UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of	)	Docket Nos. 50-247-LR and 50-286-LR
	)	
ENTERGY NUCLEAR OPERATIONS, INC.	)	
	)	
(Indian Point Nuclear Generating Units 2 and 3)	)	
	)	March 30, 2012

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)

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I. WITNESS BACKGROUND

A. Alan B. Cox ("ABC")

Q1. Please state your full name.

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

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

A2. (ABC) I am employed by Entergy Nuclear Operations, Inc. ("Entergy"), the Applicant in this matter, as Technical Manager, License Renewal. My office is located at Entergy's Arkansas Nuclear One ("ANO") facility in Russellville, Arkansas.

Q3. Please describe your educational and professional qualifications, including relevant professional activities.

A3. (ABC) My professional and educational qualifications are summarized in the *curriculum vitae* attached as Exhibit ENT000031. Briefly summarized, I hold 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. I have 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. For example, from 1993 to 1996, I was employed as a Senior Staff Engineer at ANO. From 1996 to 2001, I served as the Supervisor, Design Engineering, at ANO. I was licensed by the NRC in 1981 as a reactor operator and in 1984 as a senior reactor operator for Arkansas Nuclear One, Unit 1.

Q4. Please describe your role with respect to the Indian Point Energy Center license renewal application for Indian Point Units 2 and 3 ("IP2" and IP3").

A4. (ABC) As Technical Manager, I was directly involved in preparing the LRA and developing or reviewing aging management programs ("AMPs") for IP2 and IP3 (referred to jointly as Indian Point Energy Center, or "IPEC"). Those programs include the Buried Piping and Tanks Inspection Program ("BPTIP"), the AMP for buried piping and tanks that may be susceptible to external corrosion. I have been directly involved in developing or reviewing Entergy 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). I 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 in September 2009, respectively. Accordingly, I have personal knowledge of the development and subsequent revision of the LRA, including the BPTIP.

B. <u>Ted S. Ivy ("TSI")</u>

Q5. Please state your full name.

A5. (TSI) My name is Ted S. Ivy.

Q6. By whom are you employed and what is your position?

A6. (TSI) I am employed by Entergy as Manager, License Renewal. My office is at Entergy's ANO facility in Russellville, Arkansas.

Q7. Please describe your educational and professional qualifications, including relevant professional activities.

A7. (TSI) My qualifications are summarized in the attached *curriculum vitae* (ENT000374). In brief, I have over 30 years of work experience, more than 25 years of which has been in the nuclear industry. I hold a Bachelor of Science degree in Mechanical Engineering from the University of Arkansas and a Masters of Business Administration degree from the University of Arkansas at Little Rock. I am a licensed Professional Engineer in the States of Arkansas and Louisiana. I am 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. Additionally, I am an Entergy representative on the NEI License Renewal Mechanical Working Group and served as Vice Chairman (2009-2010) and Chairman (2010) of that organization.

As a member of the Entergy License Renewal Services team, I have been directly involved in seven license renewal projects, including the IPEC project. In addition, I am the Responsible Lead for development and maintenance of the web-based License Renewal Information System database that Entergy uses to develop aging management review reports and license renewal applications.

Q8. Please describe your role with respect to the IPEC LRA.

A8. (TSI) My principal responsibilities with respect to the IPEC LRA have 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 have encompassed review of the license renewal BPTIP and revisions to that program.

C. <u>Nelson F. Azevedo ("NFA")</u>

Q9. Please state your full name.

A9. (NFA) My name is Nelson F. Azevedo.

Q10. By whom are you employed and what is your position?

A10. (NFA) I am employed by Entergy as Supervisor, Code Programs, at the IPEC facility in Buchanan, New York.

Q11. Please describe your educational and professional qualifications, including relevant professional activities.

A11. (NFA) My qualifications are summarized in the attached *curriculum vitae* (ENT000032). I hold a Bachelor of Science in Mechanical and Materials Engineering degree from the University of Connecticut and a Master of Science degree in Mechanical Engineering from the Rensselaer Polytechnic Institute ("RPI") in Troy, New York. I also have a Masters of Business Administration degree from RPI. I have over 30 years of professional experience in the nuclear power industry. During that time, I have held engineering, supervisory, and managerial positions with Northeast Utilities and Entergy. As a Department Manager with Northeast Utilities, I managed five engineering sections responsible for implementing numerous engineering programs at Millstone Station. I oversee the engineering section responsible for

implementing a number of IPEC programs, 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 leakrate programs. I also am responsible for ensuring compliance with the ASME Code, Section XI requirements for repair and replacement activities at IPEC. I also represent IPEC before industry organizations, including the Pressurized Water Reactor ("PWR") Owners Group Management Committee.

Q12. Please describe your role with respect to the IPEC LRA.

A12. (NFA) As Supervisor, Code Programs at IPEC, I have contributed to the development and review of license renewal documentation, including the BPTIP, Entergy responses to related Staff RAIs, and amendments to the BPTIP.

D. <u>Robert C. Lee ("RCL")</u>

Q13. Please state your full name.

A13. (RCL) My name is Robert C. Lee.

Q14. By whom are you employed and what is your position?

A14. (RCL) I am employed by Entergy as Senior Engineer, Code Programs, at the IPEC facility in Buchanan, New York.

Q15. Please describe your educational and professional qualifications, including relevant professional activities.

A15. (RCL) My qualifications are summarized in the attached *curriculum vitae* (ENT000375). In brief, I received a Bachelor of Science degree in Mechanical Engineering from the City College of New York. I am a licensed Professional Engineer in the State of New York.

I have over 35 years of work experience, approximately 30 years of which have been in the nuclear power industry. My nuclear experience principally has been in the Design/Analysis groups within Combustion Engineering, the New York Power Authority, and Entergy. My current position is in the IPEC Code Programs group, where I am the lead for the following programs: inservice testing, Appendix J containment leakrate, pressure testing and the Underground Piping and Tanks Inspection and Monitoring Program ("UPTIMP").

Q16. Please describe your role with respect to the IPEC LRA.

A16. (RCL) I am the program engineer for the IPEC Underground Piping and Tanks Inspection and Monitoring Program ("UPTIMP"), Entergy's current, 10 C.F.R. Part 50-based program for managing IPEC buried piping and tanks. In this capacity, I have been responsible for developing and implementing that program, which Entergy also is using to implement its license renewal AMP (*i.e.*, the BPTIP). Therefore, I am familiar with the IPEC AMP described in LRA Section B.1.6; amendments to that program, including license renewal commitments related to buried piping; and specific actions being taken by Entergy to implement the UPTIMP and the BPTIP.

E. <u>Stephen F. Biagiotti, Jr. ("SFB")</u>

Q17. Please state your full name.

A17. (SFB) My name is Stephen F. Biagiotti, Jr.

Q18. By whom are you employed and what is your position?

A18. (SFB) I am a Senior Associate with 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. I

was retained by Entergy to provide expert services in connection with the adjudication of contention NYS-5.

Q19. Please describe your educational and professional qualifications, including relevant professional activities.

A19. (SFB) My qualifications are summarized in the attached *curriculum vitae* (ENT000376). Briefly, I hold Bachelor of Science and Master of Science degrees in Metallurgical Engineering from the Colorado School of Mines and am a Registered Professional Engineer in Colorado. I have 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.

I have been a member of the NACE International (formerly National Association for Corrosion Engineers) for over 20 years. During that time, I have 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. I also have 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.

During the past five years, I have served as the Chairman of a NACE Task Group 357, which created Standard Practice ("SP") 0507, External Corrosion Direct Assessment ("ECDA") Integrity Data Exchange ("IDX") Format, and I am an active leader in Task Group 404 on Nuclear Buried Piping. More recently, I 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, I am 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." Also, I have authored or co-authored about three dozen publications relating to corrosion risk assessment and integrity management of pipelines and buried plant piping and hold several related patents. My *curriculum vitae* (ENT000376) contains a partial list of my publications and patents.

Among other positions, I have 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, I supervised all corrosion, failure analysis, and metallurgical testing in three laboratories. More recently, from 2003 to 2006, I served as Product Manager, Integrity Services at GE Energy in Houston, Texas. There, I 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, I have 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, I 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. Entergy is deploying the MAPPro© software program at its nuclear units, including IP2 and IP3, to assist in managing aging effects on buried piping and tanks.

Q20. Please describe the basis for your familiarity with the IPEC LRA, including the associated BPTIP being challenged in NYS-5.

A20. (SFB) Among numerous other documents, I have reviewed the relevant portions of the IPEC LRA and NRC Staff's Safety Evaluation Report ("SER") and Supplemental SER, particularly those portions relating to the BPTIP. I also have reviewed Entergy responses to Staff RAIs, license renewal commitments, corrective action/operating experience documents, and fleet engineering procedures relevant to the BPTIP. SIA digitized information from over 150 pipe drawings, representing more than 400 buried lines, as part of its buried pipe database population and risk analysis effort (*i.e.*, BPWorks™ 2.0 and MAPPro©). Further, 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. I participated in the evaluation of this survey and have been to the IPEC site.

F. Jon R. Cavallo ("JRC")

Q21. Please state your full name.

A21. (JRC) My name is Jon R. Cavallo.

Q22. By whom are you employed and what is your position?

A22. (JRC) I am a Senior Consultant with Enercon Services, Inc., specializing in corrosion mitigation and protective coatings. I am based in Portsmouth, New Hampshire.

Q23. Please describe your educational and professional qualifications, including relevant professional activities.

A23. (JRC) My education and professional experience are described in the attached *curriculum vitae* (ENT000377). In brief, I hold a Bachelor of Science degree in Engineering Technology from Northeastern University in Boston, Massachusetts. I am a Registered Professional Engineer in three states. I am 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. I also hold registrations as a Certified Nuclear Coatings Engineer from the National Board of Registration for Nuclear Safety Related Coating Engineers and Specialists and Senior Nuclear Coatings Specialist from the Board of International Registration for Nuclear Coatings Specialists. In 2010, I received the ASTM International Award of Merit and the designation of Fellow from the American Society for Testing and Materials ("ASTM").

I have 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 this period, I 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. Thereafter, until 1986, I worked at Metalweld, Inc., where I served as its 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, I was a Senior Associate in the consulting engineering firm of S.G. Pinney & Associates, Inc., where I managed the Reston, VA, Eliot, ME, Oak Lawn, IL, and Seattle, WA offices and performed protective coating and lining work at a number of nuclear

generating facilities. I then worked as an independent professional engineer, providing corrosion engineering consulting services, from 1991 to 1998. From 1998 to 2009, I was the Vice President of Corrosion Control Consultant & Labs, Inc., which provides corrosion mitigation professional engineering services in surface preparation, protective coatings, and linings. Since 2009, I have been a Senior Consultant with Enercon Services, Inc.

I am active in numerous national technical societies, including SSPC, NACE, and ASTM. I served as Chairman of the Northern New England Chapter of SSPC from 1991 to 1998, have been Chairman of the New England Chapter of SSPC from 2000 to the present, and was a member of the SSPC National Strategic Planning Committee. In addition, I was elected Chairman of ASTM Technical Committee D-33 on Protective Coating and Lining Work for Power Generation Facilities for the periods 2004 through 2005, 2006 through 2007, and 2008 through 2009. I also 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).

Working with EPRI in 2001, I served as Editor of EPRI Technical Report ("TR") 1003120 (formerly TR-109937), Revision 1, *Guideline on Nuclear Safety-Related Coatings*. I also assisted in development of, and continue to teach, an EPRI Comprehensive Coatings Course. Finally, I am the Principal Investigator for Revision 2 to *Guideline on Nuclear Safety-Related Coatings*, which EPRI published as a final report in December 2009.

Q24. Please describe the basis for your familiarity with the IPEC license renewal project, including the associated LRA, with respect to the issues raised in NYS-5.

A24. (JRC) Among numerous other documents, I have reviewed the relevant portions of the IPEC LRA and NRC Staff's SER and Supplemental SER, specifically those portions

relating to the BPTIP. I also have reviewed Entergy responses to Staff RAIs, license renewal commitments, corrective action/operating experience documents, coating specifications for IPEC buried piping, and fleet engineering procedures relevant to the BPTIP.

II. OVERVIEW OF CONTENTION NYS-5

Q25. Are you familiar with Contention NYS-5, as originally proposed by NYS?

A25.[1] Yes. We have reviewed the New York State Notice of Intention to Participate and Petition to Intervene (Nov. 30, 2007) ("NYS Petition"); the Declaration of Rudolf H. Hausler (NYS's former consultant) (Nov. 26, 2007) ("Hausler Decl."); the Declaration of Timothy B. Rice (Nov. 26, 2007) ("Rice Decl."); and the New York State Reply in Support of Petition to Intervene (Feb. 22, 2008) ("NYS Reply"). As proffered, NYS-5 alleged that Entergy's AMP (*i.e.*, BPTIP) fails to comply with 10 C.F.R. §§ 54.21 and 54.29(a) because:

> (1) it does not provide for adequate inspection of all systems, structures, and components that may contain or convey water, radioactively-contaminated water, and/or other fluids; (2) there is no adequate leak prevention program designed to replace such systems, structures, and components ["SSCs"] before leaks occur; and (3) there is no adequate monitoring to determine if and when leakage from these systems, structures, and components occurs. These [SSCs] include underground pipes, tanks, and transfer canals.

NYS Petition at 80. NYS-5 also stated that the contention "also applies to IP1 to the extent that Unit 2 and Unit 3 use Unit 1's buried [SSCs] that may contain or convey water, radioactively-contaminated water, and/or other fluids." *Id.* at 80-81.

[1] Unless otherwise indicated by specific witness initials, responses to questions are by the full panel.

Q26. On what basis did the Atomic Safety and Licensing Board ("Board") admit contentions NYS-5 on July 31, 2008?

A26. The Board admitted NYS-5 to the extent that it pertains to the adequacy of Entergy's AMP for buried pipes, tanks, and transfer canals that contain radioactive fluid [and] which meet 10 C.F.R. § 54.4(a) criteria. *See Entergy Nuclear Operations, Inc.* (Indian Point Nuclear Generating Units 2 and 3), LBP-08-13, 68 NRC 43, 81 (2008). According to the Board, the questions to be addressed at 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. *Id*. The Board further stated that:

> As it relates to this contention, discussion of proposed inspection and monitoring details will come before this Board only as they are needed to demonstrate that the Applicant's AMP does or does not achieve the desired goal of *providing assurance that the intended function of relevant SSCs discussed herein will be maintained for the license renewal period*, and specifically, to detect, prevent, or mitigate the effects of future inadvertent radiological releases as they might affect the *safety function* of the buried SSCs and potentially impact public health.

Id. (emphasis added).

The Board also found that there is a material dispute as to the existence and adequacy of the AMP for IP1-buried SSCs that may be used by IP2 and IP3 during the period of extended operation. *Id.* at 82. In so ruling, the Board cited the need for Entergy to: (1) identify the relevant IP1 SSCs (per 10 C.F.R. § 54.21); (2) demonstrate that the IPEC AMP for buried pipes pertains to IP1 SSCs that may be relied upon during the extended operating period; and (3) delineate the extent of the proposed aging management activities related to the IP1 SSCs. *Id.*

Q27. Have you reviewed NYS's initial statement of position, prefiled testimony, and supporting exhibits for NYS-5, as filed on December 16, 2011?

A27. Yes, we have reviewed the following documents filed by NYS: State of New York's Initial Statement Regarding the Adequacy of Entergy's Aging Management Program for Buried Pipes and Tanks (Contention NYS-5) (NYS000163) ("NYS-5 Statement of Position"); Pre-Filed Written Testimony of Dr. David J. Duquette, Ph.D Regarding Contention NYS-5 (NYS000164) ("Duquette Testimony"); Report of Dr. David J. Duquette, Ph.D in Support of Contention NYS-5 (NYS000165) ("Duquette Report"); Biographical Sketch and Professional Activities Rensselaer Polytechnic Institute of David J. Duquette (NYS000166); and Exhibts NYS000167 through NYS000205.

Q28. What materials have you reviewed in preparation for your testimony, and what is the source of those materials?

A28. As mentioned in Section I above, many are documents prepared by government agencies, peer-reviewed articles, or documents prepared by Entergy or the utility industry. These documents include, for example, NRC regulations and guidance documents, the IPEC LRA and revisions thereto, Entergy RAI responses, the NRC Staff's SER and Supplemental SER, EPRI and NEI guidance documents, Entergy program documents and procedures, IPEC inspection reports, IPEC condition report and root cause evaluation reports, vendor reports, buried piping specifications, and engineering drawings.

Q29. I show you what has been marked as Exhibit ENT000001. Do you recognize this document?

A29. Yes. It is a list of Entergy's exhibits, and includes those documents that we used in preparing this testimony, Exhibits ENT00015A-B, ENT000031, ENT000032, ENT000098, ENT000251, ENT000252, ENT000322, and ENT000374 through ENT000446.

Q30. I show you Exhibits ENT00015A-B, ENT000031, ENT000032, ENT000098, ENT000251, ENT000252, ENT000322, and ENT000374 through ENT000448. Do you recognize these documents?

A30. Yes. These are true and accurate copies of the documents that we have relied upon in preparing this testimony. In those cases in which we have attached only an excerpt of a document, that is noted on the cover of the exhibit.

Q31. How do these documents relate to the work that you do as an expert in forming opinions such as those contained in this testimony?

A31. These documents represent the type of information that persons within our fields of expertise reasonably rely upon in forming opinions of the type offered in this testimony. We note at the outset that we cannot offer legal opinions on the language of the NRC regulations, guidance documents, or other Commission documents referenced in our testimony. However, through reading certain statements therein as technical statements and using our expertise, we can interpret the technical meaning of these statements for purposes of aging management of buried piping and tanks.

III. SUMMARY OF TESTIMONY AND CONCLUSIONS

Q32. What is the purpose of your testimony?

A32. In our testimony, we will explain why NYS-5 lacks merit and should be resolved in Entergy's favor. Specifically, we will explain why Entergy's AMP for buried pipes and tanks, the BPTIP, meets all applicable NRC requirements, is fully consistent with NRC and industry guidance, and provides reasonable assurance that buried components addressed by the BPTIP, including those that contain or may contain radioactive fluids (the focus of NYS-5), will perform their intended functions during the period of extended operation.

Q33. Please summarize the principal claims made by NYS and its consultant, Dr. Duquette, in NYS's prefiled testimony and other written submissions.

A33. NYS and Dr. Duquette's principal arguments are as follows: (1) Entergy does not know the current state or condition of IPEC buried piping; (2) Entergy's buried piping AMP lacks sufficient detail; (3) Entergy's LRA contains ambiguous and insufficient commitments; (4) the acceptability of inspection program results, including the criteria to be applied to continued operation, remediation, or replacement, must be specified; (5) both NEI and EPRI documents recommend cathodic protection for critical piping systems; (6) Entergy's AMP for IPEC buried piping does not commit to any corrosion mitigation measures, such as re-activating inoperative cathodic protection systems or installing new cathodic protection systems; and (7) Entergy's own data show that IPEC soils are mildly to moderately corrosive, "objectively" warranting cathodic protection. *See generally* NYS-5 Statement of Position (NYS000163); Duquette Testimony (NYS000164); Duquette Report (NYS000165).

Q34. Please summarize the basis for your disagreement with the claims made by NYS and its identified experts.

A34. Our testimony fully refutes each of NYS's criticisms. We will show that:

1. Entergy has a comprehensive understanding of those IPEC systems containing buried piping components, including those components that perform license renewal intended functions and may contain radiological constituents. NYS's contrary assertion is incorrect. In fact, Entergy has gained significant insights into the condition of IPEC buried piping and their coatings through numerous direct and indirect inspections performed to date. It has incorporated this information into a state-of-the-art computer database that has and will be used to prioritize inspections based on IPEC design and operating experience information.

2. Although Entergy's original AMP referenced NUREG-1801, Vol. 1, Rev. 1, Generic Aging Lessons Learned (GALL) Report (Sept. 2005) ("NUREG-1801" or "GALL Report") (NYS00146A-C), NYS's discussion of the level of detail in the LRA fails to acknowledge the most critical details of the BPTIP program description. The descriptions in Appendix B of the LRA follow the convention established in NEI 95-10, Appendix D (ENT000098). Under that convention, the IPEC LRA described the BPTIP as consistent with NUREG-1801 with no exceptions. LRA, Appendix B at B-27 (ENT000015B). This program description tells the reviewer that the IPEC program is, in essence, the exact program that the NRC staff had reviewed and approved in NUREG-1801, without exception. Therefore, the details of the ten-element NUREG-1801 program XI.M34 description were incorporated by reference into the IPEC LRA. Since the IPEC LRA was submitted, Entergy has substantially augmented the BPTIP in response to industry operating experience and the guidance contained in NUREG-1801, Rev. 2, Generic Aging Lessons Learned (GALL) Report (Dec. 2010)

(NYS000147A-D). Thus, the program is not lacking in detail, nor is it "conceptual and aspirational in nature." Duquette Testimony at 18:12. Indeed, as discussed below, the program has been implemented in part at IPEC through Entergy procedures that are based on NEI and EPRI guidelines.

3. Entergy license renewal Commitment 3 makes explicit Entergy's obligation to implement the BPTIP. *See* NUREG-1930, Supp. 1, Safety Evaluation Report Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3, App. A at A-2 (Aug. 2011) (NYS000160). Entergy's implementation of the BPTIP, including its performance of docketed commitments and adherence to applicable Entergy procedures, will be verified and enforced by the NRC through 10 C.F.R. Part 50 processes. Further, as discussed below, BPTIP implementation is closely linked to implementation of IPEC's 10 C.F.R. Part 50 underground piping program, the UPTIMP, and an industry underground piping initiative. NEI 09-14, Rev. 0, Guideline for the Management of Buried Piping Integrity (Jan. 2010) (ENT000378). Thus, NYS's claim that the BPTIP relies on ambiguous and insufficient commitments is inaccurate.

4. Any visually confirmed buried pipe coating degradation will be reported and evaluated according to IPEC corrective action procedures. The acceptance criteria for buried piping degradation found during inspections are the design criteria for the affected system. Buried piping that does not meet acceptance criteria is repaired or replaced as required by the IPEC Corrective Action Program

5. NYS incorrectly characterizes industry guidance on CP. The NEI and EPRI guidance documents cited by NYS do not recommend that CP be installed for critical piping systems. Rather, both documents recommend that if a CP system exists, then it should be properly tested and maintained. NRC guidance 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. Recent Draft License Renewal Interim Staff Guidance (LR-ISG-2011-03) further clarifies that CP is not a requirement for license renewal. Specifically, the draft ISG indicates that license renewal guidance should be revised to include inspection recommendations for plants not utilizing a cathodic protection system during the period of extended operation. *See* Draft License Renewal Interim Staff Guidance (LR–ISG), LR– ISG–2011–03, "Changes to GALL Report Revision 2 Aging Management Program (AMP) XI.M41, 'Buried and Underground Piping and Tanks.'" (Mar. 2012) ("Draft LR-ISG-2011-03") (ENT000379).

6. Entergy has not disregarded vendor recommendations as claimed by NYS and its expert. NYS-5 Statement of Position at 52-53; Duquette Testimony at 22:6-24:6. As part of current plant operations, Entergy has undertaken preventive maintenance of existing IPEC CP systems and, based on vendor recommendations, installed several new CP systems for corrosion control on buried piping that is within the scope of the BPTIP. Entergy will continue to evaluate the need for further CP based on inspection results and operating experience under the UPTIMP and BPTIP and install additional CP systems where prudent for corrosion control.

