RAS 10668

October 19, 2005

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

Before the Atomic Safety and Licensing Board

In the Matter of	)	
	)	Docket No. 50-271
ENTERGY NUCLEAR VERMONT YANKEE, LLC and ENTERGY NUCLEAR OPERATIONS, INC. (Vermont Yankee Nuclear Power Station)	)	ASLBP No. 04-832-02-OLA (Operating License Amendment)

ENTERGY'S RESPONSE TO THE NEW ENGLAND COALITION'S REQUEST FOR LEAVE TO FILE A NEW CONTENTION

Pursuant to 10 C.F.R. § 2.309(h)(1), Applicants Entergy Nuclear Vermont Yankee, LLC and Entergy Nuclear Operations, Inc.[1] (collectively "Entergy") hereby file this Response to the New England Coalition's ("NEC") "Request for Leave to File a New Contention" (Sep. 21, 2005) ("NEC Request"). The NEC Request should be rejected because it is untimely and because it fails to propose an admissible contention. *See* 10 C.F.R. §§ 2.309(f)(1), 2.309(f)(2) and 2.309(c).

I. PROCEDURAL BACKGROUND

One of the contentions originally proposed by NEC was Contention 4, which asserted that the VY extended power uprate ("EPU") applied for by Entergy should not be approved because "Entergy cannot assure seismic and structural integrity of the cooling towers under

[1] Entergy Nuclear Vermont Yankee, LLC and Entergy Nuclear Operations, Inc. are the licensees of the Vermont Yankee Nuclear Power Station ("VY").

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uprate conditions, in particular the Alternate Cooling System cell. At present the minimum appropriate structural analyses have apparently not been done."[2]

The VY Alternate Cooling System ("ACS") provides an alternate means of cooling in the unlikely event that the service water pumps become unavailable.[3] The ACS utilizes only the north end cell (CT2-1) ("Alternate Cooling System cell") of the West Cooling Tower (Cooling Tower No. 2) for service water heat removal.[4] The Alternate Cooling System cell, as well as the adjoining cell (CT2-2), are Seismic Class I structures.[5] The remaining nine cells in the West Cooling Tower and all eleven cells in the East Cooling Tower are Seismic Class II structures.[6]

In its Memorandum and Order, LBP-04-28 (Nov. 22, 2004),[7] the Board admitted NEC Contention 4 into this proceeding. As admitted, the contention read:

> The license amendment should not be approved because Entergy cannot assure seismic and structural integrity of the cooling towers under uprate conditions, in particular the Alternate Cooling System cell. At present the minimum appropriate structural analyses have apparently not been done.

LBP-04-28, 60 NRC at 580.

As part of the process that evaluates the performance of plant systems, structures and components under EPU conditions, Entergy conducted a new structural and seismic analysis of

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2 New England Coalition's Request for Hearing, Demonstration of Standing, Discussion of Scope of Proceeding and Contentions, dated August 30, 2004 ("NEC Request for Hearing") at 11.

3 Declaration of George S. Thomas dated July 10, 2005 ("Thomas Declaration"), ¶ 6. The Thomas Declaration was filed simultaneously with, and in support of, Entergy's Motion to Dismiss as Moot, or in the Alternative, for Summary Disposition of New England Coalition Contention 4, dated July 13, 2005 ("Entergy's Motion to Dismiss").

4 Thomas Declaration, ¶ 6.

5 *Id.*, ¶ 7. Seismic Class I structures are those designed to withstand the loadings produced by a design basis earthquake. Declaration of Paul D. Baughman, filed simultaneously herewith ("Baughman Declaration"), ¶4.

6 Thomas Declaration, ¶ 7; VY Updated Final Safety Analysis Report, §§ 10.8.3, 12.2.6.4.2.

7 *Entergy Nuclear Vermont Yankee L.L.C. and Entergy Nuclear Operations, Inc.* (Vermont Yankee Nuclear Power Station), Memorandum and Order, LBP-04-28, 60 NRC 548 (2004).

the cooling towers that takes into account the cooling tower modifications performed as part of the upgrade for EPU operation.[8] The new analysis is contained in the Seismic Calculation. Entergy provided the Seismic Calculation to NEC and the NRC Staff on May 25, 2005, as part of the discovery process in this proceeding.

Nearly two months later, on July 13, 2005, Entergy filed its Motion to Dismiss. The ground on which dismissal was sought was that, since the Board's admission of NEC Contention 4 was based solely on the fact that the seismic/structural analysis of the cooling towers had not yet been performed at the time the Board ruled on the admissibility of the contention, performance of the Seismic Calculation had rendered the contention moot.[9]

On September 1, 2005, the Board issued a Memorandum and Order granting Entergy's Motion to Dismiss.[10] The Board ruled: "Given that the contention was based on the 'need for Entergy to perform a seismic and structural analysis,' now that Entergy has performed this analysis, the contention is moot."[11] While dismissing NEC Contention 4 as moot[12] the Board noted that, in its response to Entergy's Motion to Dismiss, NEC had raised a number of " broad and conclusory criticisms of Entergy's seismic and structural analysis."[13] The Board declined to entertain such claims in the context of deciding whether to dismiss the existing contention, but

8 Calculation No. 1356711-C-001, *Cooling Tower Seismic Calculation* (Rev. 1), performed by ABSG Consulting ("ABS Consulting") and approved by Entergy on April 12, 2005, as VYC-2413, Rev. 0 ("Seismic Calculation"). A copy of the Seismic Calculation, minus attachments, was included as Exhibit 2 to the Thomas Declaration. A compact disk containing a copy of the entire calculation and attachments thereto was included as Exhibit 3 to that declaration. The NEC Request refers to the Seismic Calculation as the "ABS Report."

