified that his review of that document found

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[101] *See* (1) EN-DC-343, Rev. 4, "Underground Piping and Tanks Inspection and Monitoring Program" (included in IPEC Nuclear Management Manual (May 16, 2011)) (Ex. NYS000172); (2) CEP-UPT-0100, Rev. 0, "Underground Piping and Tanks Inspection and Monitoring" (Oct. 31, 2011) (Ex. NYS000173); and (3) SEP-UIP-IPEC, Rev. 0, "Indian Point 2 & 3 Underground Components Inspection Plan" (April 29, 2011) (Ex. NYS000174).

that it contains very specific information concerning such matters as site-specific inspection procedures, the identity of major piping segments and their risk-ranking and schedule to be inspected, and is not ambiguous. Tr. at 3413, 3442, 3446. Further, Mr. Holston found that Table 9-3 in procedure CEP-UPT-0100 contains very definitive criteria and specific information regarding Entergy's corrosion risk assessments at the site, comparable to what he has seen at other plants. Tr. at 3414-18, 3442.

2.183. Further, as reflected in EN-DC-343, CEP-UPT-0100 and SEP-UIP-IPEC, Entergy evaluated numerous attributes and included them, as applicable to the IPEC site and buried piping systems, in its fleet and IPEC-specific buried piping programs. Entergy is implementing the UPTIMP and BPTIP at IPEC, as evidenced by the numerous buried piping inspections and examinations performed to date and discussed below. In the witnesses' view, Entergy's commitment to implement the BPTIP is clear and unambiguous. It is fully described in the revised LRA and includes revisions to Sections A.2.1.5 and A.3.1.5 (the IP2 and IP3 UFSAR supplements) to reflect the increased number and frequency of piping inspections and additional soil testing. In addition, Entergy's implementation of the BPTIP and related commitments is subject to the NRC's inspection and enforcement processes. *Id.* at 73; *see also id* at 53-54 and 78-81. The Staff agreed with these assessments, as *discussed below.*

2.184. Entergy witness Mr. Cox accordingly disagreed with the view that Entergy had done more than merely commit to comply with the GALL Report; rather, Entergy had provided specific information as to how compliance will be accomplished, such as by specifying a significantly increased number of inspections beyond the opportunistic inspections recommended in GALL Report Rev. 1. *See* Tr. at 3317-3319. All of the AMP's acceptance criteria are summarized in one (or more) of the four AMP implementing procedures, *e.g.*, in Section 5.5 of CEP-UPT-0100. Tr. at 3514-15.

2.185. Moreover, Entergy's witnesses disagreed with Dr. Duquette's assertion that the BPTIP is "insufficient to provide an understanding of what exactly Entergy would be doing to manage aging of pipes."[102] They pointed out that the descriptions in Appendix B of the LRA follow the convention established in NEI 95-10, Appendix D (Ex. ENT000098). Under that convention, the LRA states the BPTIP is consistent with the GALL Report, Rev. 1, with no exceptions; therefore, the details of the ten-element program in AMP XI.M34 description were incorporated by reference into the LRA. Those details include, among other things, inspection methods, acceptance criteria, and corrective actions.[103] Subsequently, Entergy revised the AMP in response to industry and IPEC operating experience, and it now meets the intent of Section XI.M41 of the GALL Report, Rev. 2, as revised in Final LR-ISG-2011-03, App. A (Ex. NRC000162). Accordingly, the specific details that Dr. Duquette claims are missing from the AMP are, in fact, provided in the AMP's implementing procedures based on current NEI and EPRI guidelines; specific procedures that are being used to implement the BPTIP are

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[102] *See* New York Testimony on NYS-5 (Ex. NYS000164) at 16, 18.

[103] Entergy Testimony on NYS-5 (Ex. ENTR30373) at 17 & 68, *citing* LRA, App. B at B-27 (Ex. ENT000015B).

EN-DC-343, CEP-UPT-0100, and SEP-UIP-IPEC. Entergy Testimony on NYS-5 (Ex. ENTR30373), at 68-69.[104]

2.186. Staff witness Mr. Holston also disputed Dr. Duquette's assertion that the Applicant's AMP is ambiguous or only "conceptual" in nature. He pointed out that the Applicant will conduct excavated direct visual inspections of its buried piping as stated in Ex. NYS000160. Each inspection will consist of exposing the complete circumference of ten feet of pipe. This commitment clearly describes the monitoring that will be conducted as part of the program. Similarly, the Applicant has provided specific details regarding its commitments to conduct

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[104] Entergy's witnesses pointed out that the items which Dr. Duquette alleged to be missing from the AMP may be found in docketed license renewal correspondence and the specific program documents and procedures that are being used to implement the BPTIP – specifically, EN-DC-343, CEP-UPT-0100, and SEP-UIP-IPEC. Inspection methods, acceptance criteria, and corrective actions were identified in the LRA through its reference to the NUREG-1801 program. Further, Procedure SEP-UIP-IPEC (Ex. NYS000174) describes the IPEC Underground Components Inspection Plan; Section G of SEP-UIP-IPEC summarizes the IPEC risk ranking process, and provides specific details of the criteria and risk ranking process (quoted in the witnesses' testimony) that will be used in selecting piping locations for inspection. Section H of SEP-UIP-IPEC describes applicable inspection and examination methods for buried pipes and tanks – which are specified to include in-line pipeline examinations using instrumented vehicles (called pigs), guided wave indirect inspections, local pipe direct examination (NDE), and direct visual inspections of excavated piping. Section H also describes the pipe line grouping process, whereby pipes are grouped based on attributes such as pipe material, coating type, soil/backfill, age, operating parameters, size, process fluid, cathodic protection. The grouping of pipes with similar attributes allows the results of the inspection of one pipe to be extrapolated to the others in the group, thereby optimizing inspection scope. Id. The April 2011 NEI buried piping inspection plan guidance (NYS000169) provides guidance for the line grouping process. Entergy Testimony on NYS-5 (Ex. ENTR30373) at 69-71. Procedure SEP-UIP-IPEC identifies all buried piping in the inspection program and the schedule for inspections of that piping for the next few years. Tr. at 3620.

