UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

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

NRC STAFF'S ANSWER TO STATE OF NEW YORK AND RIVERKEEPER'S
JOINT MOTION TO FILE A NEW CONTENTION, AND
NEW JOINT CONTENTION NYS-38/RK-TC-5

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October 25, 2011

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INTRODUCTION

Pursuant to 10 C.F.R. § 2.309(h)(1), and the Atomic Safety and Licensing Board's ("Board") Scheduling Order (July 1, 2010) and Amended Scheduling Order (June 7, 2011), the Staff of the U.S. Nuclear Regulatory Commission ("NRC Staff" or "Staff") hereby files its answer to the State of New York's ("New York" or "NYS") and Riverkeeper Inc.'s ("Riverkeeper" or "RK") New Joint Contention NYS-38/RK-TC-5, filed on September 30, 2011.[1] As more fully set forth below, the Staff opposes the admission of Contention NYS-38/RK-TC-5 because, *inter alia*, the proffered contention is impermissibly late, is not based upon new, materially different information, and fails to demonstrate a genuine dispute with the application.

BACKGROUND

On April 23, 2007, Entergy Nuclear Operations, Inc. ("Entergy" or "Applicant") filed a

[1] The Intervenors' filing consisted of a transmittal letter dated September 30, 2011, along with (1) "State Of New York And Riverkeeper's Joint Motion For Leave To File A New Contention Concerning Entergy's Failure To Demonstrate That It Has All Programs That Are Required To Effectively Manage The Effects Of Aging Of Critical Components Or Systems" ("Motion"); (2) "State Of New York And Riverkeeper's New Joint Contention NYS-38/RK-TC-5" ("Contention") with Attachment, (3) Declaration of Dr. Richard T. Lahey, Jr., (4) Declaration of Dr. Joram Hopenfeld with Attachment, and (5) a Certificate of Service.

license renewal application ("LRA"), seeking to renew the operating licenses for Indian Point Nuclear Generating Units 2 and 3 ("IP2" and "IP3"), for an additional period of 20 years beyond their current expiration dates of September 28, 2013 and December 12, 2015, for IP2 and IP3, respectively. The Staff reviewed the LRA for compliance with the safety requirements of 10 C.F.R. Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants." On August 11, 2009, the Staff issued its "Safety Evaluation Report Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3" ("SER"), which it published as NUREG-1930, Vols. 1 and 2, "Safety Evaluation Report Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3" in November 2009. On August 30, 2011, the Staff issued SER Supplement 1 ("SSER"), and on August 31, 2011 the Staff notified the Board and parties of the availability of SER Supplement 1 in ADAMS.[2] On September 30, 2011, New York and Riverkeeper filed their new contention.

DISCUSSION

I. Admissibility Requirements for Timely-Filed Contentions

The legal requirements governing the admissibility of contentions are well established, and are currently set forth in 10 C.F.R. § 2.309(f). In brief, the regulations require that a contention must satisfy the following requirements in order to be admitted the request or petition must (i) provide a specific statement of the issue of law or fact to be raised or controverted, (ii) provide a brief explanation of the basis, (iii) demonstrate that the issue is within the scope of the proceeding; (iv) demonstrate that the issue raised is material to the findings the NRC must make, (v) provide a concise statement of the alleged facts or expert opinions and other support, and (vi) provide sufficient information to show that a genuine dispute exists with the

[2] Letter from Sherwin E. Turk to the Board (Aug. 31, 2011). The formal publication of the SER Supplement as a bound hard copy is pending.

applicant/licensee on a material issue of law or fact, including how a the application fails to contain information on a relevant matter as required by law. 10 C.F.R. § 2.309(f)(1)(i) – (vi).

The purpose of the contention admissibility rule § 2.309(f)(1) is to "focus litigation on concrete issues and result in a clearer and more focused record for decision." *Calvert Cliffs 3 Nuclear Project, LLC, and Unistar Nuclear Operating Services, LLC* (Combined License Application for Calvert Cliffs Unit 3), LBP-09-04, 69 NRC 170, 189 (2009) (*quoting "Changes to Adjudicatory Process*," 69 Fed. Reg. 2182, 2202 (Jan. 14, 2004)). The Commission has made clear that the contention admissibility rules are strict by design, and it "should not have to expend resources to support the hearing process unless there is an issue that is appropriate for, and susceptible to, resolution in an NRC hearing." *Id.* Conclusory assertions and speculation in pleadings are insufficient to support the admission of a contention. *See Entergy Nuclear Operations, Inc.* (Indian Point, Units 2 and 3), LBP-08-13, 68 NRC 43, 200 (2008) and cases cited therein. The Commission has stated that "[m]ere 'notice pleading' is insufficient under these standards." *Fansteel, Inc.* (Muskogee, Oklahoma Site), CLI-03-13, 58 NRC 195, 203 (2003). Failure to comply with admissibility requirements is grounds for the dismissal of a contention. *Florida Power & Light Co.* (St. Lucie Nuclear Power Plant, Units 1 and 2), LBP-08-14, 68 NRC 279, 288 (2008) (*citing* 69 Fed. Reg. at 2221); *see also Private Fuel Storage, LLC.* (Independent Spent Fuel Storage Installation), CLI-99-10, 49 NRC 318, 325 (1999).[3]

II. Additional Requirements for the Admission of Non-Timely and Late-Filed Contentions

The admissibility of late-filed contentions in NRC adjudicatory proceedings is governed by (a) 10 C.F.R. § 2.309(f)(2), concerning late-filed contentions, (b) 10 C.F.R. § 2.309(c),

[3] Further, pursuant to 10 C.F.R. § 2.335(a), contentions challenging the adequacy of the Commission's regulations are beyond the scope of individual adjudicatory proceedings unless a waiver is requested and granted. "[A] petitioner may not demand an adjudicatory hearing to attack generic NRC requirements or regulations, or to express generalized grievances about NRC policies." *Duke Energy Corp.* (Oconee Nuclear Station, Units 1, 2, & 3), CLI-99-11, 49 NRC 328, 334 (1999).

concerning non-timely contentions, and (c) 10 C.F.R. § 2.309(f)(1), establishing the general admissibility requirements for contentions. First, a late-filed contention may be admitted as a timely new contention if it meets the requirements of 10 C.F.R. § 2.309(f)(2). Under this provision, a contention filed after the initial filing period may be admitted with leave upon a showing that (i) the information upon which the amended or new contention is based was not previously available; the information upon which the amended or new contention is based is materially different than information previously available; and the amended or new contention has been submitted in a timely fashion based on the availability of the subsequent information. 10 C.F.R. § 2.309(f)(2).[4] Second, a contention that does not qualify for admission as a new contention under 10 C.F.R. § 2.309(f)(2) may be admissible under the provisions governing nontimely contentions, set forth in 10 C.F.R. § 2.309(c)(1). Nontimely contentions will not be entertained absent a determination by the presiding officer that the contentions should be admitted based upon a balancing of the eight factors in 10 C.F.R. § 2.309(c)(1); *Oyster Creek*, CLI-09-07, 69 NRC at 260; *Amergen Energy Co., LLC* (Oyster Creek Nuclear Generating Station), LBP-06-22, 64 NRC 229, 234 n.7 (2006). Of the eight criteria, the need for a showing of "good cause" for the late filing is the most important. *State of New Jersey* (Department of Public Law and Safety), CLI-93-25, 38 NRC 289, 296 (1993). To show good cause for late filing under 10 C.F.R. § 2.309(c)(1), "a petitioner must show that the information on which the new contention is based was not *reasonably available to the public*, not merely that the *petitioner* recently found out about it." *Dominion Nuclear Connecticut, Inc.* (Millstone Power Station, Unit

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[4] Here, the Board has ruled that new contentions shall be deemed timely under 10 C.F.R. § 2.309(f)(2)(iii) if filed within thirty days of the date when new material information undergirding the contention becomes available. *Entergy Nuclear Operations, Inc.* (Indian Point Nuclear Generating Units 2 and 3), (Scheduling Order) (July 1, 2010), at 6 ¶ F.2. In addition, the Board has ruled that any contentions which arise from new information contained in the Applicant's RAI responses of March 28, 2011 or other RAI responses to be submitted by Entergy prior to publication of the SER Supplement, or new information contained in the SER Supplement, are to be filed no later than thirty days after the SER Supplement is issued. Amended Scheduling Order, at 2.

No. 3), CLI-09-05, 69 NRC 115, 126 (2009); emphasis in original. The Commission emphasized in *Oyster Creek* that:

> [O]ur contention admissibility and timeliness rules require a high level of discipline and preparation by petitioners, who must examine the publicly available material and set forth their claims and the support for their claims at the outset. There simply would be no end to NRC licensing proceedings if petitioners could disregard our timeliness requirements and add new contentions at their convenience during the course of a proceeding based on information that could have formed the basis for a timely contention at the outset of the proceeding. Our expanding adjudicatory docket makes it critically important that parties comply with our pleading requirements and that the Board enforce those requirements.

Oyster Creek, CLI-09-07, 69 NRC at 271-272. (internal quotation marks and footnotes omitted).

The Commission made clear that merely filing a contention within a certain number of days after publication of the Staff's SER is insufficient; rather, where the information was available previously, a petitioner cannot delay filing a contention until a document becomes available that "collects, summarizes and places into context the facts supporting that contention." *Northern States Power Co.* (Prairie Island Nuclear Generating Plant, Units 1 and 2), CLI-10-27, 72 NRC __ (Sept. 30, 2010), slip op. at 17. Those who wish to offer contentions have an "iron-clad obligation to examine the publicly available documentary material . . . with sufficient care to enable it to uncover any information that could serve as the foundation for a specific contention." *Id.* at 18 (*quoting Sacramento Municipal Utility District* (Rancho Seco Nuclear Generating Station), CLI-93-3, 37 NRC 135, 147 (1993)). A contention based upon documents that were available well before the Staff's SER was issued "would be untimely, absent a discussion in the SER that would make 'reasonably apparent' a foundation for such a contention." *Prairie Island,* CLI-10-27, 72 NRC __ (slip op. at 17). The Commission stated that "[b]y permitting [intervenors] to wait for the Staff to compile all relevant information in a single document, the Board improperly ignored [intervenors'] obligation to conduct its own due diligence." *Id.* at 18. In addition, the Commission has held that "[n]ew bases for a contention cannot be introduced in a reply brief, or any other time after the date the original contentions are due, unless the petitioner meets the late-filing criteria set forth in 10 C.F.R. § 2.309(c), (f)(2)." *Nuclear Management Co., LLC* (Palisades Nuclear Plant), CLI-06-17, 69 NRC 727, 732 (2006) (emphasis added).

As the Commission has recognized, the requirements governing late-filed contentions and untimely filings, set forth in 10 C.F.R. §§ 2.309(c)(2) and 2.309(f)(2), "are stringent." *Oyster Creek*, CLI-09-07, 69 NRC at 260. Further, each of the factors set forth in the regulations is required to be addressed in a requestor's nontimely filing. *Id.* at 260-61. Indeed, under NRC case law, a petitioner's failure to address the late-filing criteria in 10 C.F.R. § 2.309(c) *or* 10 C.F.R. § 2.309(f)(2) "is reason enough" to reject the proposed new contention. *Millstone*, CLI-09-05, 69 NRC at 126.

III. Summary of Contention NYS-38/RK-TC-5

In their newly proffered contention, New York and Riverkeeper seek to litigate the following issue:

> Entergy is not in compliance with the requirements of 10 C.F.R. §§ 54.21(a)(3) and (c)(1)(iii) and the requirements of 42 U.S.C. §§ 2133(b) and (d) and 2232(a) because Entergy does not demonstrate that it has a program that will manage the affects [sic] of aging of several critical components or systems and thus NRC does not have a record and a rational basis upon which it can determine whether to grant a renewed license to Entergy as required by the Administrative Procedure Act[.]

Contention at 1 (capitalization omitted). New York and Riverkeeper identify four bases for the contention, in which they assert that Entergy's commitments to take certain actions in the future render its LRA incomplete, with respect to (a) identification of the most limiting locations for metal fatigue calculations, (b) use of the WESTEMS computer program for CUF_{en} metal fatigue calculations, (c) use of a Steam Generator Management Program (to be completed by the

Electric Power Research Institute ("EPRI") in 2013) and an unspecified inspection program, to manage potential primary water stress corrosion cracking ("PWSSC") in the steam generator divider plates, and (d) use of a modified inspection plan for reactor vessel internals, to be issued by EPRI upon incorporating the Staff's proposed modifications of an EPRI guidance document (MRP-227) to which Entergy has committed. Contention at 1-3. In their accompanying Motion, New York and Riverkeeper explained their contention as follows:

> The bases for proposed Contention 38, are not that the AMP proposed by Entergy is flawed (it may turn out to be flawed once it is disclosed), but that Entergy has not presented an AMP and thus cannot meet its burden to prove that the undefined and unspecified AMPs are adequate to meet the requirements of 10 C.F.R. §§ 54.21(a)(3) and (c)(1)(iii) nor to demonstrate that the yet to be defined AMP will be consistent with the 10 specific components of each AMP identified in GALL to which Entergy has committed compliance.

Motion at 7.

As discussed below, New York's and Riverkeeper's assertion of these issues is untimely, in that the underlying information that prompted the claims of omission presented in Contention NYS-38/RK-TC-5 was available long before publication of the Staff's SSER. Accordingly, all aspects of NYS-38/RK-TC-5 are impermissibly late, without the requisite showing of good cause for their tardiness. Further, the Intervenors' assertion of these issues fails to identify a genuine dispute with the Applicant's LRA. Therefore, the Staff opposes the admission of this newly proffered contention.

IV. Portions of Contention NYS-8/RK-TC-5 Are Impermissibly Late and Fail to Present A Genuine Dispute of Material Fact or A Material Issue for Litigation

Contention NYS-38/RK-TC-5 is not premised upon any new information in the SSER or associated RAIs, but instead is premised on the *absence* of information and *omission* of details. *See* e.g. Contention at 2 (asserting that an "unspecified" inspection program will be instituted for steam generator divider plates). The Intervenors do not dispute the information provided in the

RAIs, the responses, and the SSER, but instead claim the information provided to date does not meet the requirements of 10 C.F.R. §§ 54.21(a)(3) and (c)(1)(iii). Contention at 4.

Further, much of the Intervenors' newly proffered contention – and indeed, the underlying assertion that the application is incomplete pending the completion of ongoing NRC and industry programs -- is not based upon new information in the SSER or information provided by the Applicant in its RAI responses in 2011, but instead, is based upon omissions which could have been asserted based upon the original LRA, long before the Staff issued its RAIs and SER Supplement in 2011. To proffer an admissible contention, the Intervenors must show that they could not have previously detected that the LRA was incomplete until the Staff's SSER was written. They do not make this showing. Accordingly, the contention is impermissibly late. In addition, as more fully set forth below, Contention NYS-38/RK-TC-5 fails to satisfy the requirements of 10 C.F.R. §§ 2.309(c) and (f)(1), and accordingly, it is inadmissible for those reasons as well.

In the following discussion, the Staff addresses the timeliness and admissibility of each of the four claims raised in the contention, *seriatim*.

A. The Contention's Claims Regarding Identification of the Most Limiting Locations for Metal Fatigue Calculations Are Impermissibly Late and Are Inadmissible

New York and Riverkeeper assert that Entergy might identify new limiting locations, but the process used and resulting identifications will not be done prior to completion of license renewal. Contention at 1-2. In particular, New York and Riverkeeper say that Entergy has not identified plant-specific locations which might have more limiting environmentally-adjusted cumulative usage factors (i.e. "CUFen").[5] Contention at 6, 7. Further, they assert that these

[5] "Cumulative Use Factor" (or, alternatively, "Cumulative Usage Factor") – is a means of "quantif[ying] the fatigue that a particular metal component experiences during plant operation." *AmerGen Energy Co., LLC* (Oyster Creek Nuclear Generating Station), CLI-08-28, 68 NRC 658, 663 (2008). CUFen, in turn, is the term for "Cumulative Use [or Usage] Factor Environmentally Adjusted," meaning a CUF modified by an Fen ("Environmental Adjustment Factor") to reflect the corrosive

determinations must be made before the NRC makes a decision on Entergy's LRA. *See* Contention at 3; Hopenfeld Declaration at 3, 4.

New York/Riverkeeper's claims regarding this matter are impermissibly late, in that the underlying information was available prior to issuance of SER Supplement 1. Thus, in its original LRA, Entergy observed:

> As reported in SECY-95-245, the NRC believes that no immediate staff or licensee action is necessary to deal with the environmentally assisted fatigue issue. In addition, the staff concluded that it could not justify requiring a back fit of the environmental fatigue data to operating plants. However, the NRC concluded that, because metal fatigue effects increase with service life, environmentally assisted fatigue should be evaluated for any proposed extended period of operation for license renewal.

LRA at 4.3-22.

By letter dated August 9, 2010 (NL-10-082), and served upon the parties by Entergy on August 10, 2010, Entergy reported completion of "Commitment 33" under which it used its Fatigue Monitoring Program to update certain fatigue usage calculations. Later, Entergy re-addressed the topic in a letter (NL-11-032) dated March 28, 2011 (Attach. 1). Therein, through "Commitment 43," Entergy stated that prior to September 28, 2013 (for Unit 2) and December 12, 2015 (for Unit 3) (i.e., prior to commencement of the period of extended operation):

> IPEC will review design basis ASME Code Class 1 fatigue evaluations to determine whether the NUREG/CR-6260 locations that have been evaluated for the effects of the reactor coolant environment on fatigue usage are the limiting locations for the IP2 and IP3 configurations. If more limiting locations are identified, the most limiting location will be evaluated for the effects of the reactor coolant environment on fatigue usage.
>
> IPEC will use the NUREG/CR-6909 methodology in the evaluation of the limiting locations consisting of nickel alloy, if any.

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environment inside a nuclear reactor – a factor that may accelerate "fatigue failure." *See*, *e.g.*, Regulatory Guide 1.207, "Guidelines for Evaluating Fatigue Analyses Incorporating the Life Reduction of Metal Components due to the Effects of the Light-Water Reactor Environment for New Reactors," at 2 (Mar. 2007) (ML083300592).

NL-11-032, Attachment 2, at 17 (Attach. 1).

Indeed, New York's original Contention 26 disputed, *inter alia*, Entergy's LRA statement that "More limiting IPEC-specific locations with a valid CUF may be added in addition to the NUREG/ CR-6260 locations."[6] Thus, New York has known of this issue for some time, long before Entergy submitted its "Commitment 43," in which it committed to perform a review to determine whether the NUREG/CR-6260 locations that have been evaluated for the effects of the reactor coolant environment on fatigue usage are the limiting locations for the IP2 and IP3 configurations. Likewise, Riverkeeper raised concerns regarding the NUREG/CR-6260 locations in its original petition to intervene.[7] New York and Riverkeeper thus had sufficient information to form their current claim four years ago, based upon the LRA's discussion of NUREG/CR-6260.

New York and Riverkeeper do not provide any reason to believe that Entergy's plans were unclear until the Staff's SSER was published, or that the Intervenors were unable to make a claim of omission sooner. Indeed, New York raised this issue in Contention 26 in November 2007, as well as in Contention NYS-26B, filed on September 9, 2010.[8] Accordingly, this issue is impermissibly late. *See Prairie Island,* CLI-10-27, 72 NRC __ (slip op. at 14).

Further, the metal fatigue issue raised in this contention fails to satisfy 10 C.F.R. § 2.309(f)(1), in that it does not identify any failure by Entergy to satisfy a legal requirement. The claim underlying this portion of the contention is that NRC regulations require Entergy, as a pre-requisite to establishing an acceptable AMP, to identify which components (i.e. what plant-specific locations) have a limiting CUFen. *See, e.g.,* Hopenfeld Declaration at 3 ("Entergy must

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[6] *See* New York State Notice of Intention to Participate and Petition to Intervene (Nov. 30, 2007), at 231.

[7] *See* Riverkeeper, Inc.'s Request for Hearing and Petition to Intervene in the License Renewal Proceeding for the Indian Point Nuclear Power Plant (Nov. 30, 2007), at 14.

[8] *See, e.g.*, New York and Riverkeeper's "Joint Reply to Entergy and NRC Staff's Separate Answers to [New York and Riverkeeper's] New and Amended Contention [NYS]-26B/Riverkeeper TC-1B (Metal Fatigue)" (Oct. 12, 2010), at 13.

identify the locations that may be more limiting, and which will be the subject of the CUFen calculations, *now*, and not just articulate a plan to determine such locations later.") (emphasis in original). This assertion is altogether inconsistent with the Commission's rejection of similar claims in *Vermont Yankee*, where the Commission held as follows:

> According to Vermont, the mere fact that an applicant has agreed to implement an AMP does not free it of its "obligation to conduct a proper CUF_{en} analysis as a prerequisite to designing the appropriate AMP." Vermont asserts that, "[w]ithout the CUF_{en} analysis, identifying which, if any, components will have a CUF_{en} in excess of 1.0 and at what point in their operating history that is likely to occur, the parameters of the AMP monitoring cannot be determined and an applicant would not be able to demonstrate that it has a technically acceptable AMP. Vermont's position lacks legal support. We see nothing in our regulations to suggest that "baseline" CUF_{en} calculations are *prerequisites* to establish the "parameters" of the AMP.

Entergy Nuclear Vermont Yankee, L.L.C. and Entergy Nuclear Operations, Inc. (Vermont Yankee Nuclear Power Station), CLI 10-17, 72 NRC __ (July 8, 2010), slip op. at 50 (addressing Vermont's argument regarding the Board's conclusion that CUF_{en}s are TLAAs) (emphasis in original; footnotes omitted).[9] The new contention is not only late, but fails to demonstrate a material dispute with the application and lacks a legal basis. 10 C.F.R. § 2.309(f)(1)(iv), (vi).

B. The Contention's Claims Regarding the WESTEMS Code Are <u>Impermissibly Late</u>

New York and Riverkeeper seek to challenge Entergy's use of CUFen calculations to be performed with the "WESTEMS" computer program. The Intervenors allege that Entergy might make modifications to the WESTEMS computer model, and that the criteria for making such "user interventions" while conducting CUFen calculations will not be disclosed prior to license renewal. Contention at 2. Further, they assert that the AMP is undeveloped without additional

[9] Dr. Lahey incorrectly refers to "TLAA fatigue evaluations" (Lahey Declaration at 3). As the Commission has held, where (as here) a CUFen was not calculated as part of the CLB, such evaluations are not TLAAs. *Vermont Yankee*, CLI 10-17, 72 NRC __ (slip op. at 47-48).

information about the possible future user interventions, and that the documentation is not part of the implementation of the AMP, but is part of the development of the AMP. Contention at 1. The Intervenors base this concern on Entergy's commitment to provide written justifications and explanations when Entergy is executing WESTEMS. *See* NL-11-032, Attachment 1 at 27 (Attach. 1).[10] Essentially, these allegations amount to a concern over the creation of additional documentation during the use of WESTEMS following license renewal.

This issue – the documentation of user intervention – could have been raised earlier, based upon a review of the WESTEMS user manual. Thus, the issue of user intervention and the documentation of such intervention is part of the method of using WESTEMS; Entergy's use of the WESTEMS code was not raised for the first time in the Staff's SSER or associated RAIs. Indeed, the Intervenors have been aware that WESTEMS would be used as part of the aging management program for some time. *See, e.g.,* Contention at 2 (citing Applicant's answer to New and Amended Contention New York State 26B/ Riverkeeper TC-1B (Metal Fatigue, dated October 4, 2010 at 11). Thus, New York and Riverkeeper could have reviewed the available information to learn about the user intervention options within WESTEMS over a year ago. Further, Intervenors make no showing that how WESTEMS allows for user interaction was only first revealed from Entergy's commitments in NL-11-032, or that the SSER somehow provided the information needed for NYS/RK to allege an omission of details on how WESTEMS is used. *See Prairie Island,* CLI-10-27, 72 NRC __ (slip op. at 14). Consequently, Intervenors could have expressed any concern with the documentation associated with the implementation of WESTEMS in October 2010. Accordingly, they are impermissibly late in raising it now.

[10] Entergy's statements regarding WESTEMS were contained in Entergy's letter of March 28, 2011 (NL-11-032), in Commitments 44 and 45. For Commitment 44, Entergy stated, "IPEC will include written explanation and justification of any user intervention in future evaluations using the WESTEMS 'Design CUF'] module. " NL-11-032, Attachment 2, p. 17. Similarly, in Commitment 45, Entergy wrote, "IPEC will not use the NB-3600 option of the WESTEMS program in future design calculations until the issues identified during the NRC review of the program have been resolved." *Id.*

Moreover, wholly apart from any timing issue, the issue of what to document and justify in the future is part of the process of executing the computer code *while* implementing the aging management program.[11] The records that might be created in the future reflect steps in execution of the WESTEMS code, not development of the code. Thus, the Intervenors fail to identify an omission from the application, and thus the proffered contention is inadmissible. 10 C.F.R. § 2.309(f)(1)(iv).

C. The Contention's Claim Regarding Steam Generators Is Impermissibly Late, and Fails to Satisfy 10 C.F.R. § 2.309(f)(1)

New York and Riverkeeper challenge Entergy's commitment to use (a) a Steam Generator Management Program (to be completed by the Electric Power Research Institute ("EPRI") in 2013), and (b) another (unspecified) inspection program, to manage potential primary water stress corrosion cracking ("PWSCC") in the steam generator divider plates. In this regard, they argue that Entergy has omitted or not disclosed any description of the inspection program. Contention at 7-8. Further, they assert that Entergy's commitment lacks a description of an inspection program that includes examination techniques and frequencies, and they object to Entergy's commitment to develop its program in accordance with industry guidance that is to be developed. *Id.*

New York and Riverkeeper's assertion of these claims is impermissibly late, in that Entergy's plan to use industry guidance has been known for quite some time. Thus, the topic of primary water stress corrosion cracking was addressed in the original LRA, wherein Entergy wrote:

> 3.1.2.2.13. Cracking due to Primary Water Stress Corrosion Cracking (PWSCC). Cracking due to PWSCC in most components made of nickel alloy is managed by the Water Chemistry Control – Primary and Secondary, Inservice Inspection, and Nickel Alloy Inspection Programs. The Nickel Alloy Inspection

[11] Indeed, the Staff expressed this view in its SSER. *See, e.g.,* SSER at 4-42 (discussing "future calculations using the WESTEMS TM 'Design CUF' module").

> Program implements the applicable NRC Orders and will implement applicable (1) Bulletins and Generic Letters and (2) staff-accepted industry guidelines.

LRA at 3.1-9 (Attach. 2). The LRA for Indian Point directly addressed cracking due to primary water stress corrosion cracking in the nickel alloy or nickel alloy-clad steam generator divider plate exposed to reactor coolant. LRA Table 3.1.1 (Attach. 3); Reactor Coolant System, NUREG-1801 Vol. 1, Item Number 3.1.1-81 at p. 3.1-38 (Attach. 4). The LRA cited the water chemistry program as the pertinent aging management program, and no further evaluation was recommended. *Id.* Further, the LRA stated that the Nickel Alloy Inspection Program "will implement applicable . . . staff-accepted industry guidelines." LRA at 3.1-9 (Attach. 2). Thus, from the time of the original application, New York State and Riverkeeper could have reviewed the plans for PWSCC, industry actions, and which programs are appropriate for the steam generator divider plates.

In fact, New York disputed Entergy's plan to use industry programs on a different matter. In its original petition to intervene, filed on November 30, 2007, New York Contention 23 challenged Entergy's plans to participate in the industry programs for investigating and managing aging effects on reactor internals and to evaluate and implement the results of the industry programs as applicable to the reactor internals. NYS Petition at 218-19.[12] Now, NYS/RK are untimely re-asserting this issue, focusing for the first time on steam generators. Notwithstanding that this is a repeat of an issue raised in part of Contention 23, the Intervenors make no showing that NL-11-032 or the Staff's SSER somehow provided the last piece of information without which they could not have alleged this omission. *Prairie Island,* CLI-10-27, 72 NRC __ (slip op. at 14).

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[12] Contention NYS-23 asserted that the LRA for IP2 and IP3 fails to comply with the requirements of 10 C.F.R. § 54.21(a) because the applicant had not proposed comprehensive baseline inspections to support its relicensing application and proposed 20-year life extensions. NYS Petition at 21. The Board rejected Contention 23 as outside the scope of license renewal. *Indian Point*, LBP-08-13, 68 NRC at 126.

Moreover, the Intervenors' inclusion of this issue in their new contention fails to identify a genuine dispute with the LRA. On the topic of steam generators, the Intervenors argue that Entergy has omitted or not disclosed any description of the inspection program. Contention at 7-8. Their expert, Dr. Lahey, expresses concern that inspections of the steam generator tube-to-tubesheet welds for PWSCC will not be made until after the period of extended operation has begun. Dr. Lahey does not explain why this inspection schedule is insufficient to manage aging, nor does Dr. Lahey address why a concern with steam generator inspection frequency could not have been raised sooner. Significantly, he provides no information to show that the time period for Entergy's planned inspections is inconsistent with the detection of potential PWSCC cracks. Thus, the Intervenors fail to articulate a genuine dispute with the application concerning steam generator issues. *See* 10 C.F.R. § 2.309(f)(1)(vi).