7. Available soil data do not indicate that soil corrosivity is a significant concern at IPEC, or that soil corrosivity, by itself, warrants cathodic protection "as an objective matter." Duquette Testimony at 22:15-16.

8. The IPEC BPTIP meets Dr. Duquette's own recommendations for an adequate aging management program because it: (1) adopts NEI and EPRI recommendations; (2) follows the dictates of NUREG-1801, Rev. 2, Section XI.M41; (3) identifies acceptance criteria for inspections of buried pipes; and (4) states the repair and remediation procedures to be followed if

the corrosion damage exceeds the acceptance criteria. Accordingly, NYS-5 lacks merit and should be resolved in Entergy's favor.

IV. OVERVIEW OF RELEVANT REGULATIONS AND GUIDANCE

A. Applicable Part 54 Requirements

Q35. Please identify and briefly describe the NRC's aging management requirements in 10 C.F.R. Part 54.

A35. (ABC, TSI, NFA) 10 C.F.R. § 54.4(a)(1)-(3) outline the three general categories of SSCs that fall within the scope of license renewal. From among these SSCs, license renewal applicants must identify and list, in an integrated plant assessment, those structures and components subject to an aging management review. Section 54.21 provides the standards for determining which structures and components require an aging management review. 10 C.F.R. § 54.21.

Q36. What are the three general categories of SSCs within the scope of license renewal, as set forth in 10 C.F.R. § 54.4(a)(1)-(3)?

A36. (ABC, TSI, NFA) The first category consists of all "safety-related" SSCs. 10 C.F.R. § 54.4(a)(1). These are SSCs that are relied upon to remain functional during and following design basis events to ensure the integrity of the reactor coolant pressure boundary, the capability to shut down the reactor and maintain it in a safe shutdown condition, or 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. 10 C.F.R. § 54.21; *see* 10 C.F.R. § 50.2 (defining "safety-related structures, systems and components").

The second category consists of all non-safety-related SSCs whose failure could prevent satisfactory accomplishment of any of the safety functions identified in 10 C.F.R. § 54.4(a)(1)(i)-

(iii). *Id.* § 54.4(a)(2). For example, SSC's in this category include a non-safety-related system that fails during a postulated design basis accident earthquake and, as a result, prevents a safety-related SSC from performing its intended safety function.

The third category consists of all SSCs relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the NRC's regulations for fire protection (10 C.F.R. § 50.48), environmental qualification (10 C.F.R. § 50.49), pressurized thermal shock (10 C.F.R. § 50.61), anticipated transients without scram (10 C.F.R. § 50.62), and station blackout (10 C.F.R. § 50.63). *Id.* § 54.4(a)(3). These SSCs would include, for example, main or auxiliary systems necessary to meet these regulations, as defined in a plant's final safety analysis report, and a plant's fire protection systems.

Q37. What in-scope structures and components are subject to AMR?

A37. (ABC, TSI, NFA) If a structure or component performs no intended function as defined in 10 C.F.R. § 54.4(a)(1)-(3), then it is not subject to AMR. 10 C.F.R. § 54.4(b). Section 54.21(a)(1)(i), in turn, further limits the structures and components subject to AMR to those structures and components that perform an intended function, as described in § 54.4(a)(1)-(3), without moving parts or without a change in configuration or properties, and that are not subject to replacement based on a qualified life or specified time period. *Id.* § 54.21(a)(1)(i)-(ii).

Given the foregoing requirements, the preparation of an LRA involves the following 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, among those in-scope SSCs, (2) 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 AMR. Piping appears on that list. *Id.* § 54.21(a)(1)(i).

Q38. What findings must the NRC make to issue a renewed operating license?

A38. (ABC, TSI, NFA) 10 C.F.R. § 54.29(a) sets forth the findings necessary for a renewed operating license. The NRC must find that the applicant has provided reasonable assurance that structures and components will perform such that their intended functions, as identified in § 54.4(a)(1)-(3), are maintained consistent with the plant's current licensing basis ("CLB") during the period of extended operation. 10 C.F.R. § 54.29(a). That is, the applicant must provide reasonable assurance that it will manage the effects of aging on the functionality of the SSCs identified as requiring AMR. *Id.* § 54.29(a)(1). As the Commission explained in issuing current 10 C.F.R. Part 54, "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." Final Rule, *Nuclear Power Plant License Renewal, Revisions*, 60 Fed. Reg. 22,461, 22,479 (May 8, 1995) (NYS000016).

Thus, with respect to the issues raised in NYS-5, Entergy must demonstrate that the BPTIP provides reasonable assurance that the effects of aging on in-scope buried pipes 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.

B. <u>Relevant NRC Guidance</u>

Q39. Has the NRC issued guidance concerning acceptable aging management programs for components determined to experience aging effects requiring management?

A39. (ABC, TSI) Yes. The NRC Staff reviews license renewal applications in accordance with the requirements in 10 C.F.R. Part 54, as well as Staff guidance contained in NUREG-1800, Rev. 1, Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants (Sept. 2005) ("NUREG-1800" or "SRP-LR") (NYS000195). The GALL Report (NYS000146A-C) provides the technical basis for NUREG-1800 and identifies AMPs that the Staff has determined are adequate to manage the effects of aging. The NRC Staff issued NUREG-1800, Rev. 2, Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants (Dec. 2010) (NYS000161) and NUREG-1801, Rev. 2, Generic Aging Lessons Learned (GALL) Report (Dec. 2010) (NYS000147A-D) in December 2010.

Q40. Please briefly describe the purpose of NUREG-1801.

A40. (ABC, TSI) Compliance with NUREG-1801 guidance constitutes one acceptable way to manage aging effects for license renewal. NUREG-1801, Vol. 1, Rev. 1, Generic Aging Lessons Learned (GALL) Report at 4 (Dec. 2010) (NYS000146A). NUREG-1801 describes AMPs that the Staff has accepted for meeting 10 C.F.R. Part 54 requirements based on its evaluations of existing programs at operating plants during the initial license period. *Id.* at 4. NUREG-1801 is treated in the same manner as an NRC-approved topical report that is generically applicable. *Id.* at 3. An applicant may reference NUREG-1801 in an LRA to demonstrate that the programs at its facility correspond to those reviewed and approved by the NRC Staff in NUREG-1801. *Id.*

Q41. Did Entergy use the guidance in NUREG-1801 in preparing its LRA?

A41. (ABC, TSI) Yes. As stated in LRA Section B.1.6, the BPTIP described in the April 2007 LRA was consistent with the program attributes described in NUREG-1801, Section XI.M34, Buried Piping and Tanks Inspection, without exception. LRA, Appendix B at B-27 (ENT00015B); NUREG-1801 at XI M-111 to XI M-112 (NYS000146C). However, as discussed below, Entergy has substantially revised and augmented the BPTIP in response to industry operating experience and related Staff RAIs. Additionally, NUREG-1801, Rev. 2 contains certain revisions to NUREG-1801, Rev. 1 AMPs. As it relates to contention NYS-5, NUREG-1801, Rev. 2 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* NUREG-1801, Rev. 2, Generic Aging Lessons Learned (GALL) Report at XI M41-1 to XI M41-14 (Dec. 2010) (NYS000147D).

Q42. How does Section XI.M41 differ from former Section XI.M34?

A42. The new program described in Section XI.M41 of NUREG-1801, Rev. 2 increases the number of piping materials covered by the program and calls for both preventive measures and inspections. NUREG-1801, Rev. 2, Generic Aging Lessons Learned (GALL) Report at XI M41-1 (Dec. 2010) (NYS000147D). Depending on the material of construction, preventive measures address coatings, backfill, and cathodic protection. *Id.* (As discussed in Answer 59, CP is a technique used to reduce the corrosion of a metal surface by making that surface the cathode of an electrochemical cell.)

Section XI.M41 also more specifically defines inspection and monitoring activities based on plant-specific factors, such as the quality of backfill and the presence or absence of cathodic

protection. *Id.* 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.* at XI M41-4 to XI M41-9.

V. <u>BURIED PIPES AND TANKS WITHIN THE SCOPE OF LICENSE RENEWAL AND CONTENTION NYS-5 AS ADMITTED BY THE BOARD</u>

A. <u>Determination of Buried Pipes and Tanks Subject to Aging Management Review Under 10 C.F.R. Part 54</u>

Q43. What is meant by the terms "buried," versus "underground," piping?

A43**.** As referenced in NUREG-1801, Rev. 2, Section XI.M41, buried pipes are those in direct contact with soil or concrete (*e.g.*, a wall penetration). NUREG-1801, Rev. 2, Generic Aging Lessons Learned (GALL) Report at XI M41-1 (Dec. 2010) (NYS000147D). Underground pipes are below grade but are contained within a tunnel or vault such that they are in contact with air and access for inspection is restricted. *Id.* There are no underground pipes at IPEC that are subject to AMR under 10 C.F.R. Part 54.

Q44. How did Entergy determine which buried pipes and tanks are within the scope of license renewal?

A44. (ABC, TSI, NFA) 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 at 2.1-1 to 2.1-16 (ENT00015A). Entergy followed the guidance contained 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) (ENT000098). *Id.* 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 three criteria in § 54.4(a). *See id.*

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. *Id.* at 2.1-1 to 2.1-2. The database has two parts, one for IP2 (which also includes listings for IP1 systems and components), and another for IP3. *Id.* at 2.1-2. 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. *Id.* Entergy identified mechanical system functions from the IP2 and IP3 safety system function sheets ("SSFSs"), which list functions performed by each system. *Id.* at 2.1-3 to 2.1-5. Entergy also obtained additional information on mechanical system functions from plant layout drawings, the UFSARs, maintenance rule documents, piping flow diagrams, and design basis documents. *Id.* at 2.1-2, 2.1-5.

Piping systems are part of the mechanical systems. *Id.* at 2.1-5. Each mechanical system is assigned a system code. *Id.* at 2.1-2. For mechanical system scoping, mechanical system boundaries were defined, in part, by the collection of components in the component database assigned to the system code. *Id.* System functions were determined based on the functions performed by the components within those boundaries. *Id.*

Entergy evaluated mechanical systems against the criteria of 10 C.F.R. § 54.4(a)(1), (a)(2), and (a)(3). *Id.* at 2.2-1. LRA Section 2.2, Plant Level Scoping Results, presents the results of the scoping process. *Id.* 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.* 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.* at 2.2-17 to 2.2-18. 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.*

Q45. How did Entergy determine which in-scope buried piping and tanks are subject to AMR?

A45. (ABC, TSI, NFA) LRA Section 2.1.2.1 discusses the screening process for identifying mechanical components that are subject to AMR. LRA at 2.1-13 to 2.1-16 (ENT00015A). LRA Section 2.3 provides the results of the screening process, which followed NEI 95-10 guidelines. Broadly speaking, 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. *See id.* at 2.3-2, 2.3-42, 2.3-74, 2.3-318. These systems' supporting subsystems and components are 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 the aforementioned IP2 and IP3 systems.

Q46. Which specific IP2 and IP3 buried piping is subject to AMR under Part 54, and what system-intended functions does that piping support?

A46. (ABC, TSI, NFA, RCL) The following sections of IP2 and IP3 buried piping are subject to AMR and included within the scope of the BPTIP:

- <u>Safety injection (IP3 only)</u>: Approxmately 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. NL-09-106, Letter from F. Dacimo, Entergy to NRC Document Control Desk, Attach. 1 at 1 (July 27, 2009) ("NL-09-106") (NYS000203).

- 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. *Id.*

- 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. (The loop design and associated sectional isolation valves allow isolation of a leak in any segment of piping without disabling the remainder of the fire protection water system.) *Id.*

- 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). *Id.* at 2.

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

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

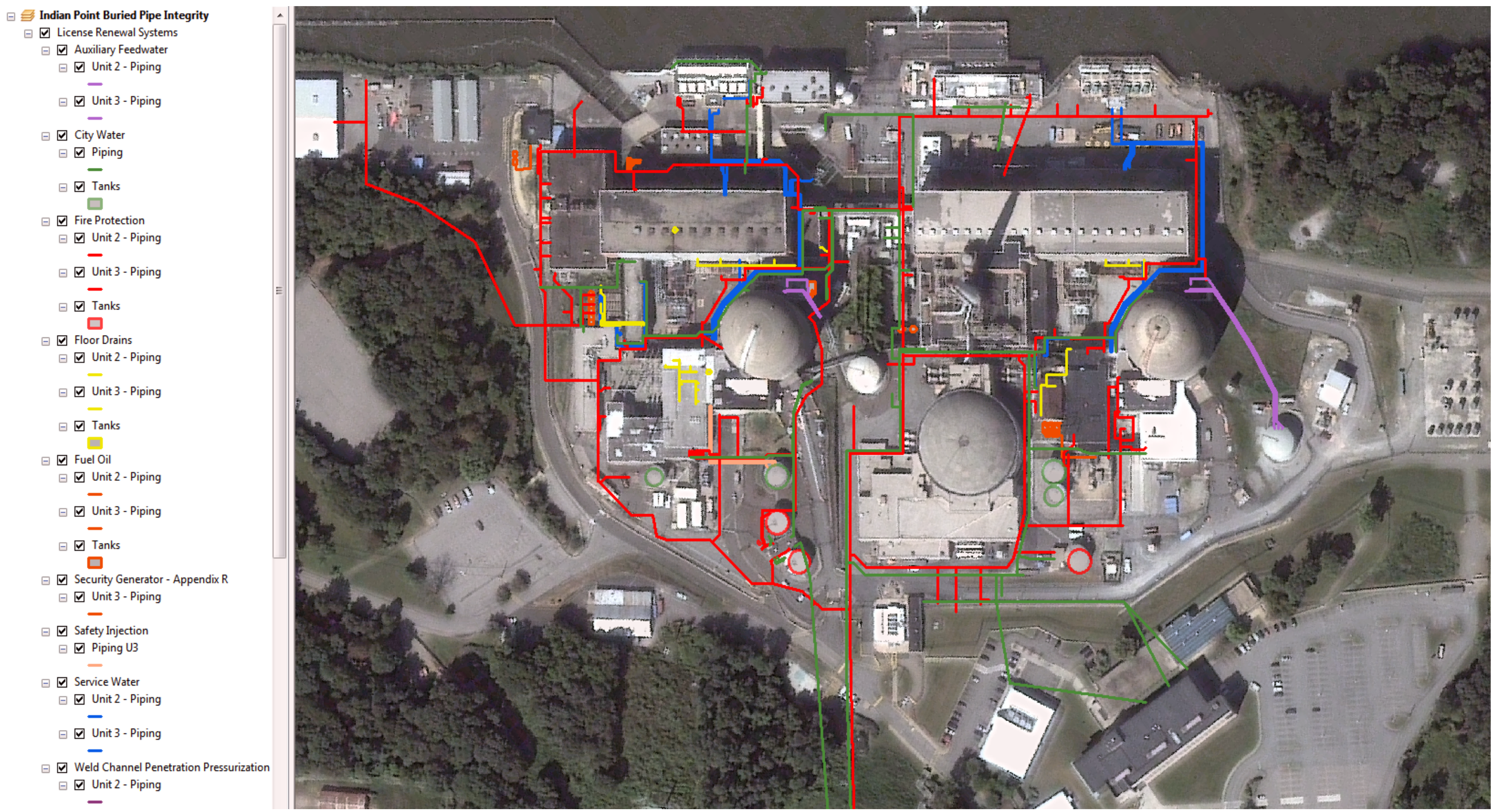
- Plant drains: Greater than 1,000 feet of IP2 and IP3 carbon steel piping that provides a drainage path from floor drains in the lower elevations of certain plant structures to waste holdup tanks. *Id.*

- 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. *Id.*

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

Figure 1 below shows the locations of IP2 and IP3 buried piping that is subject to AMR and included within the scope of the BPTIP.

Figure 1.[2] **IP2 and IP3 Buried Piping Included in the License Renewal Buried Piping and Tanks Inspection Program**



2 Generated from MAPProView© 2012 using IPEC BPWorks™ data.

Q47. Are there any buried tanks at IPEC subject to AMR?

A47. (ABC, TSI, NFA, RCL) Yes. The following IP2/IP3 buried tanks are subject to AMR and covered by the BPTIP. The designations next to each tank are component-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).

See NUREG-1930, Vol. 1, Safety Evaluation Report Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3 at 3-15 (Nov. 2009) (NYS00326B); NL-08-057, Letter from F. Dacimo, Entergy to NRC Document Control Desk, "Amendment 3 to License Renewal Application (LRA)," Attach. 5, at 31-32 (Mar. 24, 2008) (ENT000380).

Q48. Are there any IP1 buried pipes or tanks that are within the scope of license renewal?

A48. (ABC, TSI, NFA, RCL) Yes. 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. 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. *See* NL-12-032, Letter from F. Dacimo, Entergy to NRC Document Control Desk, "Correction to Previous Response Regarding Unit 1 Buried Piping" at 1-2 (Jan. 30 2012) (ENT000381).

Q49. Are there buried piping and tanks at IPEC that are *not* within the scope of license renewal?

A49. (ABC, TSI, NFA, RCL) Yes. There are numerous IPEC systems with buried piping and tanks that are not within the scope of license renewal. Specifically, 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. For example, buried piping associated with the site potable water and sanitary systems does not perform any intended function identified in § 54.4(a)(1)-(3) and, therefore, is not within the scope of license renewal. However, such buried or underground components are included within the scope of the broader, Part 50 UPTIMP.

B. Buried Piping Within the Scope of the Buried Piping and Tanks Inspection Program That Contains or Potentially Contains Radioactive Fluids

Q50. Of the IP1, IP2, and IP3 buried piping systems included in the scope of the BPTIP, which systems contain, or may contain, radioactive fluids during normal operations?

A50. (ABC, TSI, NFA, RCL) Of the systems identified in Answers 46 and 48 above, only the IP3 safety injection system contains radioactive fluids during normal operations because it contains borated water with radioactive constituents from the RWST. *See* LRA at 2.3-55 to 2.3-56 (ENT00015A). Safety injection system buried components are made of stainless steel (see Answer 44, *supra*) which has low susceptibility to corrosion.

Buried piping in the auxiliary feedwater ("AFW"), service water, and floor drain systems for IP2 and IP3 has 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

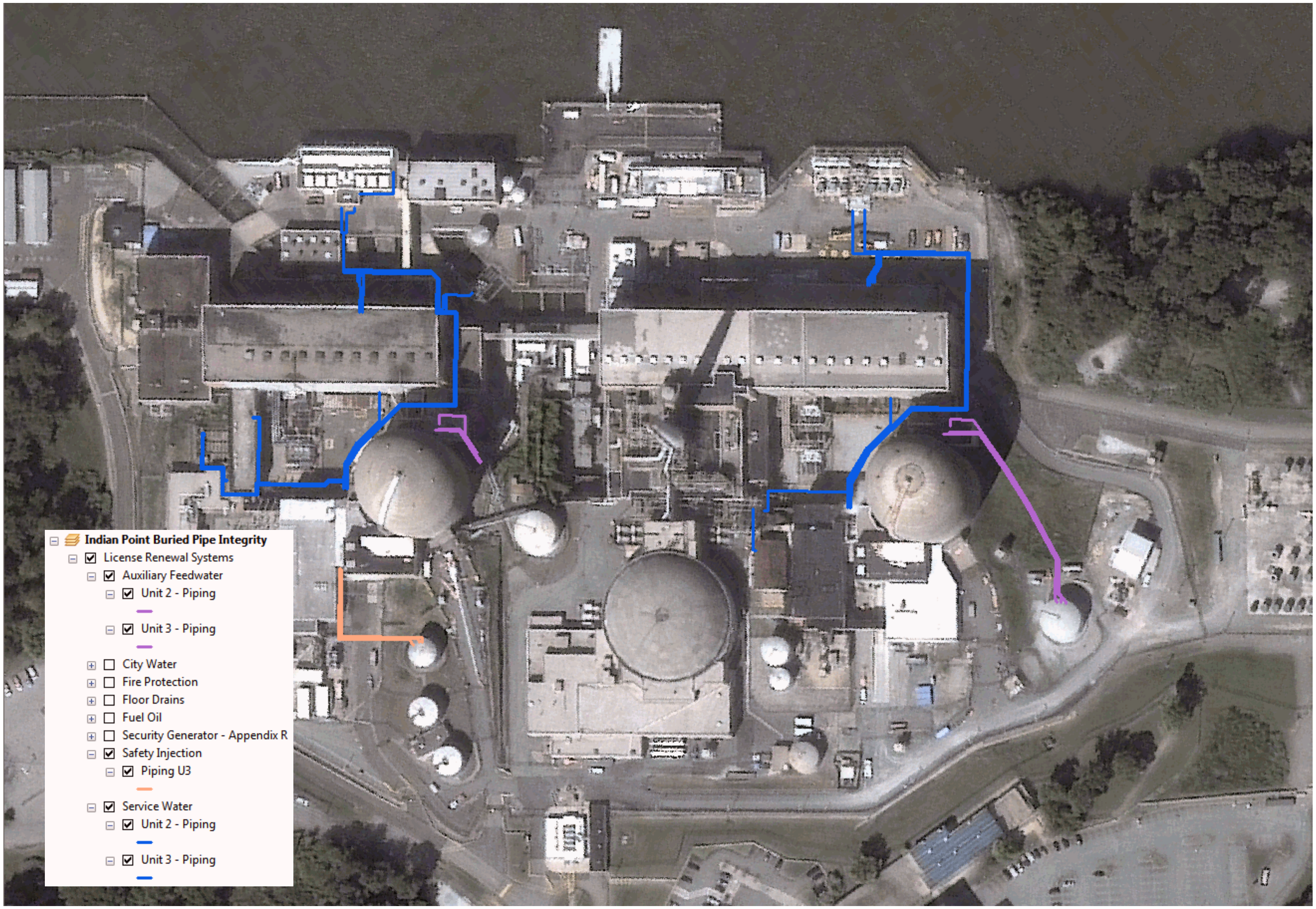
under normal operation. *See id.* at 2.3-332 to 2.3-333. However, in the event of a steam generator tube leak, it is possible for the condensate storage tanks and, therefore, the auxiliary feedwater systems, to contain trace amounts of tritiated water.

Service water has the potential to contain radioactivity via its interfaces with the component cooling water ("CCW") system heat exchangers and the containment ventilation cooling units. *See id.* at 2.3-78. There is a potential for leakage through the tubes of CCW heat exchangers to contaminate the service water system. Service water also could be contaminated from the containment ventilation cooling units if a tube leak occurred in a low-pressure portion of the service water cooling coil. The service water and CCW systems are equipped with monitors that measure radioactivity levels in discharges from containment cooling units and from the CCW heat exchangers, thus providing a means to detect radioactivity entering the service water system. *See* IP2 UFSAR, Rev. 20, §§ 9.3.2.1, 9.6.1.2 (NYSR0014F, NYSR0014G); IP3 UFSAR §§ 9.3.3, 9.6.1 (NYSR0013G, NYSR00113H).

Floor drains can potentially contain radionuclides due to drainage from radioactive systems in the vicinity of the floor drains. 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.

Figure 2 below shows the buried piping subject to AMR that contains, or potentially could contain, radioactive fluids. 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) has the potential to contain radioactive fluids, because the piping is not connected to systems containing or potentially containing radioactive materials or fluids.

Figure 2.[3] **IPEC Buried Piping That is In-Scope for License Renewal and That Contains, or May Contain, Radioactive Fluids**



[3] Generated from MAPProView© 2012 using IPEC BPWorks™ data.