The Appendices to SEP-UIP-IPEC provide additional information alleged by Dr. Duquette to be unavailable. Appendix A, for example, contains detailed piping inspection information for piping within the scope of the UPTIMP (and hence the license renewal BPTIP). That information includes, among other things, risk ranking information. For each unit, the piping is listed in order of inspection priority, from high to low. Appendix G contains an Integrated Inspection Schedule that identifies the specific excavated direct visual inspections to be performed through the third quarter of 2013. Finally, Appendix H contains program drawings of the piping systems and locations to be inspected, and identifies the exact inspection locations. *Id.* at 71, citing SEP-UIP-IPEC (Ex. NYS000174). Entergy's witnesses therefore concluded that the actions that IPEC will take (and is taking) to manage aging effects on buried piping are well understood and fully described in the IPEC program and procedures, such that there is no basis for Dr. Duquette's claim that Entergy has not provided information concerning its risk assessment and buried piping classification processes. *Id.*

buried tank inspections and soil sampling. *Id.* at 56. These specific commitments disprove the view that the AMP is merely conceptual in nature.

2.187. Mr. Holston found Dr. Duquette's assertions to be without merit. *See* Staff Testimony on NYS-5 (Ex. NRCR20016) at 44-57. In brief, Mr. Holston stated that the Staff had issued RAIs requesting that the Applicant revise its UFSAR Supplement to include the number and frequency of piping inspections and soil testing for all buried pipe within the scope of license renewal (Ex. NYS000200); in July 2011, Entergy did so. *Id.* at 45, *citing* Entergy letters of July 14 and July 27, 2011 (Exs. NYS000152 and NYS000153). These revisions were documented in SER Supplement 1. *See* SER Supp. 1 (Ex. NYS000160), at 3-1 – 3-5.

2.188. In addition, Mr. Holston pointed out that the Applicant has revised its UFSAR Supplement, providing specific details as to the number and frequency of its planned inspections and soil sampling, to state as follows:

> <u>LRA Section A.2.1.5, Buried Piping and Tanks Inspection Program [IP2]</u>
>
> The Buried Piping and Tanks Inspection Program is a new program that includes (a) preventive measures to mitigate corrosion and (b) inspections to manage the effects of corrosion on the pressure-retaining capability of buried carbon steel, gray cast iron, and stainless steel components. Preventive measures are in accordance with standard industry practice for maintaining external coatings and wrappings. Buried components are inspected when excavated during maintenance. If trending within the corrective action program identifies susceptible locations, the areas with a history of corrosion problems are evaluated for the need for additional inspection, alternate coating, or replacement.
>
> IP2 will perform 20 direct visual inspections of buried piping during the 10 year period prior the PEO. IP2 will perform 14 direct visual inspections during each 10-year period of the PEO. Soil samples will be taken prior to the PEO and at least once every 10 years in the PEO. Soil will be tested at a minimum of two locations at least three feet below the surface near in-scope piping to determine representative soil conditions for each system. If test results indicate the soil is corrosive then the number of piping inspections will be increased to 20 during each 10-year period of the PEO.

<u>LRA Section A.3.1.5, Buried Piping and Tanks Inspection Program [IP3]</u>

> The Buried Piping and Tanks Inspection Program is a new program that includes (a) preventive measures to mitigate corrosion and (b) inspections to manage the effects of corrosion on the pressure-retaining capability of buried carbon steel, gray cast iron, and stainless steel components. Preventive measures are in accordance with standard industry practice for maintaining external coatings and wrappings. Buried components are inspected when excavated during maintenance. If trending within the corrective action program identifies susceptible locations, the areas with a history of corrosion problems are evaluated for the need for additional inspection, alternate coating, or replacement.
>
> IP3 will perform 14 direct visual inspections of buried piping during the 10 year period prior the PEO. IP3 will perform 16 direct visual inspections during each 10-year period of the PEO. Soil samples will be taken prior to the PEO and at least once every 10 years into the PEO. Soil will be tested at a minimum of two locations at least three feet below the surface near in-scope piping to determine representative soil conditions for each system. If test results indicate the soil is corrosive then the number of piping inspections will be increased to 22 during each 10-year period of the PEO.

Staff Testimony on NYS-5 (Ex. NRCR20016) at 45-47.

2.189. Mr. Holston then pointed out that, in accordance with 10 C.F.R. §§ 50.59(c), 50.71(e), and 54.21(d), information that is included in the UFSAR Supplement becomes part of a licensee's CLB, and cannot be revised by the licensee without performing a safety evaluation in accordance with 10 C.F.R. § 50.59 ("Changes, Tests, and Experiments"). The requirements of 10 C.F.R. § 50.59 continue to apply to any renewed license. In addition, pursuant to 10 C.F.R. § 50.59(d)(2), the licensee is required to maintain a record and to inform the Staff of any changes to the UFSAR or UFSAR Supplement made pursuant to 10 C.F.R. § 50.59. Staff Testimony on NYS-5 (Ex. NRCR20016) at 47; *see* Tr. at 3966.