D. The Contention's Claim Regarding Vessel Internals Is Impermissibly Late, and Fails to Satisfy 10 C.F.R. § 2.309(f)(1)

New York and Riverkeeper assert that Entergy has not provided a final reactor vessel internals program and, instead, has committed to comply with an as yet unissued revision of MRP-227. Motion at 3, 4; Lahey Declaration at 3; Contention at 2-3. This assertion is untimely and fails to raise a genuine dispute with the LRA. 10 C.F.R. § 2.309(f)(1)(vi).

First, Entergy's plan to use industry guidance has been known for a long time. In Entergy's original LRA submittal (NL-07-039) dated April 23, 2007 (Attach. 5), Entergy's "Commitment 30" stated:

> For aging management of the reactor vessel internals, IPEC will (1) participate in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the NRC for review and approval.

Attachment to NL-07-039 at 30 (Attach. 5). Similar language was contained in the related LRA Updated Final Safety Analysis Report Supplement sections A.2.1.41 (Unit 2) and A.3.1.41 (Unit 3), filed with the LRA.

Thus, it was clear from the time Entergy filed its LRA that Entergy planned on future completion of programs, and future development of industry plans. If New York and Riverkeeper found this to be unacceptable, they were obliged to raise the issue at the beginning of the proceeding. As discussed above, New York did raise this issue as part of Contention 23, claiming as inadequate Entergy's plans to participate in industry programs for investigating and managing aging effects on reactor internals and to evaluate and implement the results of the industry programs as applicable to the reactor internals. NYS Petition at 218-19. The Intervenors make no showing that Entergy's plans were unclear or that the SSER somehow created the last piece of information without which they could not have alleged an omission related to Commitment 30 -- which essentially repeats information that was available for over four years. Their claim is therefore impermissibly late. *Prairie Island,* CLI-10-27, 72 NRC __ (slip op. at 14).[13]

Notwithstanding the Intervenors' claims, it appears that this issue has been mooted by Entergy's submission of September 29, 2011, inasmuch as NL-11-107 (Attach. 6) "contains the inspection plan satisfying the completion of commitment # 30 to the License Renewal Application regarding the Aging Management Programs for Reactor Vessel Internals." NL-11-107 at 1 (Attach. 6). Thus, the Intervenors' concern with just having a commitment instead of a

[13] The Intervenors state that Entergy has not provided a final reactor vessel internals program and instead Entergy has committed to comply with an unissued revision of MRP-227. Motion at 3, 4; Lahey Declaration at 3; Contention at 2-3. They acknowledge, however, that the State received information from Entergy (NL-11-107) on September 29, 2011, in which Entergy provided an inspection plan for reactor vessel internals that appears to rely on MRP-227, but indicate that they and their experts did not have sufficient time to review the document prior to filing the contention. Contention at 3. Nonetheless, they assert that a commitment to develop a program is insufficient, and that Entergy has not filed any documents to demonstrate that its AMP is consistent with GALL. *Id*. As explained herein, these claims are now moot.

plan has been overtaken by events; Entergy replaced its brief statement of commitment with a 58-page Reactor Vessel Internals Inspection Plan, and its commitment has been satisfied. Accordingly, the issue raised regarding Commitment 30 is now moot.

E. The Nontimely Factors of 10 C.F.R. § 2.309(c)(1) Weigh Against Admission

The Intervenors do not address the eight nontimely factors of 10 C.F.R. §-2.309(c)(1)(i)-(viii). A balancing of those factors weighs against admission, in that the issues raised in this contention could have been filed long ago. The Intervenors' failure to address these factors warrants the rejection of their contention. *See* 10 C.F.R. § 2.309(c)(2). Moreover, no "good cause" appears for the Intervenors' failure to raise the alleged omissions at the time the information was first available.[14]

F. The Contention's References to the Atomic Energy Act Fail to Raise a Cognizable Issue for Litigation

Contention NYS-38/RK-TC-5 broadly addresses compliance with, *inter alia,* the Atomic Energy Act of 1954, as amended (the "Act"), specifically, 42 U.S.C. §§ 2133(b) and (d), and 42 U.S.C. § 2232(a) *(i.e.,* Sections 103(b) and (d), and 182(a) of the Act). *See* Contention at 1. These claims fail to state a cognizable issue for litigation.

First, 42 U.S.C. § 2133(b) regards the "nonexclusive basis" by which the NRC issues licenses when certain criteria are met; the Intervenors do not show how the LRA fails to satisfy some requirement imposed by this section of the Act. 10 C.F.R. § 2.309(f)(1)(i). Second, 42 U.S.C. § 2133(d), deals with limitations on jurisdiction and foreign ownership, and the opinions of the NRC, and is even more removed from the scope of a license renewal proceeding. Finally, 42.U.S.C. 2232(a) addresses the "content and form" of license applications, such as the necessity for an applicant to sign an application; the Intervenors do not explain how Entergy's

[14] Furthermore, because New York and Riverkeeper are both parties to this proceeding, they can continue to participate in the proceeding and represent their interests through adjudication of their existing contentions.

LRA fails to satisfy this section of the Act. Thus, the Intervenors' citation of "42 U.S.C. §§ 2133(b) and (d) and 2232(a)" fails to raise a cognizable issue for litigation in this proceeding, and their reference to these statutory provisions should not be admitted as part of their new contention.

G. The Contention Erroneously Asserts that Commitments Are Not Acceptable in License Renewal Applications

1. Commitments to Comply with the Future NRC and Industry Developments

The focus of the proffered contention is, according to New York and Riverkeeper, a "fundamental legal deficiency of the AMP record." Contention at 16. The essence of the Intervenors' position is that Entergy's application for license renewal is insufficient and incomplete where the LRA provides a commitment to develop – in the future – plans and programs for an AMP which the Applicant has already stated will be consistent with GALL. *See* Motion at 8. The Intervenors assert that this is contrary to legal requirements and precedents, including *Vermont Yankee,* CLI-10-17. *Id.* Further, they state that a commitment to develop a plan which will be consistent with GALL does not demonstrate consistency with GALL, and is insufficient under the regulations and law. Contention at 15-16. According to the Intervenors, the missing information is part of the development of an AMP, not the implementation of an AMP. Contention at 1.

The Intervenors' view of this matter is contrary to established precedent, under which the Commission has held that "a commitment to implement an AMP that the NRC finds is consistent with the GALL Report[15] constitutes one acceptable method for compliance with 10 C.F.R.

[15] The Commission has cited the GALL Report with approval, stating:

> An applicant for license renewal "may reference the GALL Report … to demonstrate that the programs at the applicant's facility correspond to those reviewed and approved" therein, and the applicant must ensure and certify that its programs correspond to those reviewed in the GALL

§ 54.21(c)(1)(iii)." *Vermont Yankee*, CLI 10-17, 72 NRC __ (slip op at 44).[16]

In *Vermont Yankee*, the Commission "disagree[d] with the Board's conclusion that Entergy's future-oriented interpretation would avoid the whole point of the license renewal process – to demonstrate that aging will be properly managed." *Id.* The Commission repeated its holding from *Oyster Creek*, CLI-08-23, 68 NRC at 468, stating as follows:

> Section 54.29(a) of our regulations speaks of both past and future actions, referring specifically to those that "*have been or will be taken* with respect to . . . managing the effects of aging . . . and . . . time-limited aging analyses. . . ." Moreover, in *Oyster Creek* we expressly interpreted section 54.21(c)(1) to permit a demonstration *after* the issuance of a renewed license: "an applicant's use of an aging management program identified in the GALL Report constitutes reasonable assurance that it *will* manage the targeted aging effect during the renewal period." We reiterate here that a commitment to implement an AMP that the NRC finds is consistent with the GALL Report constitutes one acceptable method for compliance with 10 C.F.R. § 54.21(c)(1)(iii).

Id. (emphasis in original; footnotes omitted). Further, the Commission observed as follows:

> The GALL Report provides that one way a license renewal applicant may demonstrate that an AMP *will* effectively manage the effects of aging during the period of extended operation is by stating that a program is "consistent with" or "based on" the GALL Report.

> Report. In other words, the license renewal applicant's use of an aging management program identified in the GALL Report constitutes reasonable assurance that it will manage the targeted aging effect during the renewal period.

Oyster Creek, CLI-08-23, 68 NRC at 468.

[16] The Commission further stated as follows:

> [A]n applicant can satisfy the requirements of section 54.21(c)(1) in any of three ways – it may choose to demonstrate that its fatigue analyses remain valid through the period of extended operation under subsection (i), or that those analyses have been projected to the end of that period under subsection (ii), or that the effects of aging will be adequately managed during that period under subsection (iii) through, e.g., a commitment to implement an approved AMP.

Vermont Yankee, CLI 10-17, 72 NRC __ (slip op. at 42).

> An applicant may commit to implement an AMP that is consistent with the GALL Report and that *will* adequately manage aging. But such a commitment does not absolve the applicant from demonstrating, *prior* to issuance of a renewed license, that its AMP is indeed consistent with the GALL Report. We do not simply take the applicant at its word. When an applicant makes such a statement, the Staff will draw its own independent conclusion as to whether the applicant's programs are in fact consistent with the GALL Report.

Id., slip op. at 45-46 (emphasis in original; footnotes omitted).

In sum, a commitment to comply with the GALL provisions for an AMP does not prevent the Board from reviewing the substance of the commitment and exploring any deficiencies alleged in that commitment, to the extent they are raised by the intervenor. *Id.* at 47. Those exceptions to the general principle, that compliance with a GALL-approved program demonstrates the adequacy of an AMP, do not apply here.

2. Entergy's Commitments Relate to Implementation, not <u>Development of Its AMP</u>

New York and Riverkeeper assert that Entergy's commitments to comply with the GALL Report demonstrate that its AMP is incomplete and has yet to be developed. Contention at 15. Contrary to the Intervenors' view, the claimed omissions are all related to *implementation* of programs and are not directed to the development of an adequate AMP.

a. The CUFen Calculations Relate to Implementing the <u>Metal Fatigue Program</u>

The Commission has made clear that calculations to determine which CUFen is limiting are part of the implementation of a metal fatigue program. *Vermont Yankee*, CLI 10-17, 72 NRC __ (slip op. at 48). This is further evidenced by the Commission's observation that "None of our regulations requires that a license renewal applicant calculate CUFen – that is, adjust the CUF by applying the environmental adjustment factor – prior to the issuance of a renewed license." *Id*. Further, for an applicant proceeding under 10 C.F.R. § 54.21(c)(1)(iii), the Commission recognized in *Vermont Yankee* that such calculations are part of implementing an

AMP that is consistent with the GALL Report, and therefore in compliance with 10 C.F.R. § 54.21(c)(1)(iii). *Id.,* slip op. at 41 n.192. Similarly, in this proceeding, Entergy is reviewing locations and may potentially make additional calculations; in doing so, it is *implementing* its metal fatigue program. Therefore the Intervenors' claim that information must be provided now runs afoul of the Commission's holding in *Vermont Yankee.*

b. The Steam Generator Inspections Are Related to Implementing the Program for Steam Generators

The Intervenors allege that the steam generator AMP is missing information because the applicant committed to implementing portions of the program in the future. Contention at 2. However, the Applicant's commitment to perform future inspections of its steam generators does not affect the content of the program or impact whether the program is adequate to manage the aging effects. As the Commission has explained, such implementation of portions of the AMP at a future date is not material to the determination of whether the AMP is adequate. Thus, the Intervenors' contention challenging the Applicant's future implementation of its steam generator AMP is not properly within the scope of this proceeding.

c. The Industry Programs Are Related to Implementing the Program for Vessel Internals

Entergy's commitment to comply with industry programs for managing the aging effects of reactor vessel internals is consistent with the GALL Report. Thus, throughout section IV.B2 (Reactor Vessel Internals (PWR) - Westinghouse) of the GALL Report, the adequacy of a commitment to comply with such industry programs is repeatedly found to be acceptable:

> No further aging management review is necessary if the applicant provides a commitment in the FSAR supplement to (1) participate in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the NRC for review and approval.

E.g., NUREG-1801, Rev. 1, at IV B2-2 (Attach. 4). Further, regarding whether there is a need for any further evaluation, the GALL Report repeatedly states "No, but licensee commitment needs to be confirmed." *E.g., id.*

Entergy's commitment mirrors this approach, stating that for aging management of reactor vessel internals, it will evaluate and implement the results of the industry programs. *See* Attachment to NL-07-039 at 30 (Attach. 5). By committing to evaluate and implement industry programs, Entergy is implementing the AMP. Accordingly, its commitment establishes the adequacy of its AMP under *Vermont Yankee.*

3. Ongoing NRC and Industry Efforts Related to the Management of Aging Effects

Two of the issues in Contention NYS-38/RK-TC-5 address how Entergy will respond to future developments by the NRC and by industry that could potentially affect its AMPs. Specifically, these programs involve the EPRI Steam Generator Management Program Engineering and Regulatory Technical Advisory Group Report, and EPRI MRP-227 as ultimately approved by the Staff. Contention at 2-3.

The Intervenors' concerns over the potential development of future inspection requirements and future implementation of those requirements are speculative in nature, and do not form an acceptable basis for a contention. In the *Prairie Island* license renewal proceeding, an issue was raised regarding the applicant's promise to implement the Commission's finalized inspection requirements associated with PWSCC of nickel-alloy upper head penetrations. *Northern States Power Co. (Formerly Nuclear Management Co., LLC)* (Prairie Island Nuclear Generating Plant, Units 1 and 2), LBP-08-26, 68 NRC 905, 940-42 (2008) (admitting "PIIC Contention 8" in a modified form). The contention in that proceeding claimed that the AMP, which relied upon an NRC Order (First Revised Order EA-03-009, "Issue of Order Establishing Interim Inspection Requirements for Reactor Pressure Vessel Heads at Pressurized Water

Reactors," dated February 20. 2004), was not adequately detailed. *Id.* at 941. In response, the Board found that EA-03-009 provided adequate details and was incorporated by reference in the GALL Report, as the GALL Report identified EA-03-009 as the relevant AMP. *Id.* Accordingly, the Board concluded that the ten elements of the GALL Report need not be addressed. *Id.* In addition, the *Prairie Island* Board found inadmissible the contention's claims regarding the applicant's commitment to implement, in the future, the finalized inspection requirements once they are codified into 10 C.F.R.§ 50.55a. *Id.* The Board stated:

> The second part of this issue concerns the future AMP that will be implemented once the NRC incorporates finalized inspection requirements into 10 C.F.R. § 50.55a. The claim here is that "[t]he LRA program commitment to do whatever the NRC tells them to do does not demonstrate the effectiveness of an aging management program. The Board believes that the LRA must be evaluated on the basis of AMPs now in effect. This means we will evaluate the LRA based on the requirements of Order EA-03-009. At some future date, the NRC might or might not implement finalized inspection requirements. The Application has provided a commitment that, should the inspection requirements be changed. Applicant will implement those new inspection requirements. It will be the responsibility of NRC Staff and Applicant to ensure that this commitment is fulfilled. This Board lacks the authority — much less the ability — to require Applicant clairvoyantly to predict the future inspection requirements and to describe their future implementation. On this issue, Petitioner has failed to identify any deficiency on a relevant matter in Northern States' Application and therefore does not satisfy 10 C.F.R. § 2.309(f)(1)(vi). This part of the contention is inadmissible.

Id. at 941-942.

The issues raised in Contention NYS-38/RK-TC-5 in this proceeding are analogous to the issue that the Board rejected in *Prairie Island.* For example, Contention NYS-38/RK-TC-5 takes issue with Entergy's future reliance on an undeveloped EPRI Steam Generator Management Program ("SGMP"), and planned future inspections (*i.e.,* Commitment 41), asserting that such plans do not meet license renewal requirements. Contention at 8. However, as the Board found in *Prairie Island,* concerns over Entergy's future review and implementation of the SGMP do not form an admissible contention. *See Prairie Island*, LBP-08-26, 68 NRC at 942.

The Intervenors assert that Entergy is postponing the development of an inspection plan, and thus it cannot be determined if the plan is consistent with the GALL Report. Contention at 8. But in making this argument, they fail to show why the Applicant's current plan is insufficient, why the GALL Report is not satisfied through Commitment 41, or that any other flaw exists in the Applicant's commitment to perform future inspections. Thus, the claim does not satisfy 10 C.F.R. § 2.309(f)(1)(vi) and this part of the contention is inadmissible.

Similarly, the Intervenors take issue with Entergy's plans based on EPRI guidance document MRP-227, as approved by the Staff. *See* Contention at 2-3, 8. This issue is again analogous to the issue of non-finalized inspections plans discussed in *Prairie Island*, in that Entergy is planning to review potential modifications to its programs after the Staff completes its effort to determine what, if any, modifications to MRP-227 are needed. *Compare* Contention at 2-3 with *Prairie Island*, LBP-08-26, 68 NRC at 942. Significantly, the Intervenors fail to show why the Applicant's current plan is insufficient, why the GALL Report is not met in part through the Applicant's actions and statements, or what is otherwise wrong with the applicant's commitment to review and implement any necessary changes to the AMP based on the Staff's final evaluations, when available. Thus, this claim does not satisfy 10 C.F.R. § 2.309(f)(1)(vi).

CONCLUSION

Contention NYS-38/RK-TC-5 is not based upon new information that first became available in the SER Supplement or the Applicant's recent RAI responses, and it therefore is impermissibly late; further, NYS/RK did not show good cause for its late filing. In addition, the Contention fails to meet the admissibly criteria of 10 C.F.R. § 2.309(f)(1). For these reasons, the Staff respectfully submits that the contention is inadmissible.

Respectfully submitted,

/Signed (electronically) by/

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Dated at Rockville, MD
this 25th day of October 2011

ANSWER CERTIFICATION

I certify that I have made a sincere effort to make myself available to listen and respond to the moving parties, and to resolve the factual and legal issues raised in the motion, and that my efforts to resolve the issues have been unsuccessful.

/Signed (electronically) by/
David E. Roth
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Dated at Rockville, MD
this 25th day of October 2011

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

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

NRC STAFF'S ANSWER TO STATE OF NEW YORK AND RIVERKEEPER'S JOINT MOTION TO FILE A NEW CONTENTION, AND NEW JOINT CONTENTION NYS-38/RK-TC-5

ATTACHMENT 1

NL-11-032 – Letter from Entergy, dated March 28, 2011, regarding AMP RAIs

Entergy

Entergy Nuclear Northeast
Indian Point Energy Center
450 Broadway, GSB
P.O. Box 249
Buchanan, NY 10511-0249
Tel (914) 788-2055

Fred Dacimo
Vice President
License Renewal

NL-11-032

March 28, 2011

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555-0001

SUBJECT: Response to Request for Additional Information (RAI)
Aging Management Programs
Indian Point Nuclear Generating Unit Nos. 2 & 3
Docket Nos. 50-247 and 50-286
License Nos. DPR-26 and DPR-64

REFERENCE: 1. NRC Letter, "Request for Additional Information for the Review of the Indian Point Nuclear Generating Unit Numbers 2 and 3, License Renewal Application," dated February 10, 2011

Dear Sir or Madam:

Entergy Nuclear Operations, Inc is providing, in Attachment 1, the response to the referenced letter request for additional information (RAI). In addition, Attachment 1 includes a response to questions asked of other license renewal applicants regarding fatigue analysis software. Attachment 2 provides the latest list of regulatory commitments to include new commitments contained in this letter.

If you have any questions, or require additional information, please contact Mr. Robert Walpole at 914-734-6710.

A128
NRR

I declare under penalty of perjury that the foregoing is true and correct. Executed on March 28, 2011.

Sincerely,

FRD/cbr

Attachment: 1. Response to Request for Additional Information (RAI), Aging Management Programs

2. IPEC List of Regulatory Commitments (Rev. 13)

cc: Mr. William Dean, Regional Administrator, NRC Region I
Mr. Sherwin E. Turk, NRC Office of General Counsel, Special Counsel
Mr. Dave Wrona, NRC Branch Chief, Engineering Review Branch I
Mr. John Boska, NRR Senior Project Manager
Mr. Paul Eddy, New York State Department of Public Service
NRC Resident Inspector's Office
Mr. Francis J. Murray, Jr., President and CEO NYSERDA

ATTACHMENT 1 TO NL-11-032

LICENSE RENEWAL APPLICATION
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION (RAI)
AGING MANAGEMENT PROGRAMS

ENTERGY NUCLEAR OPERATIONS, INC.
INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 & 3
DOCKET NOS. 50-247 AND 50-286

**INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3
LICENSE RENEWAL APPLICATION
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION (RAI)
AGING MANAGEMENT PROGRAMS**

RAI 3.0.3.1.2-1

Background

In light of Operating Experience (OE) that has occurred coincident with and after the staff evaluation of the Indian Point License Renewal Application (LRA) and issuance of the Safety Evaluation Report (SER), the staff is concerned about the continued susceptibility to failure of buried (i.e., piping in direct contact with soil) and/or underground piping (i.e., piping not in direct contact with soil, but located below grade in a vault, pipe chase, or other structure where it is exposed to air and where access is limited) that is within the scope of 10 CFR 54.4 and subject to aging management for license renewal. The staff reviewed the LRA, SER and a letter dated July 27, 2009 from the applicant addressing buried pipe program modifications as a result of recent site operating experience. Based on the review of these documents subsequent to the recent industry OE, the staff does not have enough information to evaluate how Indian Point is implementing changes to their program based on the industry experience.

Issue

1. The LRA and supplemental material did not contain enough specifics on the planned inspections for the staff to determine if the inspections would be adequate to manage the aging effect for all types/materials of in-scope buried pipes (e.g., safety/code class and potential to release materials detrimental to the environment (e.g., diesel fuel and radioisotopes that exceed Environmental Protection Agency (EPA) drinking water standards)).

2. The staff believes that buried coated steel piping is more susceptible to potential failure if it is not protected by a cathodic protection system unless soil resistivity is greater than 20,000 ohm-cm.

3. The LRA and supplemental material did not contain enough specifics for the staff to understand the general condition of the backfill used in the vicinity of buried in-scope piping.

4. In a letter dated July 27, 2009, the applicant stated that it will employ qualified inspection methods with demonstrated effectiveness for detection of aging effects during the period of extended operation. The staff acknowledges that where examining buried pipe from the exterior surface is not possible due to plant configuration (e.g., the piping is located underneath foundations) it is reasonable to substitute a volumetric examination from the interior of the pipe provided the surface is properly prepared. However, beyond ultrasonic techniques, the staff is not aware of another reliable volumetric inspection methodology that is suitable for inspecting buried in scope piping. This is particularly true, in light of industry experience, with guided wave ultrasonic technology.

5. Based on a review of the LRA and UFSAR, it is not clear to the staff what in-scope systems (if any) have underground piping or if such piping will receive inspections consistent with the program described in LRA AMP B.1.11 External Surfaces Monitoring Program.

6. LRA Sections A.2.1.5 and A.3.1.5 states that corrosion risk will be determined through consideration of material, soil resistivity, drainage, presence of cathodic protection and type of coating. Given that cathodic protection has not been installed for all buried in-scope piping, the staff lacks sufficient information to conclude that the applicant's evaluation of soil corrosivity will provide reasonable assurance that in-scope buried piping will meet its intended license renewal function(s). Specifically, the staff is concerned with the following:

   a. While the applicant stated that it will include consideration of soil resistivity and drainage, it did not state that other important soil parameters would be included such as, pH, chlorides, redox potential, sulfates and sulfides.
   b. The applicant did not state how often it will conduct testing of localized soil conditions, nor provide the specific locations relative to buried in-scope piping that is not cathodically protected.
   c. The applicant did not state how they would integrate the various soil parameters into an assessment of corrosivity of the soil, such as using "Assessment of Overall Soil Corrosivity to Steel,"[1] or AWWA C105[2].
   d. The applicant did not specifically state how localized soil data will be factored into increased inspections, including the specific increase in the number of committed inspections by material type and location.

Request

1. Respond to the following:

   a. Describe how many in-scope buried piping segments for each material, code/safety-related piping, and potential to release materials detrimental to the environment category will be inspected.

Response for RAI 3.0.3.1.2-1 Part 1a

For the 10-year period prior to the PEO, the following table presents the planned inspections for buried piping subject to aging management review that is code/safety-related (Code/SR) or has the potential to release materials detrimental to the environment (hazmat). Inspections by material and category are indicated.

Material	Category	IP2 Inspections	IP3 Inspections
Carbon steel	Code/SR	13	14
Carbon steel	Hazmat	13	5
Stainless steel	Hazmat	N/A	6

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b. For the 45 planned inspections prior to the period of extended operation:

i. How many will consist of an excavated direct visual inspection of the external surfaces of the buried pipe?
ii. What length of piping will be excavated and have a direct visual inspection conducted?

Response for RAI 3.0.3.1.2-1 Part 1b

The following table provides the number of planned direct visual inspections prior to the PEO. For planned direct visual inspections, future excavations will expose a minimum of 10 linear feet of pipe, for full circumferential inspections. Ten completed inspections have ranged from approximately five feet to more than ten feet averaging approximately eight linear feet.

Material	Category	IP2 Inspections	IP3 Inspections
Carbon steel	Code/SR	9	8
Carbon steel	Hazmat	11	3
Stainless steel	Hazmat	N/A	3

c. Understanding that the total number of inspections performed will be informed by plant-specific and industry operating experience, what minimum number of inspections of buried in-scope piping is planned during the 40 – 50 and 50 – 60 year operating periods? When describing the minimum number of planned inspections, differentiate between material, code/safety-related piping, and potential to release materials detrimental to the environment category piping inspection quantities of buried in-scope piping.

Response for RAI 3.0.3.1.2-1 Part 1c

IPEC will perform direct visual inspections during each 10-year period of the PEO in accordance with the following table. The table lists inspections for different materials, for code/safety-related piping, and for piping with the potential to release materials detrimental to the environment (indicated as hazmat.)

Material	**Category**	**IP2 Inspections**	**IP3 Inspections**
Carbon steel	Code/SR	6	6
Carbon steel	Hazmat	8	8
Stainless steel	Hazmat	N/A	2

If sample results indicate the soil is corrosive as described in the response to 2.c below, then the number of inspections for the carbon steel code/safety-related piping will be increased to eight and the number of inspections for the carbon steel hazmat piping will be increased to 12.

d. What specific inspections will be performed for the IP3 security generator propane tank and at what frequency?

Response for RAI 3.0.3.1.2-1 Part 1d

The nonsafety-related security generator system is credited for lighting during the response to fires in certain plant areas. Propane fuels the engine that drives the generator. Propane is non-toxic, non-caustic and will not create an environmental hazard if released as a liquid or vapor into water or soil. Monitoring the level of propane in the tank ensures the tank is capable of fulfilling its intended function. Consequently, only opportunistic inspections will be performed on the propane tank.

2. Respond to the following:

   a. Confirm at IP2 that the service water system and at IP3 that the service water suction piping are the only in-scope steel piping systems currently protected by a cathodic protection (CP) system.

Response for RAI 3.0.3.1.2-1 Part 2a

The IP2 service water lines near the river were originally provided with cathodic protection, but the rectifiers were subsequently removed. For IP2, the only in-scope steel piping cathodically protected is a portion of the city water piping in the area where they cross over the Algonquin gas pipelines.

At IP3, the service water suction is not piping and is not buried, but is the pump column in each respective intake bay. The pump columns were originally provided with cathodic protection. The cathodic protection, however, was subsequently removed. The pump columns have been replaced with materials with greater resistance to corrosion.

For IP3, the only in-scope buried piping cathodically protected is the city water line over the Algonquin gas pipelines.

   b. For those systems that are protected by a CP system:
      i. Has annual NACE survey testing been conducted, and if so, for how many years?
      ii. Have the output of the beds been trended, and if so, what are the results of the trending?
      iii. What is the availability of the cathodic protection system?

Response for RAI 3.0.3.1.2-1 Part 2b

A cathodic protection rectifier was installed in 2009 to protect the IP2 and IP3 city water lines near the Algonquin Gas pipelines.

i. **Annual NACE surveys have been performed on the system since its installation in November 2009.**
ii. **The rectifier output has been steady. Final testing and adjustment of the system occurred in July 2010.**

iii. **The system has been in service since installation. It was out of service in July 2010 for one week. System availability since installation in November 2009 has been greater than 98%.**

c. For buried in-scope steel piping systems that are not cathodically protected:

i. Justify why this piping will continue to meet or exceed the minimum design wall thickness throughout the period of extended operation, assuming that no coatings are applied to the piping, or

ii. Justify why the number of the planned inspections of this piping is sufficient to reasonably assure that this piping will continue to meet or exceed the minimum design wall thickness throughout the period of extended operation.

Response for RAI 3.0.3.1.2-1 Part 2c

The piping in question is coated which provides a significant barrier to corrosion. Inspections of excavated piping as discussed in the response to 3a below have found the coatings to be in good condition with no piping degradation. In addition, soil resistivity measurements as discussed in 3b below have shown the soil is non- aggressive. The number of planned inspections as discussed in 1a and the recent operating experience from site excavations provide reasonable assurance the piping will meet its license renewal intended functions during the PEO.

In addition, Entergy uses risk ranking to identify piping segments that are limiting (for example, closest to the water table) for direct visual inspection. Inspection results from these segments that show that the piping continues to maintain adequate wall thickness, provides reasonable assurance that similar piping in less limiting locations will maintain adequate wall thickness for the PEO.