Q51. Please briefly describe the IP2 and IP3 systems discussed in response to Question 50 above (*i.e.*, those systems with buried piping that contain, or may contain, radioactive constituents) and their license renewal intended functions.

A51. (ABC, TSI, NFA, RCL) Basic descriptions of the systems are provided below. More complete descriptions are provided in Chapter 2 of the LRA. Surveillance and testing activities relevant to these systems also are noted, as applicable. Although such activities are not credited in the BPTIP, they 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.

- IP3 Safety Injection System: The IP3 safety injection system provides automatic delivery of cooling water to the reactor core in the event of a loss-of-coolant accident ("LOCA"). This system contains safety-related components relied on to remain functional during and following design basis events. It also contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety function and perform functions that support fire protection. LRA Section 2.3.2.4 further describes this system. *See* LRA at 2.3-55 to 2.3-58 (ENT00015A).

    - The IP3 safety injection pumps are periodically tested to ensure flow and discharge pressure requirements are met. *See* Program Section No. SEP-IP3-IST-2, Rev. 0, Indian Point 3 Fourth Ten-Year Interval Inservice Testing Program Plan at 5-7, 119, 120,123 (June 2011) (ENT000382); ASME OM Code-2001, Section ISTA 1100, "General Requirements" (ENT000383).

IP2/IP3 Auxiliary Feedwater (AFW) Systems: The AFW systems ensure that adequate feedwater is supplied from the condensate storage tanks (CST) via the auxiliary feedwater pumps to the steam generators for decay heat removal under accident conditions, including loss of power and normal heat sink (*e.g.*, loss of cooling water to the condenser). The AFW systems contain safety-related components relied on to remain functional during and following design basis events. In addition, the AFW systems perform functions that provide support related to fire protection, anticipated transient without scram, and station blackout. These specific functions are described further in LRA Section 2.3.4.3. *See* LRA at 2.3-332 to 2.3-334 (ENT00015A). LRA Tables 2.3.4-3-IP2 and 2.3.4-3-IP3 identify AFW system component types within the scope of license renewal and subject to an AMR, as well as their intended functions. *Id.* at 2.3-354 to 2.3-355.

- The IP2 and IP3 auxiliary feedwater pumps are periodically tested to ensure that flow and discharge pressure requirements are met. *See* Program Section No. SEP-IP2-IST-2, Rev. 0, Indian Point 2 Fourth Ten-Year Interval Inservice Testing

Program Plan at 1-1 to 1-2, 2-1 (July 2011) (ENT000384); Program Section No. SEP-IP3-IST-2, Rev. 0, Indian Point 3 Fourth Ten-Year Interval Inservice Testing Program Plan at 5-7, 120-21 (June 2011) (ENT000382); ASME OM Code-2001, Section ISTA 1100, "General Requirements" (ENT000383).

  - CST fluid levels are monitored remotely at least once every 12 hours through level instrumentation to ensure minimum technical specification volume requirements are met. This instrumentation is monitored in the control room and includes low-level alarms.

- IP2/IP3 Service Water Systems: As described in LRA Section 2.3.3.2, the service water systems supply cooling water from the Hudson River to various heat loads in both the primary and secondary portions of the plants necessary for plant safety during either normal operation or abnormal or accident conditions. *See* LRA at 2.3-78 (ENT00015A). These systems contain safety-related components relied on to remain functional during and following design basis events. They also contain non-safety-related components whose failure potentially could prevent the satisfactory accomplishment of a safety function. These systems also perform functions that provide support related to fire protection and station blackout. *Id.* at 2.3-78 to 2.3-81. LRA Tables 2.3.3-2-IP2, 2.3.3-19-39-IP2, 2.3.3-2-IP3, and 2.3.3-19-56-IP3 identify in-scope service water system component types and their component intended functions. *Id.* at 2.3-182, 2.3-183, 2.3-251, and 2.3-311.

  - The IPEC service water system buried lines are periodically flow tested or pressure tested as required by the ASME Section XI Code. *See* Program Section No. SEP-IP2-IST-2, Rev. 0, Indian Point 2 Fourth Ten-Year Interval Inservice Testing Program Plan at 1-1, 1-3, 2-1 (July 2011) (ENT000384); Program Section No. SEP-IP3-IST-2, Rev. 0, Indian Point 3 Fourth Ten-Year Interval Inservice Testing Program Plan at 5-7, 123-25 (June 2011) (ENT000382); ASME OM Code-2001, Section ISTA 1100, "General Requirements" (ENT000383); Letter from Chairman G. Jaczko, NRC to Senator E. Markey, Enclosure at 1 (June 17, 2009) (ENT000385).

  - Radiation monitors are installed on the service water systems that automatically alarm in the control rooms in the event radioactivity is detected. *See* IP2 UFSAR, Rev. 20, §§ 9.3.2.1, 9.6.1.2 (NYSR0014F, NYSR0014G); IP3 UFSAR §§ 9.3.3, 9.6.1 (NYSR0013G, NYSR00113H).

- Plant Drains: As described in LRA Section 2.3.3.18, the IP2 and IP3 plant drains systems are passive protection features required for adequate protection of safety-related equipment from water damage in areas with fixed fire suppression systems. *See* LRA at 2.3-143 (ENT00015A). Plant drain components also prevent drain systems in areas with combustible materials from spreading fires to other areas of the plant. *Id.* Some drains protect safety-related equipment in the diesel generator rooms, electrical tunnels, primary auxiliary building, and auxiliary feed pump room from being damaged due to flooding. *Id.* at 2.3-144.

> The IP2/IP3 liquid waste disposal systems also include plant drain components within the scope of license renewal. The liquid waste disposal system collects and processes liquid wastes from throughout the plant, including wastes from equipment drains, radioactive chemical laboratory drains, decontamination drains, demineralizer regeneration, and floor drains for collection in the waste holdup tank. The waste disposal system also collects and transfers liquid drained from the reactor coolant system directly to the chemical and volume control system for processing. The system includes piping, valves, pumps, collection tanks, instruments, and controls. *Id.* at 2.3-143 to 2.1-145.
>
> LRA Tables 2.3.3-18-IP2, 2.3.3-19-42-IP2, 2.3.3-18-IP3, and 2.3.3-19-33-IP3 identify plant drains system component types within the scope of license renewal and subject to AMR, as well as their intended functions. *Id.* at 2.3-212, 2.3-254, 2.3-212, 2.3-288.

Q52. Do any of the IP2 or IP3 buried tanks identified in response to Question 47 contain, or potentially contain, radioactive fluids?

A52. (ABC, TSI, NFA, RCL) No. None of the buried tanks identified in Answer 47 contains, or has the potential to contain, radioactive fluids. As is evident from their names, those tanks are used only to store hydrocarbon fuels (fuel oil, diesel fuel, propane) and are not connected to systems that contain radioactive materials.

VI. <u>OVERVIEW OF RELEVANT AGING MECHANISMS AND EFFECTS</u>

Q53. What are the principal aging effects and mechanisms of concern for IPEC buried pipes and tanks that are subject to AMR, as identified above?

A53. The IPEC buried piping and tanks subject to AMR include metallic components (*i.e.*, buried carbon steel, ductile or gray cast iron, and stainless steel components). As stated in the LRA and SER, the aging effect of concern for buried pipes and tanks is loss of material due to various forms of corrosion (*i.e.*, general, pitting, crevice, and microbiologically-induced corrosion.) LRA at 3.4-8 (ENT00015B). NUREG-1930, Vol. 1, Safety Evaluation Report Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3 (Nov. 2009) at 3-336, 3-372 (NYS000326D). Corrosion mechanisms are discussed in greater detail in several exhibits to this testimony. *See* NUREG/CR-6876, Risk-Informed Assessment of Degraded Buried

Piping Systems in Nuclear Power Plants at 25-28 (June 2005) (ENT000386); CEP-UPT-0100, Rev. 0, Underground Piping and Tanks Inspection and Monitoring, Appendix A (Oct. 31, 2011) (NYS000173); Herbert H. Uhlig & R. Winston Revie, *Corrosion and Corrosion Control, An Introduction to Corrosion Science and Engineering* 90-122 (John Wiley & Sons, Inc. 3d ed. 1985) ("Corrosion and Corrosion Control") (ENT000387).

Q54. Do the aging effects mentioned above affect the external or internal surfaces of buried components?

A54. Although loss of material is a potential aging effect for both the internal and external surfaces of buried components, internal and external losses of material are addressed through different aging management programs. The prefiled testimony and associated report of NYS's consultant, Dr. Duquette, focus solely on external corrosion of buried pipes and tanks. *See* State of New York, Entergy Nuclear Operations, Inc., and NRC Staff Joint Stipulation at 1 (Jan. 23, 2012); Duquette Testimony at 6:21-7:15 (NYS000164); Duquette Report at 4 (NYS000165). Accordingly, our testimony similarly focuses solely on loss of material due to external corrosion of buried components and IPEC's related AMP, *i.e.*, the BPTIP.

Q55. What factors affect the rate of degradation of buried metallic components?

A55. (SFB, JRC, RCL) The rate of degradation of steel (ferrous materials, *i.e.*, stainless and carbon steels, cast irons) buried piping is a function of environmental, metallurgical, and hydrodynamic variables. NUREG/CR-6876, Risk-Informed Assessment of Degraded Buried Piping Systems in Nuclear Power Plants at 32 (June 2005) (ENT000386). 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). *See Corrosion and Corrosion Control* at 91-114 (ENT000387); CEP-UPT-0100, Rev. 0,

Underground Piping and Tanks Inspection and Monitoring, App. A (Oct. 31, 2011) (NYS000173). 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. *See Corrosion and Corrosion Control* at 91-114 (ENT000384).

Q56. Please briefly describe the process by which metal corrodes.

A56. (SFB, JRC) Corrosion is largely an electrochemical phenomenon, whereby metals revert to a lower energy state (*e.g.*, an oxide) by electrochemical or chemical reactions. *See Corrosion and Corrosion Control* at 90-91 (ENT000387). 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: $Fe \rightarrow Fe^{2+} + 2e^-$, $2H_2O + 2e^- \rightarrow H_2 + 2OH^-$, respectively. *Id*. 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 either reaction is inhibited, then it becomes the rate controlling reaction, thereby controlling corrosion. *Id.*

Q57. What role do soil characteristics play in the potential corrosion of buried piping?

A57. (SFB, JRC) It is generally understood that 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. *See NACE SP0169-2007, Standard Practice – Control of External Corrosion*

on Underground or Submerged Metallic Piping Systems ("NACE SP0169-2007") (ENT000388); S.F. Biagiotti, Jr., *et al.*, *Using Soil Analysis and Corrosion Rate Modeling to Support ECDA and Integrity Management of Pipelines and Buried Plant Piping*, NACE Corrosion/2010, Paper 10059 (Mar. 2010) ("NACE Paper 10059") (ENT000389).

Q58. What is soil resistivity?

A58. (SFB, JRC) 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 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. 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 (aka coating holidays) for corrosion control. It is important to note that 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. *See* NACE SP0169-2007 (ENT000388); NACE Paper 10059 (ENT000389).

Q59. You previously mentioned cathodic protection of buried piping. Please further explain that concept.

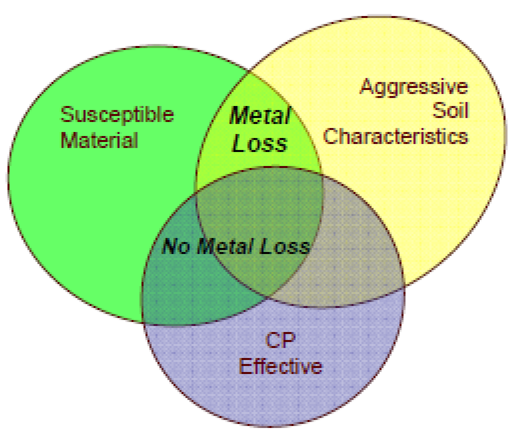
A59. (SFB, JRC, RCL) Corrosion of buried pipes and tanks can occur when two or more electrochemically dissimilar metals are electrically connected to each other and in physical contact with the same electrolyte, such that a "corrosion cell" is created. The direction of positive current flow is from the 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. *See Corrosion and Corrosion Control* at XX (ENT000387). Conventional dry cell batteries (*e.g.*, AA, C cells) are examples of corrosion cells where a zinc foil is wound around a graphite post to generate 1.5 volts.

Cathodic protection 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. A detailed discussion of cathodic protection theory as applied to buried piping is contained in A.W. Peabody, *Peabody's Control of Pipeline Corrosion* 21-48 (NACE International 2d ed. 2001) ("Peabody's Control of Pipeline Corrosion") (ENT000390).

Q60. NYS's consultant, Dr. Duquette, states that "[p]rimarily, corrosion is prevented by applying coatings to the piping systems, and by cathodically protecting the pipes." Duquette Testimony at 8 (NYS000164). Do you agree?

A60. (SFB, JRC, RCL) We generally agree with that statement but subject to the important qualification that cathodic protection is a secondary corrosion control technique to inhibit corrosion as bare material becomes exposed to the surrounding soil. Coatings provide the primary form of corrosion control because the fundamental principle in corrosion control is preventing (1) a susceptible material from (2) coming in contact with a *corrosive* environment. *See* NACE SP0169-2007 (ENT000388); NACE Paper 10059 at 1-2 (ENT000389). Specifically, coatings form a moisture and chemical-resistant barrier that is bonded to the outer surface of the pipe and thereby creates a barrier between the soil and the pipe. In addition, not all soils are inherently corrosive, as described in Answer 56. This is illustrated in Figure 3 below.

<u>Figure 3</u>: Relationship That Supports External Corrosion of Buried Piping

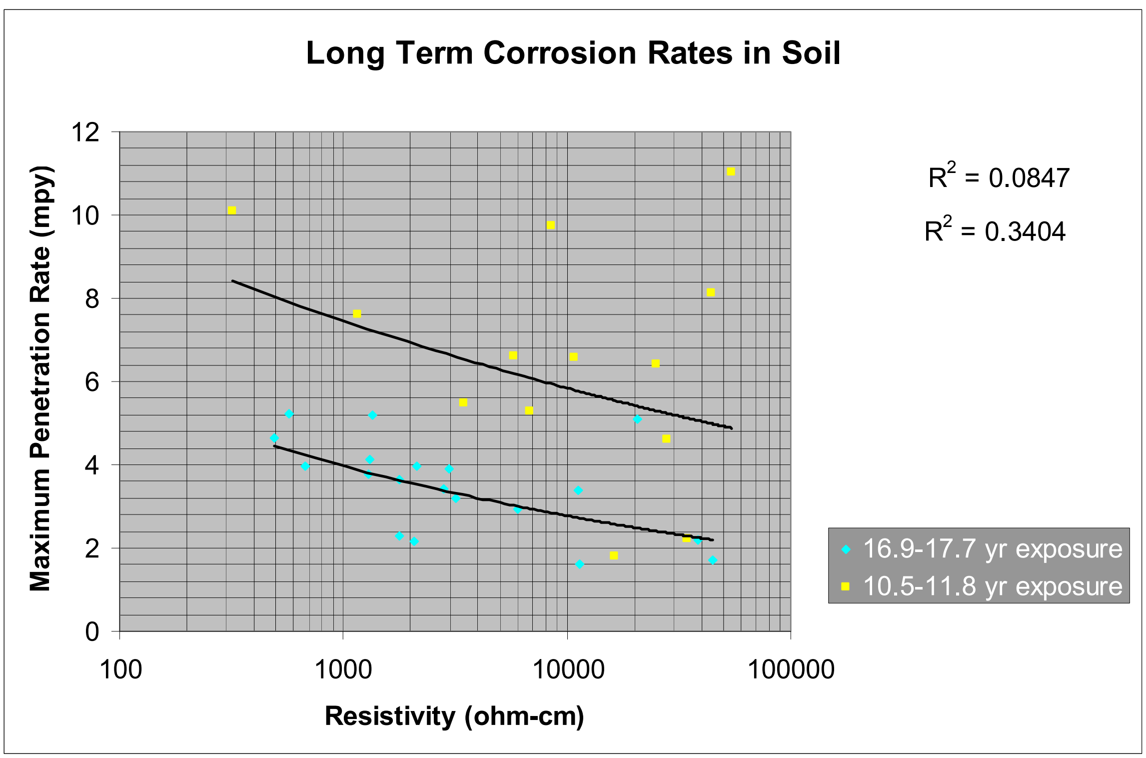


Source: NACE Paper 10059 at 2 (Fig. 1) (ENT000389).

External coatings effectively perform the function of isolating piping from a corrosive environment, so that no corrosion occurs. *Id.* at 2. If coatings degrade, a path between the pipe and soil may develop. *Id.* If the soil is corrosive, then corrosion may proceed. *Id.*

A 45-year study by the U.S. National Bureau of Standards that considered more than 150 locations and soil types revealed that the corrosiveness of most soils reduces with time (as oxygen in the soil is consumed, corrosion inhibited) trending toward lower metal loss rates (2-4 mils per year, or mpy). Marvin Romanoff, *Underground Corrosion,* National Bureau of Standards Circular 579 (1957) ("NBS Circular 579") (ENT000391). The graph below, which plots data from NBS Circular 579, illustrates the decrease in soil corrosivity (shown as a function of measured soil resistivity) with time. The yellow dots represent buried piping in service for approximately 10-12 years, and the blue dots represent buried piping in service for approximately 17-18 years. As the plot shows, the buried piping with the longer service life was subject to less corrosive soil conditions and hence lower corrosion rates.

<u>Figure 4</u>. Relationship Between Soil Corrosion Rates and Time



Source: Structural Integrity Associations, Inc. (based on data from NBS Circular 579) (ENT000391).

The calculated required wall thickness (WT) for stainless and carbon steel pipe at IPEC (*see* IPEC Buried Piping Specification 9321-05-248-18 at 9.5 (ENT000394)) includes corrosion allowance of 12.5% of pipe wall thickness. Additional margin may be attained by selecting the next standard wall class thickness (which generally steps 0.065 to 0.125 inch for pipe diameters greater than 4 inches) above the required thickness. *See* The Engineering Toolbox (www.engineeringtoolbox.com) (ENT000392). Pipe sizes, inside and outside diameters, wall thickness, schedules, moment of inertia, transverse area, weight of pipe filled with water - U.S. Customary Units," The Engineering Toolbox (www.engineeringtoolbox.com) (ENT000392). This indicates 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).

Q61. When is cathodic protection necessary to prevent corrosion of buried components?

A61. (SFB, JRC, RCL) Cathodic protection is necessary to prevent corrosion of buried piping when its coating has degraded and exposes the metallic surface of the piping to a corrosive environment. NACE SP0169-2007 (ENT000388); NACE Paper 10059 at 2 (ENT000389). If the coating applied to buried piping is still effective, then CP is not necessary to prevent external corrosion of the piping and will offer no addition corrosion control. *Id.* CP systems are only required, or effective, when supplemental corrosion protection is needed at localized areas of coating degradation in corrosive soil environments. *Id.*

Q62. Dr. Duquette also states that, when breaks in pipe coating occur, the corrosion damage, in some cases, can be more severe than if the there is no coating at all. Duquette Testimony at 9 (NYS000164). How do you respond?

A62. (SFB, JRC) Dr. Duquette states that, at breaks in the coating, all of the corrosion damage may be concentrated in a single location, so that a deep pit may perforate the pipe. Duquette Testimony at 9:14-16 (NYS000164). He also claims that the interface between the coating and the pipe surface may introduce an effective crevice for crevice corrosion. *Id.* at 9:16-18. However, these corrosion phenomena are not expected at IPEC, where the buried piping applications have a common electrical ground. A specific galvanic or impressed driving force (*e.g.*, stray current or close galvanic couple) is required for the corrosion phenomena cited by Dr. Duquette. Where buried pipes at plants utilize a common grounding approach (for personnel safety), the likelihood of stray currents is low. Furthermore, for crevice corrosion to occur, an oxygen concentration cell is required. *Corrosion and Corrosion Control* at 92-93 (ENT000387). In long-term buried applications such as with the pipe at this site, oxygen levels will be low or absent. *See* Answer 60, *supra*. Also, over-the-line survey techniques have been developed to detect potential gradients indicative of current flow consistent with these forms of corrosion cells. *Peabody's Control of Pipeline Corrosion* at 69-73 (ENT000390). As our testimony explains, Entergy is taking measures through the BPTIP to identify and address potential degradation of in-scope buried piping and its protective coatings.

In process industry (*i.e.*, refineries, chemical plants, etc.) applications, where dissimilar metals are in proximity to one another in an aqueous (not soil) environment (*i.e.*, in a vessel with different material types exposed to a common fluid), the cited phenomenon occur (and typically, the cathode is coated instead of the anode, the reverse of buried pipe practices). Based on our

experience and our review of relevant technical literature, we conclude that this phenomenon does not occur commonly in buried piping applications.

VII. AGING MANAGEMENT OF EXTERNAL CORROSION OF IPEC IN-SCOPE BURIED COMPONENTS THAT MAY CONTAIN RADIOACTIVE FLUIDS

A. The IPEC Buried Piping and Tanks Inspection Program (BPTIP)

Q63. Please describe the IPEC BPTIP.

A63. (ABC, TSI, NFA, RCL) The BPTIP manages loss of material due to external corrosion of buried piping and tanks to provide reasonable assurance that the associated systems can perform their intended functions. LRA, App. B at B-27 (ENT00015B); NL-09-106, Attach. 1 at 5 (NYS000203). As described in Section B.1.6 of Entergy's April 2007 LRA, the BPTIP includes two key elements: (1) reliance on *preventive measures* (*i.e.*, protective coatings) to mitigate external corrosion and (2) *inspections* to manage the effects of corrosion on the pressure-retaining capability of buried carbon steel, gray cast iron, and stainless steel components. LRA, App. B at B-27 (ENT00015B). As discussed below, such inspections are conducted to assess the condition of coatings and to detect and quantify the potential loss of material due to corrosion.

1. Preventive Measures for IPEC In-Scope Buried Piping

Q64. Please describe the corrosion resistance of stainless and carbon steel piping buried in soil.

A64. (SFB, JRC, NFA, RCL) 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. As discussed in Answer 68, 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.

Q65. What preventive measures does IPEC rely on for in-scope buried piping that contains, or may contain, radioactive fluids?

A65. 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. As discussed further in Answer 68, all buried piping within the scope of contention NYS-5 was coated in accordance with AWWA C-203-62, AWWA Standard for Coal-Tar Enamel Protective Coatings for Steel Water Pipe (Jan. 1962) (ENT000393).

Q66. What are the primary attributes of the protective coatings applied to buried carbon steel piping at IPEC?

A66. (SFB, JRC, NFA, RCL) The desirable characteristics of a protective coating system for buried piping 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; (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. *See* NACE SP0169-2007 at 6-7 (2007) (ENT000388).

Q67. What is the nuclear power industry standard applicable to protective coatings that are applied to buried piping used in nuclear applications?

A67. (SFB, JRC) Standard industry practice for coatings requires that the pipe be cleaned and primed before coatings are applied. The primer is applied first to enhance the bond between the pipe and subsequent wrappings. The number of layers of wrapping (*e.g.*, insulation, epoxy, coal tar, or bonded asbestos wrap paper) that are applied depends on the piping function and the soil conditions.

The nuclear power industry relies on several common specifications for the installation of corrosion-resistant coatings developed by industry organizations, such as the American Water Works Association ("AWWA"), NACE, American National Standards Institute ("ANSI"), International Organization for Standardization ("ISO"), National Association of Pipe Coating Applicators, American Petroleum Institute ("API"), Society for Protective Coatings, and ASTM International.