2.190. Various details which Dr. Duquette believed to be missing from the AMP (such as "what factors Entergy will take into account in performing a risk assessment or to classify its pipe, or how frequently Entergy will inspect pipes according to their priority)" are at a level of detail that is not needed to be specifically stated in an applicant's AMP to satisfy NRC regulatory requirements or for its AMP to conform to the AMP(s) set out in the GALL Report. Rather, such details are typically contained in a licensee's inspection plans or procedures for implementation of its aging management programs; such details are not subject to NRC review and approval prior to license renewal; rather, the Applicant is required to have such details available for Staff verification during an on-site inspection prior to or subsequent to license renewal, conducted to confirm that the Applicant's license renewal commitments have been implemented (under Inspection Procedure 71003 ("Post Approval Site Inspection for License Renewal") (Ex. ENT000251) or Temporary Instruction (TI) 2516/001 ("Review of License Renewal Activities") (Ex. ENT000252). *Id.* at 47; *see* Entergy Testimony on NYS-5 (Ex. ENTR30373) at 79.[105]

2.191. While Dr. Duquette asserted that Entergy had only committed to an "inspection schedule," rather than "creating an unspecified plan that will manage aging,"[106] the Staff found that Entergy's AMP, as revised, provides sufficient and unambiguous requirements (a) to ensure that preventive measures are in accordance with standard industry practice for maintaining external coatings and wrappings, (b) to conduct the specified number of inspections and soil sampling, as stated in Entergy's responses to the Staff's RAI (Ex. NYS000152 and NYS000153) and UFSAR Supplement (including an increase in the number of inspections if the soil is found

[105] During the week of March 5-9, 2012, the Staff conducted an inspection of the Applicant's progress in satisfying its license renewal commitments, under TI 2516/001. During that inspection, Mr. Holston personally confirmed that the Applicant's Inspection Plan, which is modeled on its corporate program, CEP-UPT-0100, Underground Piping and Tanks Inspection and Monitoring, Revision 0, (Ex. NYS 000173) contains adequate details for assessing the risk of failure and corrosion for in scope buried piping and tanks. In addition, Mr. Holston personally confirmed that the Applicant utilized its corporate process to classify its in scope buried piping and tanks, as documented in site procedure SEP-UIP-IPEC, Underground Components Inspection Plan, Revision 0 (NYS Ex. 000174). Staff Testimony on NYS-5 (Ex. NRCR20016) at 47-48; *cf.* Entergy Testimony on NYS-5 (Ex. ENTR30373) at 79-80.

[106] New York Testimony on NYS-5 (NYS000164), at 25.

to be corrosive), and (c) as a result of adverse inspection findings, to evaluate the need for additional inspections, alternate coatings, or replacement for areas that may be susceptible to corrosion based on its inspection findings. In addition, the Applicant must conduct a safety evaluation under 10 C.F.R. § 50.59, if it chooses to revise the description of the program contained in the UFSAR Supplement. Staff Testimony on NYS-5 (Ex. NRCR20016) at 48.[107]

2.192. Likewise, Staff witness Mr. Holston disagreed with Dr. Duquette's assertion, at pages 21-22 of his testimony, that "it is not clear how many inspections, if any, have already taken place that Entergy is counting against this requirement [to conduct 34 buried piping inspections prior to the PEO] but that were not conducted to the standards to which Entergy's new program would dictate they should be conducted." Mr. Holston testified that Entergy had conducted 10 of the 34 inspections that are to be conducted in the ten-year period prior to extended operation before it responded to the Staff's RAI on March 28, 2011 (Ex. NYS000151).[108] Those inspections exposed 80 feet of pipe during which the coatings and backfill were inspected; the method of inspection and parameters being inspected were consistent with both GALL Report AMP XI.M34 and XI.M41. Staff Testimony on NYS-5 (Ex. NRCR20016), at 49-50.

2.193. Mr. Holston further disagreed with Dr. Duquette's assertion (at pages 16-17 of his testimony and page 14 of his Report (Ex. NYS000165)), that Entergy's AMP offers only unspecified preventive and mitigative measures, and that "Entergy makes no commitment to

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[107] Mr. Holston further disputed Dr. Duquette's view that the Applicant had only committed to an unspecified plan. The Applicant has committed to the number of inspections, soil testing (which could lead to further inspections), and trending of inspection results in its UFSAR or UFSAR Supplement. Those commitments conform to NRC regulatory guidance, including the periodicity of buried piping and tank inspections contained in GALL Report AMPs XI.M34 and XI.M41 and LR ISG-2011-03 (i.e., inspections are specified to occur during discrete ten year inspection intervals starting ten years prior to the period of extended operation), and are acceptable. Staff Testimony on NYS-5 (Ex. NRCR20016) at 67.

[108] Entergy recently completed additional inspections, beyond those identified in the parties' testimony. *See* n. 51 *supra*.

taking any mitigative measures if problems are found." Mr. Holston explained that based on its review, the Staff concluded that (a) the AMP includes provisions for ensuring that the coatings remain intact on buried piping; (b) the inspection portion of the program works in conjunction with various preventive features; (c) the Applicant has committed to trend results from inspections to ensure that areas with a history of corrosion problems are considered for additional inspection, alternate coating, or replacement; and (d) the Applicant's AMP functions in conjunction with the requirements imposed by its current licensing basis – including requirements to ensure that conditions adverse to quality are corrected, under 10 C.F.R. Part 50, Appendix B. *Id.* at 51. Mr. Holston then provided a detailed explanation in support of these conclusions, recited below, which we find to be persuasive.

2.194. First, with respect to the Staff's conclusion that the AMP includes provisions for ensuring that the coatings remain intact on buried piping, the Applicant stated in both its AMP and UFSAR Supplement that external coatings and wrappings will be maintained in accordance with standard industry practice. The Applicant also stated that the quality of backfill, an essential preventive element in protecting the coatings, will be verified during excavated inspections. These are two key preventive measures that are contained in GALL Report AMP XI.M41 (Ex. NYS000147A-D) and NACE recommendations (Ex. NRC000027). As long as coatings remain intact, such that water intrusion is prevented, it is very unlikely that external piping corrosion will occur. Staff Testimony on NYS-5 (Ex. NRCR20016), at 51.