To provide additional assurance that the piping will remain capable of performing its intended function, soil will be sampled prior to the PEO to confirm that the soil conditions are not aggressive. The number of inspections during the PEO will be based on the results the soil samples. The soil samples will be taken prior to the period of extended operation and at least once every 10 years thereafter to confirm the initial sample results. Soil samples will be taken at a minimum of two locations at least three feet below the surface near in-scope piping to obtain representative soil conditions for each system. The parameters monitored will include soil moisture, pH, chlorides, sulfates, and resistivity. American Water Works Association (AWWA) Standard C105 Appendix A will be used to determine corrosiveness of the soil in addition to soil resistivity. If the soil resistivity is < 20,000 ohm-cm or the soil scores higher than 10 points using AWWA C105, the number of inspections provided in the response to question 1.c will be increased to provide additional assurance that the piping can perform its design function during the PEO.

This approach provides reasonable assurance that piping will continue to meet its design function without cathodic protection.

3. Respond to the following:

a. Provide details on any further excavations conducted since July 2009 that provide insight on the extent of condition of the quality of the backfill in the vicinity of buried pipes.

Response for RAI 3.0.3.1.2-1 Part 3a

Excavations since 2009:

- **Oct, 2009 – 16-inch and 10-inch city water lines from the city water storage tank were inspected during a plant modification to install cathodic protection for 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. Inspections found good coating condition and good quality backfill.**

- **Nov. 2009 - 10-inch fire protection header. Inspection of approximately eight feet of piping found good condition of the coating and good quality of the backfill.**

  In summary, visual inspections have not identified coating failures. Other than the condensate storage lines, visual observation of the backfill, has not identified rocks or foreign material with a reasonable potential to damage the piping external coating.

b. If there is no further information on the condition of the quality of backfill, justify why the planned inspections are adequate to detect potential degradation as a result of coating damage, particularly in steel buried pipe systems that are not protected by a CP system.

Response for RAI 3.0.3.1.2-1 Part 3b

The results of the visual inspections performed to date indicate that the quality of the backfill in contact with the coatings is generally good (i.e. no large, sharp rock material in contact with the coating). In addition to those inspection results, data will be acquired from future excavations and direct inspections that will provide input to determine the need for additional inspections or adjusted inspection frequencies.

4. Respond to the following:

a. In absence of a qualified method, and until such time that one is demonstrated to be effective, what alternative inspection methods will Entergy employ when excavated direct visual examinations are not possible due to plant configuration.

Response for RAI 3.0.3.1.2-1 Part 4a

In absence of a qualified method, and until such time that one is demonstrated to be effective, Entergy has no plans to employ alternate inspection methods.

b. Justify why the methods identified in response to request 4a will be effective at providing reasonable assurance that the buried in-scope piping systems will meet their current licensing basis function.

Response for RAI 3.0.3.1.2-1 Part 4b

Entergy has no plans to employ alternate inspection methods

c. If a volumetric examination method is used, what percentage of interior axial length of the pipe will be inspected?

Response for RAI 3.0.3.1.2-1 Part 4c

Entergy has no plans to employ alternate volumetric examination methods.

5. For in-scope underground piping, respond to the following:

a. State what systems have underground piping and indicate the corresponding length of piping

Response for RAI 3.0.3.1.2-1 Part 5a

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. In-scope SSCs that are subject to aging management review at IPEC include no underground piping or tanks.

b. State how often and what quantity of underground piping for each system will be inspected by AMP, and indicate which AMP will be used.

Response for RAI 3.0.3.1.2-1 Part 5b

Not applicable.

6. Respond to the following for buried in-scope steel piping without cathodic protection:

   a. State what soil parameters will be included in the analysis of soil corrosivity beyond soil resistivity and drainage.
   b. State how often soil sampling will be conducted and in what locations.
   c. State how the various soil parameters will be integrated into an assessment of the corrosivity of the soil.
   d. State how localized soil conditions will be factored into increased inspections, including the specific increase in the number of committed inspections by material type and location.

Response for RAI 3.0.3.1.2-1 Part 6a

Two commonly used methods for assessing soil corrosivity are (1) determination of soil resistivity alone, and (2) based on AWWA C105, which considers the following soil parameters: soil resistivity, pH, redox potential, sulfides, and moisture (drainage). Both of these measures will be used for determining soil corrosivity.

Response for RAI 3.0.3.1.2-1 Part 6b

Soil samples will be taken prior to the period of extended operation and at least once every 10 years thereafter to confirm the initial sample results. Soil samples will be taken at a minimum of two locations at least three feet below the surface near the in-scope piping to obtain representative soil conditions for each system.

Response for RAI 3.0.3.1.2-1 Part 6c

AWWA C105 soil corrosivity assessment utilizes a point system, using five (5) soil parameters: soil resistivity, pH, redox potential, sulfides, and moisture (drainage). Accordingly, soils scoring more than 10 points are considered corrosive. Based on soil resistivity alone, a resistivity > 20,000 ohm-cm is considered non-corrosive.

Response for RAI 3.0.3.1.2-1 Part 6d

Initial piping inspection priority and re-inspection interval will be based on the overall assessment of a piping segment's impact risk and corrosion risk, based on the best available data. Soil will be sampled prior to the PEO to confirm that the soil conditions are not aggressive. The number of inspections during the PEO will be based on the results of this soil survey. The soil samples will be taken prior to the period of extended operation and at least once every 10 years thereafter to confirm the initial sample results. If the soil resistivity is < 20,000 ohm-cm and the soil scores higher than 10 points using AWWA C105, the number of inspections will be increased as discussed in the response to question 1.c to ensure the piping can perform its design function during the PEO. The additional inspections will be in locations with aggressive soil condition.

RAI 3.0.3.1.6-1

Background

NUREG-1801, Rev. 1, "Generic Aging Lessons Learned," (the GALL Report) addresses inaccessible medium voltage cables in Aging Management Program (AMP) XI.E3, "Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements." The purpose of this program is to provide reasonable assurance that the intended functions of inaccessible medium voltage cables (2 kV to 35 kV), that are not subject to environmental qualification requirements of 10 CFR 50.49 and are exposed to adverse localized environments caused by moisture while energized, will be maintained consistent with the current licensing basis. The scope of the program applies to inaccessible (in conduits, cable trenches, cable troughs, duct banks, underground vaults or direct buried installations) medium-voltage cables within the scope of license renewal that are subject to significant moisture simultaneously with significant voltage.

The application of AMP XI.E3 to medium voltage cables was based on the operating experience available at the time Revision 1 of the GALL Report was developed. However, recently identified industry operating experience indicates that the presence of water or moisture can be a contributing factor in inaccessible power cables failures at lower service voltages (480 V to 2 kV). Applicable operating experience was identified in licensee responses to Generic Letter (GL) 2007-01, "Inaccessible or Underground Power Cable Failures that Disable Accident Mitigation Systems or Cause Plant Transients," which included failures of power cable operating at service voltages of less than 2 kV where water was considered a contributing factor.
Recently identified industry operating experience provided by NRC licensees in response to GL 2007-01 has shown: (a) that there is an increasing trend of cable failures with length in service beginning in the 6th through 10th years of operation and, (b) that moisture intrusion is the predominant factor contributing to cable failure. The staff has determined, based on the review of the cable failure distribution, that an annual inspection of manholes and a cable test frequency of at least every 6 years is a conservative approach to ensuring the operability of power cables and, therefore, should be considered.

In addition, recently identified industry operating experience has shown that some NRC licensees may experience cable manhole water intrusion events, such as flooding or heavy rain, that subjects cables within the scope of program for GALL Report XI.E3 to significant moisture. The staff has determined that event driven inspections of cable manholes, in addition to a 1 year periodic inspection frequency, is a conservative approach and, therefore, should be considered.

Issue

The staff has concluded, based on recently identified industry operating experience concerning the failure of inaccessible low voltage power cables (480 V to 2 kV) in the presence of significant moisture, that these cables can potentially experience age related degradation. The staff noted that the applicant's Inaccessible Medium-Voltage Cables Program does not address inaccessible low voltage power cables [400 V (nominally 480 V) to 2 kV inclusive]. In addition, more frequent cable test and cable manhole inspection frequencies (e.g., from 10 and two years to six and one year, respectively) should be evaluated to ensure that the Non-EQ Inaccessible Medium Voltage Cable program test and inspection frequencies reflect industry and plant-specific operating experience and that test and inspection frequencies may be increased based on future industry and plant-specific operating experience.

Request

Provide a summary of your evaluation of recently identified industry operating experience and any plant-specific operating experience concerning inaccessible low voltage power cable failures within the scope of license renewal (not subject to 10 CFR 50.49 environmental qualification requirements), and how this operating experience applies to the need for additional aging management activities at your plant for such cables.

Response for RAI 3.0.3.1.6-1

As reported in the NRC's November 12, 2008 summary of licensee responses to GL 2007-01, the number of cable failures is a small percentage of the total number of cables in these categories for all nuclear plants.

Indian Point responded to GL 2007-01 on May 7, 2007 (ML071350410), and reported that Indian Point Unit 3 had experienced two cable failures, and that Unit 2 had experienced no failures based on the scope criteria set forth in GL 2007-01. Both Unit 3 failures involved low-voltage power cables, and were due to mechanical damage rather than the effects of aging. A search of plant-specific OE since the May 7, 2007 response to GL 2007-01 identified one Unit 2 failure and no Unit 3 failures of low or medium-voltage power cables that are in the scope of the maintenance rule or license renewal rule. Excavation activities associated with a plant modification damaged a Unit 2 13.8kV off-site power feeder cable causing the Unit 2 cable failure. The effects of aging did not cause the cable failure.

Indian Point is revising its Non-EQ Inaccessible Medium-Voltage Cable Program to include low-voltage power cables that may be exposed to significant moisture.

1. Explain how Entergy will manage the effects of aging on inaccessible low voltage power cables within the scope of license renewal and subject to aging management review; with consideration of recently identified industry operating experience and any plant-specific operating experience. The discussion should include assessment of your aging management program description, program elements (i.e., Scope of Program, Parameters Monitored/Inspected, Detection of Aging Effects, and Corrective Actions), and FSAR summary description to demonstrate reasonable assurance that the intended functions of inaccessible low voltage power cables subject to adverse localized environments will be maintained consistent with the current licensing basis through the period of extended operation.

Response for RAI 3.0.3.1.6-1 Part 1

Indian Point will include low-voltage power cables in the non-EQ inaccessible medium-voltage cable program, will increase cable testing and manhole inspedction frequency, and will provide for manhole inspections after events that could cause flooding of inaccessible cable raceways. The program will include provisions to increase cable testing and manhole inspection frequency based on the results of testing and inspections.

The following changes to LRA Sections A.2.1.22 and B.1.23 provide for the inclusion of low-voltage power cable in the Non-EQ Inaccessible Medium-Voltage Cable program.

A.2.1.22 Non-EQ Inaccessible Medium-Voltage Cable Program

The Non-EQ Inaccessible Medium-Voltage Cable Program is a new program that entails periodic and event-driven inspections for water collection in cable manholes, and periodic testing of cables. In scope medium-voltage cables (cables with operating voltage from 2kV to 35kV) and low-voltage power cables (400 V to 2 kV) exposed to significant moisture ~~and voltage~~ will be tested at least once every ~~ten~~ six years to provide an indication of the condition of the conductor insulation. Test frequencies are adjusted based on test results and operating experience. The program includes periodic inspections for water accumulation in manholes at least once every ~~two~~ year~~s~~ (annually). In addition to the periodic manhole inspections, inspection of event-driven occurrences, such as heavy rain or flooding will be performed. Inspection frequency will be increased as necessary based on evaluation of inspection results.

The Non-EQ Inaccessible Medium-Voltage Cable Program will be implemented prior to the period of extended operation. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.E3, Inaccessible Medium-Voltage Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements.

B.1.23 NON-EQ INACCESSIBLE MEDIUM-VOLTAGE CABLE

Program Description

The Non-EQ Inaccessible Medium-Voltage Cable Program is a new program that entails periodic inspections for water collection in cable manholes and periodic testing of cables. In scope medium-voltage cables (cables with operating voltage from 2kV to 35kV) and low-voltage power cables (400 V to 2 kV) exposed to significant moisture ~~and voltage~~ will be tested at least once every ~~ten~~ six years to provide an indication of the condition of the conductor insulation. Test frequencies will be adjusted based on test results and operating experience. The program includes inspections for water accumulation in manholes at least once every ~~two~~ year~~s~~ (annually). In addition to the periodic manhole inspections, inspection for event-driven occurrences, such as heavy rain or flooding will be performed. Inspection frequency will be increased as necessary based on evaluation of inspection results.

This program will be implemented prior to the period of extended operation.

Operating Experience

The Non-EQ Inaccessible Medium-Voltage Cable Program is a new program. Industry and plant-specific operating experience will be considered when implementing this program. Industry operating experience that forms the basis for the program is described in the operating experience element of the NUREG-1801 program description. IPEC plant-specific operating experience is not inconsistent with the operating experience in the NUREG-1801 program description.

The inspection frequency for manholes is based on plant-specific operating experience with cable wetting or submergence in manholes (i.e., the inspection is performed periodically based on water accumulation over time and events such as heavy rain or flooding).

The IPEC program is based on the program description in NUREG-1801, which in turn is based on industry operating experience. As such, operating experience provides assurance that the Non-EQ Inaccessible Medium-Voltage Cable Program will manage the effects of aging such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

Conclusion

The Non-EQ Inaccessible Medium-Voltage Cable Program will be effective for managing aging effects since it will incorporate proven monitoring techniques and industry and plant-specific operating experience. The Non-EQ Inaccessible Medium-Voltage Cable Program assures that the effects of aging will be managed such that the applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

Commitment 15

Implement the Non-EQ Inaccessible Medium-Voltage Cable Program for IP2 and IP3 as described in LRA Section B.1.23.

This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.E3, Inaccessible ~~Medium-Voltage~~ Power Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements.

2. Provide an evaluation showing that the proposed Non-EQ Inaccessible Medium-Voltage Cable program test and inspection frequencies, including event-driven inspections, incorporate recent industry and plant-specific operating experience for both inaccessible low and medium voltage cable.

Response for RAI 3.0.3.1.6-1 Part 2

The Non-EQ Inaccessible Medium-Voltage Cable Program has been revised to include low-voltage inaccessible power cables. The cable test and manhole inspection frequencies have been increased in response to recent industry operating experience and license renewal correspondence. Provisions have been added to the program to increase the test and inspection frequencies if warranted by plant-specific test and inspection results or industry operating experience. Event-driven inspections have been added to the program based on recent industry license renewal correspondence. No recent adverse plant-specific operating experience has been identified that is inconsistent with industry operating experience. Therefore, the revised program incorporates recent operating experience associated with inaccessible low- and medium-voltage power cables.

3. In Commitment 40, Entergy committed to evaluate plant-specific and industry operating experience prior to entering the period of extended operation. Explain how the proposed Inaccessible Medium Voltage Program will continue to ensure that future industry and plant-specific operating experience will be incorporated into the program such that inspection and test frequencies may be increased based on test and inspection results.

Response for RAI 3.0.3.1.6-1 Part 3

The revised Non-EQ Inaccessible Medium Voltage Cable Program specifies that cable testing frequency and manhole inspection frequency will be adjusted as necessary based on the results of cable testing and manhole inspections. Indian Point will incorporate lessons learned from future industry and plant-specific operating experience, including plant-specific test and inspection results during implementation of the Non-EQ Inaccessible Medium Voltage Program.

RAI 3.0.3.1.10-1

Background

By letter dated July 26, 2010, the applicant provided clarification of LRA Section B.1.28, "One Time Inspection – Small Bore Piping." The applicant stated that its Inservice Inspection (ISI) Program includes periodic volumetric examinations on ASME Class 1 small bore socket welds. The applicant further stated that the inspection volume is in accordance with guidelines established in MRP-146 which recommends examination of the base metal one-half inch beyond the toe of the weld. The applicant also cited recent plant-specific operating experience in which leakage was detected in a Class 1 socket weld, and referenced the related Licensee Event Report (LER#2010-004-00). The staff noted that the applicant did not provide information that supports its conclusion on the failure mechanism.

The staff noted that for IP2, the facility operating license (DPR-26) expires at midnight September 28, 2013, and for IP3, the facility operating license (DPR-64) expires at midnight December 12, 2015. The staff further noted that both IP2 and IP3 will be in their 4th ISI interval upon entering the period of extended operation.

Issue

The staff noted that the inspections performed by its Inservice Inspection Program for ASME Class 1 small bore socket welds only include the base metal, one-half inch beyond the toe of the weld. It is not clear to the staff how an inspection of the base metal, one-half inch beyond the toe of the weld, is capable of detecting cracking in the ASME Class 1 small bore socket weld metal.

Request

1. Explain how Entergy will manage aging (i.e., cracking) in the weld metal of ASME Code Class 1 small bore socket welds.

Response for RAI 3.0.3.1.10-1 Part 1

IPEC will continue to perform visual examination (VT-2) as is required by ASME Code Case N-578, to manage the effects of aging on the ASME Class 1 small-bore socket welds for both units. In addition, IPEC will implement the One-Time Inspection - Small Bore Piping Program for IP3 and for butt welds on IP2.

For butt welds, IP2 will implement the One-Time Inspection - of ASME Code Class 1 Small Bore Piping Program, which manages cracking due to aging effects. The program will include volumetric examinations of small-bore piping butt weld metal on locations selected by the ISI Program using risk-informed methods to detect potential indications of cracking due to thermal fatigue and stress corrosion. For IP2, IPEC will perform volumetric examination of the weld metal of ten socket welds in 2012 and of at least ten socket welds during each 10-year period of the period of extended operation. These inspections will be included in the IP2 ISI Program.

IP3 has performed volumetric inspections on 25 small-bore piping welds, 21 of which were socket welds. Inspections on 18 of the welds inspected the root of the socket weld metal. The remaining three welds were inspected in accordance with MRP-146 (the base metal ½ inch from the weld). Sixteen (16) inspections had no recordable indications. Two socket welds had recordable indications and were cut out and destructively tested by EPRI. Metallographic evaluation determined that the recordable indications noted during the NDE inspections were root anomalies due to lack of fusion (LOF) during the welding process and were not part of the effective throat of the welds.

2. Clarify if the inspection volume selected for the proposed volumetric examinations of ASME Class 1 small bore butt welds, performed by the One Time Inspection – Small Bore Piping Program, includes the weld metal. If it does not include the weld metal, justify that the inspection volume is sufficient and capable of detecting cracking in the ASME Code Class 1 small bore butt weld metal.

Response for RAI 3.0.3.1.10-1 Part 2

The inspection volume selected for the proposed volumetric examination of ASME Class 1 small bore butt welds, performed under the One Time Inspection – Small Bore Piping Program, includes the weld metal. The inspection volume of the completed volumetric examinations of ASME Class 1 small bore butt welds, credited for the One Time Inspection – Small Bore Piping Program, included the weld metal.

3. Based on the operating experience at Indian Point, justify that an aging management program that performs periodic volumetric inspections of the weld metal for ASME Code Class 1 small bore socket and butt welds is not necessary. In lieu of this justification provide an aging management program that includes periodic volumetric inspections to manage cracking in small-bore piping and the associated weld metal (socket weld metal and butt weld metal).

Response for RAI 3.0.3.1.10-1 Part 3

The operating experience at IPEC indicates no Class 1 small bore socket weld or butt weld failures due to stress corrosion, cyclical loading (thermal, mechanical, and vibration fatigue), or thermal stratification and thermal turbulence. A review of operating experience at IP3 identified no leaks from small bore Class 1 piping socket welds. In approximately 38 years of operation, IP2 has experienced five leaks from small bore Class 1 socket welds, but cracking has never been identified as the cause. Rounded or pin hole defects caused three leaks, including the May 2010 leak, and mechanical damage caused a fourth. No cause was determined for the fifth leak which occurred in 1980, over 30 years ago. Nevertheless, IPEC performs periodic volumetric inspections of ASME Code Class 1 small bore socket welds. Ongoing inspections under the IPEC Inservice Inspection Program include periodic volumetric inspections of small bore piping welds on both units as determined by risk-informed selection criteria in the program. IPEC will volumetrically inspect the weld metal of at least ten socket welds in 2012 and at least ten socket welds during each 10-year period of the period of extended operation.

4. Whether a one-time inspection program or periodic inspection program is selected, clarify the implementation schedule of the inspections for ASME Code Class 1 small-bore piping including the associated welds (socket welds and butt welds).

Response for RAI 3.0.3.1.10-1 Part 4

For IP2, the schedule for ASME Class 1 small-bore piping inspections is contained in the IP2 ISI Program. In 2006, two butt welds were inspected. In 2010, three butt welds were inspected. Ten small-bore piping socket welds will be inspected in 2012 and one butt weld will be inspected prior to the period of extended operation. These future inspections will include the weld metal. In addition to the ten socket weld inspections in 2012, IPEC will perform volumetric weld metal inspections of ten socket welds during each 10-year period of the period of extended operation.

For IP3, One-Time Inspections have been completed. The associated inspections were completed from 2003 through 2007. In 2003, three welds were inspected; two socket welds and one butt weld. In 2005, 18 welds were inspected; 16 socket welds and two butt welds. In 2007, four welds were inspected; three socket welds and one butt weld. Thus, the total numbers of welds inspected was 21 socket welds and four butt welds. Eighteen of the socket weld inspections were volumetric inspections of the weld metal, two of which underwent subsequent destructive examinations. Because more information can be obtained from a destructive examination than from a nondestructive examination, each weld destructively examined is considered equivalent to two welds volumetrically examined. Counting the destructive examinations as two each, the number of volumetric socket weld inspections is 20 welds, which represents 6% of the population of 333 Class 1 small-bore piping socket welds at IP3. The four butt weld inspections, which inspected the weld metal, constitute 4.1% of the population of 96 butt welds.

RAI 3.0.3.1.10-2

Background

SRP-LR Section A.1.2.3.4 states that when sampling is used a basis should be provided for the inspection population and sample size.
The "monitoring and trending" program element of GALL AMP XI.M35 recommends that the volumetric inspection should be performed at a sufficient number of locations to assure an adequate sample. Furthermore, this number, or sample size, will be based on susceptibility, inspectability, dose considerations,

operating experience, and limiting locations of the total population of ASME Code Class 1 small bore piping locations.
Issue

The staff noted that the applicant did not provide its basis for the sample size that it selected. Specifically, the weld populations and the sample size were not provided to the staff, therefore it is not clear to the staff what percentage of ASME Code Class 1 welds, both full penetration welds and socket welds, will be inspected. It is also not clear to the staff if a sufficient number of locations will be selected to ensure an adequate sample.

Request

Provide the total populations of ASME Code Class 1 small bore butt welds and socket welds at Indian Point for each unit. Justify that the number of samples, for both butt welds and socket welds, is sufficient to ensure that an adequate sample is selected for inspections to be performed.

Response for RAI 3.0.3.1.10-2

There are 433 small bore socket welds and 195 small bore butt welds at IP2. There are 333 small bore socket welds and 96 small bore butt welds at IP3.

Of the 195 small bore butt welds on IP2, 5 butt welds have been inspected. All five weld inspections included the weld metal. In addition one butt weld (including the weld metal) will be inspected in 2012, thereby yielding a total sample size of 3%. Of the 333 small bore socket welds on IP3, 21 welds have been inspected. Of those 21 weld inspections, 18 inspections included the weld metal, two of which underwent subsequent destructive examinations. Counting the destructive examinations as two each, the total volumetric socket weld inspections is 20 welds, which represents 6% of the population of 333 Class 1 small-bore piping socket welds at IP3. Of the 96 small bore butt welds, four welds, or 4.1% of butt welds, have been inspected. All four weld inspections included the weld metal. Since IPEC has had no failures of small bore piping welds due to cracking resulting from stress corrosion, cyclical loading (thermal, mechanical, and vibration fatigue), or thermal stratification and thermal turbulence, the numbers of inspections constitute an adequate sample of the small bore weld populations.

Of the 433 small bore socket welds on IP2, 10 welds will be inspected (including the weld metal) in 2012 and 10 welds will be inspected during each 10-year period of the period of extended operation.

Commitment #46
Include in the IP2 ISI Program volumetric weld metal inspections of ten socket welds in 2012 and of at least ten socket welds during each 10-year period of the period of extended operation.

RAI 3.0.3.2.10-1

Background

NRC staff has determined that masonry walls that are within the scope of license renewal should be visually examined at least every five years, with provisions for more frequent inspections in areas where significant loss of material or cracking is observed.
Issue

The LRA did not discuss the inspection interval for in scope masonry walls.

Request

Provide the inspection interval for in-scope masonry walls. If the interval exceeds five years, clearly explain why and how the interval will ensure that there is no loss of intended function between inspections.

Response for RAI 3.0.3.2.10-1

The inspection interval for masonry walls within the scope of license renewal is every five years.

RAI 3.0.3.2.15-1

Background

NRC staff has determined that adequate acceptance criteria for the Structures Monitoring Program should include quantitative limits for characterizing degradation. Chapter 5 of ACI 349.3R provides acceptable criteria for concrete structures. If the acceptance criteria in ACI 349.3R are not used, the plant-specific criteria should be described and a technical basis for deviation from ACI 349.3R should be provided.

Issue

The LRA did not clearly identify quantitative acceptance criteria for the Structures Monitoring Program inspections.

Request

1. Provide the quantitative acceptance criteria for the Structures Monitoring Program. If the criteria deviate from those discussed in ACI 349.3R, provide technical justification for the differences.

Response for RAI 3.0.3.2.15-1 Part 1

For concrete structures, the Structures Monitoring Program (SMP) has a responsible engineer with the appropriate education and experience to identify and evaluate existing conditions using the appropriate industry standards for concrete structures, including ACI standards. Prior to the period of extended operation (PEO), Entergy will enhance the SMP to include more detailed quantitative acceptance criteria of ACI 349.3R, "Evaluation of Existing Nuclear Safety-Related Concrete Structures" for concrete structures.

<u>Commitment</u>
Entergy is revising the following commitment (Commitment 25) for the Structures Monitoring Program for implementation prior to the PEO.

Enhance the Structures Monitoring Program to include more detailed quantitative acceptance criteria for inspections of concrete structures in accordance with ACI 349.3R, "Evaluation of Existing Nuclear Safety-Related Concrete Structures".

2. If quantitative acceptance criteria will be added to the program as an enhancement, state whether Entergy plans to conduct an inspection with the quantitative acceptance criteria prior to the period of extended operation. If there are no plans to conduct an inspection with quantitative acceptance criteria prior to entering the period of extended operation, explain how Entergy plans to monitor and trend data.

Response for RAI 3.0.3.2.15-1 Part 2

Program procedures specify that the inspection engineer be a degreed engineer or registered professional engineer, knowledgeable or trained in the design, evaluation, and performance requirements of structures, with at least 5 years structural design/analysis/field evaluation experience. Using applicable industry codes and standards, the responsible engineer has adequate training and education to determine the acceptability of identified conditions using appropriate references, which may include ACI 349.3R.

While all the detailed quantitative acceptance criteria of ACI 349.3R are not in the existing SMP procedures, the knowledge and experience of the qualified inspection engineers performing regularly scheduled inspections provides reasonable assurance of continued functionality of the concrete structures at IPEC. The enhanced inspection criteria from ACI 349.9-3R will be adopted prior to the PEO and will be applied during regularly scheduled inspections.

The enhancement described in part 1 (above) to include more detailed acceptance criteria of ACI 349.3R does not affect ongoing monitoring and trending of data collected during the inspections. Although the acceptance criteria of ACI 349.3R are not explicitly identified in inspection procedures, qualified inspection personnel have a working knowledge of those criteria. Based on their knowledge and experience, inspectors identify and record degradation outside the acceptance criteria of ACI 349.3R discovered during the inspections so that future monitoring can determine a trend. The documentation includes critical measurements, i.e., crack width, length, depth, or area and depth of spall, so that future inspectors can determine the degree of change, if any. Prior to performing inspections, inspection engineers perform a thorough review of previous inspection reports to identify existing deficiencies. Photos, checklists, notes, etc. are used to determine if further deterioration has occurred. This process for monitoring and trending inspection data will continue during the period of extended operations.

RAI 3.1.2.2.13-1

Background

SRP-LR Section 3.1.2.2.13 identifies that cracking due to primary water stress corrosion cracking (PWSCC) could occur in PWR components made of nickel alloy and steel with nickel alloy cladding, including reactor coolant pressure boundary components and penetrations inside the RCS such as pressurizer heater sheathes and sleeves, nozzles, and other internal components. GALL Report Volume 2 Item IV.D1-06 recommends Chapter XI.M2, "Water Chemistry," for PWR primary water to manage the aging effect of cracking in the nickel alloy steam generator (SG) divider plate exposed to reactor coolant.

LRA Table 3.1.1, item 3.1.1-81, credits the Water Chemistry Control – Primary and Secondary Program to manage cracking due to primary stress corrosion cracking in nickel-alloy steam generator primary channel head divider plate exposed to reactor coolant in the steam generators, and LRA Table 3.1.1, Item 82, indicates that the SG primary side divider plates are composed of nickel alloy.

Unit 2 FSAR Section 4.2.2.3 and Table 4.2-1 describe the construction materials for the replacement Model 44F steam generators. The staff noted that there is no information about the construction materials of the divider plate assembly for the Unit 2 steam generators.

Unit 3 FSAR Section 4.2.2 and Table 4.2-1 describe the construction materials for the replacement Model 44F steam generators. The staff noted that there is no information about the construction materials of the divider plate assembly for the Unit 3 steam generators.