Q68. Was the installation of corrosion-resistant coatings on IPEC buried piping within the scope of license renewal governed by one or more of these standards?

A68. (RCL, SFB, JRC) Yes. 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 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) (ENT000393). Table 1 below provides examples of the relevant IPEC buried piping specifications, which are attached as Exhibits ENT000394 to ENT000400, for the in-scope systems identified in Answer 46.

Table 1. Example IPEC Piping Specifications for In-Scope Buried Piping Systems

Unit(s)	System	Specification No. (-01 denotes IP2) (-05 denotes IP3)	Exh. No.	Reference to AWWA C-203
IP3	Safety Injection	9321-05-248-18	ENT000394	Page 2.3, para. 2.2.22 (Pipe Class 151)
IP2/IP3	Service Water	9321-01-248-35 9321-05-248-35	ENT000395 ENT000396	Page III-A-3, para. A.(3) Page 3.2, para. 3.2.1.3
IP2/IP3	Fire Protection	9321-01-44-1 9321-05-44-3	ENT000397 ENT000398	Page 5, Sec. III.1 Page 4, Sect III.1
IP2/IP3	Fuel Oil	9321-01-248-18 9321-05-248-18	ENT000399 ENT000394	Page III-16, para. E.2 (Pipe Class N-1) Page 2.3, para. 2.2.22 (Pipe Class N-1)
IP3	Security Generator	9321-05-248-18	ENT000394	Page 2.3, para. 2.2.22
IP2/IP3	City Water	9323-01-248-18 9321-05-248-18	ENT000399 ENT000394	Page III-16, para. E.2 (Pipe Class J-4) Page 2.3, para. 2.2.22 (Pipe Class J-4)
IP2/IP3	Yard Drains Floor Drains Yard Storm Drainage/Fire Protection	9321-01-44-1 9321-01-44-2 9321-05-44-3	ENT000397 ENT000400 ENT000398	Page 5, Sec. III.1 Page 5, Sec. III.1 Page 4, Sec. III.1
IP2/IP3	Auxiliary Feedwater	9321-01-248-18 9321-05-248-18	ENT000399 ENT000394	Page III-16, para. E.2 (Pipe Classes C-1 & C-3) Page 2.3, para. 2.2.22 (Pipe Classes C-1 & C-3)
IP2	Containment Isolation Support	9321-05-248-18	ENT000394	Page III-16, para. E.2 (Pipe Class K-2)

With respect to coatings applied by the manufacturer, IPEC specifications required the following steps. First, the pipe is cleaned of all dirt, grease, mill scale, or any loose debris using

some mechanical means (*e.g.*, impact wheel or wire brush). After the pipe is cleaned, a layer of primer is painted onto the exterior of the cleaned pipe. Following application of the primer, a coal-tar enamel coating is applied to the clean dry surface of the pipe at the correct temperature to ensure that the primer bonds with the enamel to form a coating on the pipe. The enamel is then visually inspected for uniformity. Before the enamel cools, bonded asbestos felt wrapper is applied over the enamel in a uniform wrap to cover the entire outside surface of the enamel. *See* AWWA C-203-62, AWWA Standard for Coal-Tar Enamel Protective Coatings for Steel Water Pipe (Jan. 23, 1962) (ENT000393).

Site piping specifications provided instructions for field applications of coatings to pipe joints where pipe segments are joined. The relevant specifications required the following steps in the field application of coatings:

- Cleaning of the piping by wire brushing to remove rust, scale, dust, or dirt; oil or grease is removed with a solvent;
- After the pipe is cleaned, application of a layer of primer to the exterior of the cleaned pipe and allowing the primer to dry;
- Application of coal tar tape to the primed surface.

See, *e.g.*, IPEC Buried Piping Specification 9321-05-248-18 at 5.1 to 5.2 (ENT000394); AWWA C-203-62, AWWA Standard for Coal-Tar Enamel Protective Coatings for Steel Water Pipe (Jan. 23, 1962) (ENT000393).

Q69. What steps are undertaken to ensure that coatings have been properly applied to ensure that there are no places on the buried pipe exposed to the soil?

A69. (RCL, JRC) The purchase specifications and established industry practices require that the coatings be inspected at every stage in the process. All manufacturer-applied coatings are required to be inspected in accordance with AWWA Standard C-203-62. This involves visual

inspection of the coated piping for any misapplication of the coatings. *See*, *e.g.,* IPEC Buried Piping Specification 9321-05-248-18 at 4.1 to 4.5. (ENT000394);

In the field, the pipes are visually inspected upon receipt to ensure that no damage to the coating occurred during shipment. Finally, after pipes are fully joined and assembled in place and the field joints are wrapped, and before covering them with soil, the entire pipe is again tested for voids using a high-voltage holiday detector to assure the field joints were properly wrapped and that the shop applied coatings were not damaged during installation. AWWA C-203-62, AWWA Standard for Coal-Tar Enamel Protective Coatings for Steel Water Pipe at 16-18 (Jan. 23, 1962) (ENT000393).

Q70. How do IPEC coatings for the in-scope buried piping systems requiring aging management compare to nuclear power industry standards?

A70. (RCL, SFB, JRC) The coating specification applicable during IP2 and IP3 construction required a coal tar coating covered with a fiber-based wrap saturated with coal tar. *See* Answer 68, *supra*. This is consistent with nuclear and industry standards for buried piping at the time of construction of Indian Point. *See* AWWA C-203-62, AWWA Standard for Coal-Tar Enamel Protective Coatings for Steel Water Pipe (Jan. 23, 1962) (ENT000393).

Q71. Does overall industry experience show that such coatings are sufficient to protect the piping from external corrosion during the period of extended operation?

A71. (RCL, SFB, JRC) Yes. Overall industry experience demonstrates that coal tar coatings of the type specified for IPEC buried piping have been in service for periods exceeding 75 years. *See Paint & Coatings Industry Magazine*, “Coal Tar Enamel,” http://www.pcimag.com/articles/coal-tar-enamel (May 31, 2001) (ENT000404); Brian Scott, *Pipeline & Gas Journal*, “Coal Tar Enamel Coatings Prove Out in Service”, http://findarticles.com/p/articles/mi_m3251/

is_6_228/ ai_n25035018 (June 2001) (ENT000405). Coal tar enamel has the longest performance record of all pipeline coatings available today and ranks first in the following five essential post-installation measurements of successful performance: (1) resistance to cathodic disbondment; (2) resistance to water penetration; (3) in-use with a cathodic protection system; (4) low maintenance costs; and (5) resistance to physical changing/aging. *See id.* In fact, the standards for this type of coating have existed for many decades with only minor changes (*i.e.*, generally formulation changes due to environmental regulations governing use of volatile organic compounds, or "VOCs"). Such durability attests to the validity of the procedures specified in the standard and used in the industry.

2. Inspection Program for External Surfaces of IPEC Buried Piping

a. <u>Relationship to Part 50 Program and Industry Initiatives</u>

Q72. In addition to relying on protective coatings to mitigate external corrosion, will Entergy also inspect buried piping?

A72. Yes.

Q73. Please describe the purpose of the inspection program that is part of the IPEC license renewal BPTIP?

A73. The inspection program assesses the integrity of the protective coatings 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. *See* NACE SP0169-2007 (ENT000388); NACE Paper 10059 at 2 (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.

Q74. In view of the industry and IPEC operating experience, has Entergy revised the BPTIP described in the LRA to include more inspections of buried piping?

A74. (ABC, TSI, NFA, RCL) Yes. The BPTIP includes a significantly larger number of inspections of buried piping than was proposed in the 2007 IPEC LRA.

Q75. Please explain why and how Entergy has modified the BPTIP since submitting its LRA in April 2007.

A75. (ABC, TSI, NFA) Consistent with Section XI.M34 of NUREG-1801, Rev. 1, the BPTIP described in Section B.1.6 of the April 2007 LRA relied on opportunistic inspections. The program 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). LRA, App. B at B-27 (ENT00015B). However, in 2009, as a result of recent industry and IPEC operating experience, related industry and Entergy fleet initiatives, and NRC Staff license renewal RAIs, Entergy significantly increased the number of inspections of in-scope IPEC buried piping that it will perform before and during the period of extended operation. *See* NL-09-106, Attach. 1 at 3 (NYS000203); NUREG-1930, Supp. 1, Safety Evaluation Report Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3 at 3-1 to 3-2 (Aug. 30, 2011) (NYS000160). By letter dated July 14, 2011, and amended July 27, 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. NL-11-074, Letter from Fred Dacimo, Vice President, IPEC, to NRC Document Control Desk, "Response to Request for Additional Information (RAI) Aging Management Programs," Attach. 1 at 3-4 (July 14, 2011) (NYS000152); NL-11-090, Letter from Fred Dacimo, Vice President, IPEC, to NRC Document Control Desk,

"Clarification for Request for Additional Information (RAI) Aging Management Programs," Attach. 1 at 2-3 (July 27, 2011) (NYS000153).

Q76. What are the industry initiatives to which you referred?

A76. (ABC, TSI, NFA) In November 2009, the nuclear industry, through the NEI Nuclear Strategic Issues Advisory Committee ("NSIAC"), approved the Proposed Buried Piping Integrity Initiative (Nov. 18, 2009) (ENT000406). NSIAC is an NEI standing committee whose members include the Chief Nuclear Officer ("CNO") of every utility that operates a nuclear power plant in the United States. Approved initiatives are formal commitments among CNOs to follow a defined policy or plan of action. All U.S. nuclear power plants, including Entergy's plants, adopted the Buried Piping Integrity Initiative.

The goal of the November 2009 Buried Piping Integrity Initiative is to proactively assess and manage the condition of buried piping systems, share industry operating experience, and continue technology development to improve available inspection and analysis techniques. The industry later revised the *Buried Piping Integrity Initiative* to expand its scope to underground piping and components. The industry issued the revised initiative in September 2010 as Underground Piping and Tanks Integrity Initiative (Sept. 2010) (ENT000407), which addresses both buried and underground piping. The terms "buried" and "underground" are fully defined in Chapter IX of the GALL Report. Briefly, buried piping and tanks are in direct contact with soil or concrete (*e.g.*, a wall penetration). 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.

Shortly after the NSIAC approved the Buried Piping Integrity Initiative, the NEI Buried Piping Integrity Working Group and Task Force issued NEI 09-14, Rev. 0, Guideline for the

Management of Buried Piping Integrity (Jan. 2010), to explain the intent of the initiative and facilitate its implementation. NEI then issued Revision 1 of NEI 09-14 (NYS000168) in December 2010 to incorporate changes associated with the *Underground Piping and Tanks Integrity Initiative*, as approved in September 2010. NEI 09-14, Rev. 1 added to its scope all piping that is (i) below grade, (ii) contains any fluid, and (iii) is in direct contact with the soil. NEI 09-14, Rev. 1, Guideline for the Management of Underground Piping and Tank Integrity at 5 (Dec. 2010) ("NEI 09-14, Rev. 1") (NYS000168). It also includes underground piping and tanks that are outside of a building and below grade (whether or not they are in direct contact with the soil) if they (i) are safety-related or (ii) contain licensed material (as defined on pages 10-11 of NEI 09-14, Rev. 1) or are known to be contaminated with such licensed material. *Id.*

Broadly speaking, the Underground Piping and Tanks Integrity Initiative includes the following key program attributes: (1) Procedure and Oversight, (2) Risk Ranking/Prioritization, (3) Inspection Plan/Condition Assessment Plan, (4) Plan Implementation, and (5) Asset Management Plan. Table 2 below lists the completion dates specified in NEI 09-14, Rev. 1.

Table 2. Industry Implementation Schedule for NEI 09-14 Buried Piping Initiatives

Program Attribute	Deadline (Per NEI 09-14, Rev. 1)
Buried Piping	
Procedures and Oversight	6/30/2010
Risk Ranking	12/31/2010
Inspection Plan	6/30/2011
Plan Implementation (radiological)	Start by 6/30/2012 and end by 6/30/2013
Asset Management Plan	12/31/2013
Underground Piping and Tanks	
Procedures and Oversight	12/31/2011
Prioritization	6/30/2012
Condition Assessment Plan	12/31/2012
Plan Implementation (radiological)	Start by 6/30/2013 and end by 6/30/2014
Asset Management Plan	12/31/2014

Source: NEI 09-14, Rev. 1 (NYS000168)

Entergy plants, including IPEC, are complying with these initiative deadlines.

Additional detailed guidance on program attributes is provided in EPRI 1016456, Recommendations for an Effective Program to Control the Degradation of Buried Pipe (Dec. 2008) (NYS000167). EPRI 1016456 is a technical basis document created to assist the development of licensee buried piping programs and is specifically referenced in NEI 09-14 as implementation guidance. EPRI 1016456, Rev. 1 contains six program elements that encompass the five elements specified in NEI 09-14, Rev. 1. It recommends that each company develop a program for buried and underground piping and tanks.

Finally, in April 2011, the NEI Buried Piping Integrity Task Force issued the Industry Guidance for the Development of Inspection Plans for Buried Piping, Final Draft ("NEI Buried Piping Inspection Plan Guidance") (NYS000169), which it plans to incorporate into the next revision of NEI 09-14. This guidance provides a technically-sound, consistent industry approach to developing inspection plans that establish reasonable assurance of structural and leakage integrity of buried piping. It addresses topics such as susceptibility analysis, direct and indirect inspection methods, post-examination assessment, and fitness-for-service evaluations.

Q77. Does NEI's April 2011 guidance document further explain what is meant by "reasonable assurance" in the context of buried piping integrity at nuclear plants?

A77. (ABC, TSI, NFA) Yes, it states as follows with respect to reasonable assurance:

> A reasonable assurance of integrity process is based on defining systems that are in scope, risk ranking these systems, and then identifying a sample of locations in these systems for inspections. It relies on engineering analyses, expert judgment, operating experience, and groundwater protection program data to determine what regions of the buried pipes are vulnerable to degradation and adequately characterizing the vulnerability so that, if necessary, appropriate corrective actions may be taken. This process is based on risk identification and inspection sampling intended to greatly

> reduce the potential for unacceptable leakage or failures in the most susceptible systems.
>
> Engineering evaluation is an important part of the "reasonable assurance of integrity" process. The engineering evaluation will consider but not be limited to items such as high consequence and/or likelihood areas, previous inspection results, fabrication practices, material type, backfill, coating, soil condition, water levels, water and soil chemistry, cathodic protection, operational history, industry operating experience, site operating experience and groundwater protection program data. This engineering evaluation will identify the risk of potential leakage, the most probable locations, and/or areas of likely susceptibility. The evaluation will also identify the potential consequences that could result if a leak occurred. With this information, an inspection plan can be developed and implemented that provides information regarding the condition of the structure, system or component.

NEI Buried Piping Integrity Take Force Guidance at 5 (NYS000169).

Q78. Has Entergy developed an inspection program for buried and underground piping and tanks in accordance with the industry guidance discussed above?

A78. (ABC, TSI, NFA, RCL) Yes. Entergy is implementing a program to meet the industry initiative in NEI 09-14, Rev. 1 (NYS000168) 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) (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) (NYS000173). Entergy also has issued EN-EP-S-002-MULTI, Rev. 0, Buried Piping and Tanks General Visual Inspection (Oct. 30, 2009) (ENT000408), which specifies requirements for buried piping general visual inspections. The

fleet approach promotes consistency, sharing of resources, and provides a means of disseminating operating experience among the nuclear units and Entergy's corporate offices.

The Entergy procedures identified above are being used to implement the UPTIMP at IPEC and address the various technical procedures recommended in EPRI 1016456. 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.

Entergy has completed its initial risk ranking and prioritization of IPEC buried piping. It is engaged in the third phase of the industry initiative, which involves developing condition assessment plans that provide reasonable assurance of the integrity of components within the scope of the NEI 09-14 initiatives. Entergy is using the NEI Buried Piping Inspection Plan Guidance (NYS000169) and related fleet procedures to implement the UPTIMP and BPTIP at IPEC. We discuss the specifics of Entergy's IPEC implementation efforts later in our testimony.

Q79. How does the scope of Entergy's UPTIMP compare to that of the IPEC BPTIP (*i.e.*, the license AMP subject to challenge in contention NYS-5)?

A79. (NFA, RCL, ABC, TSI) The UPTIMP, as implemented in accordance with NEI 09-14, Rev. 1 and related Entergy fleet procedures, includes all buried and underground SSCs, including those that are not in scope and subject to AMR for license renewal in accordance with 10 CFR Part 54. The BPTIP, in contrast, includes only buried components that are in scope and

subject to AMR under Part 54—a discrete subset of those buried and underground components covered by the UPTIMP.

b. Planned Direct Inspections of Buried Piping

Q80. You stated above that the IPEC BPTIP has been revised since 2007 to include many more inspections of in-scope buried piping. Please describe those revisions.

A80. (NFA, RCL, ABC, TSI) Entergy first revised the BPTIP in 2009 in response to the operating experience and industry initiatives discussed above. Specifically, in July 2009, Entergy revised the BPTIP to increase the number of planned inspections of buried piping and tanks described in the April 2007 LRA. Specifically, Entergy committed to perform fifteen IP2 inspections before entering the IP2 period of extended operation in 2013, and thirty IP3 inspections before entering the IP3 period of extended operation in 2015. *See* NL-09-106, Attach. 1 at 3 (NYS000203); NUREG-1930, Supp. 1, Safety Evaluation Report Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3 at 3-1 to 3-2 (Aug. 2011) (NYS000160). The six direct (visual and direct UT) inspections that Entergy performed on certain in-scope IP2 buried piping in October 2008 were the first inspections credited under the BPTIP.

Entergy also revised Commitment 3 (*i.e.*, its commitment to implement the BPTIP as described in LRA Section B.1.6) 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. *See* NL-09-106, Attach. 2 at 2 (NYS000203). It also 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 period of extended operation and other applicable industry and plant-specific operating experience. *See* NL-

09-111, Letter from F. Dacimo, Entergy to NRC Document Control Desk, Attach. 1 at 1 (Aug. 6, 2009) (NYS000171).

Entergy again revised the BPTIP in March 2011, principally in response to further NRC Staff RAIs. *See* NL-11-032, Letter from F. Dacimo, Entergy to NRC Document Control Desk, Attach. 1 at 3-4 (Mar. 28, 2011) ("NL-11-032") (NYS000151). Specifically, it revised the BPTIP to include additional details on its buried piping inspections, including the number of total inspections planned for each unit before and during the period of extended operation, 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 3-9. The March revised BPTIP is Entergy's NRC Staff-approved aging management program. *See id.* at 6, 9; NUREG-1930, Supp. 1, Safety Evaluation Report Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3 at 3-3 (NYS000160).

Q81. Which buried piping materials will Entergy inspect *before* IP2 and IP3 enter their respective periods of extended operation?

A81. (ABC, TSI, NFA, RCL) For the 10-year period preceding the period of extended operation, Table 3 below presents the planned inspections of buried piping subject to AMR that is (i) code/safety-related ("Code/SR") or (ii) has the potential to release materials detrimental to the environment ("Hazmat").[4] The total number of inspections includes both excavated direct visual inspections and inspections performed using indirect methods.

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[4] Hazmat pipe is pipe that, during normal operation, contains material that, if released, could be detrimental to the environment. This includes chemical substances such as diesel fuel and radioisotopes. To be considered hazmat, the concentration of radioisotopes within the pipe during normal operation must exceed established standards such as the EPA drinking water standard. In the absence of such standards, the concentration of the radioisotope must exceed the greater of background or reliable level of detection. For tritium, the EPA drinking water standard (20,000 pCi/L) is used. *See* NUREG-1801, Rev. 2 at XI M41-6 (NYS000147D).

Table 3. **Number of IP2 and IP3 Inspections to be Completed Before Each Unit's Period of Extended Operation ("Pre-PEO Inspections")**

Piping Material	Piping Category	Number of IP2 Pre-PEO Inspections (Total/Direct)	Number of IP3 Pre-PEO Inspections (Total/Direct)
Carbon steel	Code/SR	13/9	14/8
Carbon steel	Hazmat	13/11	5/3
Stainless steel	Hazmat	Not Applicable	6/3

Source: "NL-11-032, Attach. 1 at 3-4 (NYS000151).

As discussed in Section VIII.D below, Entergy already has completed and credited 24 total inspections (including 13 excavated direct visual inspections) of piping within the scope of the BPTIP.

Q82. On which piping materials will inspections be performed *during* the extended operating periods for IP2 and IP3?

A82. (ABC, TSI, NFA, RCL) Entergy will perform excavated direct visual inspections during each 10-year interval of the period of extended operation as shown in Table 2 below.

Table 4. **Number of IP2 and IP3 Excavated Direct Visual Inspections to be Completed During Each 10-year Interval of the Units' 20-Year Extended Operating Periods**

Material	Category	IP2 Inspections (Direct Visual) (for each 10-year interval of the PEO)	IP3 Inspections (Direct Visual) (for each 10-year interval of the PEO)
Carbon steel	Code/SR	6	6
Carbon steel	Hazmat	8	8
Stainless steel	Hazmat	Not Applicable	2

Source: "NL-11-032, Attach. 1 at 3-4 (NYS000151)

Q83. Does Entergy intend to conduct additional soil testing at IPEC?

A83. (ABC, TSI, NFA, RCL) As discussed in Section VII.G below, available data do not indicate that soil surrounding in-scope buried piping at IPEC is corrosive. Nonetheless, Entergy will collect and analyze additional soil samples prior to the beginning of the period of extended operation 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. *See* NUREG-1930, Supp. 1, Safety Evaluation Report Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3 at 3-1 to 3-3 (NYS000160).

The number of inspections performed during the period of extended operation will depend on the results of the soil samples. If soil sample results indicate that the soil is corrosive, then the number of inspections for carbon steel code/safety-related piping shown in Table 4 above will be increased to eight, and the number of inspections for carbon steel hazmat piping shown in Table 4 will be increased to twelve. *See* NL-11-032, Attach. 1 at 4-5 (NYS000151).

3. *Reasonable Assurance That the Integrity of In-Scope Buried Piping Will Be Maintained During the Period of Extended Operation*

Q84. Please explain why implementation of the BPTIP will manage aging effects due to external corrosion and provide reasonable assurance that in-scope IPEC buried piping will continue to perform its intended functions during extended operations.

A84. The significant number of inspections to which Entergy has committed in the BPTIP and the focus of those inspections on the most susceptible buried piping at IPEC provides the reasonable assurance required by 10 C.F.R. Part 54. By the time IP2 and IP3 enter their respective periods of extended operation in 2013 and 2015, Entergy will have completed a

combined total of 51 risk-informed inspections, including 34 direct visual inspections of excavated piping. In addition, during each 10-year interval of the license renewal term, Entergy will perform 14 direct visual inspections of excavated IP2 buried piping, and 16 inspections of excavated IP3 buried piping (a combined total of 60 additional direct inspections for the full 20-year period of extended operation).

Furthermore, in accordance with the BPTIP and implementing procedures, Entergy will continue to review operating experience, including inspection results, and other relevant site data, to confirm the adequacy of its inspection plan and make any necessary adjustments to that plan (*e.g.*, increased inspections). For example, if additional soil analyses performed both before and during the period of extended operation indicate the presence of corrosive soils (which have not been detected in analyses performed to date), then the number of planned inspections will be increased. The BPTIP thus provides a high level of confidence (*i.e.*, reasonable assurance) that the structural and leak integrity of in-scope buried piping components at IPEC will be maintained during the period of extended operation.

Q85. Based upon its detailed review of the BPTIP, what conclusions did the NRC Staff reach with respect to the adequacy of the BPTIP?