2.195. Second, with respect to the Staff's conclusion that the inspection portion of the Applicant's program operates in conjunction with various preventive features, the Staff recognizes that inspections, in and of themselves are not a preventive measure (such as coatings, quality backfill and cathodic protection). Nonetheless, inspections work in conjunction with the preventive actions (here, Entergy's coatings and backfill requirements) to provide information to an applicant on the condition and performance of the existing preventive actions.

In this regard, Mr. Holston pointed out that NRC regulations do not require that all buried in-scope piping at a nuclear power plant be cathodically protected, under either an initial or a renewed license; nor is this a requirement or feature in the existing licenses for IP2 and IP3. The Staff developed a draft ISG for GALL Report AMP XI.M41 (Ex. NRC000019), which was then revised and reissued as Final LR-ISG-2011-03 (Ex. NRC000162), to identify appropriate alternative means to establish reasonable assurance that in-scope buried components will meet their CLB function(s) without cathodic protection. The ISG recommends a higher number of inspections for plants without cathodic protection, to augment the protection afforded by coatings and backfill quality against external corrosion of the piping. The ISG also recommends a further increase in the number of inspections if plant-specific operating experience has revealed prior coating damage or foreign material in the backfill, or if soil conditions are corrosive. *Id.* at 52.

2.196. Given that plant-specific operating experience at Indian Point includes the discovery of some poor quality backfill resulting in coating damage, which eventually led to piping through-wall penetration, the Staff evaluated the Applicant's AMP for buried piping and tanks against the higher number of inspections recommended in the ISG for AMP XI.M41 (LR-ISG-2011-03, Ex. NRC000162). The Staff concluded that the Applicant's proposed number of 94 inspections, with an additional 24 inspections to be performed if the soil is determined to be corrosive, in conjunction with 24 planned inspections of its 8 buried fuel oil storage tanks over the thirty year period starting ten years prior to the period of extended operation, will provide sufficient data to inform the Applicant on the condition of piping coatings and backfill, consistent with the intent of LR-ISG-2011-03 (Ex. NRC000162). Staff Testimony on NYS-5 (Ex. NRCR20016), at 52-53.

2.197. Third, with respect to the Staff's conclusion that the Applicant has committed to trend results from inspections to ensure that areas with a history of corrosion problems are considered for additional inspection, alternate coating, or replacement, Mr. Holston pointed out that the Applicant has committed to perform trending of adverse buried pipe conditions in its UFSAR Supplement. There, the Applicant stated, “If trending within the corrective action program identifies susceptible locations, the areas with a history of corrosion problems are evaluated for the need for additional inspection, alternate coating, or replacement.” Trending provides an additional means of assuring that preventive or corrective actions will be taken in areas with a history of corrosion problems, thus providing additional assurance that the coatings will remain effective in preventing external corrosion of piping. *Id*. at 53.

2.198. Fourth, with respect to the Staff’s conclusion that the Applicant’s AMP functions in conjunction with the requirements imposed by its current licensing basis -- including requirements to ensure that conditions adverse to quality are corrected under 10 C.F.R. Part 50, Appendix B, Mr. Holston pointed out that if renewed licenses are issued for IP2 and IP3, all aspects of the licensee’s current licensing basis will remain in effect during the period of extended operation. Therefore, the provisions of 10 C.F.R. Part 50, Appendix B, Criterion XVI, Corrective Actions, will apply -- which require that conditions adverse to quality (e.g., coating damage, external corrosion of buried piping) are corrected. This consideration is factored into the Staff’s evaluation of each aging management program. Thus, GALL Report program element seven, “corrective actions,” is addressed for every program submitted by a license renewal applicant. In addition, Staff personnel in the four NRC regional offices periodically conduct “Problem Identification and Resolution” inspections at all nuclear plants that look for gaps in corrective action program performance. Given that correcting conditions adverse to quality is a current licensing basis requirement and there are periodic NRC inspections of the corrective action program, there is reasonable assurance that adverse buried piping and tank inspection results will be corrected. Accordingly, if the external surfaces of the piping, coatings, and backfill quality are found to not meet the standards imposed by the plants’ CLB, there is reasonable assurance that they will be restored to meet existing license requirements. *Id.* at 53-54.

2.199. Mr. Holston also disputed Dr. Duquette's assertion that the buried piping AMP "contains very few actual commitments" and does not identify the "proven monitoring techniques, acceptance criteria, corrective actions, and administrative controls" referred to in the AMP, such that "it is not possible to determine at this time whether the inspection program will meet the requirements for an adequate AMP."[109] Mr. Holston testified that although LRA Section B.1.6 does not provide explicit details on the Applicant's acceptance criteria, corrective actions, and administrative controls, the AMP cites GALL Report AMP XI.M34, which states that:

> Any coating and wrapping degradations are reported and evaluated according to site corrective actions procedures. <u>The site corrective actions program, quality assurance (QA) procedures, site review and approval process, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B.</u> The staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions, confirmation process, and administrative controls.

Id., emphasis added. By committing to adhere to existing IP2/IP3 corrective action programs, procedures and administrative controls – which were established under the current licenses in accordance with 10 C.F.R. Part 50, Appendix B – the AMP satisfies GALL Report AMP XI.M34 and provides sufficient information to support a conclusion that the corrective action program is adequate. NRC Staff Testimony on NYS-5 (Ex. NRCR20016), at 54-55

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[109] New York Testimony on NYS-5 (NYS000164), at 18-19. As noted above, the GALL Report provides NRC Staff recommendations which, if adopted by an applicant, would be found to be sufficient to satisfy the regulations in 10 C.F.R. Part 54; neither the GALL Report nor AMP XI.M41 constitutes a regulatory "requirement." Tr. at 3730, 3732.