Issue

In some foreign steam generators with a similar design to that of Indian Point Units 2 and 3 steam generators, extensive cracking due to PWSCC has been identified in SG divider plate assemblies made with Alloy 600, even with proper primary water chemistry. Specifically, cracks have been detected in the stub runner, very close to the tubesheet/stub runner weld and with depths of almost a third of the divider plate thickness. Therefore, the staff noted that the Water Chemistry Control – Primary and Secondary Program may not be effective in managing the aging effect of cracking due to PWSCC in SG divider plate assemblies.

Although these SG divider plate assembly cracks may not have a significant safety impact in and of themselves, such cracks could affect adjacent items that are part of the reactor coolant pressure boundary, such as the tubesheet and the channel head, if they propagate to the boundary with these items. For the tubesheet, PWSCC cracks in the divider plate could propagate to the tubesheet cladding with possible consequences to the integrity of the tube-to-tubesheet welds. For the channel head, the PWSCC cracks in the divider plate could propagate to the SG triple point and potentially affect the pressure boundary of the SG channel head.

Request

1. Discuss the materials of construction of the Units 2 and 3 SG divider plate assemblies, including the welds within these assemblies and to the channel head and to the tubesheet.

Response for RAI 3.1.2.2.13-1 Part 1

At IP2 and IP3 the divider plates are Inconel 600 (ASME-SB-168). It is conservatively assumed that the weld materials are the associated Alloy 600 weld materials.

2. If any constitutive/weld material of the SG divider plate assemblies is susceptible to cracking (e.g., Alloy 600 or the associated Alloy 600 weld materials), explain how Entergy plans to manage PWSCC of the SG divider plate assemblies to prevent the propagation of cracks into other items that are part of the RCPB, whereby it challenges the integrity of the adjacent items.

Response for RAI 3.1.2.2.13-1 Part 2

At IP2 the original Westinghouse Model 44 steam generators were replaced with Model 44F steam generators in 2000. At IP3 the original Westinghouse Model 44 steam generators were replaced with Model 44F steam generators in 1989.

The Electric Power Research Institute (EPRI) has extensively evaluated the foreign operating experience with divider plate cracking in their reports dated June 2007, November 2008, and December 2009, and concluded that a cracked divider plate in a Westinghouse Model F SG is not a safety concern, and does not affect the design of the adjacent pressure boundary components.

The industry plans are to study the potential for divider plate crack growth and develop a resolution to the concern through the EPRI Steam Generator Management Program (SGMP) Engineering and Regulatory Technical Advisory Group. This industry-lead effort is expected to begin in 2011 and be completed within two years.

Recognizing that the EPRI SGMP resolution of this issue is under development, Entergy will inspect all IPEC steam generators to assess the condition of the divider plate assembly. The examination technique used will be capable of detecting PWSCC in the steam generator divider plate assembly welds. The steam generator divider plate inspections will be completed within the first ten years of the PEO. (Commitment 41)

RAI 3.1.2.2.16-1

Background

SRP-LR Section 3.1.2.2.16 identifies that cracking due to primary water stress corrosion cracking (PWSCC) could occur on the primary coolant side of PWR steel steam generator (SG) tube-to-tube sheet welds made or clad with nickel alloy. The GALL Report recommends ASME Section XI ISI and control of water chemistry to manage this aging effect and recommends no further aging management review for PWSCC of nickel alloy if the applicant complies with applicable NRC Orders and provides a commitment in the FSAR supplement to implement applicable (1) Bulletins and Generic Letters and (2) staff-accepted industry guidelines. In GALL Report Revision 1, Volume 2, this aging effect is addressed in item IV.D2-4, applicable only to once-through SGs, but not to recirculating SGs.

The staff noted that ASME Code Section XI does not require any inspection of the tube-to-tubesheet welds. In addition, there are no NRC Orders or bulletins requiring examination of this weld. However, the staff's concern is that, if the tubesheet cladding is Alloy 600 or the associated Alloy 600 weld materials, the tube-to-tubesheet weld region may have insufficient Chromium content to prevent initiation of PWSCC. Similarly, this concern applies to SG tubes made from Alloy 690TT. Consequently, such a PWSCC crack initiated in this region, close to a tube, could propagate into/through the weld, causing a failure of the weld and of the reactor coolant pressure boundary, for both recirculating and once-through steam generators.

In LRA Table 3.1.1, item 3.1.1-35, the applicant stated that the corresponding GALL Report line applies to once-through steam generators and was used as a comparison for the steam generator tubesheets. The applicant further stated that for the steel with nickel alloy clad steam generator tubesheets, cracking is managed by the Water Chemistry Control – Primary and Secondary and Steam Generator Integrity Programs. In LRA Section 2.3.1.4, the applicant described that the Unit 2 replacement Westinghouse Model 44 steam generator tubes are fabricated from Alloy 600TT and the Unit 3 replacement Westinghouse Model 44 steam generator tubes are fabricated from Alloy 690TT. The applicant also described that the tubesheet surfaces in contact with reactor coolant are clad with Inconel, and the tube-to-tube sheet joints are welded.

Issue
Unless the NRC has approved a redefinition of the pressure boundary in which the autogenous tube-to-tubesheet weld is no longer included, or the tubesheet cladding and welds are not susceptible to PWSCC, the staff considers that the effectiveness of the primary water chemistry program should be verified to ensure PWSCC cracking is not occurring. Moreover, it is not clear to the staff how the Steam Generator Integrity Program is able to manage PWSCC of the tubesheet cladding, including the tube-to-tubesheet welds.

Request

1a. For Unit 2 SGs, clarify whether the tube-to-tubesheet welds are included in the reactor coolant pressure boundary or alternate repair criteria have been permanently approved.

Response for RAI 3.1.2.2.16-1 Part 1a

At IP2 the tube to tubesheet welds are included in the RCS pressure boundary. IP2 does not employ any tubesheet region alternate repair criterion.

1b. If the SGs do not have permanently approved alternate repair criteria, justify how your Steam Generator Integrity Program is capable to manage PWSCC in tube-to-tubesheet welds, or provide a plant-specific AMP that will complement the primary water chemistry program, in order to verify the effectiveness of the primary water chemistry program and ensure that cracking due to PWSCC is not occurring in tube-to-tubesheet welds.

Response for RAI 3.1.2.2.16-1 Part 1b

IP2 will address the potential failure of the steam generator reactor coolant pressure boundary due to PWSCC cracking of tube-to-tubesheet welds via one of two options, an analysis or an inspection. (Commitment 42)

Analysis Option:

IP2 will perform an analytical evaluation of the steam generator tube-to-tubesheet welds in order to establish a technical basis for either determining that the tubesheet cladding and welds are not susceptible to PWSCC, or redefining the pressure boundary to exclude the tube-to-tubesheet weld, and therefore the weld will not be required for the reactor coolant pressure boundary function. The redefinition of the reactor coolant pressure boundary will be submitted as part of a license amendment request requiring approval from the NRC. An approved analytical evaluation would obviate the need to develop a plant-specific AMP to verify effectiveness of the Water Chemistry Control – Primary and Secondary program.

Inspection Option:

Perform a one time inspection of a representative number of tube-to-tubesheet welds in each steam generator to determine if PWSCC cracking is present. If weld cracking is identified:

a. The condition will be resolved through repair or engineering evaluation to justify continued service, as appropriate, and

b. An ongoing monitoring program will be established to perform routine tube-to-tubesheet weld inspections for the remaining life of the steam generators.

IP2 replaced its steam generators in 2000. The tube-to-tubesheet welds have been in service approximately eleven years. Considering this limited service time, if Option 1 is not implemented, IP2 will implement Option 2 that includes tube-to-tubesheet weld inspections for PWSCC. These inspections will be performed between March 2020 and March 2024 such that the steam generators will have been in service between 20 and 24 years.

In 2R17 (2006), 166 tubes were inspected to the tube end with a rotating pancake coil (RPC) probe. No degradation was detected.

2. For Unit 3 SGs tube-to-tubesheet welds, justify how your Steam Generator Integrity Program is capable to manage PWSCC in tube-to-tubesheet welds, or provide either a plant-specific AMP that will complement the primary water chemistry program, in order to verify the effectiveness of the primary water chemistry program and ensure that cracking due to PWSCC is not occurring in tube-to-tubesheet welds, or a rationale for why such a program is not needed.

Response for RAI 3.1.2.2.16-1 Part 2

IP3 will address the potential failure of the steam generator reactor coolant pressure boundary due to PWSCC cracking of tube-to-tubesheet welds via one of two options, an analysis or an inspection. (Commitment 42)

Analysis Option:

IP3 will perform an analytical evaluation of the steam generator tube-to-tubesheet welds in order to establish a technical basis for either determining that the tubesheet cladding and welds are not susceptible to PWSCC, or redefining the pressure boundary to exclude the tube-to-tubesheet weld, and therefore the weld will not be required for the reactor coolant pressure boundary function. The redefinition of the reactor coolant pressure boundary will be submitted as part of a license amendment request requiring approval from the NRC. An approved analytical evaluation would obviate the need to develop a plant-specific AMP to verify effectiveness of the Water Chemistry Control – Primary and Secondary program.

Inspection Option:

Perform a one time inspection of a representative number of tube-to-tubesheet welds in each steam generator to determine if PWSCC cracking is present. This one-time inspection would verify the effectiveness of the water chemistry AMP. If weld cracking is identified:

> **a. The condition will be resolved through repair or engineering evaluation to justify continued service, as appropriate, and**
>
> **b. An ongoing monitoring program will be established to perform routine tube-to-tubesheet weld inspections for the remaining life of the steam generators.**

IP3 replaced its steam generators in 1989. The tube-to-tubesheet welds have been in service approximately twenty two years. If Option 1 is not implemented, IP3 will implement Option 2 that includes tube-to-tubesheet weld inspections for PWSCC. For IP3 these inspections will be performed within the first 2 refueling outages following the period of extended operation.

RAI RCS-3

Background

In LRA Section 4.3.3 and Commitment 33 (as amended by the letter dated January 22, 2008) the applicant discussed the methodology used to determine the locations that required environmentally-assisted fatigue analyses consistent with NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components." The staff recognized that, in LRA Tables 4.3-13 and 4.3-14, there are eight plant-specific locations listed based on the six generic components identified in NUREG/CR-6260. The applicant also discussed in LRA Tables 4.3-13 and 4.3-14 that the surge line nozzle in the RCS piping is bounded by the surge line piping to safe end weld at the pressurizer nozzle. LRA Section 4.3.3 and Commitment 33 were amended as follow:

At least 2 years prior to entering the period of extended operation, for the locations identified in LRA Table 4.3-13 (IP2) and LRA Table 4.3-14 (IP3), under the Fatigue Monitoring Program, IP2 and IP3, IPEC will implement one or more of the following:

(1) Consistent with the Fatigue Monitoring Program, Detection of Aging Effects, update the fatigue usage calculations using refined fatigue analyses to determine valid CUFs less than 1.0 when accounting for the effects of reactor water environment. This includes applying the appropriate Fen factors to valid CUFs determined in accordance with one of the following.

For locations in LRA Table 4.3-13 (IP2) and LRA Table 4.3-14 (IP3) with existing fatigue analysis valid for the period of extended operation, use the existing CUF.
More plant-specific limiting locations with a valid CUF may be evaluated. In particular, the pressurizer lower shell will be reviewed to ensure the surge nozzle remains the limiting component.

Representative CUF values from other plants, adjusted to or enveloping the IPEC plant-specific external loads may be used if demonstrated applicable to IPEC.

An analysis using an NRC-approved version of the ASME code or NRC-approved alternative (e.g., NRC-approved code case) may be performed to determine a valid CUF.

Issue

GALL AMP X.M1 states the impact of the reactor coolant environment on a sample of critical components should include the locations identified in NUREG/CR-6260, as a minimum, and that additional locations may be needed. The staff identified two concerns regarding the applicant's environmentally-assisted fatigue analyses. First, item (1) of above LRA section and Commitment 33 indicated that more limiting plant-specific locations may be evaluated. However, it is only one of the *options* that may be taken. Furthermore, the limiting locations *may* be added and the staff is concerned whether the applicant is committed to verify that the plant-specific locations per NUREG/CR-6260 are bounding for the generic NUREG/CR-6260 components. Second, the staff noted that the applicant's plant-specific configuration may contain locations that should be analyzed for the effects of reactor coolant environment, that are more limiting than those identified in NUREG/CR-6260. This may include locations that are limiting or bounding for a particular plant-specific configuration or that have calculated CUF values that are greater when compared to the locations identified in NUREG/CR-6260.

Request

1. Confirm and justify that the plant-specific locations listed in LRA Tables 4.3-13 and 4.3-14 are bounding for the generic NUREG/CR-6260 components.

Response for RAI RCS-3 Part 1

A review of the locations provided in LRA Tables 4.3-13 and 4.3-14 confirmed that they are equivalent to the locations provided in NUREG/CR-6260.

2. Confirm and justify that the locations selected for environmentally-assisted fatigue analyses in LRA Tables 4.3-13 and 4.3-14 consist of the most limiting locations *for the plant* (beyond the generic components identified in the NUREG/CR-6260 guidance). If these locations are not bounding, clarify which locations require an environmentally-assisted fatigue analysis and the actions that will be taken for these additional locations. If the limiting locations identified consist of nickel alloy, state whether the methodology used to perform environmentally-assisted fatigue calculation for nickel alloy is consistent with NUREG/CR-6909. If not, justify the method chosen.

Response for RAI RCS-3 Part 2

Entergy will review design basis ASME Code Class 1 fatigue evaluations to determine whether the NUREG/CR-6260 locations that have been evaluated for the effects of the reactor coolant environment on fatigue usage are the limiting locations for the Indian Point plant configurations. If more limiting locations are identified, the most limiting location will be evaluated for the effects of the reactor coolant environment on fatigue usage.

IPEC will use the NUREG/CR-6909 methodology in the evaluation of the limiting locations consisting of nickel alloy, if any. This evaluation will be completed prior to entering the period of extended operation.

<u>Commitment</u>

Entergy is providing the following new commitment (Commitment 43) for the Metal Fatigue NUREG/CR-6260;

Entergy will review design basis ASME Code Class 1 fatigue evaluations to determine whether the NUREG/CR-6260 locations that have been evaluated for the effects of the reactor coolant environment on fatigue usage are the limiting locations for the Indian Point 2 and 3 plant configurations. If more limiting locations are identified, the most limiting location will be evaluated for the effects of the reactor coolant environment on fatigue usage.

IPEC will use the NUREG/CR-6909 methodology in the evaluation of the limiting locations consisting of nickel alloy, if any. This evaluation will be completed prior to the period of extended operation.

NRC WESTEMS Questions

Question #1

For any use of the WESTEMS "Design CUF" module in the future at IPEC, include written explanation and justification of any user intervention in the process.

Response for Question #1

IPEC will include written explanation and justification of user intervention in any future use of the WESTEMS "Design CUF" module. (Commitment 44)

Question #2

Provide a commitment that the NB-3600 option of the WESTEMS "Design CUF" module will not be implemented or used in the future at IPEC.

Response for Question #2

IPEC will not use the ASME Section III, NB-3600 option of the WESTEMS "Design CUF" module until the issues identified during the NRC review of the program has been resolved. (Commitment 45)

ATTACHMENT 2 TO NL-11-032

LICENSE RENEWAL APPLICATION
IPEC LIST OF REGULATORY COMITMENTS

Rev. 13

ENTERGY NUCLEAR OPERATIONS, INC.
INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 & 3
DOCKET NOS. 50-247 AND 50-286

List of Regulatory Commitments

Rev. 13

The following table identifies those actions committed to by Entergy in this document.

Changes are shown as strikethroughs for ~~deletions~~ and underlines for additions.

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
1	Enhance the Aboveground Steel Tanks Program for IP2 and IP3 to perform thickness measurements of the bottom surfaces of the condensate storage tanks, city water tank, and fire water tanks once during the first ten years of the period of extended operation. Enhance the Aboveground Steel Tanks Program for IP2 and IP3 to require trending of thickness measurements when material loss is detected.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.1 A.3.1.1 B.1.1
2	Enhance the Bolting Integrity Program for IP2 and IP3 to clarify that actual yield strength is used in selecting materials for low susceptibility to SCC and clarify the prohibition on use of lubricants containing MoS_2 for bolting. The Bolting Integrity Program manages loss of preload and loss of material for all external bolting.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.2 A.3.1.2 B.1.2 Audit Items 201, 241, 270

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
3	Implement the Buried Piping and Tanks Inspection Program for IP2 and IP3 as described in LRA Section B.1.6. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.M34, Buried Piping and Tanks Inspection. 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.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153 NL-09-106 NL-09-111	A.2.1.5 A.3.1.5 B.1.6 Audit Item 173

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
4	Enhance the Diesel Fuel Monitoring Program to include cleaning and inspection of the IP2 GT-1 gas turbine fuel oil storage tanks, IP2 and IP3 EDG fuel oil day tanks, IP2 SBO/Appendix R diesel generator fuel oil day tank, and IP3 Appendix R fuel oil storage tank and day tank once every ten years. Enhance the Diesel Fuel Monitoring Program to include quarterly sampling and analysis of the IP2 SBO/Appendix R diesel generator fuel oil day tank, IP2 security diesel fuel oil storage tank, IP2 security diesel fuel oil day tank, and IP3 Appendix R fuel oil storage tank. Particulates, water and sediment checks will be performed on the samples. Filterable solids acceptance criterion will be less than or equal to 10mg/l. Water and sediment acceptance criterion will be less than or equal to 0.05%. Enhance the Diesel Fuel Monitoring Program to include thickness measurement of the bottom of the following tanks once every ten years. IP2: EDG fuel oil storage tanks, EDG fuel oil day tanks, SBO/Appendix R diesel generator fuel oil day tank, GT-1 gas turbine fuel oil storage tanks, and diesel fire pump fuel oil storage tank; IP3: EDG fuel oil day tanks, EDG fuel oil storage tanks, Appendix R fuel oil storage tank, and diesel fire pump fuel oil storage tank. Enhance the Diesel Fuel Monitoring Program to change the analysis for water and particulates to a quarterly frequency for the following tanks. IP2: GT-1 gas turbine fuel oil storage tanks and diesel fire pump fuel oil storage tank; IP3: Appendix R fuel oil day tank and diesel fire pump fuel oil storage tank. Enhance the Diesel Fuel Monitoring Program to specify acceptance criteria for thickness measurements of the fuel oil storage tanks within the scope of the program. Enhance the Diesel Fuel Monitoring Program to direct samples be taken and include direction to remove water when detected. Revise applicable procedures to direct sampling of the onsite portable fuel oil contents prior to transferring the contents to the storage tanks. Enhance the Diesel Fuel Monitoring Program to direct the addition of chemicals including biocide when the presence of biological activity is confirmed.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153 NL-08-057	A.2.1.8 A.3.1.8 B.1.9 Audit items 128, 129, 132, 491, 492, 510

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
5	Enhance the External Surfaces Monitoring Program for IP2 and IP3 to include periodic inspections of systems in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(1) and (a)(3). Inspections shall include areas surrounding the subject systems to identify hazards to those systems. Inspections of nearby systems that could impact the subject systems will include SSCs that are in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(2).	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.10 A.3.1.10 B.1.11
6	Enhance the Fatigue Monitoring Program for IP2 to monitor steady state cycles and feedwater cycles or perform an evaluation to determine monitoring is not required. Review the number of allowed events and resolve discrepancies between reference documents and monitoring procedures. Enhance the Fatigue Monitoring Program for IP3 to include all the transients identified. Assure all fatigue analysis transients are included with the lowest limiting numbers. Update the number of design transients accumulated to date.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.11 A.3.1.11 B.1.12, Audit Item 164
7	Enhance the Fire Protection Program to inspect external surfaces of the IP3 RCP oil collection systems for loss of material each refueling cycle. Enhance the Fire Protection Program to explicitly state that the IP2 and IP3 diesel fire pump engine sub-systems (including the fuel supply line) shall be observed while the pump is running. Acceptance criteria will be revised to verify that the diesel engine does not exhibit signs of degradation while running; such as fuel oil, lube oil, coolant, or exhaust gas leakage. Enhance the Fire Protection Program to specify that the IP2 and IP3 diesel fire pump engine carbon steel exhaust components are inspected for evidence of corrosion and cracking at least once each operating cycle. Enhance the Fire Protection Program for IP3 to visually inspect the cable spreading room, 480V switchgear room, and EDG room CO_2 fire suppression system for signs of degradation, such as corrosion and mechanical damage at least once every six months.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.12 A.3.1.12 B.1.13

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
8	Enhance the Fire Water Program to include inspection of IP2 and IP3 hose reels for evidence of corrosion. Acceptance criteria will be revised to verify no unacceptable signs of degradation. Enhance the Fire Water Program to replace all or test a sample of IP2 and IP3 sprinkler heads required for 10 CFR 50.48 using guidance of NFPA 25 (2002 edition), Section 5.3.1.1.1 before the end of the 50-year sprinkler head service life and at 10-year intervals thereafter during the extended period of operation to ensure that signs of degradation, such as corrosion, are detected in a timely manner. Enhance the Fire Water Program to perform wall thickness evaluations of IP2 and IP3 fire protection piping on system components using non-intrusive techniques (e.g., volumetric testing) to identify evidence of loss of material due to corrosion. These inspections will be performed before the end of the current operating term and at intervals thereafter during the period of extended operation. Results of the initial evaluations will be used to determine the appropriate inspection interval to ensure aging effects are identified prior to loss of intended function. Enhance the Fire Water Program to inspect the internal surface of foam based fire suppression tanks. Acceptance criteria will be enhanced to verify no significant corrosion.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153 NL-08-014	A.2.1.13 A.3.1.13 B.1.14 Audit Items 105, 106

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
9	Enhance the Flux Thimble Tube Inspection Program for IP2 and IP3 to implement comparisons to wear rates identified in WCAP-12866. Include provisions to compare data to the previous performances and perform evaluations regarding change to test frequency and scope. Enhance the Flux Thimble Tube Inspection Program for IP2 and IP3 to specify the acceptance criteria as outlined in WCAP-12866 or other plant-specific values based on evaluation of previous test results. Enhance the Flux Thimble Tube Inspection Program for IP2 and IP3 to direct evaluation and performance of corrective actions based on tubes that exceed or are projected to exceed the acceptance criteria. Also stipulate that flux thimble tubes that cannot be inspected over the tube length and cannot be shown by analysis to be satisfactory for continued service, must be removed from service to ensure the integrity of the reactor coolant system pressure boundary.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.15 A.3.1.15 B.1.16

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
10	Enhance the Heat Exchanger Monitoring Program for IP2 and IP3 to include the following heat exchangers in the scope of the program. • Safety injection pump lube oil heat exchangers • RHR heat exchangers • RHR pump seal coolers • Non-regenerative heat exchangers • Charging pump seal water heat exchangers • Charging pump fluid drive coolers • Charging pump crankcase oil coolers • Spent fuel pit heat exchangers • Secondary system steam generator sample coolers • Waste gas compressor heat exchangers • SBO/Appendix R diesel jacket water heat exchanger (IP2 only) Enhance the Heat Exchanger Monitoring Program for IP2 and IP3 to perform visual inspection on heat exchangers where non-destructive examination, such as eddy current inspection, is not possible due to heat exchanger design limitations. Enhance the Heat Exchanger Monitoring Program for IP2 and IP3 to include consideration of material-environment combinations when determining sample population of heat exchangers. Enhance the Heat Exchanger Monitoring Program for IP2 and IP3 to establish minimum tube wall thickness for the new heat exchangers identified in the scope of the program. Establish acceptance criteria for heat exchangers visually inspected to include no indication of tube erosion, vibration wear, corrosion, pitting, fouling, or scaling.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153 NL-09-018	A.2.1.16 A.3.1.16 B.1.17, Audit Item 52
11	Delete commitment.		NL-09-056	

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
12	Enhance the Masonry Wall Program for IP2 and IP3 to specify that the IP1 intake structure is included in the program.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.18 A.3.1.18 B.1.19
13	Enhance the Metal-Enclosed Bus Inspection Program to add IP2 480V bus associated with substation A to the scope of bus inspected. Enhance the Metal-Enclosed Bus Inspection Program for IP2 and IP3 to visually inspect the external surface of MEB enclosure assemblies for loss of material at least once every 10 years. The first inspection will occur prior to the period of extended operation and the acceptance criterion will be no significant loss of material. Enhance the Metal-Enclosed Bus Inspection Program to add acceptance criteria for MEB internal visual inspections to include the absence of indications of dust accumulation on the bus bar, on the insulators, and in the duct, in addition to the absence of indications of moisture intrusion into the duct. Enhance the Metal-Enclosed Bus Inspection Program for IP2 and IP3 to inspect bolted connections at least once every five years if performed visually or at least once every ten years using quantitative measurements such as thermography or contact resistance measurements. The first inspection will occur prior to the period of extended operation. The plant will process a change to applicable site procedure to remove the reference to "re-torquing" connections for phase bus maintenance and bolted connection maintenance.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153 NL-08-057	A.2.1.19 A.3.1.19 B.1.20 Audit Items 124, 133, 519
14	Implement the Non-EQ Bolted Cable Connections Program for IP2 and IP3 as described in LRA Section B.1.22.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.21 A.3.1.21 B.1.22

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
15	Implement the Non-EQ Inaccessible Medium-Voltage Cable Program for IP2 and IP3 as described in LRA Section B.1.23. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.E3, Inaccessible Medium-Voltage Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.22 A.3.1.22 B.1.23 Audit item 173
16	Implement the Non-EQ Instrumentation Circuits Test Review Program for IP2 and IP3 as described in LRA Section B.1.24. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.E2, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.23 A.3.1.23 B.1.24 Audit item 173
17	Implement the Non-EQ Insulated Cables and Connections Program for IP2 and IP3 as described in LRA Section B.1.25. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.E1, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.24 A.3.1.24 B.1.25 Audit item 173
18	Enhance the Oil Analysis Program for IP2 to sample and analyze lubricating oil used in the SBO/Appendix R diesel generator consistent with oil analysis for other site diesel generators. Enhance the Oil Analysis Program for IP2 and IP3 to sample and analyze generator seal oil and turbine hydraulic control oil. Enhance the Oil Analysis Program for IP2 and IP3 to formalize preliminary oil screening for water and particulates and laboratory analyses including defined acceptance criteria for all components included in the scope of this program. The program will specify corrective actions in the event acceptance criteria are not met. Enhance the Oil Analysis Program for IP2 and IP3 to formalize trending of preliminary oil screening results as well as data provided from independent laboratories.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.25 A.3.1.25 B.1.26

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
19	Implement the One-Time Inspection Program for IP2 and IP3 as described in LRA Section B.1.27. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M32, One-Time Inspection.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.26 A.3.1.26 B.1.27 Audit item 173
20	Implement the One-Time Inspection – Small Bore Piping Program for IP2 and IP3 as described in LRA Section B.1.28. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M35, One-Time Inspection of ASME Code Class I Small-Bore Piping.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.27 A.3.1.27 B.1.28 Audit item 173
21	Enhance the Periodic Surveillance and Preventive Maintenance Program for IP2 and IP3 as necessary to assure that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.28 A.3.1.28 B.1.29
22	Enhance the Reactor Vessel Surveillance Program for IP2 and IP3 revising the specimen capsule withdrawal schedules to draw and test a standby capsule to cover the peak reactor vessel fluence expected through the end of the period of extended operation. Enhance the Reactor Vessel Surveillance Program for IP2 and IP3 to require that tested and untested specimens from all capsules pulled from the reactor vessel are maintained in storage.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.31 A.3.1.31 B.1.32
23	Implement the Selective Leaching Program for IP2 and IP3 as described in LRA Section B.1.33. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M33 Selective Leaching of Materials.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.32 A.3.1.32 B.1.33 Audit item 173
24	Enhance the Steam Generator Integrity Program for IP2 and IP3 to require that the results of the condition monitoring assessment are compared to the operational assessment performed for the prior operating cycle with differences evaluated.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.34 A.3.1.34 B.1.35

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
25	Enhance the Structures Monitoring Program to explicitly specify that the following structures are included in the program. • Appendix R diesel generator foundation (IP3) • Appendix R diesel generator fuel oil tank vault (IP3) • Appendix R diesel generator switchgear and enclosure (IP3) • city water storage tank foundation • condensate storage tanks foundation (IP3) • containment access facility and annex (IP3) • discharge canal (IP2/3) • emergency lighting poles and foundations (IP2/3) • fire pumphouse (IP2) • fire protection pumphouse (IP3) • fire water storage tank foundations (IP2/3) • gas turbine 1 fuel storage tank foundation • maintenance and outage building-elevated passageway (IP2) • new station security building (IP2) • nuclear service building (IP1) • primary water storage tank foundation (IP3) • refueling water storage tank foundation (IP3) • security access and office building (IP3) • service water pipe chase (IP2/3) • service water valve pit (IP3) • superheater stack • transformer/switchyard support structures (IP2) • waste holdup tank pits (IP2/3) Enhance the Structures Monitoring Program for IP2 and IP3 to clarify that in addition to structural steel and concrete, the following commodities (including their anchorages) are inspected for each structure as applicable. • cable trays and supports • concrete portion of reactor vessel supports • conduits and supports • cranes, rails and girders • equipment pads and foundations • fire proofing (pyrocrete) • HVAC duct supports • jib cranes • manholes and duct banks • manways, hatches and hatch covers • monorails	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153 NL-08-057	A.2.1.35 A.3.1.35 B.1.36 Audit items 86, 87, 88, 417