A85. Based on its review of Entergy's LRA, including related RAI responses and related revisions to the BPTIP, the Staff concluded that Entergy has 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 CFR 54.21(a)(3). NUREG-1930, Supp. 1, Safety Evaluation Report Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3 at 3-5 (NYS000160). The

Staff also reviewed the UFSAR supplement for the BPTIP and concluded that it provides an adequate summary description of the program, as required by 10 C.F.R § 54.21(d). *Id.*

Thus, the Staff agreed that there is reasonable assurance that buried piping within the scope of license renewal will continue to meet its design function without cathodic protection because: (1) recent inspections (as discussed further below) have generally found the piping's coating to be in acceptable condition, (2) soil resistivity measurements have shown the soil to be non-aggressive, (3) risk ranking of inspection locations has been and will be used to identify those areas most susceptible to corrosion, (4) further soil samples will be obtained with the number of inspections being increased if the soil is corrosive, and (5) an adequate number of inspections have been conducted to date and are planned. *See id.* at 3-3.

VIII. RESPONSE TO ISSUES RAISED IN NYS-5 AND DR. DUQUETTE'S TESTIMONY AND REPORT

A. Entergy Has a Comprehensive Understanding of IPEC Buried Piping

Q86. In its Statement of Position, NYS claims that "Entergy does not know the existing state of buried components at Indian Point." NYS-5 Statement of Position at 41 (NYS000163). What is your response to that statement?

A86. NYS's statement is inaccurate. As demonstrated in Section V above, Entergy has a comprehensive understanding of: (1) those IPEC systems containing buried piping components; (2) those buried components which support systems performing license renewal intended functions; (3) those systems containing, or potentially containing, radioactive fluids; and (4) the specifications that governed installation of IPEC buried piping and its protective coatings. Further, in accordance with EN-DC-343, Entergy has developed "as-built" drawings of in-scope buried piping systems. EN-DC-343, Rev. 4, Underground Piping and Tanks Inspection and Monitoring Program at 13 (May 16, 2011) (NYS000172). Those drawings are provided as

Exhibits 409-422 to this testimony and show the routes of buried pipes, including their location relative to other buried pipes and aboveground structures.

As discussed below, Entergy also has gained significant insights into the condition of IPEC buried pipes and their coatings through excavated direct visual inspections and indirect (*e.g.*, UT, guided-wave) examinations performed to date. To properly manage and utilize this information, Entergy has implemented the industry standard buried asset database BPWorks™ 2.0 issued by EPRI. The database allows for the storage of design, operation, inspection and corrosion control information. This information includes, for example, the results of the APEC survey (discussed in Answer 119, *infra*) in relation to the underground structures, grounding grid and other inspection information (*e.g.*, guided wave tests, visual inspections, UT, leaks, etc.), photographs, and drawings. Although Entergy has detected some degradation of, or damage to, buried piping coatings, only limited evidence of piping corrosion has been observed.

Therefore, the assertion that Entergy cannot understand existing buried piping conditions absent an excavation of all relevant IPEC buried piping is unfounded. *See* NYS-5 Statement of Position at 43 (NYS000163). In fact, excavating all in-scope buried piping at IPEC, even if practicable, would significantly increase the potential for mechanical damage to that piping and its coatings caused by excavation activities.

Q87. Do you agree with NYS's position that "Entergy can assume that *all* pipes were defectively coated and that *all* pipes were improperly backfilled, thus necessitating a 100% inspection of all in-scope buried pipes"? NYS-5 Statement of Position at 43 (NYS000163).

A87. No. Although coating imperfections can and do occur, it is not reasonable or technically justified to assume that all IPEC buried piping has defective coatings, as Dr. Duquette

suggests. We recognize that Entergy has detected some degradation of, or damage to, buried piping coatings at IPEC, including damage apparently caused by large rocks in certain backfill. The 2009 IP2 CST pipe leak cited by NYS and discussed further resulted from damage to a pipe coating and corrosion of the underlying pipe. However, as we explain below, based on the available operating experience, such adverse conditions are not common at IPEC and certainly do not render the BPTIP inadequate. Indeed, more recent inspections of IPEC in-scope buried piping have found that the backfill did not contain rocks or foreign material that would damage external coatings and that the coatings were in an acceptable condition.

In short, the fact that imperfections in buried piping coatings and backfill may exist is the reason Entergy developed the AMP described in LRA Section B.1.6 and is implementing that program through EN-DC-343 and other Entergy procedures. If the protective coatings on buried piping and tanks could be assumed or demonstrated to remain 100% intact, then there would be no need to implement an AMP as extensive as the BPTIP. However, it is true that such coatings have been shown to be effective long-term barriers against externally initiated corrosion. Even if coating imperfections are present, it is our professional opinion that the BPTIP will be effective in identifying and mitigating potential corrosion of buried piping resulting from such imperfections, such that there is reasonable assurance that the piping will remain capable of performing its intended function during the period of extended operation.

B. <u>The BPTIP is a Detailed Program that Comports with Current NRC and Industry Guidelines and Meets Part 54's Requirements for an AMP</u>

Q88. Dr. Duquette claims that the IPEC BPTIP is "insufficient to provide an understanding of what exactly Entergy would be doing to manage aging of buried pipes," and that the program is thus conceptual and aspirational in nature." Duquette Testimony at 16, 18 (NYS000164). Do you agree?

A88. (ABC, NAF, RCL, SFB) No. As noted previously, the IPEC LRA described the BPTIP as consistent with NUREG-1801 with no exceptions. LRA, Appendix B at B-27 (ENT00015B). This program description indicates that the IPEC program is, in essence, the exact program that the NRC staff had reviewed and approved in NUREG-1801. Therefore, the details of the ten-element NUREG-1801 program XI.M34 description were incorporated by reference into the IPEC LRA. Those details include, among other things, inspection methods, acceptance criteria, and corrective actions.

Furthermore, the IPEC BPTIP has been substantially augmented since 2007 in response to industry and IPEC operating experience. *See* Answers 80-85, *supra*. The revised program far exceeds the recommendations of NUREG-1801, Rev. 1, and clearly meets the intent of the new AMP described in Section XI.M41 of NUREG-1801, Rev. 2 issued in December 2010. The NRC Staff reviewed the IPEC LRA, as supplemented by additional information provided by Entergy in response to RAIs. The Staff also performed onsite audits and inspections to review onsite documentation supporting the application and to address any issues identified during the Staff's review of the application, and to verify Entergy's claim of consistency with the corresponding NUREG-1801 program. *See* NUREG-1930, Vol. 1, Safety Evaluation Report Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3 at 3-13 to 3-18 (NYS00326B); NUREG-1930, Supp. 1, Safety Evaluation Report Related to the License Renewal

of Indian Point Nuclear Generating Unit Nos. 2 and 3 at 3-1 to 3-5 (NYS000160). Moreover, Entergy is implementing the program at IPEC through fleet and site-specific documents that are based on current NEI and EPRI guidelines. *See* Answers 75-79, *supra*. The program thus is not lacking in detail or "conceptual and aspirational in nature" as Dr. Duquette claims.

In so asserting, Dr. Duquette does not take into account docketed license renewal correspondence and the specific program documents and procedures that are being used to implement the BPTIP (EN-DC-343, CEP-UPT-0100, and SEP-UIP-IPEC). For example, Dr. Duquette states:

> Entergy offers no pipe classification, determination of corrosion risk, inspection priority or frequency list, or specific inspection techniques it will use. Without seeing the actual program, including acceptance criteria and commitments to undertake repairs that Entergy intends to adopt, it is not possible to determine at this time whether the inspection program will meet the requirements for an adequate AMP.

Duquette Testimony at 19:4-11 (NYS000164). As explained above, inspection methods, acceptance criteria, and corrective actions were identified in the LRA through its reference to the NUREG-1801 program. Moreover, contrary to Dr. Duquette's claim, all of the information that he alleges is missing is contained in the referenced Entergy program documents and procedures that have been disclosed to NYS and included by NYS as exhibits to its testimony.

SEP-UPT-IPEC (NYS000174), in particular, is the IPEC Underground Components Inspection Plan. SEP-UIP-IPEC, Rev. 0, Underground Components Inspection Plan (Apr. 29, 2011) (NYS000174). Section G of that document summarizes the IPEC risk ranking process as follows:

> Scope was identified and risk ranking criteria were developed to help the Entergy Fleet prioritize the inspections of underground pipes and components subject to degradation initiating from either the inside of the pipe (ID initiated), or the outside of the pipe (OD

> initiated), or both acting in combination. Impact assessment (based on safety, public risk and economics) and corrosion risk assessment (based on soil resistivity, drainage, material and cathodic protection/coating) were initially completed to determine an inspection priority (high, medium, low). The prioritization is determined by the use of a risk matrix that rates the likelihood of failure against the consequences of failure for a given system, structure, or component (SSC) location. Since radiological SSCs were by definition considered high risk, these were further risk ranked relative to one another and characterized as high-high, high-medium, or high-low risk.
>
> The required inspections are selected depending upon the risk ranking. Those components and structures ranked the highest will be addressed with a higher priority and will be examined more extensively. The components and structures ranked in the medium and lowest category may be candidates for initial deferral.

Id. at 9. Entergy has completed this process for IPEC. All of this information has been entered into the BPWorks™ 2.0 Risk Ranking Module database, which, as explained above, stores and integrates design, operation, inspection, and corrosion control information for use in the risk ranking and inspection prioritization processes.

Section H of SEP-UIP-IPEC describes applicable inspection and examination methods for buried pipes and tanks, which 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. *Id.* at 10-14. 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. *Id.* at 11. 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.

The Appendices to SEP-UIP-IPEC (NYS000174) 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). *Id.* at 19-51. 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. *Id.* at 65. Finally, Appendix H contains program drawings of the piping systems and locations to be inspected, and identifies the exact inspection locations. *Id.* at 66-69.

In summary, the actions that IPEC will take (and, indeed, is taking) to manage aging effects on buried piping are well understood and fully described in the program and procedures discussed above. There is no basis for Dr. Duquette's claim that Entergy has not provided information concerning its risk assessment and buried piping classification processes. *See* Duquette Testimony at 17:7-11 (NYS000164).

C. <u>The BPTIP Is Not Based on "Ambiguous or Insufficient" Commitments</u>

Q89. Dr. Duquette argues that the IPEC BPTIP contains "ambiguous and insufficient commitments," implying that Entergy's implementation of the BPTIP cannot be enforced by the NRC. Duquette Testimony at 18 (NYS000164). Do you agree?

A89. (ABC, TSI, NFA) No. IPEC has committed to implement the BPTIP in license renewal Commitment 3, which the NRC Staff has found acceptable in its Supplemental SER. NUREG-1930, Supp. 1, App. A at A-2 (Aug. 30, 2011) (NYS000160). That commitment is neither ambiguous nor insufficient. It states that IPEC will:

> 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.

Id.

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. 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. 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.

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. 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 (see Answers 75 and 100). And, as

discussed below (see Answers 98-99), Entergy's implementation of the BPTIP and related commitments is subject to the NRC's inspection and enforcement processes.

Q90. With respect to the Entergy procedures cited above, Dr. Duquette states: "Entergy has not incorporated these internal documents into its commitments to the NRC, and it does not appear that Entergy believes the documents to be binding." Duquette Report at 2 (NYS000165). What is your response to these allegations?

A90. (ABC, TSI, NFA, RCL) As an initial matter, 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's adherence to such procedures is subject to ongoing NRC oversight, review and enforcement under 10 C.F.R. Part 50. *See* Answers 78-79, *supra*. Furthermore, the NEI 09-14 initiative requirements, albeit related to current plant operations, are treated with the same level of obligation as a licensing commitment. NEI 09-14 activities are subject to CNO-level oversight, and compliance with the initiative milestones are reviewed by EPRI, INPO and NEI. Entergy and the broader U.S. nuclear power industry have a history of meeting these commitments. Finally, as discussed in Answer 95, the NRC is closely monitoring licensees' (including Entergy's) implementation of the NEI 09-14 initiatives.

Q91. Why is the NRC monitoring licensee implementation of the NEI 09-14 initiatives, if such initiatives are voluntary?

A91. (ABC, TSI, NFA, RCL) In recent years, the NRC has taken numerous actions to review and address leakage from buried piping, tanks, and spent fuel pools. These include actions taken in response to the recommendations of the NRC's Liquid Release Task Force and Groundwater Task Force, which issued final reports in September 2006 and June 2010,

respectively. The purpose of these actions is to further assure licensee compliance with public dose limits and CLB requirements in 10 C.F.R. Parts 20 and 50. These actions stem from operational issues involving existing facilities, regardless of whether those facilities are seeking or will seek license renewal.

As part of these efforts, the Staff has decided to monitor nuclear industry initiatives developed in response to leakage and groundwater contamination incidents at nuclear power plants. As discussed in SECY-11-0019, Senior Management Review to Overall Regulatory Approach to Groundwater Protection (Feb. 9. 2011) (ENT000322), those initiatives include (1) NEI 07-07, Industry Ground Water Protection Initiative (GPI) (Aug. 2007) (ENT000423), (2) NEI 09-14, Rev. 0, Guideline for the Management of Buried Piping Integrity (Jan. 2010) (ENT000378), and (3) NEI 09-14, Rev. 1, Guideline for the Management of Underground Piping and Tank Integrity (Dec. 2010) (NYS000168). In Staff Requirements Memorandum SECY-11-0019 (ENT000424), the Commission approved the Staff's recommended approach to "monitor the effectiveness of the industry initiatives." Staff Requirements – SECY-11-0019 – Senior Management Review of Overall Regulatory Approach to Groundwater Protection (Aug. 15, 2011) (ENT000424).

Q92. What is NEI 07-07, or Groundwater Protection Initiative?

A92. (ABC, TSI, NFA, RCL) The industry issued NEI 07-07 in August 2007 in response to industry operating experience involving leakage (not all of which involved leaks from in-scope buried piping) and radiological contamination of ground water. NEI 07-07, Industry Ground Water Protection Initiative – Final Guidance Document (Aug. 2007) (ENT000423). The objective of NEI 07-07, which all U.S. nuclear plants have committed to follow, is to identify actions to optimize licensee response to inadvertent releases that may result in detectable levels of

plant-related radioactive materials in subsurface soils and water. These actions include the development of written groundwater protection programs, improved stakeholder communications, and program oversight. Key activities include hydrogeologic studies, site risk assessments, onsite groundwater monitoring, and the establishment of remediation protocols. *Id.*

Q93. What is the relationship, if any, between NEI 07-07 and NEI 09-14?

A93. (ABC, TSI, NFA, RCL) NEI-09-14, Rev. 1 describes the relationship between the Underground Piping and Tanks Integrity Initiative and the NEI-07-07 groundwater protection initiative as follows:

> The Underground Piping and Tanks Integrity Initiative focus is on assessing in-scope components in order to *provide reasonable assurance of their continued structural and leakage integrity with special emphasis on licensed materials*. The focus of the Ground Water Protection Initiative (GPI) is on improving the management of situations involving inadvertent radiological releases that get into ground water and the communications with external stakeholders about those events. Integral to the Ground Water Protection Initiative is an evaluation of the potential for unintended leaks of licensed materials resulting from work activities and components that contain or could contain licensed material, including some components that are within the Underground Piping and Tanks Integrity Initiative scoping. In addition, under the GPI, early detection measures are established. If licensed material is detected by early detection measures, plant personnel are expected to appropriately investigate, remediate and communicate with external stakeholders. Utilities should establish governance to ensure that the activities under the two Initiatives are communicated and coordinated.

NEI-09-14, Rev. 1, (emphasis added) (NYS000168). These statements reinforce that, consistent with Part 54, the NEI 09-14, Rev. 1 initiative and related EPRI implementation guidance are intended to help achieve safe and reliable operation of buried and underground piping and tanks at nuclear power plants, some of which perform license renewal intended functions.

Q94. In your opinion, is groundwater monitoring necessary to provide reasonable assurance that in-scope buried piping which may contain radioactive fluids will perform its intended functions through the period of extended operation?

A94. (ABC, TSI, NFA, RCL) No. For the foregoing reasons, the IPEC BPTIP provides reasonable assurance that external corrosion of in-scope buried piping (including piping containing or potentially containing radioactive fluids) will not preclude the ability of that piping to perform its intended function (maintaining pressure boundary) during extended operations. Therefore, monitoring wells are not required to demonstrate reasonable assurance as required by 10 C.F.R. § 54.29.

Nonetheless, for reasons unrelated to 10 C.F.R. Part 54's aging management requirements, Entergy has implemented a radiological groundwater monitoring program at IPEC. That program is described more fully in Entergy's testimony on contention Riverkeeper EC-3/Clearwater EC-1. In brief, the program monitors, investigates, and characterizes contamination of groundwater from licensed radioactive material at IPEC. While groundwater protection data (*e.g.*, water levels, water and soil chemistry, radionuclide concentrations in ground water) may be factored into engineering evaluations conducted under the BPTIP, groundwater monitoring is not an aging management program activity necessary to ensure that in-scope buried components will maintain their pressure boundaries and perform their *license renewal intended functions* during extended operations. That is, prevention or remediation of inadvertent leaks and groundwater protection, while important, are not intended functions identified in 10 C.F.R. § 54.4. The Commission emphasized this point in the license renewal adjudication for the Pilgrim plant (in which Mr. Cox participated as an expert witness):

> The question before us here is not the adequacy to date of NRC regulatory actions to address leakage incidents, but 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 not.

Entergy Nuclear Generation Co. and Entergy Nuclear Operations, Inc. (Pilgrim Nuclear Power Station), CLI-10-14, slip op. at 15 (June 17, 2010) (emphasis added).

Q95. You mentioned that the NRC is monitoring licensee compliance with the industry initiatives identified above. How is the NRC monitoring licensee implementation of the NEI 09-14 initiative, in particular?

A95. (ABC, TSI, NFA, RCL) Pursuant to its 10 C.F.R. Part 50 authority and processes, the NRC Staff will perform inspections of licensee programs for buried and underground piping and tanks to (1) determine whether licensees are implementing the NEI 09-14 initiatives, and (2) gather information that will enable the Staff to assess whether the initiatives provide reasonable assurance of the structural and leakage integrity of buried and underground piping and tanks. The Staff will perform these inspections in accordance with the detailed requirements and guidance contained in 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) (ENT000425).

Q96. What aspects of a licensee's buried/underground piping and tank program, as implemented pursuant to 10 C.F.R. Part 50, will the NRC review during these inspections?

A96. (ABC, TSI, NFA, RCL) TI 2515/182 describes the scope and content of these NRC inspections. *See* NRC Inspection Manual, TI 2515/182, Review of the Implementation of the Industry Initiative to Control Degradation of Underground Piping and Tanks at 3-5 (Nov. 17, 2011) (ENT000425). The inspections will occur in two phases. In Phase I, NRC inspectors will review the licensee's program to determine whether it contains the NEI 09-14 Rev. 1 attributes,

and to ensure that the program includes the completion dates recommended in NEI 09-14 Rev. 1. *Id.* at 3-4. In Phase 2, inspectors will verify completion dates and perform a more in-depth review of the licensee's implementation of the program. *Id.* at 4. Sections 03.03 through 03.07 of TI 2515/182 identify attributes of the NEI initiatives that NRC inspectors may consider during the inspections. *Id.* at 5-10. Notably, inspectors may assess whether the licensee has implementing procedures that describe the following areas of the buried pipe program: risk ranking process and methods; inspection techniques, implementation of inspections, scope expansion, fitness-for-service assessment and trending, storage and retrieval of results; fitness-for-service calculation methods and margins; and repair options. *Id.* at 6.

Q97. Has the NRC scheduled any such inspections for IPEC?

A97. (NFA, RCL) Yes. The IPEC Phase 1 inspections under TI 2515/182 are scheduled for July 2012.

Q98. Temporary Instruction 2515/182 states that because the NEI 09-14 initiatives and related licensee commitments are not regulatory requirements, enforcement action resulting from the inspections is not anticipated. What other regulatory mechanism(s) does the NRC Staff have to enforce Entergy's implementation of the BPTIP?

A98. (ABC, TSI, NFA) Although the BPTIP is bounded by the UPTIMP and is being implemented in accordance with the same Entergy procedures, the BPTIP is a license renewal AMP developed to comply with 10 C.F.R. Part 54. Accordingly, the NRC processes that apply to verification of Entergy's implementation of its AMPs and related commitments are the same processes (including the FSAR change process set forth in 10 C.F.R. § 50.59) that apply to all licensees with renewed operating licenses. For example, after a renewed operating license is issued, and before extended operation begins, NRC regional inspectors will perform a focused

inspection in accordance with NRC Inspection Procedure 71003, Post-Approval Site Inspection for License Renewal (Feb. 15, 2008) (ENT000251). The IP 71003 process includes "[verification] that license conditions added as part of the renewed license, license renewal commitments, selected aging management programs, and license renewal commitments revised after the renewed license was granted, are implemented in accordance with [10 C.F.R. Part 54]." *Id.* at 1. It also verifies that AMP descriptions and related activities are, or will be, contained in the UFSAR, and that the descriptions are consistent with the programs being implemented by the licensee. *Id.* As part of this process, the NRC reviews program documents, instructions, or procedures that the licensee has committed to follow in implementing its AMPs.

We note that, given the potential for the end of some license renewal applicants' initial operating terms before receipt of a renewed license, the NRC issued Temporary Instruction 2516/001 to allow NRC inspectors to assess progress in implementing license renewal AMPs and commitments during the pendency of the renewed license approval process. NRC Inspection Manual, TI 2516/001, Review of License Renewal Activities (Mar. 30, 2011) (ENT000252). NRC Region I inspectors completed an inspection at IP2 under TI 2516/001 during the week of March 5-9, 2012.

Q99. What is your response to Dr. Duquette's statement that the BPTIP contains "few actual commitments" and is largely unenforceable? Duquette Testimony at 18:10-11 (NYS000164).

A99. (ABC, TSI, NFA) He is incorrect. As an initial matter, Entergy is an NRC licensee and thus has an obligation to comply with NRC safety requirements and to operate IPEC safely during the initial and renewed operating license terms. That obligation includes maintaining plant equipment so that it is capable of performing its intended safety functions.

Entergy's compliance with NRC safety requirements and related regulatory obligations are subject to ongoing agency oversight, review and enforcement.

With respect to the BPTIP, Commitment 3 is explicit with respect to Entergy's obligation to implement that aging management program. NYS overlooks established NRC regulations, policies, and programs in making contrary claims. It also fails to recognize the regulatory processes that govern commitments made in an LRA.

Commitments made to the NRC by an applicant/licensee as part of *docketed licensing correspondence*, including an LRA, become part of a facility's licensing basis as described in the associated NRC safety evaluation report. *See* 10 C.F.R. § 54.3 (definition of "current licensing basis"). Licensee activities to manage commitments, including modification of commitments, are subject to the NRC's inspection program. Failure to implement or adequately manage docketed commitments is subject to NRC enforcement, as discussed in the NRC Enforcement Policy (June 12, 2011). This is as true for commitments made in an LRA as it is for commitments made during the initial 40 years of licensed operation. Thus, there is no regulatory basis for Dr. Duquette's suggestion that Entergy will not be required to complete the number of inspections to which it has committed in docketed licensing correspondence with the NRC, including responses to Staff requests for additional information. *See* Duquette Report at 18-19 (NYS000165).

Q100. What regulatory process controls commitments contained in an LRA?