2.200. In this regard, 10 C.F.R. Part 50, Appendix B, Criterion III ("Design Control"), requires that:

> Measures shall be established to assure that applicable regulatory requirements and the design basis, as defined in § 50.2 and as specified in the license application, for those structures, systems, and components to which this appendix applies are correctly translated into specifications, drawings, procedures, and instructions. These measures shall include provisions to assure that appropriate quality standards are specified and included in design documents and that deviations from such standards are controlled.

As at other nuclear power plants, the Indian Point specifications, drawings, procedures, and instructions establish the basis for the plants' acceptance criteria. As discussed above, under the IP2/IP3 licenses, conditions adverse to quality are required to be promptly identified and corrected. The identification of a condition adverse to quality is accomplished by comparing the as-found condition of the piping and coatings to the acceptance criteria, and to determine if the SSC is either fit for duty until a subsequent inspection, repair the SSC, or replace the affected item. Thus, the correction is accomplished by repair, replacement or modification in accordance with the design controls as described in 10 C.F.R. Part 50, Appendix B, Criterion III. Given that these requirements reside in the existing CLB, there is no need to repeat them in an aging management program. Thus, the regulatory requirement in Appendix B effectively provides for a comparison of the as-found piping to the plant's design criteria. *Id.* at 55.

2.201. The Staff's evaluation of Entergy's discussion of operating experience, discussed in SER Section 3.3.2.2.8 (Ex. NYS000326D), at page 3-373, took note of Entergy's statement that leaks involving non-safety related piping, outside the scope of license renewal (i*.e.,* the auxiliary steam line), had been addressed in two condition reports – and apart from those leaks, since 2000, "no other buried piping repair or replacement was identified during its review of operating experience." *Id.* at 55-56.[110] The Staff's on-site review of corrective action reports and other documents pertaining to Indian Point's operating experience found that on-site and industry-wide operating experience had properly been accounted for in its AMP. Tr. at 3364-67, 3368-70.

2.202. In sum, the Staff concluded that the description of the Applicant's corrective action program in its buried piping and tank AMP is adequate because (a) it is in accordance with the Staff's position as promulgated in GALL Report AMP XI.M34, (b) the current licensing basis 10 C.F.R. Part 50, Appendix B program provides adequate controls for acceptance criteria and repairs, and (c) the Staff has conducted routine inspections of the corrective action program under the existing licenses, and will continue to conduct routine inspections of the corrective action program during the period of extended operation, thus providing verification of the adequacy of the corrective action program. *Id.* at 56.[111]

2.203. Dr. Duquette also asserted, at page 20 of his testimony, that "[i]n the risk-ranking section, an assemblage of as-built-drawings is required. It is not clear if such a set actually exists or if it was or will be provided for review in the LRA licensing process." Staff witness Mr. Holston disagreed. As he stated, under the CLB for IP2 and IP3, Entergy is required to maintain plant drawings, to document any adverse as-found conditions and to update its drawings to reflect such conditions, pursuant to 10 C.F.R. Part 50, Appendix B, Criterion V

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[110] As discussed above, in 2009 (one year after Entergy made the statement recited in the text above), it discovered a further leak in the CST return line, which it then repaired. NRC Staff Testimony on NYS-5 (Ex. NRCR20016), at 56.

[111] Mr. Holston also disagreed with Dr. Duquette's view that the LRA's identification of the number of inspections to be conducted per each 10-year interval of the PEO is too indefinite. Mr. Holston testified that it is inconceivable that a licensee would wait until the end of the 10-year period to conduct all of the required inspections, but would instead plan and budget the inspections to occur throughout each 10-year inspection period. Tr. at 3443-44. Further, each inspection serves to help the licensee decide upon its future inspections. Tr. at 3446.

("Instructions, Procedures, and Drawings"). This requirement will continue to apply during the period of extended operation; there is no need to duplicate this requirement in the LRA or AMP. *Id.* at 57.[112] In fact, such as-built drawings are available at the site, as both Mr. Cox and Mr. Holston testified. Tr. at 3419-20.

2.204. Ultimately, while Dr. Duquette continued to express reservations about various aspects of Entergy's BPTIP, he conceded that other aspects of Entergy's AMP are acceptable, stating as follows:

> I agree that the priority system they set up is a good one. The criteria they set up for priorities are a good one. I think that the priorities for where you would inspect first are good ones. . . . I don't have a problem with their ranking the pipes for how dangerous it might be to have a leak at that location. . . .

Tr. at 3449. Further, he agreed that Entergy had specified "the number and frequency" of its inspections, Tr. 3462 (as corrected), and that Entergy has performed a detailed inventory of piping, and he does not disagree with their conclusions, Tr. at 3706-07.

9. Entergy's Corporate Procedures

2.205. Among the challenges to Entergy's AMP for buried piping and tanks (the BPTIP), New York asserted that it is not clear how the AMP comports with three Entergy procedures: EN-DC-343 (Ex. NYS000172), CEP-UPT-0100 (Ex. NYS000173), and SEP-UIP-IPEC (Ex. NYS000174). In this regard, Dr. Duquette stated his view that these procedures "are not

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[112] The requirement in 10 C.F.R. Part 50, Appendix B, that Entergy document any finding of adverse as-found conditions and update its drawings to reflect such conditions, applies as well to the discovery of poor backfill conditions in its buried piping inspections during the PEO. Entergy's witnesses testified that the discovery of such conditions during the PEO would be addressed in a condition report and would be addressed with corrective actions, as appropriate. Tr. at 3835-36, 3839, 3864-65.

explicitly part of its LRA, AMP," and he does "not understand these to be part of Entergy's LRA." New York Testimony on NYS-5 (NYS000164), at 17. He further stated as follows:

> Entergy has offered more detail in corporate documents it disclosed (of primary relevance EN-DC-343 (Rev. 4), CEP-UPT-0100, and SEP-UIP-IPEC), but these internal documents are not included in the commitment from Entergy or made a part of the LRA. They are presumably subject to modification by Entergy without NRC approval and would not be obligations imposed on Entergy by a renewed license.