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
	• new fuel storage racks • sumps, sump screens, strainers and flow barriers Enhance the Structures Monitoring Program for IP2 and IP3 to inspect inaccessible concrete areas that are exposed by excavation for any reason. IP2 and IP3 will also inspect inaccessible concrete areas in environments where observed conditions in accessible areas exposed to the same environment indicate that significant concrete degradation is occurring. Enhance the Structures Monitoring Program for IP2 and IP3 to perform inspections of elastomers (seals, gaskets, seismic joint filler, and roof elastomers) to identify cracking and change in material properties and for inspection of aluminum vents and louvers to identify loss of material. Enhance the Structures Monitoring Program for IP2 and IP3 to perform an engineering evaluation of groundwater samples to assess aggressiveness of groundwater to concrete on a periodic basis (at least once every five years). IPEC will obtain samples from at least 5 wells that are representative of the ground water surrounding below-grade site structures and perform an engineering evaluation of the results from those samples for sulfates, pH and chlorides. Additionally, to assess potential indications of spent fuel pool leakage, IPEC will sample for tritium in groundwater wells in close proximity to the IP2 spent fuel pool at least once every 3 months. Enhance the Structures Monitoring Program for IP2 and IP3 to perform inspection of normally submerged concrete portions of the intake structures at least once every 5 years. Inspect the baffling/grating partition and support platform of the IP3 intake structure at least once every 5 years. Enhance the Structures Monitoring Program for IP2 and IP3 to perform inspection of the degraded areas of the water control structure once per 3 years rather than the normal frequency of once per 5 years during the PEO.		NL-08-127	Audit Item 360 Audit Item 358

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
	Enhance the Structures Monitoring Program to include more detailed quantitative acceptance criteria for inspections of concrete structures in accordance with ACI 349.3R, "Evaluation of Existing Nuclear Safety-Related Concrete Structures" prior to the period of extended operation.		NL-11-032	
26	Implement the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program for IP2 and IP3 as described in LRA Section B.1.37. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M12, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.36 A.3.1.36 B.1.37 Audit item 173
27	Implement the Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program for IP2 and IP3 as described in LRA Section B.1.38. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.M13, Thermal Aging and Neutron Embrittlement of Cast Austenitic Stainless Steel (CASS) Program.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.37 A.3.1.37 B.1.38 Audit item 173
28	Enhance the Water Chemistry Control – Closed Cooling Water Program to maintain water chemistry of the IP2 SBO/Appendix R diesel generator cooling system per EPRI guidelines. Enhance the Water Chemistry Control – Closed Cooling Water Program to maintain the IP2 and IP3 security generator and fire protection diesel cooling water pH and glycol within limits specified by EPRI guidelines.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-08-057	A.2.1.39 A.3.1.39 B.1.40 Audit item 509
29	Enhance the Water Chemistry Control – Primary and Secondary Program for IP2 to test sulfates monthly in the RWST with a limit of <150 ppb.	IP2: September 28, 2013	NL-07-039	A.2.1.40 B.1.41
30	For aging management of the reactor vessel internals, IPEC will (1) participate in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the NRC for review and approval.	IP2: September 28, 2011 IP3: December 12, 2013	NL-07-039	A.2.1.41 A.3.1.41

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
31	Additional P-T curves will be submitted as required per 10 CFR 50, Appendix G prior to the period of extended operation as part of the Reactor Vessel Surveillance Program.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.2.1.2 A.3.2.1.2 4.2.3
32	As required by 10 CFR 50.61(b)(4), IP3 will submit a plant-specific safety analysis for plate B2803-3 to the NRC three years prior to reaching the RT_{PTS} screening criterion. Alternatively, the site may choose to implement the revised PTS rule when approved.	IP3: December 12, 2015	NL-07-039 NL-08-127	A.3.2.1.4 4.2.5
33	At least 2 years prior to entering the period of extended operation, for the locations identified in LRA Table 4.3-13 (IP2) and LRA Table 4.3-14 (IP3), under the Fatigue Monitoring Program, IP2 and IP3 will implement one or more of the following: (1) Consistent with the Fatigue Monitoring Program, Detection of Aging Effects, update the fatigue usage calculations using refined fatigue analyses to determine valid CUFs less than 1.0 when accounting for the effects of reactor water environment. This includes applying the appropriate Fen factors to valid CUFs determined in accordance with one of the following: 1. For locations in LRA Table 4.3-13 (IP2) and LRA Table 4.3-14 (IP3), with existing fatigue analysis valid for the period of extended operation, use the existing CUF. 2. Additional plant-specific locations with a valid CUF may be evaluated. In particular, the pressurizer lower shell will be reviewed to ensure the surge nozzle remains the limiting component. 3. Representative CUF values from other plants, adjusted to or enveloping the IPEC plant specific external loads may be used if demonstrated applicable to IPEC. 4. An analysis using an NRC-approved version of the ASME code or NRC-approved alternative (e.g., NRC-approved code case) may be performed to determine a valid CUF. (2) Consistent with the Fatigue Monitoring Program, Corrective Actions, repair or replace the affected locations before exceeding a CUF of 1.0.	IP2: September 28, 2011 IP3: December 12, 2013 Complete	NL-07-039 NL-07-153 NL-08-021 NL-10-082	A.2.2.2.3 A.3.2.2.3 4.3.3 Audit item 146

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
34	IP2 SBO / Appendix R diesel generator will be installed and operational by April 30, 2008. This committed change to the facility meets the requirements of 10 CFR 50.59l(1) and, therefore, a license amendment pursuant to 10 CFR 50.90 is not required.	April 30, 2008 Complete	NL-07-078 NL-08-074	2.1.1.3.5
35	Perform a one-time inspection of representative sample area of IP2 containment liner affected by the 1973 event behind the insulation, prior to entering the extended period of operation, to assure liner degradation is not occurring in this area. Perform a one-time inspection of representative sample area of the IP3 containment steel liner at the juncture with the concrete floor slab, prior to entering the extended period of operation, to assure liner degradation is not occurring in this area. Any degradation will be evaluated for updating of the containment liner analyses as needed.	IP2: September 28, 2013 IP3: December 12, 2015	NL-08-127 NL-09-018	Audit Item 27
36	Perform a one-time Inspection and evaluation of a sample of potentially affected IP2 refueling cavity concrete prior to the period of extended operation. The sample will be obtained by core boring the refueling cavity wall in an area that is susceptible to exposure to borated water leakage. The inspection will include an assessment of embedded reinforcing steel. Additional core bore samples will be taken, if the leakage is not stopped, prior to the end of the first ten years of the period of extended operation. A sample of leakage fluid will be analyzed to determine the composition of the fluid. If additional core samples are taken prior to the end of the first ten years of the period of extended operation, a sample of leakage fluid will be analyzed.	IP2: September 28, 2013	NL-08-127 NL-09-056 NL-09-079	Audit Item 359
37	Enhance the Containment Inservice Inspection (CII-IWL) Program to include inspections of the containment using enhanced characterization of degradation (i.e., quantifying the dimensions of noted indications through the use of optical aids) during the period of extended operation. The enhancement includes obtaining critical dimensional data of degradation where possible through direct measurement or the use of scaling technologies for photographs, and the use of consistent vantage points for visual inspections.	IP2: September 28, 2013 IP3: December 12, 2015	NL-08-127	Audit Item 361

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
38	For Reactor Vessel Fluence, should future core loading patterns invalidate the basis for the projected values of RTpts or C_VUSE, updated calculations will be provided to the NRC.	IP2: September 28, 2013 IP3: December 12, 2015	NL-08-143	4.2.1
39	Deleted		NL-09-079	
40	Evaluate plant specific and appropriate industry operating experience and incorporate lessons learned in establishing appropriate monitoring and inspection frequencies to assess aging effects for the new aging management programs. Documentation of the operating experience evaluated for each new program will be available on site for NRC review prior to the period of extended operation.	IP2: September 28, 2013 IP3: December 12, 2015	NL-09-106	B.1.6 B.1.22 B.1.23 B.1.24 B.1.25 B.1.27 B.1.28 B.1.33 B.1.37 B.1.38
41	IPEC will inspect steam generators for both units to assess the condition of the divider plate assembly. The examination technique used will be capable of detecting PWSCC in the steam generator divider plate assembly welds. The steam generator divider plate inspections will be completed within the first ten years of the period of extended operation (PEO).	IP2: Prior to September 28, 2023 IP3: Prior to December 12, 2025	NL-11-032	N/A

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
42	IPEC will develop a plan for each unit to address the potential for cracking of the primary to secondary pressure boundary due to PWSCC of tube-to-tubesheet welds using one of the following two options. Option 1 (Analysis) IPEC will perform an analytical evaluation of the steam generator tube-to-tubesheet welds in order to establish a technical basis for either determining that the tubesheet cladding and welds are not susceptible to PWSCC, or redefining the pressure boundary in which the tube-to-tubesheet weld is no longer included and, therefore, is not required for reactor coolant pressure boundary function. The redefinition of the reactor coolant pressure boundary will be submitted as part of a license amendment request requiring approval from the NRC. Option 2 (Inspection) IPEC will perform a one-time inspection of a representative number of tube-to-tubesheet welds in each steam generator to determine if PWSCC cracking is present. If weld cracking is identified: a. The condition will be resolved through repair or engineering evaluation to justify continued service, as appropriate, and b. An ongoing monitoring program will be established to perform routine tube-to-tubesheet weld inspections for the remaining life of the steam generators.	IP2: Prior to March 2024 IP3: Within the first 2 refueling outages following the beginning of the PEO.	NL-11-032	N/A
43	IPEC will review design basis ASME Code Class 1 fatigue evaluations to determine whether the NUREG/CR-6260 locations that have been evaluated for the effects of the reactor coolant environment on fatigue usage are the limiting locations for the IP2 and IP3 configurations. If more limiting locations are identified, the most limiting location will be evaluated for the effects of the reactor coolant environment on fatigue usage. IPEC will use the NUREG/CR-6909 methodology in the evaluation of the limiting locations consisting of nickel alloy, if any.	IP2: Prior to September 28, 2013 IP3: Prior to December 12, 2015	NL-11-032	4.3.3

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
44	IPEC will include written explanation and justification of any user intervention in future evaluations using the WESTEMS "Design CUF" module.	Within 60 days of issuance of the renewed operating license.	NL-11-032	N/A
45	IPEC will not use the NB-3600 option of the WESTEMS program in future design calculations until the issues identified during the NRC review of the program have been resolved.	Within 60 days of issuance of the renewed operating license.	NL-11-032	N/A
46	Include in the IP2 ISI Program volumetric weld metal inspections of ten socket welds in 2012 and of at least ten socket welds during each 10-year period of the period of extended operation.	IP2: Prior to September 28, 2013	NL-11-032	N/A

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

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

NRC STAFF'S ANSWER TO STATE OF NEW YORK AND RIVERKEEPER'S
JOINT MOTION TO FILE A NEW CONTENTION, AND
NEW JOINT CONTENTION NYS-38/RK-TC-5

ATTACHMENT 2

LRA 3.1-9 – Indian Point License Renewal Application page 3.1-9

3.1.2.2.10 Loss of Material due to Erosion

Loss of material due to erosion could occur in steel steam generator feedwater impingement plates and supports exposed to secondary feedwater. The IPEC steam generator design does not employ a feedwater impingement plate. This item is not applicable to IPEC.

3.1.2.2.11 Cracking due to Flow-Induced Vibration

This paragraph in NUREG-1800 applies to BWRs only.

3.1.2.2.12 Cracking due to Stress Corrosion Cracking and Irradiation-Assisted Stress Corrosion Cracking (IASCC)

Cracking due to SCC and IASCC could occur in PWR stainless steel reactor internals exposed to reactor coolant. To manage cracking in vessel internals components, IPEC maintains the Water Chemistry Control – Primary and Secondary Program and will (1) participate in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the NRC for review and approval. The IPEC commitment to these RVI programs is included in UFSAR Supplement, Appendix A, Sections A.2.1.41 and A.3.1.41.

3.1.2.2.13 Cracking due to Primary Water Stress Corrosion Cracking (PWSCC)

Cracking due to PWSCC in most components made of nickel alloy is managed by the Water Chemistry Control – Primary and Secondary, Inservice Inspection, and Nickel Alloy Inspection Programs. The Nickel Alloy Inspection Program implements the applicable NRC Orders and will implement applicable (1) Bulletins and Generic Letters and (2) staff-accepted industry guidelines. UFSAR Supplement, Appendix A, Sections A.2.1.20 and A.3.1.20 provide a commitment for this program.

3.1.2.2.14 Wall Thinning due to Flow-Accelerated Corrosion

Wall thinning due to flow-accelerated corrosion could occur in steel feedwater inlet rings and supports. The Steam Generator Integrity Program manages loss of material due to flow-accelerated corrosion in the feedwater inlet ring using periodic visual inspections.

3.1.2.2.15 Changes in Dimensions due to Void Swelling

Changes in dimensions due to void swelling could occur in stainless steel and nickel alloy reactor internal components exposed to reactor coolant. To manage changes in

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ATTACHMENT 3

Table 3.1.1 – Indian Point License Renewal Application Table 3.1.1 – Reactor Coolant System, NUREG-1801 Vol. 1

Table 3.1.1: Reactor Coolant System, NUREG-1801 Vol. 1

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-80	Cast austenitic stainless steel reactor vessel internals (e.g., upper internals assembly, lower internal assembly, CEA shroud assemblies, control rod guide tube assembly, core support shield assembly, lower grid assembly)	Loss of fracture toughness due to thermal aging and neutron irradiation embrittlement	Thermal Aging and Neutron Irradiation Embrittlement of CASS	No	Consistent with NUREG-1801. The Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program will manage loss of fracture toughness of cast austenitic stainless steel vessel internals components exposed to reactor coolant and high neutron fluence.
3.1.1-81	Nickel alloy or nickel-alloy clad steam generator divider plate exposed to reactor coolant	Cracking due to primary water stress corrosion cracking	Water Chemistry	No	Consistent with NUREG-1801. TheWater Chemistry Control – Primary and Secondary Program manages cracking of the nickel-alloy steam generator divider plate exposed to reactor coolant. The Water Chemistry Control – Primary and Secondary Program also manages cracking of the primary nozzle closure rings which form a temporary pressure boundary (nozzle dam) during outages.
3.1.1-82	Stainless steel steam generator primary side divider plate exposed to reactor coolant	Cracking due to stress corrosion cracking	Water Chemistry	No	Not applicable. The steam generator primary side divider plate is composed of nickel alloy.

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ATTACHMENT 4

NUREG-1801, Vol. 1 – Page IV B2-2: Reactor Vessel Internals (PWR) - Westinghouse

IV REACTOR VESSEL, INTERNALS, AND REACTOR COOLANT SYSTEM
B2 Reactor Vessel Internals (PWR) - Westinghouse

Item	Link	Structure and/or Component	Material	Environment	Aging Effect/ Mechanism	Aging Management Program (AMP)	Further Evaluation
IV.B2-1 (R-124)	IV.B2.4-b	Baffle/former assembly Baffle and former plates	Stainless steel	Reactor coolant	Changes in dimensions/ void swelling	No further aging management review is necessary if the applicant provides a commitment in the FSAR supplement to (1) participate in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the NRC for review and approval.	No, but licensee commitment needs to be confirmed

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(Indian Point Nuclear Generating	)	
Units 2 and 3)	)	

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NEW JOINT CONTENTION NYS-38/RK-TC-5

ATTACHMENT 5

NL-07-039 – Excerpt from Entergy LRA Submittal, dated April 23, 2007, regarding
Commitments 28 - 32

#	COMMITMENT	IMPLEMENTATION SCHEDULE	Related LRA Section
28	Enhance the Water Chemistry Control – Closed Cooling Water Program to maintain water chemistry of the IP2 SBO/Appendix R diesel generator cooling system per EPRI guidelines. Enhance the Water Chemistry Control – Closed Cooling Water Program to maintain the IP2 and IP3 security generator cooling water system pH within limits specified by EPRI guidelines.	IP2: September 28, 2013 IP3: December 12, 2015	A.2.1.39 A.3.1.39 B.1.40
29	Enhance the Water Chemistry Control – Primary and Secondary Program for IP2 to test sulfates monthly in the RWST with a limit of <150 ppb.	IP2: September 28, 2013	A.2.1.40 B.1.41
30	For aging management of the reactor vessel internals, IPEC will (1) participate in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the NRC for review and approval.	IP2: September 28, 2011 IP3: December 12, 2013	A.2.1.41 A.3.1.41
31	Additional P-T curves will be submitted as required per 10 CFR 50, Appendix G prior to the period of extended operation as part of the Reactor Vessel Surveillance Program.	IP2: September 28, 2013 IP3: December 12, 2015	A.2.2.1.2 A.3.2.1.2 4.2.3
32	As required by 10 CFR 50.61(b)(4), IP3 will submit a plant-specific safety analysis for plate B2803-3 to the NRC three years prior to reaching the RT_{PTS} screening criterion. Alternatively, the site may choose to implement the revised PTS (10 CFR 50.61) rule when approved, which would permit use of Regulatory Guide 1.99, Revision 3.	IP3: December 12, 2015	A.3.2.1.4 4.2.5

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

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

NRC STAFF'S ANSWER TO STATE OF NEW YORK AND RIVERKEEPER'S
JOINT MOTION TO FILE A NEW CONTENTION, AND
NEW JOINT CONTENTION NYS-38/RK-TC-5

ATTACHMENT 6

NL-11-107 – Entergy Letter, dated September 28, 2011, regarding Completion of Commitment # 30

Entergy

Entergy Nuclear Northeast
Indian Point Energy Center
450 Broadway, GSB
P.O. Box 249
Buchanan, N.Y. 10511-0249
Tel (914) 788-2055

Fred Dacimo
Vice President
Operations License Renewal

NL-11-107

September 28, 2011

ATTN: Document Control Desk
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

SUBJECT: License Renewal Application – Completion of Commitment #30 Regarding the Reactor Vessel Internals inspection Plan
Indian Point Nuclear Generating Unit Nos. 2 and 3
Docket Nos. 50-247 and 50-286
License Nos. DPR-26 and DPR-64

REFERENCE:
1. Entergy Letter dated April 23, 2007, Fred Dacimo to Document Control Desk, "License Renewal Application" (NL-07-039)
2. Entergy Letter dated July 14, 2010, Fred Dacimo to Document Control Desk, "Amendment 9 to License Renewal Application (LAR) – Reactor Vessel Internals Program" (NL-10-063)
3. EPRI, Materials Reliability Program (MRP), Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227)
4. NRC, "Final safety Evaluation of EPRI Report, Materials Reliability Program Report 1016596, Revision 0, Pressurized Water reactor (PWR) Internals Inspection and Evaluation Guidelines" dated June 22, 2011

Dear Sir or Madam:

Entergy Nuclear Operations, Inc. applied for renewal of the Indian Point Nuclear Generating Unit Nos. 2 and 3 operating licenses by the reference 1 letter which included a list of regulatory commitments. The commitment list contained commitment # 30 for submitting an inspection plan for reactor vessel internals. Reference 2 provided the Indian Point Nuclear Generating Unit Nos. 2 and 3 Reactor Vessel Internals Program. This letter contains the inspection plan satisfying the completion of commitment # 30 to the License Renewal Application regarding the Aging Management Programs for Reactor Vessel Internals. The Indian Point Energy Center (IPEC) Reactor Vessel Internals Inspection Plan was developed in accordance with the results of industry programs applicable to the reactor vessel internals and addresses the action items and conditions stated in the NRC Final Safety Evaluation of MRP-227 (Reference 4).

A128
NRR

There are no new commitments identified in this submittal. If you have any questions, or require additional information, please contact Mr. Robert Walpole at 914-734-6710.

Sincerely,

FD/cbr

Attachment: Indian Point Energy Center Reactor Vessel Internals Inspection Plan

cc: Mr. William Dean, Regional Administrator, NRC Region I
Mr. J. Boska, Senior Project Manager, NRC, NRR, DORL
Mr. David Wrona, NRC Branch Chief, Engineering Review Branch I
Mr. Sherwin E. Turk, NRC Office of General Counsel, Special Counsel
NRC Resident Inspectors Office, Indian Point
Mr. Paul Eddy, NYS Dept. of Public Service
Mr. Francis J. Murray, Jr., President and CEO, NYSERDA

ATTACHMENT TO NL-11-107

Indian Point Energy Center Reactor Vessel Internals Inspection Plan

ENTERGY NUCLEAR OPERATIONS, INC
INDIAN POINT NUCLEAR GENERATING UNITS 2 AND 3
DOCKET NOS. 50-247 & 50-286

1 INTRODUCTION

1.1 Aging Management Program Inspection Plan

The EPRI MRP guidelines define a supplemental inspection program for managing aging effects on the reactor vessel internals and were used to develop this inspection plan for IPEC Units 2 and 3. The EPRI MRP Reactor Internals Focus Group developed the MRP-227 Guidelines to support the demonstration of continued functionality, with requirements for inspections to detect the effects of aging along with requirements for the evaluation of detected aging effects, if any. The development of MRP-227 combined the results of component functionality assessments with component accessibility, operating experience, existing evaluations and prior examination results to determine the appropriate aging management methods, initial examination timing and the need and timing of subsequent inspections and identified the components and locations for supplemental examination.

In accordance with MRP-227, this inspection plan includes:

- Identification of items for inspection,
- Specification of the type of examination appropriate for each degradation mechanism,
- Specification of the required level of examination qualification,
- Schedule of initial inspection and frequency of subsequent inspections,
- Criteria for sampling and coverage,
- Criteria for expansion of scope if unanticipated indications are found,
- Inspection acceptance criteria,
- Methods for evaluating examination results not meeting the acceptance criteria,
- Updating the program based on industry-wide results, and
- Contingency measures to repair, replace or mitigate.

2
BACKGROUND OF IPEC REACTOR VESSEL INTERNALS DESIGN

This section provides a summary of the design characteristics for the IPEC Westinghouse PWR internals.

2.1 Westinghouse Internals Design Characteristics

A schematic view of a typical set of Westinghouse-designed PWR internals is Figure 2-1. More detailed views of selected internals components are Figures 2-2 through 2-16 at the end of this section. These figures are typical and are not an exact representation of the IPEC internals.

To help in the categorization of IPEC internals design characteristics as discussed in MRP-227 Section 3.1.3, the following information is provided. IPEC Units 2 and 3 are Westinghouse four loop plants with a downflow baffle-barrel region flow design, and a top hat design upper support plate. Unit 2 had an original thermal output of 2758 MWth and Unit 3 had an original thermal output of 3025 MWth.

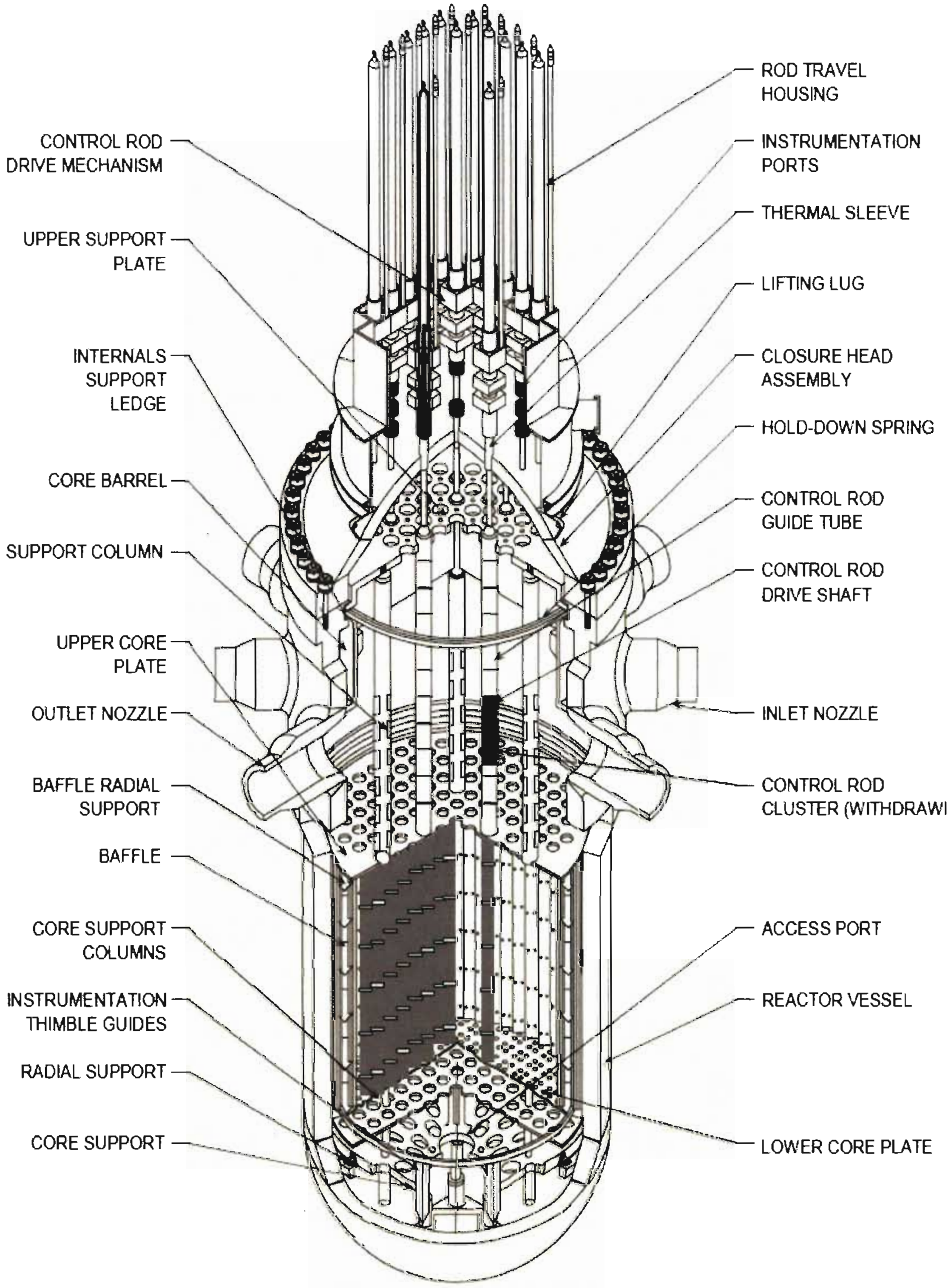

Figure 2-1
Overview of typical Westinghouse internals

Westinghouse internals consist of two basic assemblies: an upper internals assembly that is removed during each refueling operation to obtain access to the reactor core and a lower internals assembly that can be removed following a complete core off-load.

The reactor core is positioned and supported by the upper internals and lower internals assemblies. The individual fuel assemblies are positioned by fuel alignment pins in the upper core plate and the lower core plate. These pins control the orientation of the core with respect to the upper and lower internals assemblies. The lower internals are aligned with the upper internals by the upper core plate alignment pins and secondarily by the head/vessel alignment pins. The lower internals are aligned to the vessel by the lower radial support/clevis assemblies and by the head/vessel alignment pins. Thus, the core is aligned with the vessel by a number of interfacing components.

The lower internals assembly is supported in the vessel by clamping to a ledge below the vessel-head mating surface and is closely guided at the bottom by radial support/clevis assemblies. The upper internals assembly is clamped at this same ledge by the reactor vessel head. The bottom of the upper internals assembly is closely guided by the core barrel alignment pins of the lower internals assembly.

Upper Internals Assembly

The major sub-assemblies that constitute the upper internals assembly are the: (1) upper core plate (UCP); (2) upper support column assemblies; (3) control rod guide tube assemblies; and (4) upper support plate (USP).

During reactor operation, the upper internals assembly is preloaded against the fuel assembly springs and the internals hold down spring by the reactor vessel head pressing down on the outside edge of the USP. The USP acts as the divider between the upper plenum and the reactor vessel head and as a relatively stiff base for the rest of the upper internals. The upper support columns and the control rod guide tubes are attached to the USP. The UCP, in turn, is attached to the upper support columns. The USP design at IPEC is designated as a top hat design.

The UCP is perforated to permit coolant to pass from the core below into the upper plenum between the USP and the UCP. The coolant then exits through the outlet nozzles in the core barrel. The UCP positions and laterally supports the core by fuel alignment pins extending below the plate. The UCP contacts and preloads the fuel assembly springs and thus maintains contact of the fuel assemblies with the lower core plate (LCP) during reactor operation.

The upper support columns vertically position the UCP and are designed to take the uplifting hydraulic flow loads and fuel spring loads on the UCP. The control rod guide tubes are bolted to the USP and pinned at the UCP so they can be easily removed if replacement is desired. The control rod guide tubes are designed to guide the control rods in and out of the fuel assemblies to control power generation. Guide tube cards are located within each control rod guide tube to guide the absorber rods. The control rod guide tubes are also slotted in their lower sections to allow coolant exiting the core to flow into the upper plenum.

The upper instrumentation columns are bolted to the USP. These columns support the thermocouple guide tubes that lead the thermocouples from the reactor head through the upper plenum to just above the UCP.

The UCP alignment pins locate the UCP laterally with respect to the lower internals assembly. The pins must laterally support the UCP so that the plate is free to expand radially and move axially during differential thermal expansion between the upper internals and the core barrel. The UCP alignment pins are the interfacing components between the UCP and the core barrel.