A100. (ABC, TSI, NFA) Commitments (like Commitment 3) are documented in the Staff's SER (and, in this case, also in the Supplemental SER). Although the increased number of buried piping inspections that Entergy will perform before and during the period of extended operation are not explicitly listed in Commitment 3, Entergy revised the UFSAR supplement to reflect the increased numbers of inspections. As the Staff explained in its Supplemental SER:

> [B]y letter dated June 15, 2011, the staff issued RAI 3.0.3.1.2-3 requesting that the applicant revise the UFSAR supplement to reflect the number and frequency of inspections and soil testing planned for all buried pipe within the scope of license renewal.
>
> In its response dated July 14, 2011, and amended by letter dated July 27, 2011, the applicant revised LRA Sections A.2.1.5 and A.3.1.5 to reflect the number and frequency of piping inspections and soil testing.
>
> The staff finds the applicant's response acceptable because the UFSAR supplement establishes the number and frequency of piping inspections and soil testing licensing basis for the program. The staff's concern described in RAI 3.0.3.1.2-3 is resolved.

NUREG-1930, Supp. 1, Safety Evaluation Report Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3 at 3-5 (NYS000160). Any future changes to the FSAR must be made in accordance with the regulatory process described in 10 C.F.R. § 50.59.

Q101. Do the requirements in 10 C.F.R. §§ 50.59 and 50.71 change when a renewed license is issued?

A101. (ABC, TSI, NFA) No. The requirements of Sections 50.59 and 50.71 continue to apply during the period of extended operation. *See* 10 C.F.R. § 54.35 (listing the requirements during term of renewed license). The result is that an AMP approved by the NRC, including implementation details contained in the UFSAR, is documented and controlled by the licensee in accordance with licensee procedures and NRC change process/recordkeeping requirements. Specifically, revisions to NRC-approved AMPs and the UFSAR must be made in accordance with applicable regulations, such as 10 C.F.R. § 50.59, and documented in accordance with 10 C.F.R. § 50.71. Licensee compliance with these requirements is subject to the NRC inspection and enforcement processes.

D. <u>The IPEC Buried Piping Inspection Program Provides for Sufficient Inspections, Acceptance Criteria, and Corrective Actions</u>

1. Number and Timing of Planned BPTIP Inspections

Q102. Dr. Duquette alleges that Entergy has made "inconsistent statements" concerning the number and timing of inspections? Is that true?

A102. (ABC, TSI, NFA) No. Dr. Duquette appears to misunderstand the applicable program documentation. For example, he states:

> [I]nspections are supposed to be done every ten years. As an initial matter, such a long period between inspections is questionable, especially for the highest risk piping systems. But in its response to NRC's most recent RAI on buried pipes, Entergy stated it would perform more than 80 inspections. It is not clear how Entergy's response to the RAI squares with the information in Entergy's corporate documents setting inspection priority and scheduling every ten years.

Duquette Testimony at 25:5-12 (NYS000164).

As described in Answers 81-82, Entergy has committed to perform 20 direct visual inspections for IP2 and 14 direct visual inspections for IP3 *before* the period of extended operation commences, and 14 direct visual inspections for IP2 and 16 direct visual inspections for IP3 *during each 10-year interval* of period of extended operation. This equates to 34 and 60 direct visual inspections of excavated IPEC buried piping before and during extended operations, respectively. These inspections are in addition to numerous indirect (*e.g.*, Guided Wave UT) examinations that will be performed during the same periods. If planned soil testing identifies corrosive conditions, then Entergy will increase the number of direct inspections. *See* Answers 80-83, *supra.*

The buried piping inspections during the period of extended operation will be performed over the course of each 10-year period—not once every ten years—basing inspection locations in each round of inspections building upon prior inspection results and other available operating

experience. The buried piping AMP is built on a continuous improvement cycle. It involves an iterative process, not a one-time compliance activity, in which new data and lessons learned are continually fed into the risk model to inform future inspection planning. This approach is reflected in the IPEC program documentation and the EPRI guidance on which it is based. EPRI 1016456 at 1-8 to 1-10 (NYS000167).

2. BPTIP Acceptance Criteria and Corrective Actions

Q103. Dr. Duquette states that "an inspection program, *per se*, is not adequate to ensure the safe operation of engineering systems." Duquette Testimony at 21:16-17 (NYS000164). What is your understanding of his claim, and do you agree with it?

A103. (ABC, TSI, NFA, RCL) No, we disagree. Dr. Duquette's statement appears to be based on two premises. Specifically, he states as follows:

- The acceptability of the results of the inspection program, including the criteria to be applied to continued operation, remediation, or replacement, should be specified. Entergy has not identified when it will take mitigative measures if problems are found, or what those mitigative measures will be. Duquette Testimony at 21:17-22 (NYS000164).
- [I]t is not clear how many inspections, if any, have already taken place that Entergy is counting against this requirement but that were not conducted to the standards to which Entergy's new program would dictate they should be conducted. *Id.* at 22:1-5.

Both of these statements lack a factual basis and, therefore, do not support his overbroad assertion that "an inspection program, *per se*, is not adequate." *Id.* at 21:16-17.

Q104. So Entergy has specified appropriate acceptance criteria for buried piping inspections, as well as any necessary corrective actions?

A104. (ABC, TSI, NFA, RCL) Yes. Entergy has specified appropriate acceptance criteria for inspections of buried piping coatings and buried piping surfaces. We discuss the

acceptance criteria for coating inspections in Answer 107. We discuss here the acceptance criteria for inspections of buried piping surfaces.

If Entergy detects any corrosion of a buried component, then that component is evaluated against the system design requirements to ensure that it does not reduce the system structural capabilities below those required to maintain structural integrity during and after design basis accidents. This approach is fully consistent with current NRC requirements, standard industry practices, and IPEC-specific procedures.

Since the location-specific acceptance criteria (*i.e.*, specific degradation dimensions and acceptable pipe wall thickness) are necessarily dependent on the design loads for that location (seismic moments and forces, etc.), it is not necessary or required to develop the acceptance criteria for all buried piping locations in advance. As required by CEP-UPT-0100, the acceptance criteria for a specific piping location will be developed *before* performing the actual inspection of that location. CEP-UPT-0100, Rev. 0, Underground Piping and Tanks Inspection and Monitoring at 16 (Oct. 31, 2011) (NYS000173). However, any pipe wall thickness that is found to exceed 87.5% of its nominal thickness is acceptable without further evaluation, because this represents the manufacturer's tolerance, and the pipe already has been designed to account for this tolerance. *See* EPRI/NEI Industry Guidance for the Development of Inspection Plans for Buried Piping at 17 (Apr. 2011) (NYS000169)

Any degradation detected during buried piping inspections is entered into the IPEC Corrective Action Program and evaluated for extent of condition. *Id.* Entergy takes any necessary corrective actions in accordance with the requirements of 10 C.F.R. Part 50 and Entergy procedure EN-LI-102, Rev. 17, Corrective Action Process (Dec. 8, 2011) (ENT000401). If test or inspection acceptance criteria are not met, then the affected locations will be repaired or replaced as

appropropriate. Entergy also will evaluate the significance of the test or inspection results and then, depending on the significance of the condition, evaluate the component's operability, the reportability of the event, the extent of the condition, the potential causes of the degradation and failure to meet the test or inspection acceptance criteria, the corrective actions required, and the likelihood of recurrence. As part of the extent of significant condition evaluation, other systems or components found susceptible to the same conditions will be evaluated for additional corrective actions, including mitigative actions, such as the installation of cathodic protection.

Sections 5.4, 5.5, 5.6 of EN-DC-343 provide related guidance on inspections, fitness for service, and repairs, respectively. EN-DC-343, Rev. 4, Underground Piping and Tanks Inspection and Monitoring Program at 14-16 (May 16, 2011) (NYS000172). Section 5.4 states that "[t]he applicable Code required minimum design thickness, t_{min}, to be used in the fitness-for-service assessment should be determined before the direct examinations." *Id.* at 15. Fitness-for-service evaluations are performed in accordance with EPRI guidance. *See* CEP-UPT-0100, Rev. 0, Underground Piping and Tanks Inspection and Monitoring at 16 (Oct. 31, 2011) (NYS000173) (citing EPRI/NEI Industry Guidance for the Development of Inspection Plans for Buried Piping at 18-20 (Apr. 2011) (NYS000169)). Section 6.0 of the NEI Buried Piping Inspection Plan Guidance lists ASME and API code sections and standards applicable to buried piping fitness-for-service evaluations.

Q105. With respect to EN-DC-343, Dr. Duquette claims that the procedure merely contains "best practices" for buried pipes, and does not contain specific aging management measures? Duquette Testimony at 10 (NYS000164). Do you agree?

A105. (ABC, TSI, NAF, RCL) No. The EN-DC-343 discussion cited by Dr. Duquette pertains to "best practices" for *new* buried piping installations. *See* EN-DC-343, Rev. 4,

Underground Piping and Tanks Inspection and Monitoring Program at 16-17 (May 16, 2011) (NYS000172). Dr. Duquette disregards other key sections of EN-DC-343 that relate to aging management. Consistent with EPRI, NEI and other industry references for developing effective aging management programs, EN-DC-343 and other relevant Entergy procedures rely on excavation and direct visual inspections, guided wave/UT examinations, site surveys, soil analysis, and cathodic protection (as appropriate). *See*, *e.g.*, EN-DC-343 at 14-17. Dr. Duquette's statement is incorrect.

3. Current Status of BPTIP Inspections

Q106. What is your response to Dr. Duquette's statement concerning the alleged uncertainty about the number of BPTIP-related inspections that Entergy has completed and credited to date? *See* Duquette Testimony at 21-22 (NYS000164).

A106. (ABC, TSI, NFA, RCL) As indicated in Table 5 below, Entergy has completed 24 total inspections (direct and indirect) of IP2 and IP3 code/safety-related carbon steel piping, including 13 excavated direct visual inspections of that piping, as part of its license renewal BPTIP. As noted above, under the BPTIP, Entergy has committed to perform 51 total inspections (direct and indirect combined) of in-scope IP2 and IP3 buried piping, including 34 excavated direct visual inspections, before the IP2 and IP3 periods of extended operation.

Table 5. <u>Status of Pre-PEO Inspections of Buried Piping at IPEC (as of 3/30/12)</u>

Piping Material	Piping Category	Number of IP2 Pre-PEO Inspections Required (Total/Direct)	Number of IP2 Pre-PEO Inspections <u>Completed</u> (as of 3/30/12) (Total/Direct)	Number of IP3 Pre-PEO Inspections Required (Total/Direct)	Number of IP3 Pre-PEO Inspections <u>Completed</u> (as of 3/30/12) (Total/Direct)
Carbon steel	Code/SR	13/9	12/7	14/8	12/6

Carbon steel	Hazmat	13/11	0/0	5/3	0/0
Stainless steel	Hazmat	Not Applicable	Not Applicable	6/3	**0/0**

Q107. Dr. Duquette suggests that IPEC buried piping inspections completed to date may not have been performed "conducted to the standards to which Entergy's new program would dictate they should be conducted." Duquette Testimony at 21-22 (NYS000164). Do you agree?

A107. (ABC, TSI, NFA, RCL) No. Consistent with EN-DC-343, Section 5.4 (NYS000172), in visually assessing the condition of pipe coatings and pipe base metal surfaces for indications of degradation that may affect structural integrity or leak tightness, Entergy inspectors have applied criteria consistent with those in Entergy Engineering Standard EN-EP-S-002-MULTI, Rev. 0, Buried Piping and Tanks General Visual Inspection (Oct. 30, 2009) (ENT000408). With respect to the piping base metal, the standard specifies additional review and the initiation of a condition report if any of the following conditions are observed: cracking in the base metal; discoloration resulting from age, heat, or corrosion; discernible wear; pits, dents, or gouges in the base metal; excessive external corrosion; corrosion which results in discernible base metal loss; discernible bulges; arc strikes; or any other conditions causing discernible degradation of the base metal. EN-EP-S-002-MULTI at 8-9, 11 (ENT000408). With respect to coatings, it specifies additional review and the initiation of a condition report if there is any indication of coating degradation (*e.g.*, discoloration, discontinuities, bubbling, blistering, flaking, peeling, separation from pipe, embrittlement). *Id.* at 9, 11. For UT inspections, the acceptance criterion is a wall thickness greater than 87.5% of the nominal wall thickness. CEP-UPT-0100, Rev. 0, Underground Piping and Tanks Inspection and Monitoring at 16 (Oct. 31, 2011) (NYS000173).

Thus, for past inspections credited by Entergy, any unsatisfactory inspection results were documented in a condition report in accordance with the IPEC Corrective Action Process. For some of the earlier inspections (2008-2009 timeframe), if no outside diameter coating degradation was identified, then Entergy left the coating intact, with no additional inspection required. If the coating was degraded, then Entergy issued a condition report, removed the coating from that pipe location, and performed a direct UT (ultrasonic testing) determination of the wall thickness. If the pipe met the 87.5% wall thickness criterion, then Entergy re-coated the pipe, with no further actions required. If the pipe did not meet that criterion, then Entergy repaired or replaced the affected piping as required based on evaluation of the remaining wall against required minimum design wall thickness, the estimated corrosion rate, and the pipe's remaining life. We discuss the results of specific inspections below.

Q108. Has Entergy made any recent augmentations to the program or procedure documents described above?

A108. (RCL, NFA) Yes. As noted above, CEP-UPT-0100 was issued in October 2011. CEP-UPT-0100 contains the following program augmentations: (1) a minimum of 10 feet linear length of piping is exposed for inspection purposes (opportunistic or collateral piping inspections may cover less than 10 feet of pipe length); (2) if coated, the coating is removed for its entire exposed length (an exception allows for only partial coating removal if the coating material contains asbestos), and (3) the required design minimum wall criteria is to be published in an engineering document in advance of performing the inspection. CEP-UPT-0100, Rev. 0, Underground Piping and Tanks Inspection and Monitoring at 14, 16 (Oct. 31, 2011) (NYS000173). These additional requirements were in effect during the most recent direct visual

inspections of in-scope IPEC buried piping in 2011 (discussed below) and also will be implemented in future inspections.

Q109. For which specific IPEC systems within the scope of the license renewal BPTIP has Entergy performed direct visual inspections to date?

A109. (RCL, NFA) Entergy has excavated and visually inspected portions of buried piping associated with the following in-scope systems: (1) auxiliary feedwater (AFW), which includes the condensate storage tank (CST) lines (in 2008, 2009, and 2011); (2) city water (in 2009); (3) fire protection (in 2009 and 2011); and (4) service water (in 2011). *See* Answers 110-118, *infra*.

Q110. Please describe the 2008 direct visual inspections of the buried AFW piping, including the results of those inspections.

A110. (RCL, TSI) In October 2008, Entergy excavated and visually inspected the piping from the IP2 CST to the AFW pump building. Three buried piping lines run in parallel from the CST to the AFW pump building: (1) Line 1505 (a 12-inch diameter AFW pumps suction line from the CST); (2) Line 1509 (an 8-inch diameter CST return line); and (3) a 10-inch overflow line to manhole #5. Lines 1505 and 1509 are safety-related. Entergy selected these specific lines for inspection based on an assessment of the piping's safety significance, the potential radiological and operational impacts of piping failure, and the piping's corrosion risk.

These three underground lines were excavated at two locations. The first location was in the horizontal run of the pipe near the base of the CST. The second location was at the approximate "one-third point" along the sloped length of the piping (*i.e.*, approximately 100 feet down the hill). The lines from the CST to the AFW pump building are about 320-330 feet in length.

The excavations exposed portions of each line (*i.e.*, the AFW pump supply, CST return, and CST overflow lines) at the two locations. Inspections identified five small areas in the upper excavation that required coating repairs. Inspection of the piping in the lower excavation identified two areas requiring minor coating repairs on the 8-inch and 10-inch lines. Entergy also performed UT thickness measurements on those areas where the base metal was exposed. These inspections confirmed that the pipe thickness remained at its nominal thickness (*i.e.*, within the manufacturer's tolerance), and found no evidence of measureable wall loss due to corrosion.

After completing these inspections and coating repairs in accordance with applicable Entergy procedures and industry standards, Entergy backfilled both holes with sand around the piping and normal fill for the remainder of the hole. As a result of this examination, IPEC issued condition report CR-2008-04754 (ENT000426) and two associated corrective actions ("CA"), CA 0001 and CA 0002. The defective areas of coating observed during these inspections were attributed to the introduction of rocks in the backfill material used when covering the piping during initial construction, and possible coating damage incurred during the excavation process itself. CA 0002 called for an engineering evaluation of possible future inspection locations in accordance with the IPEC BPTIP based on the results of these inspections. A third corrective action (CA 0003) was issued to track the scheduling of future inspections of these lines.

Q111. What buried AFW piping did Entergy examine in 2009?

A111. (NFA, RCL) The inspection performed in 2009 was not a planned inspection. Rather, it resulted from an operational event. On February 15, 2009, IPEC personnel observed water in a pipe sleeve in the floor of the AFW pump building. Entergy determined that the water observed in the pipe sleeve was due to a leak in the 8-inch diameter IP2 CST return line. After excavating a portion of the CST piping in the area of the identified leakage, Entergy identified a

hole in the pipe where a small area of protective coating was missing. Entergy also identified two areas of thinned piping that still exceeded minimum required wall thickness. Entergy replaced a section of the pipe containing the leak and performed weld repairs on the nearby areas exhibiting shallow corrosion. It also recoated the affected piping sections in accordance with Entergy procedures. *See* Root Cause Analysis Report, CST Underground Recirc Line Leak, CR-IP2-2009-00666, Rev. 0 (May 14, 2009) ("2009 Root Cause Report") (NYS000179).

As part of its root cause evaluation, Entergy sent the failed pipe segment to a laboratory for analysis. It was determined that the direct cause of the event was a failure of the external protective pipe coating applied at the time of original construction, resulting in localized external corrosion of the pipe. Although the external pipe coating was correctly specified for the application, damage to the coating in this area of the pipe resulted in corrosion of the underlying metal. Specifically, Entergy determined that the root cause of the leak was the apparent introduction of large rocks in the backfill during original construction that damaged the protective coating, ultimately leading to corrosion of the external piping surface and leakage from the pipe. High moisture in the soil surrounding the pipe also contributed to the corrosion, as the pipe was located at an elevation that placed it in proximity to the water table. Damp or wet conditions accelerate the general corrosion of exposed carbon steel.

Based on an evaluation of the findings from this event, Entergy undertook numerous corrective actions. These correction actions are described in the 2009 Root Cause Report. *See* 2009 Root Cause Report at 33-35. For example, Entergy used improved backfill specifications to cover the pipe. *Id.* NRC inspectors concluded that the actions Entergy implemented to evaluate and repair the leaking CST pipe were adequate and in accordance with the IP2 operating license.

See Letter from M. Gray, NRC, to J. Pollock, Entergy, Enclosure at 31-32 (May 15, 2009) (ENT000427).

Q112. Did the February 2009 IP2 CST return line leakage event have any safety impact or consequences?

A112. (NFA, RCL, ABC, TSI) No, although a leak occurred, there was no loss of an intended safety function for the piping at issue. PWRs such as IP2 generally rely upon the AFW system and the steam generators for core decay heat removal for all reactor shutdowns and accident conditions, except during a large loss-of-coolant accident (LOCA), in which case the emergency core cooling system (ECCS) supplies water directly to the reactor coolant system for decay heat removal. At IP2, the AFW system supplies water to the steam generators in the event that the nonsafety-related main feedwater system, which normally maintains the water level in the steam generators during power operations, becomes unavailable. The primary water supply for the AFW system is the condensate storage tank (CST), which contains demineralized water. A backup water supply is available at IP2 from the plant's city water storage tank, which is filled with municipal water, but is maintained and operated onsite independent of the local city water system. *See* Letter from Chairman G. Jaczko, NRC to Senator E. Markey, Enclosure at 1 (June 17, 2009) (ENT000385).

The February 2009 leak at IP2 was on the CST return line. Although Entergy declared the CST inoperable, the supply line from the CST to the AFW system remained in service and capable of fulfilling its safety function. If a reactor shutdown had occurred during this time, then the AFW system still would have delivered water from the CST to the steam generators. The ECCS also is available for core decay heat removal in the unlikely event that the AFW system does not function during an unexpected plant shutdown. *Id*.

Q113. NYS's expert states that the 2009 CST return line leakage event "provides a cautionary tale about the condition of *all* of the buried piping at Indian Point," and that IPEC's current proposed inspection program would not have been sufficient to have identified the possibility of a leak in this buried pipe. Duquette Report at 9-10 (NYS000165) (emphasis added). What is your response?

A113. We disagree. The location of the 2009 leak in the 8-inch condensate return line to the CST was in a pipe segment that had been assigned a high risk ranking and priority for inspection. As discussed above, the return line and the 12-inch CST supply line to the AFW pumps, which is routed with the 8-inch line, had been inspected in October 2008 at two locations between the failure location and the CST. These two locations were the first buried piping inspections performed as part of the IPEC BPTIP.

The results of those inspections found coating degradation/damage on the piping, but there was no visual evidence of corrosion of the pipe outside diameter (OD). After the coating was removed, the pipe wall thickness was measured using the UT method. The pipe wall was found to be greater than 87.5% of the nominal wall thickness (*i.e.*, the required minimum allowable thickness, accounting for manufacturing tolerances). Therefore, if the coating had been degraded for a considerable period, the soil environment was not aggressive to the extent it resulted in corrosion of the pipe. The lack of corrosion is consistent with the historical characterizations of soils at IPEC.

Entergy performed additional indirect inspections of the IP2 CST and condensate return line piping in September 2009 utilizing "guided wave" UT methods, as described in Answer 114. As discussed further below, the testing results indicated that the 8-inch condensate return and 12-inch CST supply lines may have moderate corrosion at the outside surface at lower plant

elevations where soil moisture content is higher. On that basis, cathodic protection was installed to protect this piping at the lower plant elevations. This approach, which includes the use of inspection and field survey results to assess the potential need for cathodic protection, is consistent with the industry guidelines discussed above.

If the 2009 CST inspections had been indicative of a widespread pipe coating degradation at the site, then subsequent indirect assessments that were performed at IPEC (*e.g.*, the 2010 APEC survey discussed in Answer 119) would have identifed the condition. As explained below, subsequent assessments have not indicated extensive coating degradation. Dr. Duquette's statement is incorrect.

Q114. Please describe the October 2009 guided wave inspections, including the methods used and the results obtained, in greater detail.

A114. (NFA, RCL, SFB) In view of the site-specific operating experience discussed above, Entergy contracted with SIA to perform guided wave ultrasonic testing ("GWT") on certain piping systems. *See* Structural Integrity Associates, Inc., G-Scan Assessment of Various Buried Piping (Nov. 16, 2009) ("SIA Guide Wave Testing Report") (ENT000428). GWT is a low-frequency UT technique developed for the rapid survey of pipes to detect both internal and external wall loss in portions of buried piping that are difficult to access. It uses multiple transducer arrays to direct sound energy in a circumferential mode, which creates a torsional guided wave within the pipe walls. These torsional waves propagate away from the transducer collar along the length of the pipe and reflect off features such as welds, supports, or areas of wall loss. *Id.* at 2-6. These reflections are collected and analyzed to identify specific locations along the pipe and the nature of the indications. GWT can be used to confirm that significant corrosion

has not occurred and to indicate the need for further inspections of piping sections considered vulnerable to corrosion.

On September 22-23, 2009, SIA used GWT to test for wall loss at six locations on the IP2 and IP3 service water and condensate piping. IPEC engineers selected the locations for these inspections based on a determination that these locations have the highest risk of corrosion due to their proximity to the water table. The specific lines and locations tested by SIA with GWT are listed in Table 6 below.