Id. at 19. Dr. Duquette nonetheless proceeded to evaluate these procedures, and found them to be inadequate. *See id*. at 19-21 & 23-25; Duquette Report (Ex. NYS000165) at 2 & 12-19.

2.206. Entergy's witnesses provided further clarification of the role of these three procedures in the IP2/IP3 buried piping and tank AMP. As discussed *supra* (PFF ¶¶ 2.113 – 2-114 & 2.181 – 2.185), Entergy is using these procedures to implement the UPTIP and BPTIP. As also discussed above (PFF ¶ 2.181), LRA Commitment 3 follows the same approach that Entergy has taken in implementing the UPTIMP (and BPTIP) specific procedures; the UPTIMP, as defined by procedures EN-DC-343, CEP-UPT-0100 and SEP-UIP-IPEC, provides that specific inspections and examinations be based on observed or expected degradation, pipe susceptibility to corrosion, leak consequences, and piping location, as part of the risk ranking process that is used to determine the likelihood and consequence of failure for each piping segment to prioritize inspections. Further, as reflected in EN-DC-343, CEP-UPT-0100 and SEP-UIP-IPEC, Entergy evaluated numerous attributes and included them, as applicable to the IPEC site and buried piping systems, in its fleet and IPEC-specific buried piping programs. *See* Entergy Testimony on NYS-5 (Ex. ENTR30373) at 72-73.

2.207. Entergy's witnesses further testified that Entergy developed EN-DC-343, CEP-UPT-0100, and (site-specific) SEP-UIP-IPEC to implement the UPTIMP and meet the industry initiative in NEI 09-14, Rev. 1 (NYS000168) for its entire fleet. Entergy treats the NEI 09-14 initiative requirements (albeit related to current plant operations), with the same level of obligation as a licensing commitment. Id. at 73-74. These procedures are used at all of Entergy's nuclear plants, including Indian Point. Tr. at 3420, 3464-66. As applicable here, Entergy's corporate procedures EN-DC-343,[113] CEP-UPT-0100, and EN-EP-S-002-MULTI, along with site-specific procedure SEP-UIP-IPEC, constitute its implementing procedures for the BPTIP. Tr. at 3420, 3484-87, 3666.

2.208. Staff witness William Holston provided the Staff's view with respect to the four corporate procedures discussed above.[114] In this regard, Mr. Holston agreed with Dr. Duquette in part, stating that to the extent Entergy's corporate procedures are not incorporated in the plants' operating licenses or the plants' updated UFSARs, they are not binding upon the licensee. He further testified, however, that this is of no concern here, in that the essential or key aspects of the corporate program including preventive measures to mitigate corrosion, trending of inspection results, quantity and frequency of inspections, quantity and frequency of soil sampling, and expansion of inspection scope if the soil is demonstrated to be corrosive, are all included in the UFSAR. Further, changes to procedures described in the UFSAR can only be made in accordance with the 10 C.F.R. § 50.59 process. Staff Testimony on NYS-5 (Ex. NRCR20016), at 56-57; Tr. at 3542.

2.209. In addition, Mr. Holston disputed Dr. Duquette's view that "it is not clear how Entergy's response to the [Staff's] RAI squares with the information in Entergy's corporate documents setting inspection priority and scheduling every ten years." *Id*. at 48-49, *citing* New York Testimony on NYS-5 (Ex. NYS000164) at 25. In the event that the NRC issues renewed

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[113] In response to the Board's questions, Entergy witness Mr. Azevedo confirmed that all aspects of EN-DC-343 apply at the Indian Point site. Tr. at 3465-66.

[114] Mr. Holston initially addressed three of the corporate procedures; he later clarified that his remarks apply to all four procedures. *See* Tr. at 3487-88; 3666.

licenses for IP2 and IP3, those renewed licenses (with their accompanying license conditions and technical specifications) would govern the operation of Indian Point, subject to NRC regulatory requirements, including the requirements in 10 C.F.R. Parts 50 and 54.[115] Any corporate policies that may be adopted by Entergy are not binding on the licensee, for NRC regulatory purposes, unless they are NRC regulatory requirements or are incorporated in the license or the UFSAR. Although Entergy may elect to supplement its license requirements by following its corporate policies at the Indian Point site, those policies would not be enforced by the NRC unless they are incorporated in the current or renewed license or otherwise become NRC requirements. This applies to the three Entergy documents cited by Dr. Duquette (EN-DC-343, CEP-UPT-0100, and SEP-UIP-IPEC).

2.210. Further, in the event of any conflict between the license or other NRC requirements and Entergy's corporate policies, the license or other NRC requirements would control the plants' operations. Thus, despite any requirements that may exist in Entergy's corporate procedures, IP2 and IP3 must at a minimum meet the requirements contained in their licenses and UFSARs. Procedures that are included in the UFSAR may only be changed in accordance with the provisions of 10 C.F.R. § 50.59. Staff Testimony on NYS-5 (Ex. NRCR20016), at 48-49; Tr. at 3334-35, 3398-99, 3542, 3646.