Lower Internals Assembly

The fuel assemblies are supported inside the lower internals assembly on top of the LCP. The functions of the LCP are to position and support the core and provide a metered control of reactor coolant flow into each fuel assembly. The LCP is elevated above the lower support casting by support columns and bolted to a ring support attached to the inside diameter of the core barrel. The support columns transmit vertical fuel assembly loads from the LCP to the much thicker lower support casting. The function of the lower support casting is to provide support for the core. The lower support casting is welded to and supported by the core barrel, which transmits vertical loads to the vessel through the core barrel flange.

The primary function of the core barrel is to support the core. A large number of components are attached to the core barrel, including the baffle/former assembly, the core barrel outlet nozzles, the thermal shields, the alignment pins that engage the UCP, the lower support casting, and the LCP. The lower radial support/clevis assemblies restrain large transverse motions of the core barrel but at the same time allow unrestricted radial and axial thermal expansion.

The baffle and former assembly consists of vertical plates called baffles and horizontal support plates called formers. The baffle plates are bolted to the formers by the baffle/former bolts, and the formers are attached to the core barrel inside diameter by the barrel/former bolts. Baffle plates are secured to each other at selected corners by edge bolts. In addition, at IPEC, corner brackets are installed behind and bolted to the baffle plates. The baffle/former assembly forms the interface between the core and the core barrel. The baffles provide a barrier between the core and the former region so that a high concentration of flow in the core region can be maintained. A secondary benefit is to reduce the neutron flux on the vessel.

The function of the core barrel outlet nozzles is to direct the reactor coolant, after it leaves the core, radially outward through the reactor vessel outlet nozzles. The core barrel outlet nozzles are located in the upper portion of the core barrel directly below the flange and are attached to the core barrel, each in line with a vessel outlet nozzle.

Additional neutron shielding of the reactor vessel is provided in the active core region by thermal shields attached to the outside of the core barrel.

A flux thimble is a long, slender stainless steel tube that passes from an external seal table, through a bottom mounted nozzle penetration, through the lower internals assembly, and finally extends to the top of a fuel assembly. The flux thimble provides a path for a neutron flux detector into the core and is subjected to reactor coolant pressure and temperature on the outside surface and to atmospheric conditions on the inside. The flux thimble path from the seal table to the bottom mounted nozzles is defined by flux thimble guide tubes, which are part of the primary pressure boundary and not part of the internals. The bottom-mounted instrumentation (BMI) columns provide a path for the flux thimbles from the bottom of the vessel into the core. The BMI columns align the flux thimble paths with instrumentation thimbles in the fuel assembly.

In the upper internals assembly, the upper support plate, the upper support columns, and the upper core plate are considered core support structures. In the lower internals assembly, the lower core plate, the lower support casting, the lower support columns, the core barrel including the core barrel flange, the radial support/clevis assemblies, the baffle plates, and the former plates are classified as core support structures.

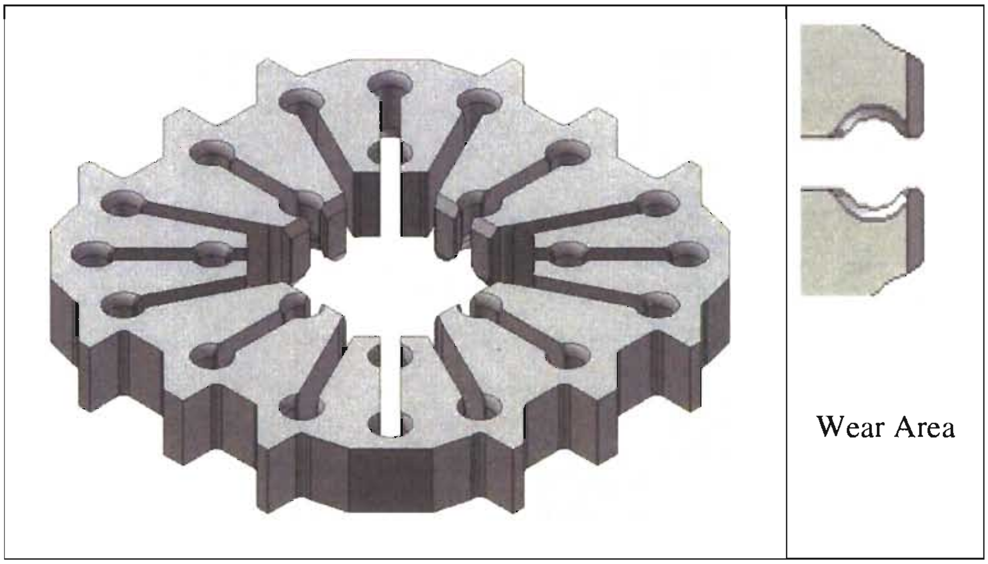

Figure 2-2
Typical Westinghouse control rod guide card (17x17 fuel assembly)

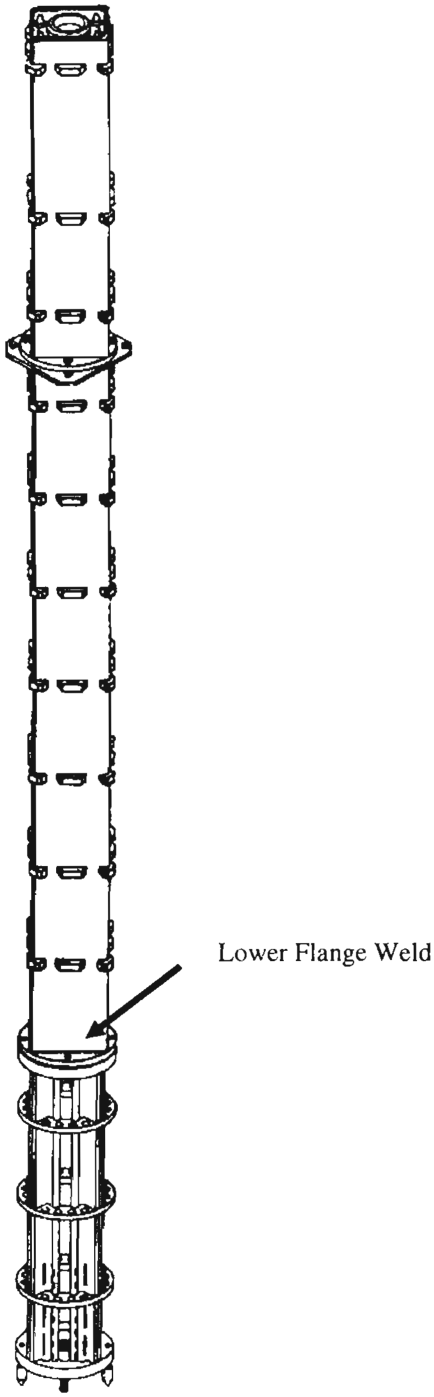

Figure 2-3
Typical Westinghouse control rod guide tube assembly

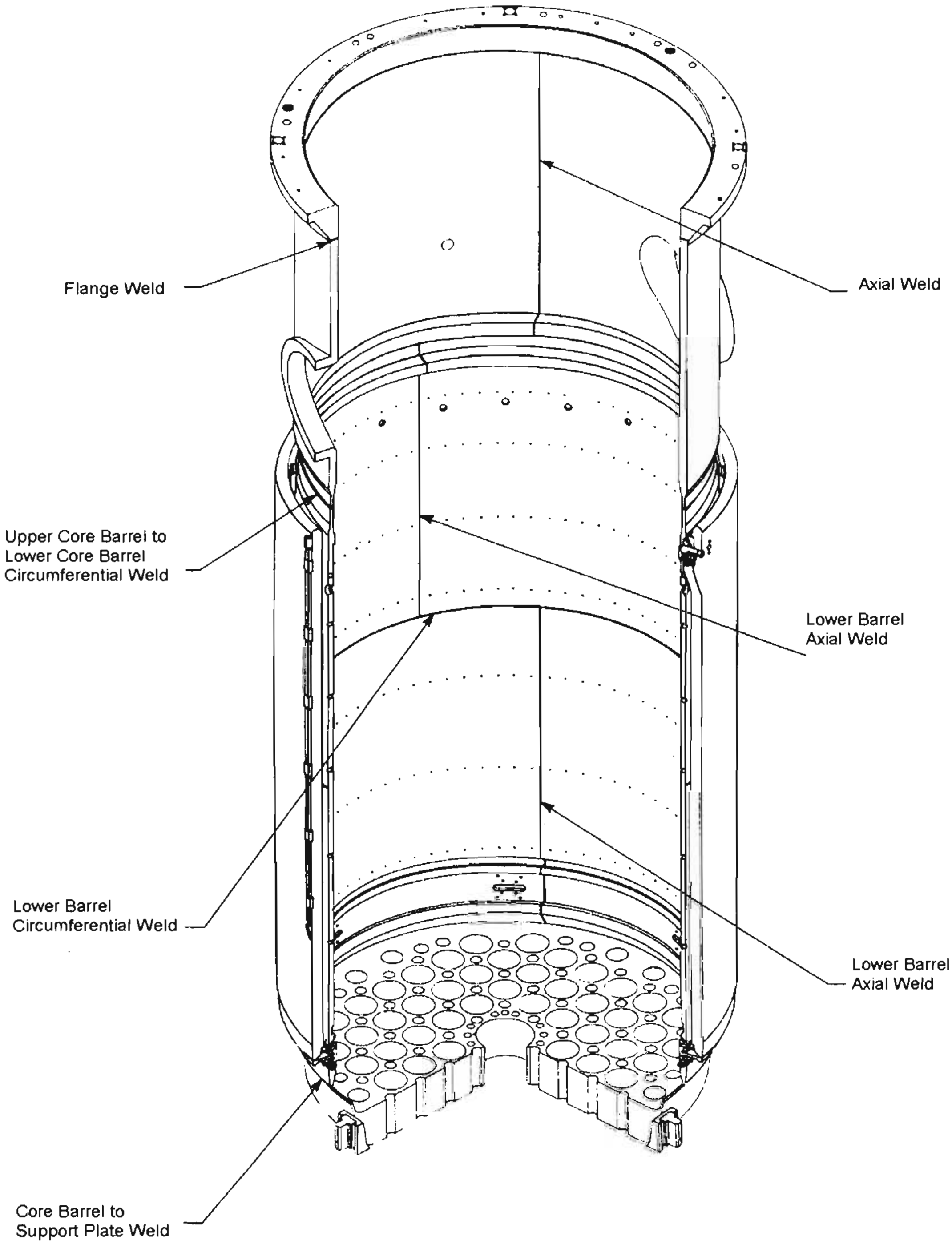

Figure 2-4
Major fabrication welds in typical Westinghouse core barrel

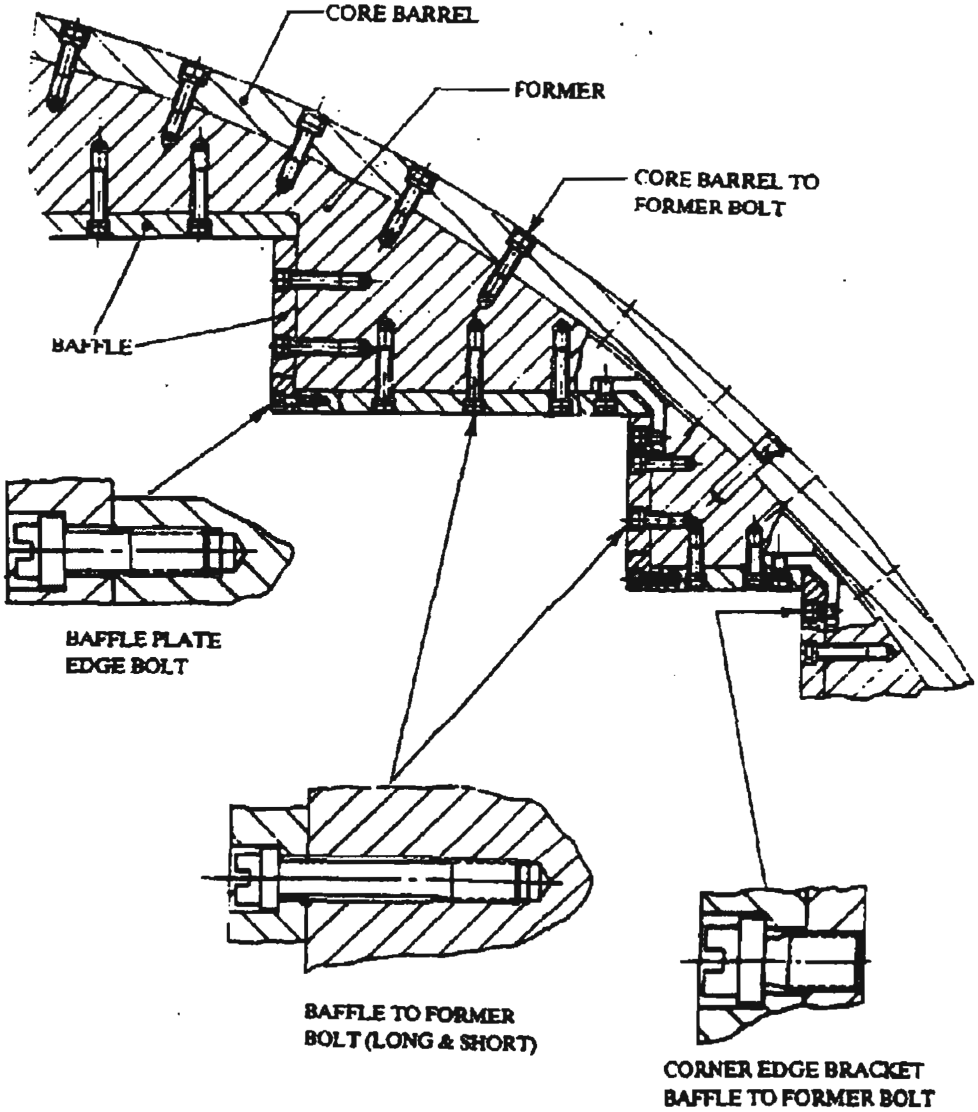

Figure 2-5
Bolt locations in typical Westinghouse baffle-former-barrel structure.

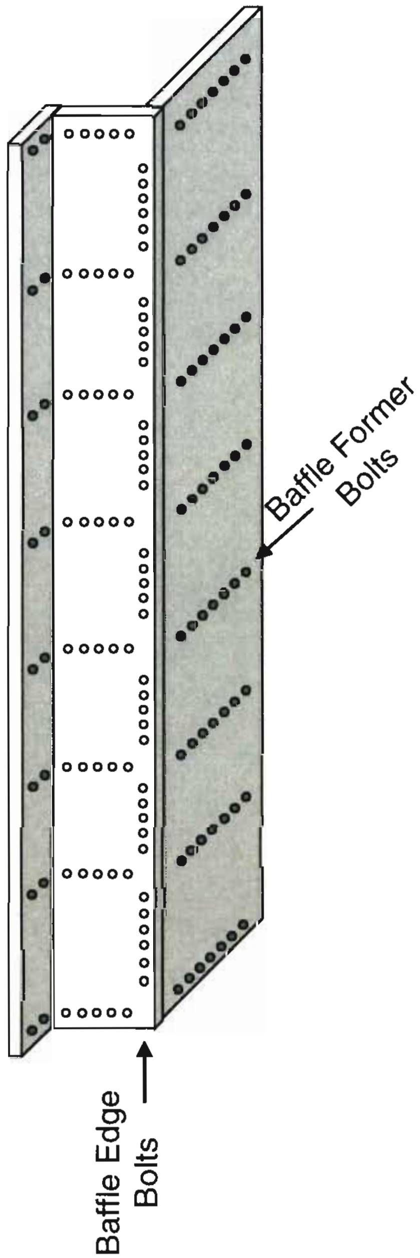

Figure 2-6
Baffle-edge bolt and baffle-former bolt locations at high fluence seams in bolted baffle-former assembly

Figure 2-7
High fluence seam locations in Westinghouse baffle-former assembly

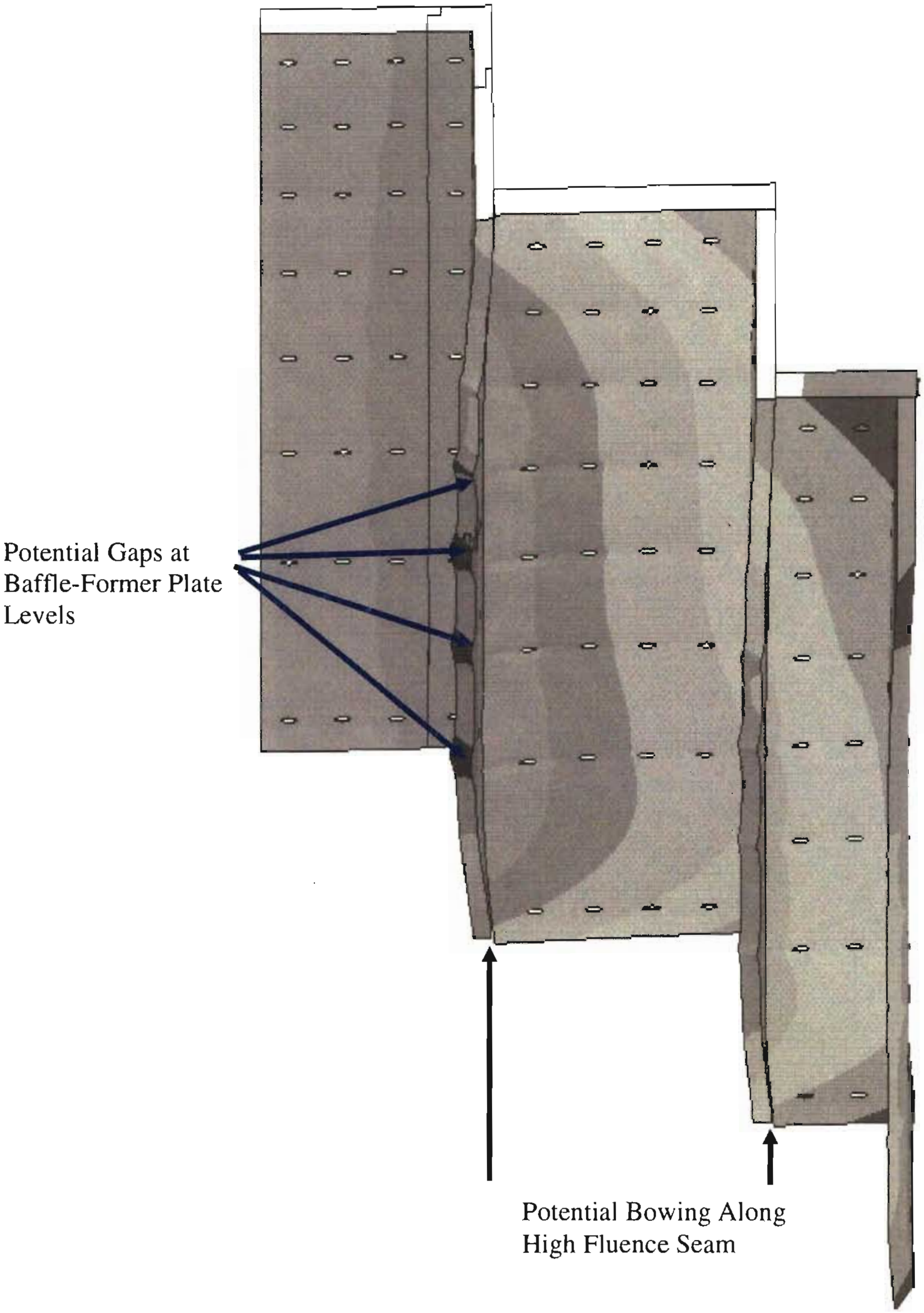

Figure 2-8
Exaggerated view of void swelling induced distortion in Westinghouse baffle-former assembly.

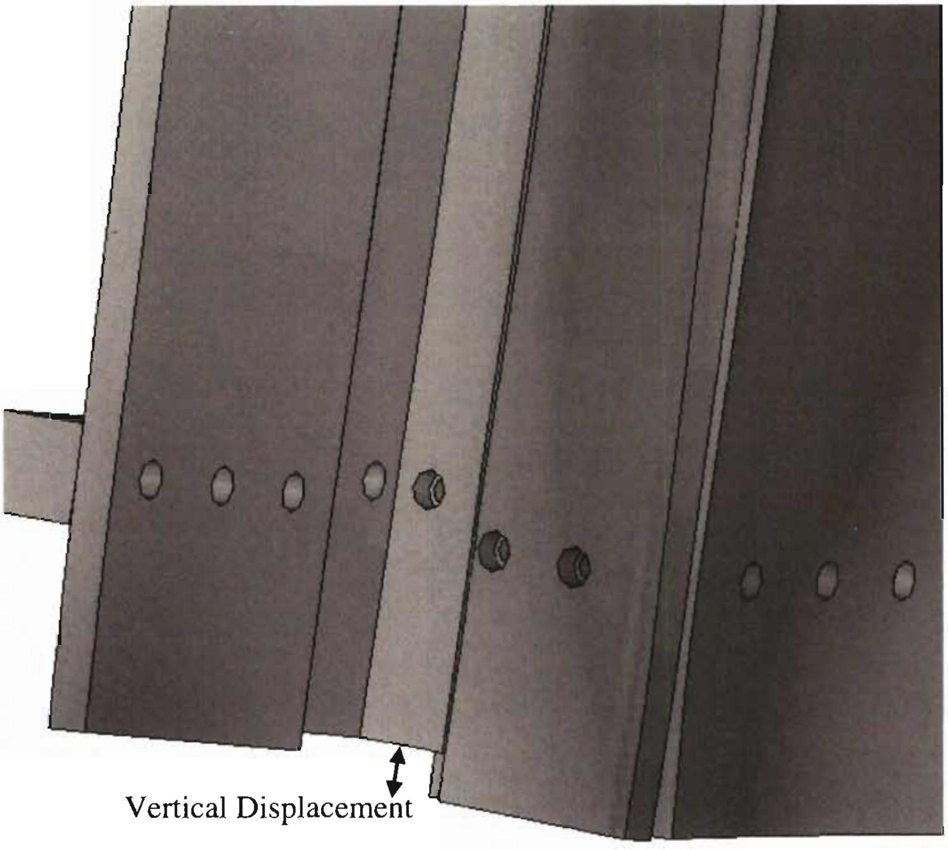

Figure 2-9
Vertical displacement of Westinghouse baffle plates caused by void swelling.

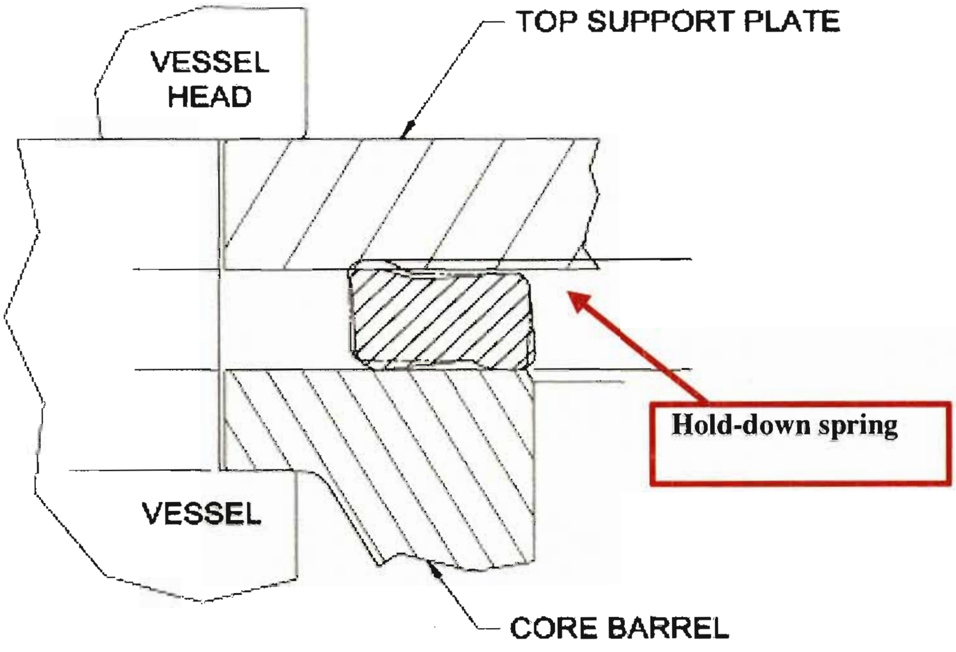

Figure 2-10
Schematic cross-sections of the Westinghouse hold-down springs

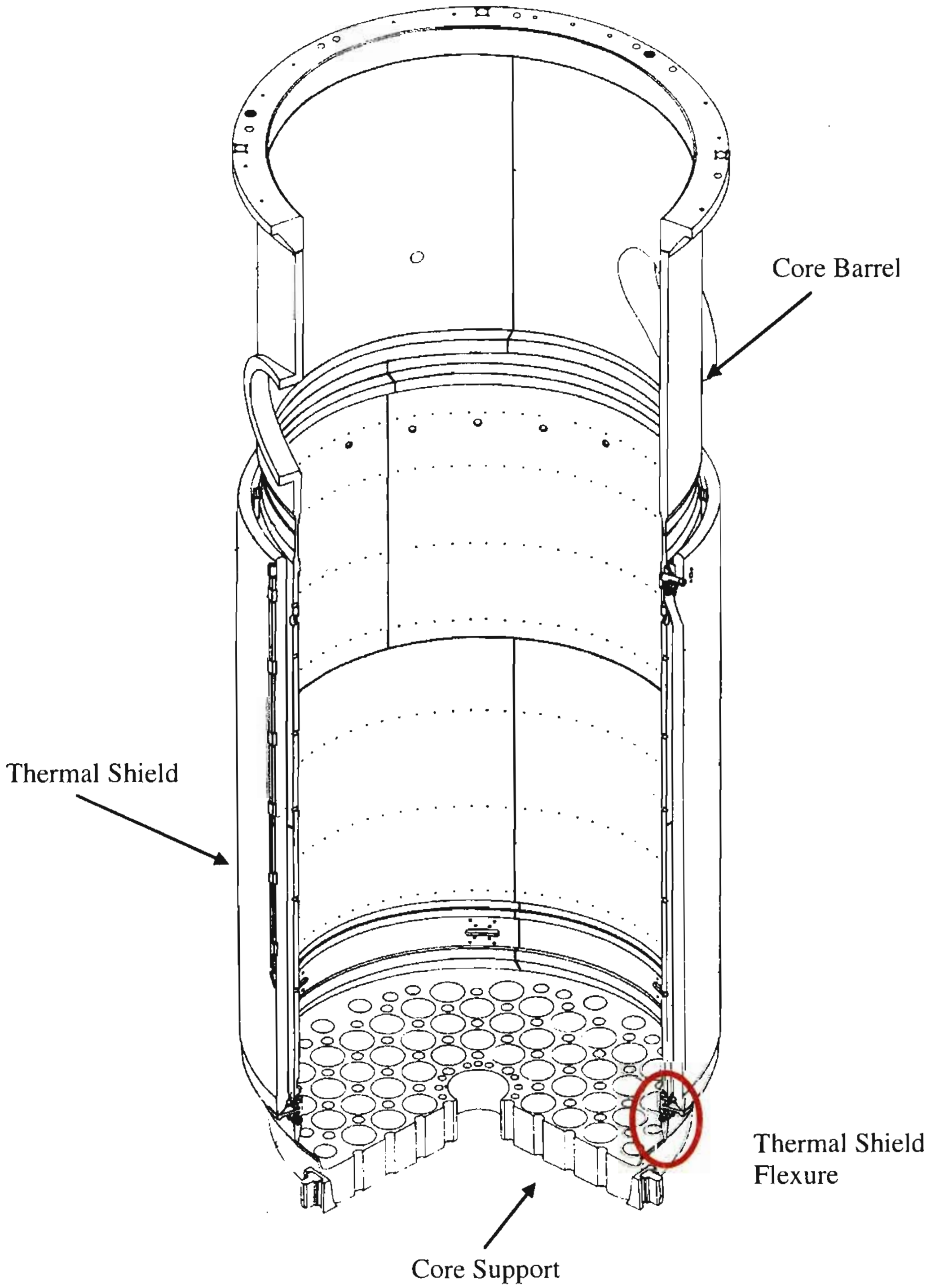

Figure 2-11
Location of Westinghouse thermal shield flexures

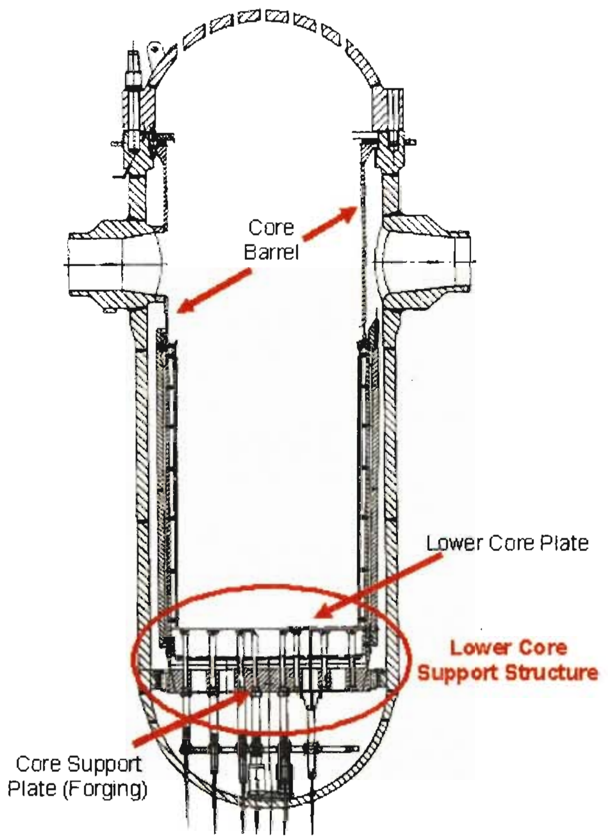

Figure 2-12
Schematic indicating location of Westinghouse lower core support structure. Additional details shown in Figure 2-13