Table 6. IP2 and IP3 Piping Locations Examined in 2009 Using G-Scan Technology

General Information					Pipe Data			
Loc. #	Unit	Line Name	Line #	Location	G-Scan Test #	Outside Diam. (in)	External Coating	Internal Lining
1	2	Service Water Supply Header	408	Transformer Yard Area	2979 2982	24	Coal Tar Enamel w/ saturated asbestos	Mortar Lined
2	3	Service Water Supply Header	408	Service Water Valve Pit	2983	24	Coal Tar Enamel w/ saturated asbestos	Mortar Lined
3	3	Cond. Return to CST	1080	Unit 3 CST to AFW Bldg. – Bottom of Hill	2984	8	Coal Tar Enamel w/ saturated asbestos	None
4	2	Cond. Return to CST	1509	FRV Bldg Excavation	2991	8	Coal Tar Enamel w/ saturated asbestos	None
5	2	CST to AFW Pump Bldg	1505	FRV Bldg Excavation	2993	12	Coal Tar Enamel w/ saturated asbestos	None
6	3	CST to AFW Pump Bldg	1070	Unit 3 to AFW Pump Bldg – Bottom of Hill	2995	12	Coal Tar Enamel w/ saturated asbestos	None

Source: SIA Guide Wave Testing Report (ENT000428).

The results of this GWT investigation are documented in the SIA Guided Wave Testing Report (ENT000428), which presents a detailed discussion of the GWT technology, including the necessary equipment, underlying physics, the methods used to interpret the test results, and the IPEC test results. The report contains illustrations and photos of the test locations and detailed descriptions of the test results. The test evaluation criteria and test results are summarized in

Table E2 and Table E3, respectively, of the report. Indications are on a scale of 1-4, with Level 1 indications being the most severe.

In short, while the GWT testing indicated the presence of some "Level 2" indications (*i.e.*, moderate areas of interest) in the IP2 service water supply header piping and piping from the IP2/IP3 CST to the AFW pump building, no "Level 1" indications (areas of substantial interest) were identified. SIA recommended that the "Level 2" indications, if reasonably accessible, be further explored with another NDE technique or direct visual examination. SIA recommended that the "Level 3" areas be monitored over time. The Level 2 and 3 indications were evaluated under the IPEC Corrective Action Program.

Based on the GWT results, plant modification packages were developed to install cathodic protection on buried piping between the CST and the AFW buildings for both IP2 and IP3 (*i.e.*, to protect the piping at the lower plant elevations, which are most susceptible to variations in the water table). Locations 1 (IP2 SW), 5 (IP2 CST to AFW Pump Buildings), and 6 (IP3 Return to CST) are the piping that will be protected by the CP modifications. Location 5 is on the line that experienced the leak in 2009 as well as the adjacent parallel line, and Location 6 is on the corresponding IP3 line. These CP systems were installed during the first quarter of 2012. *See* Screen Shots of Work Orders Associated with the Installation of Modifications to Add Cathodic Protection to Protect Indian Point Unit 2 Buried CST lines to the Auxiliary Feedwater Building/Pumps (Engineering Change 25391) and Indian Point Unit 3 Buried CST Lines to the Auxiiliary Feedwater Building/Pumps (Engineering Change 27604) (Marr. 2012) ("IP2/IP3 CST Piping CP System Work Orders") (ENT000429).

In view of the above, we note that there is no basis for Dr. Duquette's claim that "Entergy has not indicated that it has investigated the [corrosion] problem for adjacent [CST] piping or

made repairs to adjacent piping based on such investigation." Duquette Report at 22 (NYS000165). As a result of the February 2009 CST line leakage event, Entergy took appropriate corrective actions that included inspecting (and later cathodically protecting) IP2 and IP3 CST buried piping.

Q115. Has Entergy performed any additional direct visual inspections of AFW piping since 2009?

A115. (NFA, RCL) Yes. In December 2011, IPEC excavated and visually inspected approximately 12-feet linear segments of two IP3 buried piping lines (8-inch line COND-1080-1 and 12-inch line COND-1070-1) running from the condensate storage tank to the AFW building in accordance with in EN-EP-S-002-MULTI, Rev. 0, Buried Piping and Tanks General Visual Inspection (Oct. 30, 2009) (ENT000408). The coating on both lines was acceptable. The coating was removed for UT and GWT examinations. There were no signs of degradation of the base metal. *See* General Visual Inspection Report for IP3 AFW/Cond Return Line to CST (8-inch Line 1080) (Ref. WO # 279578-03) (Dec. 2011) (ENT000430); General Visual Inspection Report IP3 CST supply to AFW Pumps (12-inch Line 1070) (Ref. WO # 279578-03) (Dec. 2011) (ENT000431). The UT examinations confirmed that the wall thickness of both pipes exceeded 87.5% of the nominal wall thickness, and the guided-wave examinations did not identify any areas of concern on either pipe. *See* UT Erosion/Corrosion Examination Report No. IP3-UT-11-076 (8" Line #1080, CST return line) (Dec. 2011) (ENT000432); UT Erosion/Corrosion Examination Report No. IP3-UT-11-077 (12" Line #1070, CST supply to the AFW pump section) (Dec. 2011) (ENT000433).

Q116. Please describe the city water line buried piping inspections performed in 2009, including the results of those inspections.

A116. (NFA, RCL) In October 2009, 16-inch and 10-inch diameter city water lines from the city water storage tank were inspected during a plant modification to install cathodic protection for those portions of the IP2 and IP3 city water lines near the Algonquin gas pipelines. Excavation and inspection covered approximately two 10-foot sections of 16-inch piping and approximately eight feet of the 10-inch piping. The inspections found both the coating and piping condition to be acceptable per the acceptance criteria contained in EN-EP-S-002-MULTI (ENT000408). The backfill did not contain rocks or foreign material that could damage external coatings. The reports documenting these inspections contain figures showing the locations of the inspected piping and photographs of the excavated pipes. *See* General Visual Inspection Report for 10-inch City Water Line from Catskill Water Supply (Oct. 2009) (ENT000434); General Visual Inspection Report for 16-inch City Water Line from CWST (Oct. 2009) (ENT000435).

Q117. Please describe the inspections of buried fire protection piping performed in 2009 and 2011, including the results of those inspections.

A117. (NFA, RCL) In November 2009, Entergy inspected approximately eight feet of the 10-inch fire protection header near IP2. This inspection, which also applied EN-EP-S-002-MULTI, found acceptable coating and piping conditions. The backfill did not contain rocks or foreign material that would damage external coatings. The report documenting this inspection contains detailed figures illustrating the location of the inspected piping and photographs of the pipe coatings and backfill. *See* General Visual Inspection Report for 10-inch City Water/Fire Water Line at Maintenance Training Facility (MTF) (Nov. 2009) (ENT000436).

In August 2011, Entergy performed opportunistic inspections of sections of IP3 8-inch and 6-inch fire protection lines running north-south under the dry cask travel pad. Those inspections also found the coating and piping condition acceptable per the criteria in EN-EP-S-002-MULTI. Additionally, the backfill did not contain rocks or foreign material that would damage external coatings. General Visual Inspection Report for IP3 8-inch Fire Protection Line (N/S) at N/W corner of the WHUT Pit (Aug. 2011 (ENT000437); General Visual Inspection Report for IP3 6-inch Dire Protection Line (N/S) corner of the WHUT Pit (Aug. 2011) (ENT000438).

Q118. What portion(s) of the service water system did Entergy visually inspect in 2011, and what were the inspection results?

A118. (NFA, RCL) In November and December 2011, IPEC performed direct visual inspections of sections of the IP2 service water piping (24-inch lines 408 & 409). IPEC exposed approximately 12 linear feet of each line, including 90-degree elbows. With the exception of some coating separation at one 90-degree elbow, the coating on both lines was in acceptable condition, as assessed under EN-EP-S-002-MULTI. The elbow with coating separation was stripped of coating and re-coated and taped. No corrosion of the exterior surface of the pipe was identified, and direct UT measurements showed the wall thickness at the site of coating separation was greater than 87.5 % of the 24-inch piping nominal wall thickness. No rocks or foreign material that would damage external coatings were observed. *See* General Visual Inpsection Report for IP2 Service Water 24-inch Line 408 (WO #279576-02) (Nov. 2011) (ENT000439); General Visual Inpsection Report for IP2 Service Water 24-inch Line 409 (WO #279576-02) (Nov. 2011) (ENT000440); UT Erosion/Corrosion Examination Report No. IP2-UT-11-048 (Service Water 24-inch Line 408) (Dec. 2011) (ENT000441); UT Erosion/Corrosion Examination Report No. IP2-UT-11-050 (Service Water 24-inch Line 409) (Dec. 2011) (ENT000448).

IPEC also removed coating on straight sections of the pipe (both lines) for direct UT measurement of pipe wall thickness and for guided wave collar installation. Direct UT results confirmed that wall thickness exceeded 87.5% of the nominal wall thickness. GWT inspections recorded a signal reflection about five feet downstream of the collar on Line 409. This location was excavated to expose the pipe, and then prepped for UT examination to determine the pipe wall thickness. IPEC completed the UT measurements in January 2012 and identified no issues. The measured wall thicknesses were at nominal (and thus acceptable) values. *See* UT Erosion/Corrosion Examination Report No. IP2-UT-12-002 (Service Water 24-inch Line 409) (Jan. 2012) (ENT000442); Condition Report CR-IP2-2011-06248 (Dec. 8, 2011) (ENT000443); Condition Report CR-IP2-2011-06250 (Dec. 8, 2011) (ENT000444).

4. IPEC Field Surveys of Buried Piping

Q119. In addition to the targeted inspections discussed above, has Entergy conducted any broader site surveys of buried piping within the scope of the BPTIP?

A119. (NFA, RCL, SFB) Yes. In addition to completing the direct visual inspections discussed above, Entergy also conducted a corrosion/CP survey in October 2008, and an Area Potential Earth current ("APEC") survey of the IPEC site in November 2010. These surveys are described further below.

a. <u>October 2008 PCA Corrosion/Cathodic Protection Field Survey</u>

In October 2008, PCA Engineering, Inc. ("PCA") performed a corrosion/CP field survey and assessment of underground structures at IPEC. These buried and underground structures included 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, and a revised version thereof 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") (NYS000178).

Sections VI and VII of the PCA Report summarize the investigation results and PCA's recommendations. PCA Report at 13-18. PCA recorded soil resistivity data for the 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. *See* PCA Report Table, "Corrosion Field Survey Data and Tables." Those data are summarized and discussed in Answer 128.

Based on the results of these and other tests it conducted, PCA made several recommendations regarding cathodic protection. PCA first recommended 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. *See* PCA Report at 12-13, 16 (NYS000178). Entergy installed a CP system in November 2009 to resolve the stray current issue and protect the affected portions of the IP2 and IP3 city water lines. Direct visual inspections of the piping when the CP system was installed revealed no adverse impacts from the stray current. *See* Answer 116, *supra*. PCA also recommended that Entergy evaluate additional CP needs, noting that a progressive or multi-phase plan would provide the most effective return. Entergy's related actions are discussed below. *See* PCA Report at 17 (NYS000178).

b. <u>November 2010 SIA Area Potential Earth Current (APEC) Survey</u>

In 2010, Entergy also commissioned SIA to conduct a site-wide APEC survey within the protected area at IPEC. SIA completed the APEC survey in November 2010. The final technical report was approved by Entergy in November 2011. *See* Report No. 0900271, Rev. 0, Indian Point Energy Center APEC Survey (Nov. 17, 2011) ("APEC Survey Report") (ENT000445).

The APEC survey of buried piping systems provides information on the condition of multiple buried pipes in an area. APEC survey uses 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. *See* APEC Survey Report at 2-4 to 2-7 (ENT000445).

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, Standard Practice, Control of External Corrosion on Underground or Submerged Metallic Piping Systems (Mar. 15, 2007) (ENT000338); (2) where localized changes in the measured potentials exist, relative to surrounding readings, as a means to locate potential areas containing corrosion cells; (3) localized variations in earth currents, relative to surrounding readings, which would indicate coating degradation. APEC Survey Report at 2-4 (ENT000445).

SIA performed two types of APEC surveys at IPEC: (1) a native survey and (2) an interrupted cathodic protection current survey, and then integrated the results for interpretation. *See id.* at 1-1, 3-1 to 3-16. An APEC survey collects area potential measurements based on a modified close interval survey approach in combination with an evaluation of the earth current gradients using an enhanced 3-half cell methodology. Area potential measurements are indicative

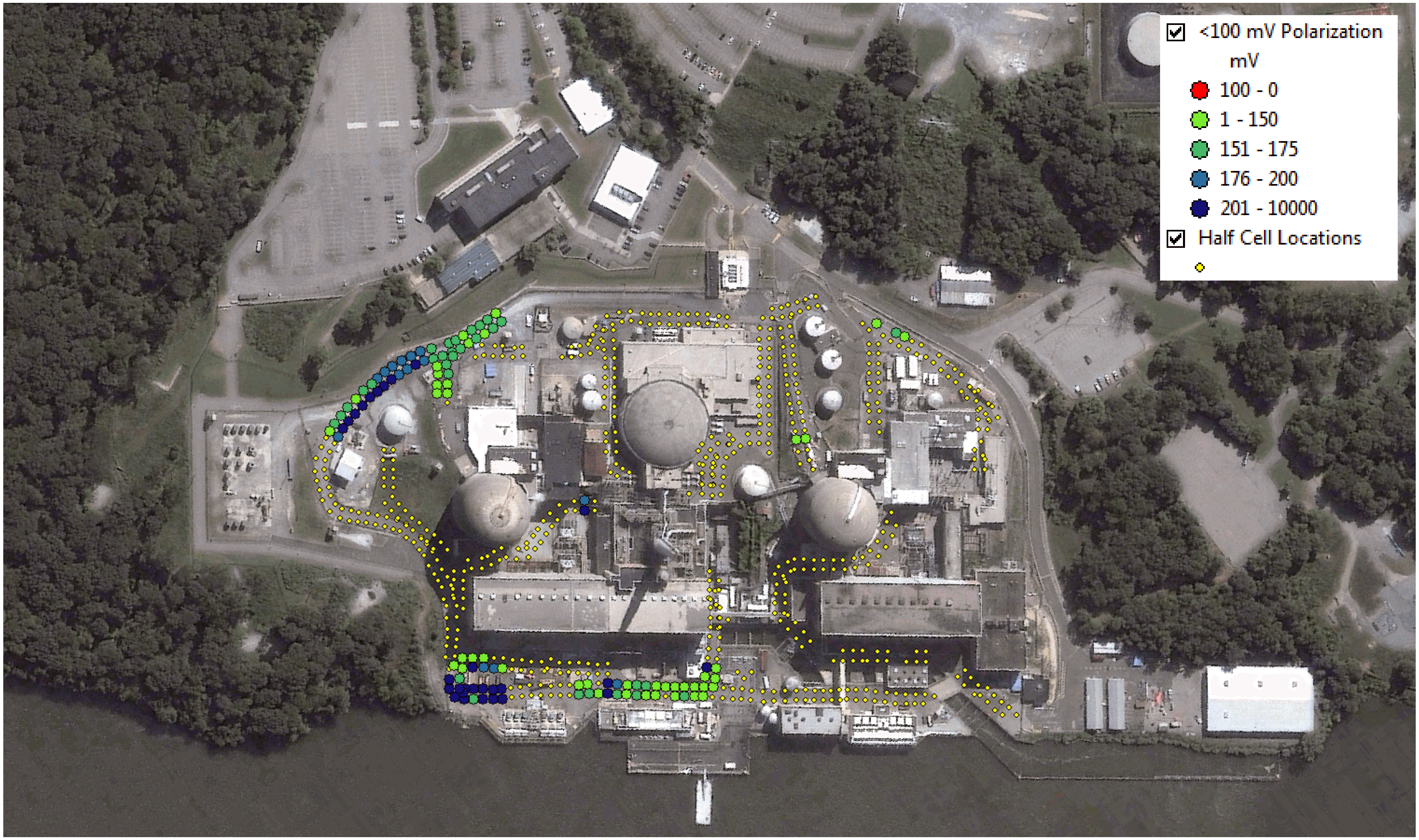
of the corrosion condition and CP state of the buried piping or structures in the area of the readings. Earth current gradients are an indicator of the condition of a piping system's coating and the excessive collection of CP current on the station grounding grid. In a plant environment, it is important to know where any DC corrosion cell is operating or where cathodic protection current is collecting. When CP system rectifiers are cycled "ON" and "OFF", the migration of CP current around the plant can be understood and used to adjust and balance the overall CP system for enhanced performance. *See id.* at 2-7.

A total of 335 APEC test locations (grids – yellow dots) were monitored throughout the protected area at IPEC. *See id.* at 1-1, 2-8. The results shown in Figure 5A below 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, however, the native APEC survey results 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*.

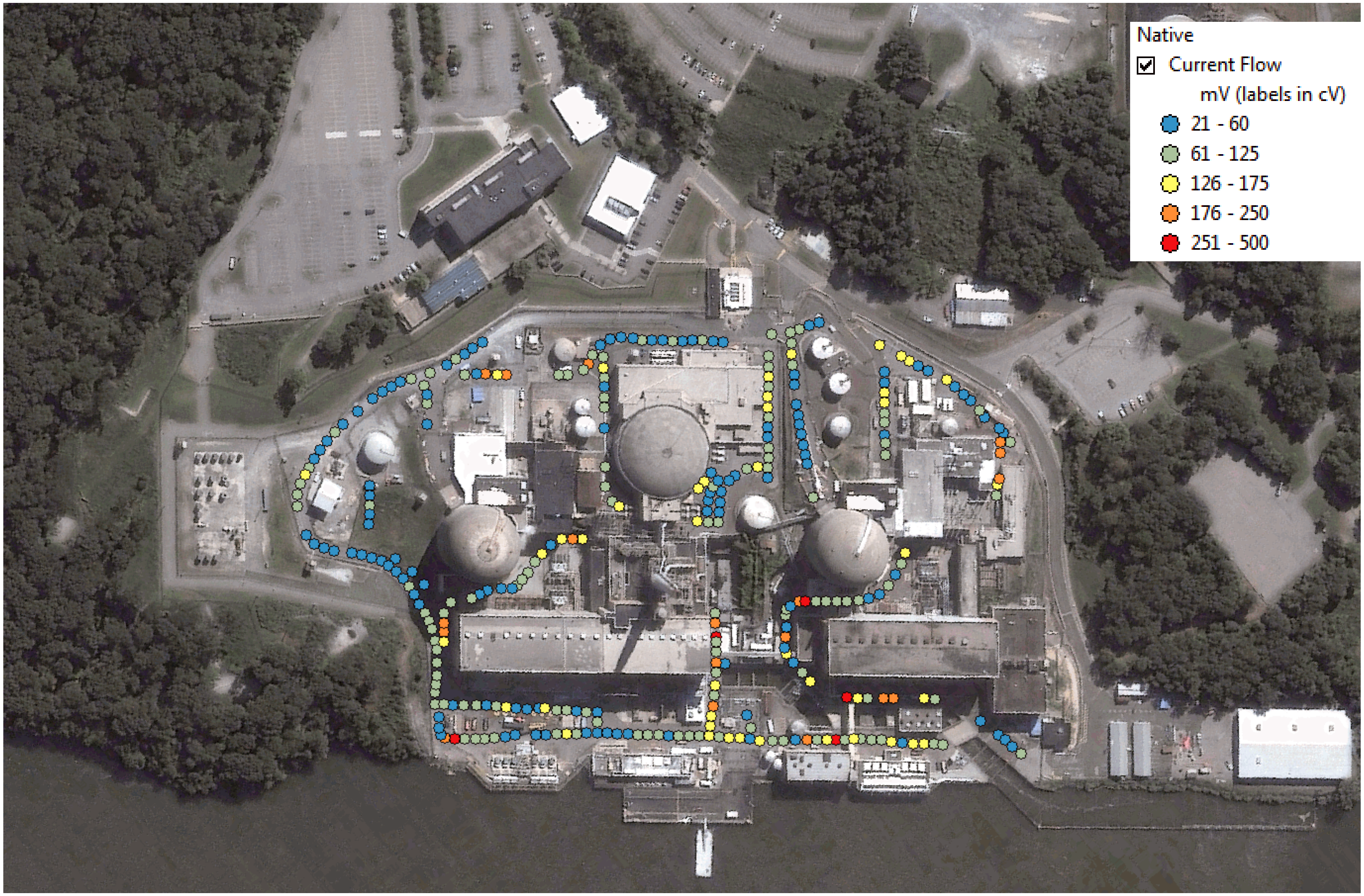
Additionally, as shown in Figure 5C, when the installed CP is applied, the data show that sufficient current is applied at the IP2 intake to effectively control corrosion at sites where there may be minor coating degradation (see Figure 5B above). Nonetheless, SIA recommended that Entergy perform excavations at the few anomalous locations (red areas) identified in Figure 5B to further quantify piping condition. This recommendation will be used in the selection of future locations to excavate and to perform direct visual inspections.

<u>Figure 5A</u>.[5] IPEC Cathodic Protection Polarization Measurements (Nov. 2010)



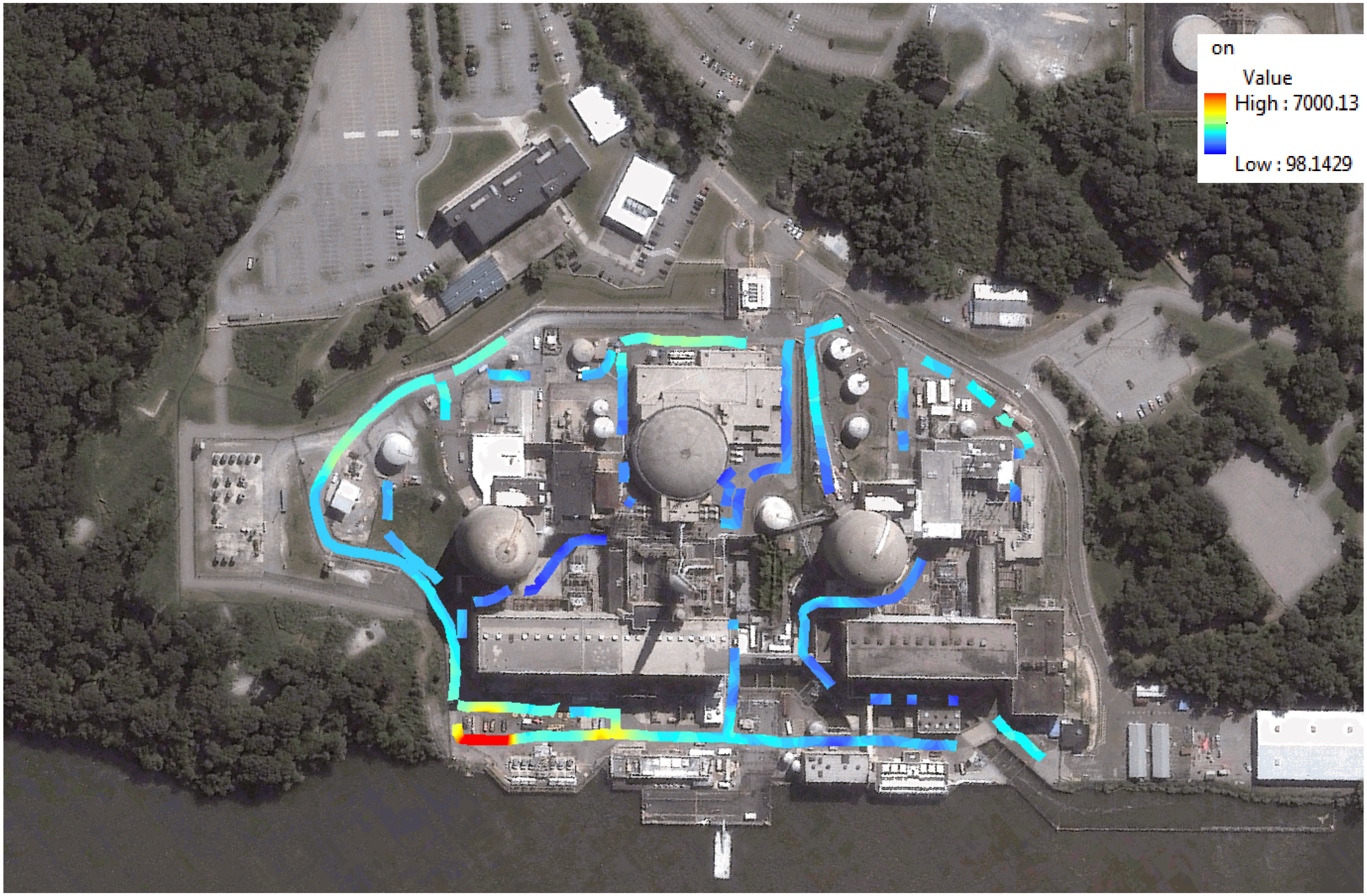
5 Generated from MAPProView© 2012 based on information from APEC Survey Report (ENT000445).