2.211. Mr. Holston testified that the Standard Review Plan pre-sanctioned the level of detail that the Staff would expect to see in the FSAR supplement. Tr. 3537-38. As he further stated, the Standard Review Plan identified what must be included in an AMP, and the level of

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[115] On December 6, 2012, Entergy filed Revision 1 of CEP-UPT-0100, Underground Piping and Tanks Inspection and Monitoring, as Exhibit ENT000598. Mr. Holston testified that the statements in Answer 37 of his testimony regarding CEP-UPT-0100 and EN-DC-343 apply, as well, to Revision 1 of CEP-UPT-0100 (Nov. 30, 2012) and Revision 6 of EN-DC-343 (Nov. 30, 2012) (Exs. ENT000598 and ENT000599, respectively). Staff Testimony (Ex. NRCR20016) at 49 n.7.

detail that is expected for the FSAR Supplement. Tr. at 3376, 3531-32. The most critical aspects of Entergy's AMP are incorporated in its UFSAR; likewise, the principal bases for the Staff's acceptance of the AMP [*i.e*., coatings, number of inspections, risk-informing, and soil sampling] are set out in SER Supplement 1 (Ex. NYS000160) at 3-4, Tr. at 3641-42.[116] Other aspects of the procedure that are not captured in the UFSAR can be changed without requiring an analysis under 10 C.F.R. § 50.59. Tr. at 3329-30, 3334-35, 3398-99, 3467-69, 3474-76, 3530-31, 3533, 3542.[117]

2.212. Despite the fact that only certain BPTIP provisions have been incorporated in the UFSAR, Entergy's witnesses testified that Entergy's administrative controls require that even

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[116] Although he disagreed with the Staff's conclusions, Dr. Duquette concurred that the Staff had "reasonably covered most of what we should be concerned about." Tr. at 3478. Further, he testified that "the Staff has done a really good job of improving the situation for buried pipelines" in its AMP XI.M41, although he still believed cathodic protection is required under that GALL Report AMP. Tr. at 3725.

[117] As set forth in 10 C.F.R. § 50.59(c)(1), a licensee may make changes in the facility as described in the FSAR (as updated),may make changes in the procedures as described in the FSAR (as updated), and may conduct tests or experiments not described in the FSAR (as updated) without obtaining a license amendment pursuant to 10 C.F.R. §.50.90 <u>only if</u> (i) a change to the technical specifications incorporated in the license is not required, and (ii) The change, test, or experiment does not meet any of the criteria in § 50.59(c)(2). In turn, 10 C.F.R. § 50.59(c)(2) requires that the licensee must obtain a license amendment pursuant to §.50.90 prior to implementing a proposed change, test, or experiment if the change, test, or experiment would:

> (i) Result in more than a minimal increase in the frequency of occurrence of an accident previously evaluated in the [FSAR] (as updated);
>
> (ii) Result in more than a minimal increase in the likelihood of occurrence of a malfunction of a structure, system, or component (SSC) important to safety previously evaluated in the [FSAR] (as updated);
>
> (iii) Result in more than a minimal increase in the consequences of an accident previously evaluated in the [FSAR] (as updated);
>
> (iv) Result in more than a minimal increase in the consequences of a malfunction of an SSC important to safety previously evaluated in the [FSAR] (as updated);
>
> (v) Create a possibility for an accident of a different type than any previously evaluated in the [FSAR] (as updated);
>
> (vi) Create a possibility for a malfunction of an SSC important to safety with a different result than any previously evaluated in the [FSAR] (as updated);
>
> (vii) Result in a design basis limit for a fission product barrier as described in the FSAR (as updated) being exceeded or altered; or
>
> (viii) Result in a departure from a method of evaluation described in the FSAR (as updated) used in establishing the design bases or in the safety analyses.

implementing procedures that are not incorporated in the UFSAR must undergo a screening process (involving three screening questions developed by Entergy) before they can be changed, to determine whether a § 50.59 analysis is required. Tr. at 3399-3400, 3470-72, 3650-51, 3655-56, 3661. If the Applicant then determines that § 50.59 applies to a proposed procedure change, Entergy would perform a § 50.59 analysis in accordance with that regulation. Tr. at 3661-64. The screening process and Entergy's screening determinations are described in documents that are maintained at the Indian Point site, which are available for NRC Staff inspection. Tr. at 3942-43. The NRC audits Entergy's § 50.59 process on an annual basis. Tr. at 3943. The implementing procedures for all of the IP2/IP3 AMPs are comprised of thousands of pages. Tr. at 3967. Entergy's screening process applies not only to the BPTIP implementing procedures, but to hundreds of other procedures that are not included in the UFSAR; it would be unnecessary and cumbersome to include the details of so many procedures in a UFSAR, since changes would require use of the § 50.59 process. Tr. at 3656-58, 3659.

2.213. Mr. Holston confirmed that all three of these corporate procedures are available on-site, to demonstrate how the AMP is implemented. Tr. at 3467. He further stated the Staff's conclusion that sufficient details are provided in the AMP for buried piping and tanks, and that the controls provided by 10 C.F.R. § 50.59 are adequate to control future changes to the program. Tr. at 3334-35, 3467-69. In addition, the Staff will conduct on-site inspections, under Inspection Procedure IP-71003 (or TI-2516), to verify that the Applicant has met its commitments, and retains the ability to take enforcement action in the future, if it finds those commitments have not been met. Tr. at 3356-60, 3469.

2.214. Likewise, Entergy's commitments, recited in SER Supplement 1 (Ex. NYS000160), Appendix A, "Indian Point Nuclear Generating Unit Nos. 2 and 3 License Renewal Commitments," become part of the plants' CLB if renewed licenses are issued; these include Entergy's Commitment Nos. 3 and 48, pertaining to implementation of the BPTIP. *See* SER

Supp. 1 (Ex. NYS000160), App. A. at A-2 (Commitment 3); Entergy letter NL-12-174 (Nov. 29, 2012) (Ex. ENT000597) (Commitment 48). Once a commitment is incorporated in the UFSAR, it cannot be changed without use of the § 50.59 process. Tr. at 3641, 3644-46, 3649.