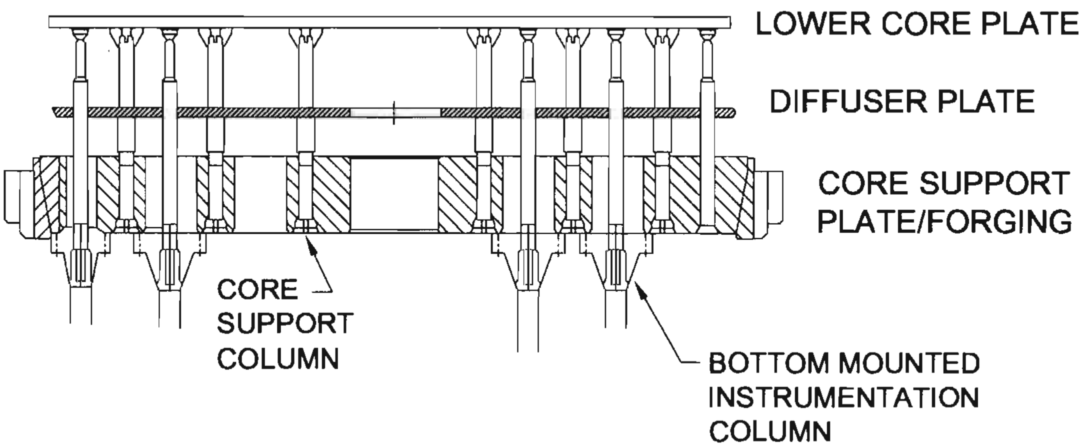

Figure 2-13
Westinghouse lower core support structure and bottom mounted instrumentation columns. Core support column bolts fasten the core support columns to the lower core plate

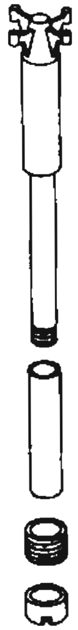

Figure 2-14
Typical Westinghouse core support column. Core support column bolts fasten the top of the support column to the lower core plate

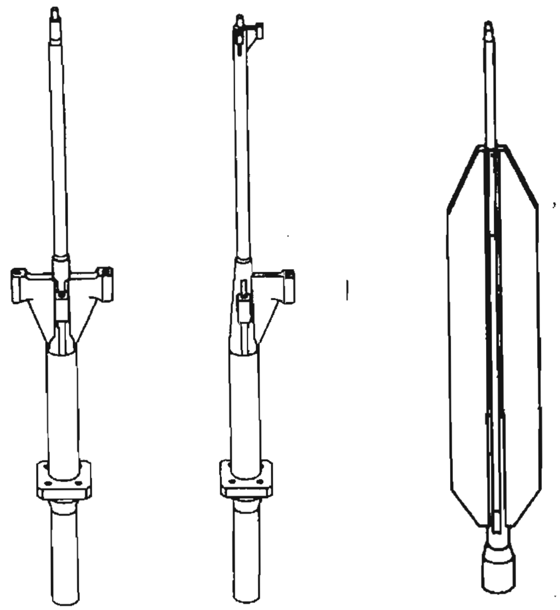

Figure 2-15
Examples of Westinghouse bottom mounted instrumentation column designs

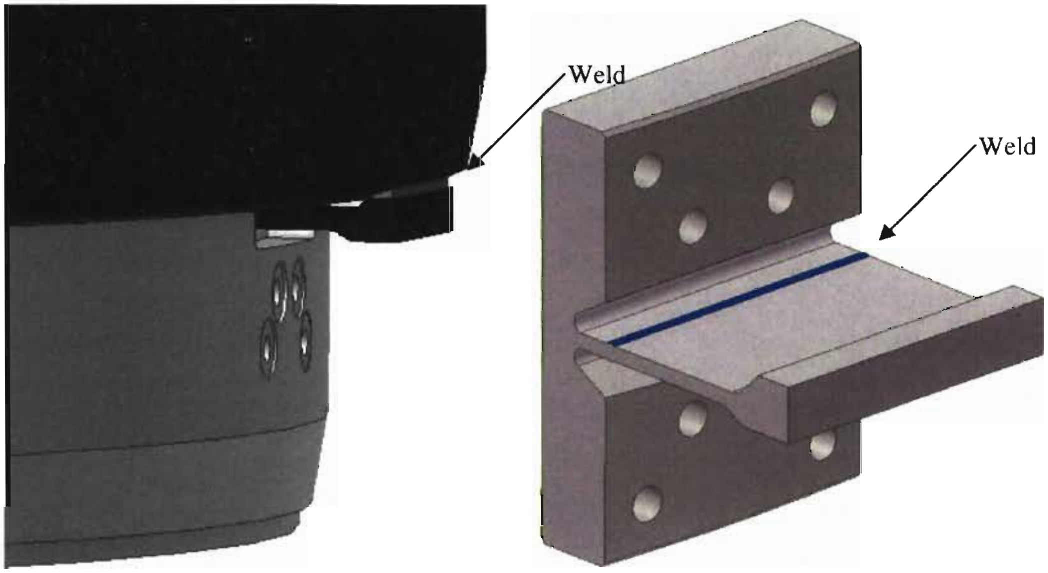

Figure 2-16
Typical Westinghouse thermal shield flexure

3
INSPECTION PLAN SUMMARY

Management of component aging effects includes actions to prevent or control aging effects, review of operating experience to better understand the potential for aging effects to occur, inspections to detect the onset of aging effects in susceptible components, protocols for evaluation and remediation of the effects of aging, and procedures to ensure component aging effects are managed in a coordinated program.

3.1 Component Inspection and Evaluation Overview

This discussion summarizes the guidance of the MRP Inspection & Evaluation (I&E) guidelines necessary to understand implementation but does not duplicate the full discussion of the technical bases. MRP-227 and its supporting documents provide further information on the technical bases of the program.

MRP-227 establishes four groups of reactor internals components with respect to inspections: Primary, Expansion, Existing Programs and No Additional Measures, as summarized below.

- **Primary:** Those PWR internals that are highly susceptible to the effects of at least one of the eight aging mechanisms were placed in the Primary group. The aging management requirements that are needed to ensure functionality of Primary components are described in the I&E guidelines. The Primary group also includes components which have shown a degree of tolerance to a specific aging degradation effect, but for which no highly susceptible component exists or for which no highly susceptible component is accessible.
- **Expansion:** Those PWR internals that are highly or moderately susceptible to the effects of at least one of the eight aging mechanisms, but for which a functionality assessment has shown a degree of tolerance to those effects, were placed in the Expansion group. The schedule for implementation of aging management requirements for Expansion components will depend on the findings from the examinations of the Primary components.
- **Existing Programs:** Those PWR internals that are susceptible to the effects of at least one of the eight aging mechanisms and for which generic and plant-specific existing AMP elements are capable of managing those effects, were placed in the Existing Programs group.
- **No Additional Measures:** Those PWR internals for which the effects of all eight aging mechanisms are below the screening criteria were placed in the No Additional Measures group. Items categorized as Category A in MRP-191 are those for which aging effects are below the screening criteria, so that aging degradation significance is minimal. Primary, expansion, and

existing examinations verify that the chemical control program has been effective at controlling stress corrosion cracking and loss of material due to corrosion for Category A components. Additional components were placed in the No Additional Measures group as a result of Failure Modes, Effects and Criticality Analysis (FMECA) and the functionality assessment. No further action is required for managing the aging of the No Additional Measures components. However, any core support structures subject to ASME Section XI Examination Category B-N-3 requirements continue to be subject to those ASME Code requirements throughout the period of extended operation.

The inspections required for Primary and Expansion components were selected from visual, surface and volumetric examination methods that are applicable and appropriate for the expected degradation effect (e.g. cracking caused by particular mechanisms, loss of material caused by wear). The inspection methods include: Visual examinations (VT-3, VT-1, EVT-1), surface examinations, volumetric examinations (specifically UT) and physical measurements. MRP-227 provides detailed justification for the components selected for inspection and the specific examination methods selected for each. The MRP-228 report, PWR Internals Inspection Standards, provides detailed examination standards and any inspection technical justification or inspection personnel training requirements.

3.2 Inspection and Evaluation Requirements for Primary Components

The inspection requirements for Primary Components at IPEC Units 2 and 3 from MRP-227 are provided in Table 5-2.

3.3 Inspection and Evaluation Requirements for Expansion Components

The inspection requirements for Expansion Components at IPEC Units 2 and 3 from MRP-227 are provided in Table 5-3.

3.4 Inspections of Existing Program Components

The list of Existing Program Components at IPEC Units 2 and 3 from MRP-227 are provided in Table 5-4. This includes components in the Section XI ISI Program for IPEC Units 2 and 3 designated as B-N-2 and B-N-3 locations.

The Reactor Vessel Component Inspection Plan conducted as part of the ISI program for IPEC Units 2 and 3 is provided in Table 5-6. The components are inspected as part of the ISI Program. The ISI Program inspections are implemented in accordance with ASME Section XI schedule requirements.

3.5 Examination Systems

Equipment, techniques, procedures and personnel used to perform examinations required under this program will be consistent with the requirements of MRP-228. Indications detected during these examinations will be characterized and reported in accordance with the requirements of MRP-228.

3.6 Information Supplied in Response to the NRC Safety Evaluation of MRP-227

As part of the NRC Final Safety Evaluation of MRP-227, a number of action items and conditions were specified by the staff. Table 5-8 documents the IPEC response to the NRC Final Safety Evaluation of MRP-227. Wherever possible, these items have been addressed in the appropriate sections of this document. All NRC action items and conditions not addressed elsewhere in this document are discussed in this section.

<u>SER Section 4.2.1, Applicant/Licensee Action Item 1</u>

IPEC has assessed its plant design and operating history and has determined that MRP-227 is applicable to the facility. The assumptions regarding plant design and operating history made in MRP-191 are appropriate for IPEC and there are no differences in component inspection categories at IPEC. IPEC Unit 2 (IP2) had the first 8 years of operation with a high leakage core loading pattern. IPEC Unit 3 (IP3) had the first 10 years of operation with a high leakage core loading pattern. The FMECA and functionality analyses were based on the assumption of 30 years of operation with high leakage core loading patterns; therefore, IPEC is bounded by the assumptions in MRP-191. IPEC has always operated as a base-load plant which operates at fixed power levels and does not vary power on a calendar or load demand schedule.

<u>SER Section 4.2.2, Applicant/Licensee Action Item 2</u>

IPEC reviewed the information in Table 4-4 of MRP-191 and determined that this table contains all of the RVI components that are within the scope of license renewal. This is shown in Table 5-7.

<u>SER Section 4.2.3, Applicant/Licensee Action Item 3</u>

At IP2, the original X750 guide tube support pins (split pins) were replaced in 1995 with an improved X750 Revision B material made from more selective material with more continuous carbide coverage grain boundaries and tighter quality controls, to provide greater resistance to stress corrosion cracking. At IP3 the original X750 guide tube support pins (split pins) were replaced in 2009 (after 33 years in service) with cold-worked 316 stainless steel. The cold-worked 316 stainless steel is a significant improvement over the X750. At IPEC the effects of aging on these components will be managed in the period of extended operation based on industry experience and plant specific evaluations.

SER Section 4.2.4, Applicant/Licensee Action Item 4

This action item does not apply to Westinghouse designed units.

SER Section 4.2.5, Applicant/Licensee Action Item 5

The IPEC plant specific acceptance criteria for hold down springs and an explanation of how the proposed acceptance criteria are consistent with the IPEC licensing basis and the need to maintain the functionality of the hold down springs under all licensing basis conditions will be developed prior to the first required physical measurement. In accordance with SER Section 4.2.5, IPEC will submit this information to the NRC as part of the submittal to apply the approved version of MRP-227.

SER Section 4.2.6, Applicant/Licensee Action Item 6

This action item does not apply to Westinghouse designed units.

SER Section 4.2.7, Applicant/Licensee Action Item 7

The IPEC plant specific analyses to demonstrate the lower support column bodies will maintain their functionality during the period of extended operation will consider the possible loss of fracture toughness in these components due to thermal and irradiation embrittlement. The analyses will be consistent with the IPEC licensing basis and the need to maintain the functionality of the lower support column bodies under all licensing basis conditions of operation. In accordance with SER Section 4.2.7, IPEC will submit this information to the NRC as part of the submittal to apply the approved version of MRP-227.

SER Section 4.2.8, Applicant/Licensee Action Item 8

This document includes an inspection plan which addresses the identified plant-specific action items contained in the NRC Final Safety Evaluation for MRP-227. IPEC is not requesting any deviations from the guidance provided in MRP-227, as approved by the NRC.

4
EXAMINATION ACCEPTANCE AND EXPANSION CRITERIA

4.1 Examination Acceptance Criteria

4.1.1 Visual (VT-3) Examination

Visual (VT-3) examination is an appropriate NDE method for the detection of general degradation conditions in many of the susceptible components. The ASME Code Section XI, Examination Category B-N-3, provides a set of relevant conditions for the visual (VT-3) examination of removable core support structures in Section IWB. These are:

1. structural distortion or displacement of parts to the extent that component function may be impaired;
2. loose, missing, cracked, or fractured parts, bolting, or fasteners;
3. corrosion or erosion that reduces the nominal section thickness by more than 5%;
4. wear of mating surfaces that may lead to loss of function; and
5. structural degradation of interior attachments such that the original cross-sectional area is reduced more than 5%.

For components in the Existing Programs group, these general relevant conditions are sufficient. However, for components where visual (VT-3) is specified in the Primary or the Expansion group, more specific descriptions of the relevant conditions are provided in Table 5-5 for the benefit of the examiners. One or more of these specific relevant condition descriptions may be applicable to the Primary and Expansion components listed in Tables 5-2 and 5-3.

The examination acceptance criteria for components requiring visual (VT-3) examination is thus the absence of any of the relevant condition(s) specified in Table 5-5.

The disposition can include a supplementary examination to further characterize the relevant condition, an engineering evaluation to show that the component is capable of continued operation with a known relevant condition, or repair/replacement to remediate the relevant condition.

4.1.2 Visual (VT-1) Examination

Visual (VT-1) examination is defined in the ASME Code Section XI as an examination "conducted to detect discontinuities and imperfections on the surface of components, including such conditions as cracks, wear, corrosion, or erosion." The acceptance criterion for any visual (VT-1) examinations is the absence of any relevant conditions defined by the ASME Code, as supplemented by more specific plant inservice inspection requirements.

4.1.3 Enhanced Visual (EVT-1) Examination

Enhanced visual (EVT-1) examination has the same requirements as the ASME Code Section XI visual (VT-1) examination, with additional requirements given in the Inspection Standard, MRP-228. These enhancements are intended to improve the detection and characterization of discontinuities taking into account the remote visual aspect of reactor internals examinations. As a result, EVT-1 examinations are capable of detecting small surface-breaking cracks and sizing surface crack length when used in conjunction with sizing aids (e.g. landmarks, ruler, and tape measure). EVT-1 examination is the appropriate NDE method for detection of cracking in plates or their welded joints. Thus the relevant condition applied for EVT-1 examination is the same as for cracking in Section XI which is crack-like surface-breaking indications.

Therefore, until such time as engineering studies provide a basis by which a quantitative amount of degradation can be shown acceptable for the specific component, any observed relevant condition must be dispositioned. In the interim, the examination acceptance criterion is the absence of any detectable surface-breaking indication.

4.1.4 Surface Examination

Surface ET (eddy current testing) examination is specified as an alternative or as a supplement to visual examinations. No specific acceptance criteria for surface (ET) examination of PWR internals locations are provided in the ASME Code Section XI. Since surface ET is employed as a signal-based examination, a technical justification per the Inspection Standard, MRP-228 provides the basis for detection and length sizing of surface-breaking or near-surface cracks. The signal-based relevant indication for surface (ET) is thus the same as the relevant condition for enhanced visual (EVT-1) examination. The acceptance criteria for enhanced visual (EVT-1) examinations in 4.1.3 (and accompanying entries in Table 5-5) are therefore applied when this method is used as an alternative or supplement to visual examination.

4.1.5 Volumetric Examination

The intent of volumetric examinations specified for bolts and pins is to detect planar defects. No flaw sizing measurements are recorded or assumed in the acceptance or rejection of individual bolts or pins. Individual bolts or pins are accepted based on the absence of relevant indications established as part of the examination technical justification. When a relevant indication is detected in the cross-sectional area of the bolt or pin, it is assumed to be non-functional and the indication is recorded. A bolt or pin that passes the criterion of the examination is considered functional.

Because of this pass/fail acceptance of individual bolts or pins, the examination acceptance criterion for volumetric (UT) examination of bolts and pins is based on a reliable detection of indications as established by the individual technical justification for the proposed examination. This is in keeping with current industry practice. For example, planar flaws on the order of 30% of the cross-sectional area have been determined reliably detectable in previous bolt NDE technical justifications for baffle-former bolting.

Bolted and pinned assemblies are evaluated for acceptance based on a plant specific evaluation.

4.2 Physical Measurements Examination Acceptance Criteria

Continued functionality can be confirmed by physical measurements where, for example, loss of material caused by wear, loss of pre-load of clamping force caused by various degradation mechanisms, or distortion/deflection caused by void swelling may occur. For Westinghouse designs, tolerances are available on a design or plant-specific basis. Specific acceptance criteria will be developed as required, and thus are not provided generically in this plan.

4.3 Expansion Criteria

The criterion for expanding the scope of examination from the Primary components to their linked Expansion components is contained in Table 5-5 for IPEC.

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TABLES

Table 5-1
Indian Point 2 & 3 Component Cross Reference

Item	Letter NL-10-063 Component	MRP-191 Table 4-4	MRP-227
1	Core Baffle/Former Assembly – Bolts	Lower Internals Assembly – Baffle and Former Assembly Baffle-Edge Bolts Baffle-Former Bolts	Baffle-Former Assembly – Baffle-Edge Bolts (Table 4-3 and 5-3) Baffle-Former Assembly – Baffle-Former Bolts (Table 4-3 and 5-3)
2	Core Baffle/Former Assembly – Plates	Lower Internals Assembly – Baffle and Former Assembly Baffle Plates Former Plates	Baffle-Former Assembly – Assembly (Table 4-3 and 5-3)
3	Core Barrel Assembly – Bolts and Screws	Lower Internals Assembly – Baffle and Former Assembly Barrel-Former Bolts	Core Barrel Assembly – Barrel-Former Bolts (Table 4-6)
4	Core Barrel Assembly – Axial Flexure Plates (Thermal Shield Flexures)	Lower Internals Assembly – Neutron Panels/Thermal Shield Thermal Shield Flexures	Thermal Shield Assembly – Thermal Shield Flexures (Table 4-3 and 5-3)
5	Core Barrel Assembly – Flange	Lower Internals Assembly – Core Barrel Core Barrel Flange	Core Barrel Assembly – Core Barrel Flange (Table 4-6 and 4-9)

Table 5-1
Indian Point 2 & 3 Component Cross Reference

Item	Letter NL-10-063 Component	MRP-191 Table 4-4	MRP-227
6	Core Barrel Assembly – Ring Core Barrel Assembly – Shell Core Barrel Assembly – Thermal Shield	Lower Internals Assembly – Core Barrel Upper Core Barrel Lower Core Barrel Lower Internals Assembly – Neutron panels/thermal shield Thermal shield	None
7	Core Barrel Assembly – Lower Core Barrel Flange Weld Core Barrel Assembly – Upper Core Barrel Flange Weld	None Lower Internals Assembly – Core Barrel Core Barrel Flange	Core Barrel Assembly – Lower Core Barrel Flange Weld (Table 4-6) Core Barrel Assembly – Upper Core Barrel Flange Weld (Table 4-3 and 5-3)
8	Core Barrel Assembly – Outlet Nozzles	Lower Internals Assembly – Core Barrel Core Barrel Outlet Nozzles	Core Barrel Assembly – Core Barrel Outlet Nozzles (Table 4-6)
9	Lower Internals Assembly – Clevis Insert Bolt	Interfacing Components – Interfacing Components Clevis Insert Bolts	Alignment and Interfacing Components – Clevis Insert Bolts (Table 4-9)

Table 5-1
Indian Point 2 & 3 Component Cross Reference

Item	Letter NL-10-063 Component	MRP-191 Table 4-4	MRP-227
10	Lower Internals Assembly – Clevis Insert	Interfacing Components – Interfacing Components Clevis Inserts	None
11	Lower Internals Assembly – Intermediate Diffuser Plate	Lower Internals Assembly – Diffuser Plate Diffuser Plate	None
12	Lower Internals Assembly – Fuel Alignment Pin	Lower Internals Assembly – Lower Core Plate and Fuel Alignment Pins Fuel Alignment Pins	None
13	Lower Internals Assembly – Lower Core Plate	Lower Internals Assembly – Lower Core Plate and Fuel Alignment Pins Lower Core Plate	Lower Internals Assembly – Lower Core Plate (Table 4-9, 2 places)

Table 5-1
Indian Point 2 & 3 Component Cross Reference

Item	Letter NL-10-063 Component	MRP-191 Table 4-4	MRP-227
14	Lower Internals Assembly – • Lower Core Support Castings • Column Cap • Lower Core Support Column Bodies	Lower Internals Assembly – Lower Support Casting or Forging Lower Support Casting None Lower Internals Assembly – Lower Support Column Assembly Lower Support Column Bodies	None None Lower Support Assembly – Lower Support Column Bodies (Cast) (Table 4-6)
15	Lower Internals Assembly – Lower Core Support Plate Column Bolt	Lower Internals Assembly – Lower Support Column Assembly Lower Support Column Bolts	Lower Support Assembly – Lower Support Column Bolts (Table 4-6)
16	Lower Internals Assembly – Lower Core Support Plate Column Sleeves	Lower Internals Assembly – Lower Support Column Assembly Lower Support Column Sleeves	None
17	Lower Internals Assembly – Radial Key	Lower Internals Assembly – Radial Support Keys Radial Support Keys	None

Table 5-1
Indian Point 2 & 3 Component Cross Reference

Item	Letter NL-10-063 Component	MRP-191 Table 4-4	MRP-227
18	Lower Internals Assembly – Secondary Core Support	Lower Internals Assembly – Secondary Core Support (SCS) Assembly SCS Base Plate	None
19	RCCA Guide Tube Assembly – Bolt	Upper Internals Assembly – Control Rod Guide Tube Assemblies and Flow Downcomers Bolts	None
20	RCCA Guide Tube Assembly – Guide Tube (including Lower Flange Welds)	Upper Internals Assembly – Control Rod Guide Tube Assemblies and Flow Downcomers Flanges – lower	Control Rod Guide Tube Assembly – Lower Flange Welds (Table 4-3 and 5-3)
21	RCCA Guide Tube Assembly – Guide Plates	Upper Internals Assembly – Control Rod Guide Tube Assemblies and Flow Downcomers Guide Plates/Cards	Control Rod Guide Tube Assembly – Guide Plates (Cards) (Table 4-3 and 5-3)
22	RCCA Guide Tube Assembly – Support Pin	Upper Internals Assembly – Control Rod Guide Tube Assemblies and Flow Downcomers Guide Tube Support Pins	None

Table 5-1
Indian Point 2 & 3 Component Cross Reference

Item	Letter NL-10-063 Component	MRP-191 Table 4-4	MRP-227
23	Core Plate Alignment Pin	Interfacing Components – Interfacing Components Upper Core Plate Alignment Pins	Alignment and Interfacing Components – Upper Core Plate Alignment Pins (Table 4-9)
24	Head/Vessel Alignment Pin	Interfacing Components – Interfacing Components Head and Vessel Alignment Pins	None
25	Hold-down Spring	Interfacing Components – Interfacing Components Internals Hold Down Spring	Alignment and Interfacing Components – Internals Hold Down Spring (Table 4-3 and 5-3)
26	Mixing Devices - Support Column Orifice Base - Support Column Mixer	Upper Internals Assembly – Mixing Devices Mixing devices	None
27	Support Column	Upper Internals Assembly – Upper Support Column Assemblies Column Bodies	None

Table 5-1
Indian Point 2 & 3 Component Cross Reference

Item	Letter NL-10-063 Component	MRP-191 Table 4-4	MRP-227
28	Upper Core Plate, Fuel Alignment Pin	Upper Internals Assembly – Upper Core Plate and Fuel Alignment Pins Fuel Alignment Pins	None
29	Upper Support Plate, Support Assembly (Including Ring)	Upper Internals Assembly – Upper Support Plate Assembly Upper Support Plate	Upper Internals Assembly – Upper Support Ring or Skirt (Table 4-9)
30	Upper Support Column Bolt	Upper Internals Assembly – Upper Support Column Assemblies Bolts	None
31	Bottom Mounted Instrumentation Column	Lower Internals Assembly – Bottom-Mounted Instrumentation (BMI) Column Assemblies BMI Column Bodies	Bottom Mounted Instrumentation System – Bottom Mounted Instrumentation (BMI) Column Bodies (Table 4-6)
32	Flux Thimble Guide Tube	Lower Internals Assembly – Flux Thimbles (Tubes) Flux Thimbles (Tubes)	Bottom Mounted Instrumentation System – Flux Thimble Tubes (Table 4-9)

Table 5-1
Indian Point 2 & 3 Component Cross Reference

Item	Letter NL-10-063 Component	MRP-191 Table 4-4	MRP-227
33	Thermocouple Conduit	Upper Internals Assembly – Upper Instrumentation Conduit and Support Conduits	None

Table 5-2
Primary Components at IPEC Units 2 and 3

Item	Applicability	Effect (Mechanism)	Expansion Link	Examination Method/Frequency	Examination Coverage
Control Rod Guide Tube Assembly Guide plates (cards)	IPEC Units 2 and 3	Loss of Material (Wear)	None	Visual (VT-3) examination no later than 2 refueling outages from the beginning of the license renewal period. Subsequent examinations are required on a ten-year interval.	20% examination of the number of CRGT assemblies, with all guide cards within each selected CRGT assembly examined. See Figure 2-2
Control Rod Guide Tube Assembly Lower flange welds	IPEC Units 2 and 3	Cracking (SCC, Fatigue)	Bottom-mounted instrumentation (BMI) column bodies, Lower support column bodies (cast)	Enhanced visual (EVT-1) examination to determine the presence of crack-like surface flaws in flange welds no later than 2 refueling outages from the beginning of the license renewal period and subsequent examination on a ten-year interval.	100% of outer (accessible) CRGT lower flange weld surfaces and adjacent base metal. See Figure 2-3
Core Barrel Assembly Upper core barrel flange weld	IPEC Units 2 and 3	Cracking (SCC)	None	Enhanced visual (EVT-1) examination, no later than 2 refueling outages from the beginning of the license renewal period and subsequent examination on a ten-year interval.	100% of one side of the accessible surfaces of the selected weld and adjacent base metal. See Figure 2-4

Table 5-2
Primary Components at IPEC Units 2 and 3

Item	Applicability	Effect (Mechanism)	Expansion Link	Examination Method/Frequency	Examination Coverage
Baffle-Former Assembly Baffle-edge bolts	IPEC Units 2 and 3	Cracking (IASCC, Fatigue) that results in • Lost or broken locking devices • Failed or missing bolts • Protrusion of bolt heads	None	Visual (VT-3) examination, with baseline examination between 20 and 40 EFPY and subsequent examinations on a ten-year interval.	Bolts and locking devices on high fluence seams. 100% of components accessible from core side. 75% of a component's total (accessible + inaccessible) inspection area or volume will be examined or, when addressing a set of like components (e.g., bolting), that the inspection examine a minimum sample size of 75 percent of the total population of like components. For the inspection of a set of like components, it is understood that essentially 100% of the volume/area of each accessible like component will be examined. See Figure 2-5

Table 5-2
Primary Components at IPEC Units 2 and 3

Item	Applicability	Effect (Mechanism)	Expansion Link	Examination Method/Frequency	Examination Coverage
Baffle-Former Assembly Baffle-former bolts	IPEC Units 2 and 3	Cracking (IASCC, Fatigue)	Lower support column bolts, Barrel-former bolts	Baseline volumetric (UT) examination between 25 and 35 EFPY, with subsequent examination after 10 years to confirm stability of bolting pattern.	100% of accessible bolts or as supported by plant-specific justification. Heads accessible from the core side. UT accessibility may be affected by complexity of head and locking device designs. 75% of a component's total (accessible + inaccessible) inspection area or volume will be examined or, when addressing a set of like components (e.g., bolting), that the inspection examine a minimum sample size of 75 percent of the total population of like components. For the inspection of a set of like components, it is understood that essentially 100% of the volume/area of each accessible like component will be examined. See Figures 2-5 and 2-6.