Figure 5B.[6] **IPEC Current Glow in the Native State (Nov. 2010)**



6 Generated from MAPProView© 2012 based on information from APEC Survey Report (ENT000445).

Figure 5C.[7] **IPEC Cathodic Protection Measurement with the System "On" (Nov. 2010)**



[7] Generated from MAPProView© 2012 based on information from APEC Survey Report (ENT000445).

Q120. Have the APEC survey results and other data and operating experience discussed above been considered by Entergy in its selection of locations for future inspections of in-scope buried piping at IPEC?

A120. (RCL, NFA, SFB) Yes. The APEC survey results, in conjunction with other available data and operating experience, have been factored into the IPEC BPTIP, including planned inspection activities.

E. NYS Mischaracterizes Industry and NRC Guidance on Cathodic Protection

Q121. Referring to NEI 09-14, Rev. 1 and EPRI 1016456, Dr. Duquette states: "Both the NEI and EPRI documents recommend cathodic protection for critical piping systems." Duquette Testimony at 15 (NYS000164). Is that statement accurate?

A121. (TSI, SFB, JRC) No. NEI 09-14 and EPRI 1016456 recommend that if a CP system exists, then it should be properly tested and maintained. *See* NEI 09-14, Rev. 1, Guideline for the Management of Underground Piping and Tank Integrity, Section 6.2.3 (Dec. 2010) (NYS000168); EPRI 1016456, Recommendations for an Effective Program to Control the Degradation of Buried Pipe, Sections 2.4.1.2, A.2.6 (Dec. 2008) (NYS000167). However, neither document dictates that cathodic protection be newly installed. In fact, both the NEI and EPRI documents acknowledge that CP systems may or may not be installed at a site and provide guidelines for a program that manages buried piping with or without cathodic protection. The NEI initiative requirements are summarized in Appendix B of NEI 09-14, Rev. 1 (NYS000168), and the EPRI recommendations are summarized in Appendix A of EPRI 1016456 (NYS000167).

Q122. Dr. Duquette further alleges that the IPEC BPTIP is inadequate because it purportedly is based on an outdated version of NUREG-1801 that does not require cathodic protection. Do you agree?

A122. (ABC, TSI, NFA, SFB, JRC) No. Entergy is implementing the UPTIMP and BPTIP at IPEC in accordance with EN-DC-343 and CEP-UPT-0100 and, therefore, will assess any future CP needs consistent with those procedures. Furthermore, the IPEC BPTIP is not inconsistent with Revision 2 of NUREG-1801. That document does not require or dictate the installation of new CP systems. Rather, it focuses on the effectiveness of existing systems, and permits the use of an appropriate number of excavated direct visual inspections (which Entergy has proposed and the Staff has approved for IPEC) as an alternative to CP. *See* NUREG-1801, Rev. 2, at XI M41-5 to XI M41-6 (Table 4a. Inspections of Buried Pipe) (NYS000147). In any event, maintenance of existing CP systems and phased installation of new CP systems are ongoing and will continue throughout the period of extended operation at IPEC, as discussed in this testimony.

In Draft LR-ISG-2011-03, Appendix A ("Revised GALL Report AMP XI.M41"), program elements 2.a.iii. and 2.a.iv. indicate the NRC Staff's expectation that some nuclear power plants seeking license renewal may not have cathodic protection. Program element 2.a.iii. states that such applicants must justify the lack of CP in the LRA and in sufficient detail (*e.g.*, soil sample results, pipe-to-soil potential measurements) for the Staff to independently reach the same conclusion as the applicant; *i.e.*, that CP is not necessary. Draft LR-ISG-2011-03, Appendix A at 3 (ENT000379). It also states that increased inspections may be required based on plant-specific operating experience. *Id*. Program element 2.a.iv. states that if CP is not

provided, the the license renewal applicant should perform an expanded search of plant-specific operating experience and include the results of that search in the LRA. *Id.*

F. <u>Entergy Has Acted Consistent with Industry and NRC Guidance Relevant to Cathodic Protection of Buried Piping</u>

Q123. Dr. Duquette asserts that Entergy has not committed to taking certain actions identified in fleet procedure EN-DC-343 at IPEC "despite knowing for years that its cathodic protection systems had fallen into disrepair, and has not committed to repairing them now." What is your response?

A123. (ABC, TSI, NFA, RCL) Dr. Duquette's allegation is unfounded. As an initial matter, EN-DC-343 is a fleet-wide program. IPEC is thus fully committed to the provisions of EN-DC-343, including the maintenance and upgrading of CP systems. As such, corrective actions to repair, maintain, and operate existing CP systems have been implemented in accordance with the IPEC Correction Action Program. A system engineer has been assigned to these CP systems to oversee required surveillances and any necessary corrective actions. Annual CP equipment checks and adjustments are conducted by NACE-qualified inspectors.

The IPEC program provides for focused inspections of buried piping based on a risk assessment of that piping. *See* CEP-UPT-0100, Rev. 0, Underground Piping and Tanks Inspection and Monitoring (Oct. 31, 2011) (NYS000173); SEP-UIP-IPEC, Rev. 0, Underground Components Inspection Plan (Apr. 29, 2011) (NYS000174). These inspections are in addition to opportunistic inspections. As part of its buried piping and asset management programs, Entergy evaluates the need for new CP if degradation is confirmed by inspections. The decision to install CP considers inspection data, APEC survey data, risk ranking and other program information. This approach is consistent with EPRI guidelines.

For example, as discussed in response in Answer 116, Entergy installed CP in November 2009 to protect portions of the IP2 and IP3 city water lines based on the PCA Report recommendations. Based on the results of the September 2009 guided wave inspections, Entergy installed CP for portions of the IP2/IP3 auxiliary feedwater/condensate buried piping; *i.e.*, the Unit 2 condensate storage tank lines #1505 and #1509 (12-inch to AFW and 8-inch return to the CST, respectively), and the Unit 3 condensate storage tank lines #1070 and #1080 (12" to AFW and 8-inch return to AFW, respectively). Other identified candidates for future installation of new CP systems are the Unit 2 service water 24-inch main supply headers and the Unit 3 dock seet piling just south of the intake structure. An engineering modification has been initiated for the IP2 service water line CP modification, which is expected to be installed before or shortly after the period of extended operation begins.

Q124. But Dr. Duquette states that "[t]here are no cathodic protection systems currently in operation at IPEC for the protection of safety related buried piping, and there are apparently no plans to either re-commission the existing inoperative systems or to install new systems." Duquette Report at 24 (NYS000165). In view of the foregoing, is this statement correct?

A124. (ABC, TSI, NFA, RCL) That statement is not accurate. The *safety-related* systems within the scope of the BPTIP and NYS's contention (*i.e.*, those systems that contain or may contain radioactive fluids) include the safety injection, service water, and auxiliary feedwater systems. The safety injection system is corrosion-resistant (and also coated) stainless steel and does not warrant cathodic protection per NRC or industry guidance.

As discussed above, Entergy recently installed CP systems on portions of the IP2 and IP3 CST lines that are part of the auxiliary feedwater systems based on operating experience, including the results of the October 2009 guided wave inspections of those lines.

As also noted above, Entergy has developed a plan to install CP on a portion of the IP2 service water piping. Notably, Entergy recently performed direct visual inspections and UT examinations of sections of the IP2 service water piping (24-inch lines 408 & 409), albeit at different locations than those identified for future cathodic protection. Those inspections revealed no corrosion on the piping examined. *See* Answer 118, *supra*.

Accordingly, Dr. Duquette is incorrect in claiming that IPEC uses no CP on safety-related systems and that Entergy has no intention to install new CP systems when warranted by available technical data and operating experience. Furthermore, as explained below, the "existing inoperative" CP systems, as Dr. Duquette calls them, were not installed to protect buried piping. Duquette Report at 24 (NYS000165).

Q125. Dr. Duquette also states that "SEP-UIP-IPEC acknowledges that although many buried or underground lines were once cathodically protected, such cathodic protection systems have lapsed, accelerating external corrosion where the coating has failed." Duquette Report at 16 (ENT000165). Is that accurate?

A125. (ABC, TSI, NFA, RCL) No. The SEP-UIP-IPEC procedure documents the site-specific review of IPEC buried piping and provides details on the risk assessment of the buried piping identified at the site. However, the particular statement cited by Dr. Duquette pertains generally to Entergy fleet cathodic protection systems and is *not* specific to IPEC:

> [M]ost Entergy plant's [sic] cathodic protection systems were initially installed during plant construction and were rarely maintained, and in some cases abandoned thereafter rendering the systems incapable of providing the needed corrosion protection. In

> addition, many site modifications rendering the underground piping network even more complex were implemented since initial plant construction without evaluating the required potential updates to the system. Therefore, it is recommended to conduct an Area Potential and Earth Current (APEC) Survey to analyze and implement needed improvements to the corrosion control (coatings) and cathodic protection effectiveness of the station.

SEP-UIP-IPEC, Rev. 0, Underground Components Inspection Plan at 14 (Apr. 29, 2011) (NYS00174).

Although SEP-UIP-IPEC acknowledges the installation of cathodic protection systems at IPEC, the majority of those systems were not installed to provide cathodic protection to buried piping at the site. Section 5.3.12 and Section 16.4.4, respectively, of the IP2 and IP3 FSARs confirm this fact. As stated therein:

> A complete survey and tests to determine the need for cathodic protection on Indian Point Unit 2 was made by the A. V. Smith Engineering Company of Narberth, Pennsylvania. Electrical resistivity measurements and a visual inspection of the area away from the river, where the turbine generator building, reactor building, primary auxiliary building and associated facilities are located indicated that the environment is mostly rock with areas of dry sandy clay. The electrical resistivity of the soil ranged from 3,500 to 30,000 ohm-cm with the majority of the readings being above 10,000 ohm-cm. On this basis, it was determined that cathodic protection was not required on underground facilities in areas away from the river or the containment building liner, although a protective coating on pipes was recommended to eliminate any random localized corrosion attack.

IP2 UFSAR, Rev. 20, § 5.1.3.12 (NYSR0014D); IP3 UFSAR, Rev. 20, § 16.4.4 (NYSR0013K). As a result, only a small amount of CP on the IP2 circulating and service water system buried piping near the river was installed during initial construction.

Consistent with SEP-UIP-IPEC, IPEC has performed the aforementioned APEC survey to assess additional CP needs. *See* Answer 119, *supra*; APEC Survey Report (ENT000445). The APEC Survey Report notes that the existing CP system at IPEC was designed to provide

protective current to the docks and discharge canal, but that the survey results showed that some cathodic protection is being provided to buried piping at the plant by existing CP systems at the intakes. APEC Survey Report at 1-1, 3-5 (ENT000445). The APEC Survey Report notes that additional CP may not effectively protect all IPEC buried piping due to interferences and plant configuration, such that continuing visual inspections of buried piping will be required. It also clearly states that excavations and inspections should be performed "to validate and qualify the APEC interpretations." *Id.* at 4-1.

In short, ongoing visual inspections of buried piping, as required by SEP-UIP-IPEC and the BPTIP, will provide additional information on the condition of the piping and coatings. By doing so, they provide reasonable assurance of the structural and leakage integrity of the buried piping during extended operations, irrespective of any additional cathodic protection. These pre- and post-license renewal inspections are mandated by the BPTIP.

Q126. Again citing SEP-UIP-IPEC, Dr. Duquette states that there are currently no industry guidelines for determining and achieving reasonable assurance of the integrity of inspected SSCs. Duquette Report at 16. Is that statement correct?

A126. That statement was correct at the time IPEC issued SEP-UIP-IPEC in April 2011. That same month, however, NEI finalized its Industry Guidance for the Development of Inspection Plans for Buried Piping (NYS000169) (referred to above as the NEI Buried Piping Inspection Plan Guidance). NEI issued a copy of the final draft of this document for industry use on May 4, 2011, and submitted a copy to the NRC on May 22, 2011.

The NEI Buried Piping Inspection Plan Guidance provides an engineering-based approach for developing inspection plans that establish reasonable assurance of structural and leakage integrity of buried piping based on indirect inspections, which in turn, further focus

direct examinations toward locations with greatest likelihood for degradation. This document is listed as reference 2.4.25 in CEP-UPT-0100, which is the upper-level program document governing the development of the site-specific SEP-UIP-IPEC document. It also provides reasonable assurance that the most likely piping locations for degradation have been evaluated so the structural and leakage integrity of the underground SSCs can be maintained, as stated in SEP-UIP-IPEC.

Q127. Dr. Duquette states that SEP-UPT-IPEC does not mention the December 2008 PCA Report discussed above and its cathodic protection recommendations? Duquette Report at 17 (NYS000165). Is this a concern?

A127. (ABC, TSI, NFA, RCL) No. Although SEP-UIP-IPEC does not specifically discuss the PCA report, it recognizes the potential role of CP in managing buried piping corrosion. In fact, SEP-UIP-IPEC recommends that IPEC perform an APEC survey to "analyze and implement needed improvements to the corrosion control (coatings) and cathodic protection effectiveness of the station." SEP-UIP-IPEC, Rev. 0, Underground Components Inspection Plan at 14 (Apr. 29, 2011) (NYS000174). That survey has been completed for IPEC.

Q128. What specifically did PCA recommend in its 2008 report (NYS000178), and has IPEC followed those recommendations?

A128. (ABC, TSI, NFA, RCL) The PCA Report recommended that IPEC: (1) install CP to eliminate/minimize stray current to the city water piping at the location that crosses the Algonquin gas pipeline; (2) provide a "progressive evaluation" of CP needs for high-priority piping services on a zone basis; and (3) implement an inspection program that can identify high priority zones by excavating and inspecting buried pipes and their coatings and performing UT measurements of the pipe walls. PCA Report at 16-18 (NYS000178). Our testimony above

amply demonstrates that IPEC has met *all* three of these recommendations. We elaborate on the second item here.

As suggested by the PCA Report, at established, complex sites such as IPEC (which has an extensive network of buried pipes), CP specialists typically recommend a progressive approach to the retrofitting of cathodic protection systems. Wholesale site CP retrofits are generally only recommended when upgrading existing CP infrastructure or widespread, significant degradation is observed. Applying CP to a large commonly grounded system presents unique challenges, including high current demands and the potential for creating stray current conditions. The installation of CP system at existing facilities requires careful consideration, as it could lead to unintended consequences.

Because IPEC is an existing plant without site-wide CP, the technically sound approach is to increase monitoring of buried piping to detect coating degradation, and then to *install* CP systems in targeted areas to control any detected degradation. *See* NACE SP0169-2007 at 3 (ENT000388); PCA Report at 17 (NYS000178). Entergy is following this approach, consistent with PCA recommendations and best industry practices.

In summary, there is no basis for Dr. Duquette's claims that Entergy has ignored NRC, industry, vendor, or its own guidelines or recommendations regarding cathodic protection. Notably, Dr. Duquette himself states: "Implementing the recommendations of the PCA report would have brought IPEC into reasonable agreement with NUREG-1801[Rev. 2] Section XI.M41 for buried and underground pipes." Duquette Report at 21 (NYS000165). As shown above, Energy *has* implemented those recommendations at IPEC.

G. The Available Data Do Not Indicate That Soil Corrosivity Is a Significant Concern at IPEC That By Itself Warrants Cathodic Protection

Q129. Dr. Duquette states that "Entergy's own studies show that the soils at Indian Point are mildly to moderately corrosive, warranting cathodic protection as an objective matter." Duquette Testimony at 22:13-16 (NYS000164). Is he correct?

A129. (RCL, NFA, SFB, JRC) No. Dr. Duquette bases this claim on soil resistivity data contained in the PCA Report (NYS000178). PCA recorded soil resistivity data for the 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. PCA Report at 14 & tbls. 1-IV. Soil resistivities were determined at depths of 5, 10 and 15 feet below ground surface ("bgs"), as summarized in Table 7 below.

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

Source: PCA Report (NYS000178)

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. As noted in Answer 124 above, historical soil resistivity data described in the FSAR are consistent with these data; *i.e.*, the majority of the readings being above 10,000 ohm-cm.

The interpretation of soil resistivity values varies among corrosion engineers. However, the following table below is a generally accepted guide.

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*.

Source: *Peabody's Control of Pipeline Corrosion*, at 88 (Table 5.5) (ENT000390).

The lowest IPEC recorded value is 8,043 ohm-cm, which is well above the 2,000 threshold for moderately corrosive soil. API 570 piping inspection code Table 9-1 recommends a 10-year inspection frequency for buried piping without effective CP where soil resistivity values are between 2,000 to 10,000 ohm-cms, because these values do not yield high corrosion rates. API 570, Piping Inspection Code: In-Service Inspection, Rating, Repair, Alteration of Piping Systems, American Petroleum Institute, 2d Ed (Oct. 1998) (ENT000447).

Furthermore, CP effectiveness depends not only on the soil corrosivity, but also other soil characteristics (*e.g.*, rock vs. clay vs. sand). NACE Paper 10059 at 3 (ENT000389). 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 determiniation of appropriate corrective action and preventive measures.

Q130. Dr. Duquette cites an October 31, 2005 Condition Report (CR-IP2-2005-03902) for the proposition that IPEC cathodic protection systems are severely degraded. Duquette Report at 19-20. Please address his reliance on that document.

A130. (RCL, NFA) The deficiencies in the maintenance and operation of the installed CP systems were identified in CR-IP2-2005-03902 after IPEC received an Area for Improvement ("AFI") from the Institute for Nuclear Power Operations ("INPO") for not maintaining and operating installed cathodic protection systems. However, these systems, for the most part, were not protecting buried piping, but rather, structures and components at the intake structure and discharge canal. The condition report was not issued to address a lack of cathodic protection for buried piping. IPEC completed subsequent corrective actions to restore the cathodic protection systems of concern to fully functional and operational status. SEP-UIP-IPEC, Rev. 0, Underground Components Inspection Plan, App. E (Apr. 29, 2011) (NYS000174) summarizes the CP preventive maintenance requirements for IPEC installed CP systems.

Q131. Dr. Duquette also mentions a Unit 1 CP system that was installed in 1989 and upgraded in 1993-1994, but that is no longer fully functional. Duquette Report at 19 (NYS000165). Is that system relevant to contention NYS-5 or the BPTIP?

A131. (RCL, NFA) No, it is not. As Dr. Duquette himself acknowledges, the IP1 system was "designed to provide cathodic protection to a dock, not a buried piping system." Duquette Report at 20 (NYS000165). More specifically, the IP1 cathodic protection system is associated with the Unit 1 dock (wharf). The IP1 system remains functional but is degraded.

IPEC has instituted actions to investigate and correct the condition. That system is not related to any of the buried piping systems at issue in NYS-5.

Q132. Dr. Duquette states that a modification was performed in 2001 on an IP2 CP system to bring the system back into operation but failed shortly after start-up. Duquette Report at 20 (NYS000165). Please address that claim.

A132. (RCL, NFA) The CP system installed in 2001 was designed to protect the Unit 2 intake structure sheet piling. It is not associated with any buried piping systems. The system is functional and has been functional since November 2006. Like the Unit 1 dock CP system, it is not relevant to the issues raised in NYS-5.

Q133. Please summarize why you disagree with Dr. Duquette's claim that soil corrosivity conditions at IPEC by themselves "warrant[] cathodic protection as an objective matter." Duquette Testimony at 22:15-16 (NYS000164).

A133. The available data, including the soil resistivity and corrosion potential data obtained from the 2008 PCA and 2009 APEC surveys, respectively, do not support that conclusion. Significantly, IPEC buried piping has been installed underground for approximately 40 years, and only limited evidence of corrosion has been observed. This indicates that the soil is generally *non-corrosive* and any degradation of potentially exposed buried piping is progressing at a slow rate.

In accordance with the BPTIP, Entergy will continue to assess soil conditions around buried piping. Indirect inspection methods exist to identify the presence of anomalies, which are considered in prioritizing and inspecting buried piping through excavation and direct examination. As discussed above, indirect inspections (*e.g.*, GWT inspections) characterize areas in the site both with and without corrosion cell activity.

CP systems recently have been installed on targeted piping and additional systems may be installed if warranted by the results of the future inspections and soil testing that Entergy has committed to perform at IPEC. As explained above, the original IPEC site CP systems cited by Dr. Duquette were not installed to protect buried piping and are irrelevant to the contention.

IX. CONCLUSION

Q134. Please summarize the bases for your conclusion that NYS-5 lacks merit.

A134. NYS's and Dr. Duquette's criticisms of the IPEC BPTIP lack factual and technical merit for the reasons set forth above. By performing site area corrosion potential mapping and indirect inspections to identify the areas that are most susceptible to corrosion, and by performing direct visual and UT inspections of those areas, IPEC is effectively assessing the condition of buried piping at IPEC. If the most susceptible locations are found to be free of unacceptable degradation, then it can be concluded with a high degree of confidence—*i.e.*, reasonable assurance—that the remaining portions of the buried piping are also acceptable for continued operation. If unacceptable conditions are detected, then additional inspections and examinations are performed, as required, to bound the condition and correct any deficiencies that could lead to future degradation. The criteria for repairs or replacements of degraded buried piping are governed by Entergy procedures based on well-established industry standards.

In sum, the IPEC BPTIP provides the reasonable assurance required by NRC regulations and, in doing so, meets Dr. Duquette's own recommendations for an adequate aging management program because it: (1) adopts NEI and EPRI recommendations; (2) follows the dictates of NUREG-1801, Rev. 2, Section XI.M41; (3) identifies acceptance criteria for inspections of buried pipes; and (4) states the repair and remediation procedures to be followed if the corrosion

damage exceeds the acceptance criteria. Accordingly, NYS-5 lacks merit and should be resolved in Entergy's favor.

Q135. Does this conclude your testimony?

A135. Yes.

Q136. In accordance with 28 U.S.C. § 1746, do you state under penalty of perjury that the foregoing testimony is true and correct?

A136. Yes.

Executed in accord with 10 C.F.R. § 2.304(d)
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