2.215. Entergy's practice of including the details as to how it will implement the BPTIP in its implementing procedures, rather than in the AMP itself, is consistent with NRC guidance in the Standard Review Plan, GALL Report and LR-ISG-2011-03, and is similar to established industry practice. Tr. at 3395-96, 3418-19, 3530-33, 3654, 3966-67.[118]

2.216. We find that the four Entergy corporate procedures discussed above, to the extent that they are utilized in implementing the BPTIP at IP2 and IP3, constitute implementing procedures for the BPTIP that need not be included in that AMP or the plants' UFSARs. Further, we find that the Applicant's procedure change process, as well as NRC regulatory controls and oversight, provide further assurance that the Applicant will satisfy its AMP commitments. These conclusions are consistent with established NRC and industry practice for implementing procedures of this nature.

10. Conclusion Regarding the Adequacy of Entergy's AMP

2.217. Contention NYS-5 challenges the adequacy of the aging management program for buried and underground pipes and tanks at IP2 and IP3, to manage the effects of aging on buried pipes and tanks that may contain radioactive fluids during the period of extended operation. The Board has carefully considered the evidence presented by all parties, with respect to all of the assertions presented in this contention, as amplified in the testimony of New York witness Dr. David Duquette (Ex. NYS000164) and the exhibits filed in support thereof.

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[118] All of an applicant's implementing procedures are expected to be developed and ready to be put into action the day its current license(s) expire. Tr. at 3648.

Based upon our review of all of the evidence presented by New York, Entergy and the Staff, for the reasons set forth above we find that Contention NYS-5 should be resolved in favor of the Applicant.

III. CONCLUSIONS OF LAW

2.218. The Board has considered all of the evidence presented by the parties on Contention NYS-5. Based upon a review of the entire record in this proceeding and the proposed findings of fact and conclusions of law submitted by the parties, and based upon the findings of fact set forth above, which are supported by reliable, probative and substantial evidence in the record, the Board has decided all matters in controversy concerning this contention and reaches the following conclusions.

2.219. The Commission's regulations in 10 C.F.R. § 54.21(a)(1) require every license renewal application to include an aging management review for structures and components that perform an intended function, as described in § 54.4, without moving parts or a change in configuration or properties. For each structure and component identified in § 54.21(a)(1), license renewal applicants are then required, through an aging management program developed pursuant to 10 C.F.R. § 54.21(a)(3), to identify the inspection, surveillance, monitoring and maintenance programs it intends to use to demonstrate that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation.

2.220. Entergy performed an aging management review for buried and underground piping and tanks, and provided an aging management program (the BPTIP) for such structures and components in its LRA.

2.221. Based upon the substantial and reliable evidence of record, we conclude that the Applicant has properly identified the intended functions of systems within the scope of license renewal under 10 C.F.R. § 54.4(a)(1)-(3)), as pertinent to the performance of buried and underground piping and tanks. In his regard, the Applicant has appropriately identified the components that are within the scope of license renewal, as required by 10 C.F.R. § 54.4(a), and those components that are subject to an aging management review (AMR), as required by 10 C.F.R. § 54.21(a)(1). Further, the Applicant properly included consideration of the IP1 SSCs that are included or relied upon by SSCs at IP2 and/or IP3 and are within the scope of license renewal, as well as underground and buried piping and tanks that may contain radioactive fluids that are within the scope of license renewal.

2.222. The Applicant's proposed UFSAR Supplement pertaining to its aging management program for buried and underground piping and tanks provides an adequate summary description of the program, as required by 10 C.F.R. § 54.21(d). In the event a renewed license is issued, revisions to the UFSAR will be subject to the change processes specified in 10 C.F.R. § 50.59.

2.223. We conclude, based upon the substantial and reliable evidence of record, that the Applicant has demonstrated that the effects of aging on buried piping and tanks will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 C.F.R. § 54.21(a)(3).

2.224. We further conclude, based upon the substantial and reliable evidence of record, that actions have been or will be taken with respect to the matters specified in 10 C.F.R. § 54.29(a)(1)-(2), as they pertain to in-scope IPEC buried and underground piping and tanks at issue in Contention NYS-5, such that there is reasonable assurance that the activities authorized by the renewed licenses will continue to be conducted in accordance with the CLB, and that any changes made to the plant's CLB in order to comply with 10 C.F.R. § 54.29 are in accord with the Act and the Commission's regulations, as required by 10 C.F.R. § 54.29(a).

2.225. Therefore, we conclude that Entergy's license renewal application complies with the requirements of 10 C.F.R. §§ 54.21 and 54.29, with respect to the issues raised Contention NYS-5 regarding buried and underground piping and tanks within the scope of license renewal.

2.226. In accordance with these determinations, we find that Entergy's LRA provides an adequate aging management program for in-scope buried and underground piping and tanks that contain radioactive fluid,

2.227. These findings of fact and conclusions of law resolve all contested issues raised in Contention NYS-5, in favor of Entergy's application for license renewal for Indian Point Units 2 and 3. Accordingly, we find that Contention NYS-5 should be, and is hereby, resolved in favor of the Applicant.

Respectfully submitted,

/Signed (electronically) by/

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Dated at Rockville, Maryland
this 22nd day of March 2013
As revised 04/22/2013

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of	)	
	)	
ENTERGY NUCLEAR OPERATIONS, INC.	)	Docket Nos. 50-247/286-LR
	)	
(Indian Point Nuclear Generating	)	
Units 2 and 3)	)	

CERTIFICATE OF SERVICE

Pursuant to 10 C.F.R § 2.305 (as revised), I hereby certify that copies of the foregoing "NRC STAFF'S REVISED PROPOSED FINDINGS OF FACT AND CONCLUSIONS OF LAW, PART 2: CONTENTION NYS-5 (BURIED PIPING AND TANKS)," dated March 22, 2013, as revised 04/22/2013, have been served upon the Electronic Information Exchange (the NRC's E-Filing System), in the above- captioned proceeding, this 22nd day of ~~March~~ April, 2013.

/Signed (electronically) by/

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