Table 5-2
Primary Components at IPEC Units 2 and 3

Item	Applicability	Effect (Mechanism)	Expansion Link	Examination Method/Frequency	Examination Coverage
Baffle-Former Assembly Assembly	IPEC Units 2 and 3	Distortion (Void Swelling), or Cracking (IASCC) that results in • Abnormal interaction with fuel assemblies • Gaps along high fluence baffle joint • Vertical displacement of baffle plates near high fluence joint • Broken or damaged edge bolt locking systems along high fluence baffle joint	None	Visual (VT-3) examination to check for evidence of distortion, with baseline examination between 20 and 40 EFPY and subsequent examinations on a ten-year interval.	Core side surface as indicated. See Figures 2-6, 2-7, 2-8 and 2-9.
Alignment and Interfacing Components Internals hold down spring	IPEC Units 2 and 3	Distortion (Loss of Load) Note: This mechanism was not strictly identified in the original list of age-related degradation mechanisms.	None	Direct measurement of spring height within three cycles of the beginning of the license renewal period. If the first set of measurements is not sufficient to determine life, spring height measurements must be taken during the next two outages, in order to extrapolate the expected spring height to 60 years.	Measurements should be taken at several points around the circumference of the spring, with a statistically adequate number of measurements at each point to minimize uncertainty. Replacement of 304 springs by 403 springs is required when the spring stiffness is determined to relax beyond design tolerance. See Figure 2-10

Table 5-2
Primary Components at IPEC Units 2 and 3

Item	Applicability	Effect (Mechanism)	Expansion Link	Examination Method/Frequency	Examination Coverage
Thermal Shield Assembly Thermal shield flexures	IPEC Units 2 and 3	Cracking (Fatigue) or Loss of Materials (Wear) that results in thermal shield flexures excessive wear, fracture or complete separation	None	Visual (VT-3) no later than 2 refueling outages from the beginning of the license renewal period. Subsequent examinations on a ten year interval.	100% of thermal shield flexures See Figures 2-11 and 2-16
Core Barrel Assembly Upper and lower core barrel welds	IPEC Units 2 and 3	Cracking (IASCC, Neutron Embrittlement)	None	Enhanced visual (EVT-1) examination, no later than 2 refueling outages from the beginning of the license renewal period and subsequent examination on a ten-year interval.	100% of one side of the accessible surfaces of the selected weld and adjacent base metal. See Figure 2-4
Core Barrel Assembly Lower core barrel flange weld (At IPEC this weld is the lower core barrel to lower support casting weld. IPEC does not have a lower core barrel flange)	IPEC Units 2 and 3	Cracking (IASCC, Neutron Embrittlement)	None	Enhanced visual (EVT-1) examination, no later than 2 refueling outages from the beginning of the license renewal period and subsequent examination on a ten-year interval.	100% of one side of the accessible surfaces of the selected weld and adjacent base metal. See Figure 2-4 (Core Barrel to Support Plate Weld)

Table 5-3
Expansion Components at IPEC Units 2 and 3

Item	Applicability	Effect (Mechanism)	Primary Link	Examination Method	Examination Coverage
Core Barrel Assembly Barrel-former bolts	IPEC Units 2 and 3	Cracking (IASCC, Fatigue)	Baffle-former bolts	Volumetric (UT) examination, with initial examinations dependent on results of baffle-former bolt examinations. Re-examinations at 10 year intervals once degradation is identified in the primary component.	100% of accessible bolts. The inspection shall examine a minimum sample size of 75% of the total population of bolts. Accessibility may be limited by presence of thermal shields. 75% of a component's total (accessible + inaccessible) inspection area or volume will be examined or, when addressing a set of like components (e.g., bolting), that the inspection examine a minimum sample size of 75 percent of the total population of like components. For the inspection of a set of like components, it is understood that essentially 100% of the volume/area of each accessible like component will be examined. See Figure 2-5

Table 5-3
Expansion Components at IPEC Units 2 and 3

Item	Applicability	Effect (Mechanism)	Primary Link	Examination Method	Examination Coverage
Lower Support Assembly Lower support column bolts	IPEC Units 2 and 3	Cracking (IASCC, Fatigue)	Baffle-former bolts	Volumetric (UT) examination, with initial examinations dependent on results of baffle-former bolt examinations. Re-examinations at 10 year intervals once degradation is identified in the primary component.	100% of accessible bolts or as supported by plant-specific justification. The inspection shall examine a minimum sample size of 75 percent of the total population of bolts. 75% of a component's total (accessible + inaccessible) inspection area or volume will be examined or, when addressing a set of like components (e.g., bolting), that the inspection examine a minimum sample size of 75 percent of the total population of like components. For the inspection of a set of like components, it is understood that essentially 100% of the volume/area of each accessible like component will be examined. See Figures 2-12 and 2-13

Table 5-3
Expansion Components at IPEC Units 2 and 3

Item	Applicability	Effect (Mechanism)	Primary Link	Examination Method	Examination Coverage
Core Barrel Assembly Core barrel flange, Core barrel outlet nozzles	IPEC Units 2 and 3	Cracking (SCC, Fatigue)	Upper core barrel flange weld	Enhanced visual (EVT-1) examination, with initial examination frequency dependent on the examination results for upper core barrel flange. Re-examinations at 10 year intervals once degradation is identified in the primary component.	100% of one side of the accessible surfaces of the selected weld and adjacent base metal. 75% of a component's total (accessible + inaccessible) inspection area or volume will be examined or, when addressing a set of like components (e.g., bolting), that the inspection examine a minimum sample size of 75 percent of the total population of like components. For the inspection of a set of like components, it is understood that essentially 100% of the volume/area of each accessible like component will be examined. See Figure 2-4

Table 5-3
Expansion Components at IPEC Units 2 and 3

Item	Applicability	Effect (Mechanism)	Primary Link	Examination Method	Examination Coverage
Lower Support Assembly Lower support column bodies (non cast)	IPEC lower support column bodies are cast. They are captured in the next Item of this table.				
Lower Support Assembly Lower support column bodies (cast)	IPEC Units 2 and 3	Cracking (IASCC) including the detection of fractured support columns	Control rod guide tube (CRGT) lower flanges	Visual (EVT-1) examination. Re-examinations at 10 year intervals once degradation is identified in the primary component.	100% of accessible support columns. 75% of a component's total (accessible + inaccessible) inspection area or volume will be examined or, when addressing a set of like components (e.g., bolting), that the inspection examine a minimum sample size of 75 percent of the total population of like components. For the inspection of a set of like components, it is understood that essentially 100% of the volume/area of each accessible like component will be examined. See Figure 2-14

Table 5-3
Expansion Components at IPEC Units 2 and 3

Item	Applicability	Effect (Mechanism)	Primary Link	Examination Method	Examination Coverage
Bottom Mounted Instrumentation System Bottom-mounted instrumentation (BMI) column bodies	IPEC Units 2 and 3	Cracking (Fatigue) including the detection of completely fractured column bodies	Control rod guide tube (CRGT) lower flanges	Visual (VT-3) examination of BMI column bodies as indicated by difficulty of insertion/withdrawal of flux thimbles. Flux thimble insertion/withdrawal to be monitored at each inspection interval. Re-examinations at 10 year intervals once degradation is identified in the primary component.	100% of BMI column bodies for which difficulty is detected during flux thimble insertion/withdrawal. See Figure 2-15
Upper Internals Assembly Upper core plate	IPEC Units 2 and 3	Cracking (SCC, Fatigue)	Control rod guide tube (CRGT) lower flange weld	Enhanced visual (EVT-1) examination, with initial examination frequency dependent on the examination results for CRGT lower flange weld. Re-examinations at 10 year intervals once degradation is identified in the primary component.	100% of accessible upper core plate. 75% of a component's total (accessible + inaccessible) inspection area or volume will be examined or, when addressing a set of like components (e.g., bolting), that the inspection examine a minimum sample size of 75 percent of the total population of like components. For the inspection of a set of like components, it is understood that essentially 100% of the volume/area of each accessible like component will be examined. See Figure 2-1

Table 5-3
Expansion Components at IPEC Units 2 and 3

Item	Applicability	Effect (Mechanism)	Primary Link	Examination Method	Examination Coverage
Lower Support Assembly Lower support casting	IPEC Units 2 and 3	Cracking (SCC, Fatigue)	Control rod guide tube (CRGT) lower flange weld	Enhanced visual (EVT-1) examination, with initial examination frequency dependent on the examination results for CRGT lower flange weld. Re-examinations at 10 year intervals once degradation is identified in the primary component.	100% of accessible lower support casting. 75% of a component's total (accessible + inaccessible) inspection area or volume will be examined or, when addressing a set of like components (e.g., bolting), that the inspection examine a minimum sample size of 75 percent of the total population of like components. For the inspection of a set of like components, it is understood that essentially 100% of the volume/area of each accessible like component will be examined. See Figure 2-1 (Core Support)

Table 5-4
Existing Program Components at IPEC Units 2 and 3

Item	Applicability	Effect (Mechanism)	Primary Link	Examination Method	Examination Coverage
Core Barrel Assembly Core barrel flange	IPEC Units 2 and 3	Loss of material (Wear)	ASME Code Section XI	Visual (VT-3) examination to determine general condition for excessive wear.	All accessible surfaces at ASME Section XI specified frequency.
Upper Internals Assembly Upper support ring or skirt (This item is N/A because IPEC has a tophat design)	N/A	N/A	N/A	N/A	N/A
Lower Internals Assembly Lower core plate	IPEC Units 2 and 3	Cracking (IASCC, Fatigue)	ASME Code Section XI	Visual (VT-3) examination of the lower core plates to detect evidence of distortion and/or loss of bolt integrity.	All accessible surfaces at ASME Section XI specified frequency.
Lower Internals Assembly Lower core plate	IPEC Units 2 and 3	Loss of material (Wear)	ASME Code Section XI	Visual (VT-3) examination.	All accessible surfaces at ASME Section XI specified frequency.
Bottom Mounted Instrumentation System Flux thimble tubes	IPEC Units 2 and 3	Loss of material (Wear)	N/A	Surface (ET) examination.	N/A
Alignment and Interfacing Components Clevis insert bolts	IPEC Units 2 and 3	Loss of material (Wear)	ASME Code Section XI	Visual (VT-3) examination.	All accessible surfaces at ASME Section XI specified frequency.
Alignment and Interfacing Components Upper core plate alignment pins	IPEC Units 2 and 3	Loss of material (Wear)	ASME Code Section XI	Visual (VT-3) examination.	All accessible surfaces at ASME Section XI specified frequency.

Table 5-5

Examination Acceptance and Expansion Criteria at IPEC Units 2 and 3

Item	Applicability	Examination Acceptance Criteria (Note 1)	Expansion Link(s)	Expansion Criteria	Additional Examination Acceptance Criteria
Control Rod Guide Tube Assembly Guide plates (cards)	IPEC Units 2 and 3	Visual (VT-3) examination. The specific relevant condition is wear that could lead to loss of control rod alignment and impede control assembly insertion.	None	N/A	N/A
Control Rod Guide Tube Assembly Lower flange welds	IPEC Units 2 and 3	Enhanced visual (EVT-1) examination. The specific relevant condition is a detectable crack-like surface indication.	a. Bottom-mounted instrumentation (BMI) column bodies b. Lower support column bodies (cast)	a. Confirmation of surface-breaking indications in two or more CRGT lower flange welds, combined with flux thimble insertion/withdrawal difficulty, shall require visual (VT-3) examination of BMI column bodies by the completion of the next refueling outage. b. Confirmation of surface-breaking indications in two or more CRGT lower flange welds shall require EVT-1 examination of cast lower support column bodies within three fuel cycles following the initial observation.	a. For BMI column bodies, the specific relevant condition for the VT-3 examination is completely fractured column bodies. b. For cast lower support column bodies, the specific relevant condition is a detectable crack-like surface indication.

Table 5-5

Examination Acceptance and Expansion Criteria at IPEC Units 2 and 3

Item	Applicability	Examination Acceptance Criteria (Note 1)	Expansion Link(s)	Expansion Criteria	Additional Examination Acceptance Criteria
Core Barrel Assembly Upper core barrel flange weld Upper and lower core barrel welds Lower core barel flange weld (At IPEC this weld is the lower core barrel to lower support casting weld. IPEC does not have a lower core barrel flange) Core barrel flange Core barrel outlet nozzles	IPEC Units 2 and 3	Enhanced visual (EVT-1) examination. The specific relevant condition is a detectable crack-like surface indication.	None	N/A	N/A
Baffle-Former Assembly Baffle-edge bolts	IPEC Units 2 and 3	Visual (VT-3) examination. The specific relevant conditions are missing or broken locking devices, failed or missing bolts, and protrusion of bolt heads.	None	N/A	N/A

Table 5-5

Examination Acceptance and Expansion Criteria at IPEC Units 2 and 3

Item	Applicability	Examination Acceptance Criteria (Note 1)	Expansion Link(s)	Expansion Criteria	Additional Examination Acceptance Criteria
Baffle-Former Assembly Baffle-former bolts	IPEC Units 2 and 3	Volumetric (UT) examination. The examination acceptance criteria for the UT of the baffle-former bolts shall be established as part of the examination technical justification.	a. Lower support column bolts b. Barrel-former bolts	a. Confirmation that more than 5% of the baffle-former bolts actually examined on the four baffle plates at the largest distance from the core (presumed to be the lowest dose locations) contain unacceptable indications shall require UT examination of the lower support column bolts within the next three fuel cycles. b. Confirmation that more than 5% of the lower support column bolts actually examined contain unacceptable indications shall require UT examination of the barrel-former bolts.	a and b. The examination acceptance criteria for the UT of the lower support column bolts and the barrel-former bolts shall be established as part of the examination technical justification.

Table 5-5

Examination Acceptance and Expansion Criteria at IPEC Units 2 and 3

Item	Applicability	Examination Acceptance Criteria (Note 1)	Expansion Link(s)	Expansion Criteria	Additional Examination Acceptance Criteria
Baffle-Former Assembly Assembly	IPEC Units 2 and 3	Visual (VT-3) examination. The specific relevant conditions are evidence of abnormal interaction with fuel assemblies, gaps along high fluence shroud plate joints, vertical displacement of shroud plates near high fluence joints, and broken or damaged edge bolt locking systems along high fluence baffle plate joints.	None	N/A	N/A
Alignment and Interfacing Components Internals hold down spring	IPEC Units 2 and 3	Direct physical measurement of spring height. The examination acceptance criterion for this measurement is that the remaining compressible height of the spring shall provide hold-down forces within the plant-specific design tolerance.	None	N/A	N/A

Table 5-5

Examination Acceptance and Expansion Criteria at IPEC Units 2 and 3

Item	Applicability	Examination Acceptance Criteria (Note 1)	Expansion Link(s)	Expansion Criteria	Additional Examination Acceptance Criteria
Thermal Shield Assembly Thermal shield flexures	IPEC Units 2 and 3	Visual (VT-3) examination. The specific relevant conditions for thermal shield flexures are excessive wear, fracture, or complete separation.	None	N/A	N/A
Upper Internals Assembly Upper core plate	IPEC Units 2 and 3	Enhanced visual (EVT-1) examination. The specific relevant condition is a detectable crack-like surface indication.	None	N/A	N/A
Lower Support Assembly Lower support casting	IPEC Units 2 and 3	Enhanced visual (EVT-1) examination. The specific relevant condition is a detectable crack-like surface indication.	None	N/A	N/A

Notes:
1. The examination acceptance criterion for visual examination is the absence of the specified relevant condition

Table 5-6
Reactor Vessel Component ISI Program Inspection Plan for IPEC Units 2 and 3

Component	Code Category	Examination Method	Extent of Exam
Reactor Vessel Interior Radial Support Keys	B-N-2	VT-1 or VT-3	Components and areas as accessible
Reactor Vessel Interior Bottom Head Instrumentation Nozzles	B-N-2	VT-1 or VT-3	Components and areas as accessible
Reactor Vessel Interior Outlet and Inlet Nozzle mating surfaces and inside of nozzles	B-N-2	VT-1 or VT-3	Components and areas as accessible
Reactor Vessel Interior Upper internal to vessel mating surface with keys and access slots	B-N-2	VT-1 or VT-3	Components and areas as accessible
Reactor Vessel Interior Vessel flange surface	B-N-2	VT-1 or VT-3	Components and areas as accessible
Lower Internals - Exterior Core barrel surface	B-N-3	VT-3	Components and areas as accessible
Lower Internals - Exterior Thermal Shield	B-N-3	VT-3	Components and areas as accessible
Lower Internals - Exterior Irradiation specimen tubes and guides	B-N-3	VT-3	Components and areas as accessible
Lower Internals - Exterior Flexures	B-N-3	VT-3	Components and areas as accessible

Table 5-6
Reactor Vessel Component ISI Program Inspection Plan for IPEC Units 2 and 3

Component	Code Category	Examination Method	Extent of Exam
Lower Internals - Exterior Fasteners and locking devices	B-N-3	VT-3	Components and areas as accessible
Lower Internals - Exterior Outlet nozzle at 22 deg	B-N-3	VT-3	Components and areas as accessible
Lower Internals - Exterior Outlet nozzle at 158 deg	B-N-3	VT-3	Components and areas as accessible
Lower Internals - Exterior Outlet nozzle at 202 deg	B-N-3	VT-3	Components and areas as accessible
Lower Internals - Exterior Outlet nozzle at 338 deg	B-N-3	VT-3	Components and areas as accessible
Lower Internals – Exterior Bottom Lower core support plate	B-N-3	VT-3	Components and areas as accessible
Lower Internals – Exterior Bottom Flow distribution plate	B-N-3	VT-3	Components and areas as accessible
Lower Internals – Exterior Bottom Lower support casting	B-N-3	VT-3	Components and areas as accessible
Lower Internals – Exterior Bottom Core support column	B-N-3	VT-3	Components and areas as accessible
Lower Internals – Exterior Bottom Secondary core support	B-N-3	VT-3	Components and areas as accessible

Table 5-6
Reactor Vessel Component ISI Program Inspection Plan for IPEC Units 2 and 3

Component	Code Category	Examination Method	Extent of Exam
Lower Internals – Exterior Bottom Instrumentation guides	B-N-3	VT-3	Components and areas as accessible
Lower Internals – Exterior Bottom Radial support keys	B-N-3	VT-3	Components and areas as accessible
Lower Internals – Interior Bottom Outlet nozzle at 22 deg	B-N-3	VT-3	Components and areas as accessible
Lower Internals – Interior Bottom Outlet nozzle at 158 deg	B-N-3	VT-3	Components and areas as accessible
Lower Internals – Interior Bottom Outlet nozzle at 202 deg	B-N-3	VT-3	Components and areas as accessible
Lower Internals – Interior Bottom Outlet nozzle at 338 deg	B-N-3	VT-3	Components and areas as accessible
Lower Internals – Interior Bottom Core barrel alignment pin	B-N-3	VT-3	Components and areas as accessible
Lower Internals – Interior Bottom Lower core plate	B-N-3	VT-3	Components and areas as accessible
Lower Internals – Interior Bottom Fuel alignment pins	B-N-3	VT-3	Components and areas as accessible

Indian Point Energy Center
Reactor Vessel Internals Inspection Plan

Table 5-7
List of IPEC Reactor Vessel Interior Components and Materials Based on MRP-191 – Table 4-4

UPPER INTERNALS ASSEMBLY			
Sub Assembly	**Component**	**Material**	**Category from MRP-191 Table 7-2**
Control rod guide tube assemblies and flow downcomers	Anti-rotation studs and nuts	Stainless steel	A
	Bolts	Stainless steel	A
	C-tubes	Stainless steel	C
	Enclosure pins	Stainless steel	A
	Upper guide tube enclosures	Stainless steel	A
	Flanges intermediate	Stainless steel	A
	Flanges lower	Stainless steel	A
	Flexureless inserts	Stainless steel	A
	Guide plates/cards	Stainless steel	C
	Guide tube support pins (split pins)	A X-750 (IP2 only)	C
	Guide tube support pins (split pins)	Stainless steel (IP3 only)	A
	Housing plates	Stainless steel	A
	Inserts	Stainless steel	A
	Lock bars	Stainless steel	A
	Sheaths	Stainless steel	C
	Support pin cover plate	Stainless steel	A
	Support pin cover plate cap screws	Stainless steel	A
	Support pin cover plate locking caps and tie straps	Stainless steel	A
	Support pin nuts	Alloy X-750	A
	Support pin nuts	Stainless steel	A
	Water flow slot ligaments	Stainless steel	A
Mixing Devices	Mixing devices	CASS	A
Upper core plate and fuel alignment pins	Fuel alignment pins	Stainless steel	A
	Upper core plate	Stainless steel	A
Upper instrumentation conduit and supports	Bolting	Stainless steel	A
	Brackets,clamps,terminal blocks, and conduit straps	Stainless steel	A
	Conduit seal assembly-body, tubesheets	Stainless steel	A
	Conduit seal assembly-tubes	Stainless steel	A
	Conduits	Stainless steel	A
	Flange base	Stainless steel	A
	Locking caps	Stainless steel	A
	Support tubes	Stainless steel	A
Upper plenum	UHI flow column bases	CASS	A
	UHI flow columns	Stainless steel	A

Table 5-7
List of IPEC Reactor Vessel Interior Components and Materials Based on MRP-191 – Table 4-4

UPPER INTERNALS ASSEMBLY			
Sub Assembly	**Component**	**Material**	**Category from MRP-191 Table 7-2**
Upper support column assemblies	Adapters	Stainless steel	A
	Bolts	Stainless steel	A
	Column bases	CASS	A
	Column bodies	Stainless steel	A
	Extension tubes	Stainless steel	A
	Flanges	Stainless steel	A
	Lock keys	Stainless steel	A
	Nuts	Stainless steel	A
Upper support plate assembly	Bolts	Stainless steel	A
	Deep beam ribs	Stainless steel	A
	Deep beam stiffeners	Stainless steel	A
	Flange	Stainless steel	A
	Inverted top hat flange	Stainless steel	A
	Inverted top hat upper support plate	Stainless steel	A
	Lock keys	Stainless steel	A
	Ribs	Stainless steel	A
	Upper suport plate	Stainless steel	A
	Upper support ring or skirt	Stainless steel	B
LOWER INTERNALS ASSEMBLY			
Sub Assembly	**Component**	**Material**	**Category from MRP-191 Table 7-2**
Baffle and former assembly	Baffle bolting locking bar	Stainless steel	A
	Baffle edge bolts	Stainless steel	C
	Baffle plates	Stainless steel	B
	Baffle former bolts	Stainless steel	C
	Barrel former bolts	Stainless steel	C
	Former plates	Stainless steel	B
Bottom mounted instrumentation (BMI) column assemblies	BMI column bodies	Stainless steel	B
	BMI column bolts	Stainless steel	A
	BMI column collars	Stainless steel	B
	BMI column cruciforms	CASS	B
	BMI column extension bars	Stainless steel	A
	BMI column extension tubes	Stainless steel	B
	BMI column lock caps	Stainless steel	A
	BMI column nuts	Stainless steel	A
Core barrel	Core barrel flange	Stainless steel	B
	Core barrel outlet nozzles	Stainless steel	B
	Upper core barrel	Stainless steel	C
	Lower core barrel	Stainless steel	C
Diffuser plate	Diffuser plate	Stainless steel	A

Table 5-7
List of IPEC Reactor Vessel Interior Components and Materials Based on MRP-191 – Table 4-4

LOWER INTERNALS ASSEMBLY			
Sub Assembly	**Component**	**Material**	**Category from MRP-191 Table 7-2**
Flux thimbles (tubes)	Flux thimble tube plugs - IPEC does not use tube plugs. instead tubes are capped (IP2 has 9 tubes capped, IP3 has 0 tubes capped)	Stainless steel	B
	Flux thimbles (tubes)	Stainless steel	C
Irradiation specimen guides	Irradiation specimen guide	Stainless steel	A
	Irradiation specimen guide bolts	Stainless steel	A
	Irradiation specimen lock caps	Stainless steel	A
	Specimen plugs	Stainless steel	A
Lower core plate (LCP) and fuel alignment pins	Fuel alignment pins	Stainless steel	A
	LCP fuel alignment pin bolts	Stainless steel	A
	LCP fuel alignment pin lock caps	Stainless steel	A
	Lower core plate	Stainless steel	C
Lower support column assemblies	Lower support column bodies	CASS	B
	Lower support column bolts	Stainless steel	B
	Lower support column nuts	Stainless steel	A
	Lower support column sleeves	Stainless steel	A
Lower support casting or forging	Lower support casting	CASS	A
Neutron panels/thermal shield	Thermal shield bolts	Stainless steel	A
	Thermal shield dowels	Stainless steel	A
	Thermal shield flexures	Stainless steel	B
	Thermal shield	Stainless steel	A
Radial support keys	Radial support key bolts	Stainless steel	A
	Radial support key lock keys	Stainless steel	A
	Radial support keys	Stainless steel	A
Secondary core support (SCS) assembly	SCS base plate	Stainless steel	A
	SCS bolts	Stainless steel	A
	SCS energy absorber	Stainless steel	A
	SCS guide posts	Stainless steel	A
	SCS housing	Stainless steel	A
	SCS lock keys	Stainless steel	A
Interfacing Components	Clevis insert bolts	A X-750	B
	Clevis insert lock keys	Stainless steel	A
	Clevis inserts	Alloy 600	A
	Head and vessel allignment pin bolts	Stainless steel	A
	Head and vessel alignment pin lock caps	Stainless steel	A
	Head and vessel allignment pins	Stainless steel	A
	Internals hold down spring	304 Stainless steel	B
	Upper core plate alignment pins	Stainless steel	B

Table 5-8
IPEC Response to the NRC Final Safety Evaluation of MRP-227

MRP-227 SER Item	IPEC Response
SER Section 4.1.1, Topical Report Condition 1 Moving components to "Expansion" category from "No additional measures" category.	In accordance with SER Section 4.1.1, the upper core plate and the lower support casting have been added to the IPEC "Expansion" inspection category and are contained in Table 5-3. The components are linked to the "Primary" component CRGT lower flange weld. The examination method is consistent with the examinations performed on the CRGT lower flange weld.
SER Section 4.1.2, Topical Report Condition 2 Inspection of components subject to irradiation-assisted stress corrosion cracking	In accordance with SER Section 4.1.2, the upper and lower core barrel welds and lower core barrel to lower support casting weld have been added to the IPEC "Primary" inspection category and are contained in Table 5-2. The examination method is consistent with the MRP recommendations for these components, the examination coverage conforms to the criteria described in Section 3.3.1 of the NRC SE, and the re-examination frequency is on a 10-year interval consistent with other "Primary" inspection category components.
SER Section 4.1.3, Topical Report Condition 3 Inspection of high consequence components subject to multiple degradation mechanisms	No action required. This item does not apply to components in Westinghouse designed reactors.
SER Section 4.1.4, Topical Report Condition 4 Minimum examination coverage criteria for "expansion" inspection category components	In accordance with SER Section 4.1.4, IPEC will meet the minimum inspection coverage specified in the SER. The appropriate wording has been added to Table 5-3 examination coverage.
SER Section 4.1.5, Topical Report Condition 5 Examination frequencies for baffle-former bolts	In accordance with SER Section 4.1.5, the examination frequency for baffle-former bolts specifies a 10-year inspection frequency following the baseline inspection in Table 5-2.
SER Section 4.1.6, Topical Report Condition 6 Periodicity of the re-examination of "expansion" inspection category components	In accordance with SER Section 4.1.6, Table 5-3 requires a 10-year re-examination interval for all Expansion inspection category components once degradation is identified in the associated Primary inspection category component and examination of the expansion category component commences.
SER Section 4.1.7, Topical Report Condition 7 Updating of industry guideline	This condition applies to update of the industry guidelines. No plant-specific action required.
SER Section 4.2.1, Applicant/Licensee Action Item 1	The evaluation of design and operating history demonstrating that MRP-227 is applicable to IPEC is contained in Section 3.6.
SER Section 4.2.2, Applicant/Licensee Action Item 2	The IPEC review of components within the scope of license renewal against the information contained in MRP-191 Table 4-4 is discussed in Section 3.6.
SER Section 4.2.3, Applicant/Licensee Action Item 3	The IPEC discussion regarding guide tube support pins (split pins) is contained in Section 3.6.
SER Section 4.2.4, Applicant/Licensee Action Item 4	No action required. This item does not apply to Westinghouse designed units.
SER Section 4.2.5, Applicant/Licensee Action Item 5	The IPEC discussion regarding hold down springs is contained in Section 3.6.
SER Section 4.2.6, Applicant/Licensee Action Item 6	No action required. This item does not apply to Westinghouse designed units.
SER Section 4.2.7, Applicant/Licensee Action Item 7	The IPEC discussion regarding lower support column bodies is contained in Section 3.6.
SER Section 4.2.8, Applicant/Licensee Action Item 8	The submittal of information for staff review and approval is discussed in Section 3.6.

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

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

CERTIFICATE OF SERVICE

I hereby certify that the foregoing "NRC STAFF'S ANSWER TO STATE OF NEW YORK AND RIVERKEEPER'S JOINT MOTION TO FILE A NEW CONTENTION, AND NEW JOINT CONTENTION NYS-38/RK-TC-5" in the above-captioned proceeding has been filed and served by Electronic Information Exchange (EIE), with copies to be served by the EIE system on the following persons, this 25th day of October, 2011.

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