9 Entergy's Motion to Dismiss at 3. Alternatively, Entergy argued that it was entitled to summary disposition of the contention. *Id.* at 4.

10 *Entergy Nuclear Vermont Yankee L.L.C. and Entergy Nuclear Operations, Inc.* (Vermont Yankee Nuclear Power Station), Memorandum and Order Granting Motion to Dismiss NEC Contention 4, LBP-05-24, 62 NRC ___ (Sep. 1, 2005).

11 *Id.*, slip op. at 4.

12 The Board did not reach the issue whether summary disposition of the contention should be granted. *Id.* at n. 9.

granted NEC "leave to file new or amended contentions challenging the adequacy of Entergy's seismic and structural analysis within 20 days of the date of this order."[14]

On September 21, 2005, NEC filed its Request, seeking admission of a new contention. Its Request repeats the "broad and conclusory" criticisms of the Seismic Calculation raised in its response to Entergy's Motion to Dismiss and raises new, even broader challenges to the adequacy of the ACS and the seismic qualification of its components. As discussed below, the contention propounded by NEC is untimely and its sweeping allegations lack factual support and are in part outside the scope of the proceeding. Accordingly, NEC's Request should be denied.

II. UNTIMELINESS

NEC's proposed new contention is untimely in two respects: *first*, it was filed inexcusably late, since the "new" information on which it is based was available for four months before the proposed new contention was submitted; and *second*, it seeks to raise new issues on matters that have been available, unchanged, on the record of this proceeding since the EPU application was filed in 2003.

A. The Proposed New Contention is Inexcusably Late

Entergy provided a copy of the Seismic Calculation to NEC and the NRC Staff in discovery on May 25, 2005. This is not disputed by NEC. It was not until four months later, after the Board had dismissed NEC Contention 4, that NEC framed a proposed new contention challenging the calculation. Such a dilatory response to the Seismic Calculation runs contrary to the provisions of 10 C.F.R. § 2.309 (f)(2), which allows consideration of amended or new

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13 *Id.* at 5.

14 *Id.*

contentions filed after the initial filing only upon a showing that, *inter alia,* "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)(iii).

While there appears to be no case law precisely delineating the "timely fashion" requirement on the submission of new contentions, the Commission has ruled that when a contention is superseded by the issuance of licensing-related documents, the contention must be disposed of or modified, and this must be done "as early as possible."[15] Clearly, four months after the subsequent information becomes available is not "as early as possible." Thus, NEC's new contention cannot be deemed submitted "in a timely fashion" and should be dismissed as inexcusably late.

In its Request, NEC attempts to justify its tardiness by stating: "4. Given that neither of New England Coalition's experts believe that the ABS Consulting report satisfies the NRC requirement for seismic qualification of the alternate cooling system, there is no reason for New England Coalition or its experts to have acknowledged or responded to the report, when first available, as if it met that requirement. [Entergy] did not tell New England Coalition or its experts that the report, furnished by way of a discovery disclosure, was intended to satisfy Contention 4."[16] This is, of course, no excuse. Petitioners have an "ironclad obligation to examine the publicly available documentary material pertaining to the facility in question with sufficient care to enable the petitioner to uncover any information that could serve as the

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[15] *Duke Energy Corp.* (McGuire Nuclear Station, Units 1 and 2; Catawba Nuclear Station, Units 1 and 2), CLI-02-28, 56 NRC 373, 382 & n. 42 (*citing Duke Power Co.* (Catawba Nuclear Station, Units 1 and 2), CLI-83-19, 17 NRC 1041, 1050 (1983)).

[16] NEC Request at 14.

foundation for a specific contention."[17] NEC knew that a seismic calculation for the cooling towers was in preparation, and was also aware that NEC Contention 4 had been admitted as a claim of omission and was subject to being dismissed once the calculation was performed. NEC also does not deny that it became aware of the Seismic Calculation when it was produced in discovery. Therefore, the "ironclad obligation" that NEC had to examine the licensing documentation to identify potential new issues was particularly strong in this instance, and NEC simply failed to satisfy its obligation.

In its Memorandum and Order dismissing NEC Contention 4, the Board stated that "'if NEC moves for leave to file new or amended contentions challenging the adequacy of Entergy's seismic and structural analysis within 20 days of the date of this order, then the motion and contentions will be deemed timely for purposes of 10 C.F.R. § 2.309(f)(2)(iii)."[18] Entergy believes, however, that the Board was unaware of the above described circumstances, and respectfully requests that it reconsider its ruling in light of them and the controlling Commission precedent in *McGuire*.

B. Many of the Allegations in NEC's Proposed New Contention are Untimely Raised

NEC's proposed new contention reads:

> The Entergy Vermont Yankee [Entergy] license application (including all supplements) for an extended power uprate of 20% over rated capacity is not in conformance with the plant specific original licensing basis and/or 10 CFR Part 50, Appendix S, paragraph I(a), and/or 10 CFR Part 100, Appendix A, because it

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17 *McGuire, supra,* 56 NRC at 36, *quoting* Final Rule, "Rules of Practice for Domestic Licensing Proceedings – Procedural Changes in the Hearing Process," 54 Fed. Reg. 33,168, 33,170 (Aug. 11, 1989). Although *McGuire* and the excerpt from the Federal Register notice it cites refer to petitions for a hearing and the filing of contentions at the beginning of the hearing process, there is no principled basis for applying a different rule to late-filed contentions by intervenors like Petitioner.

18 LBP-05-24, slip op. at 5. This timeliness determination was made without the parties having an opportunity to address the issue.

> does not provide analyses that are adequate, accurate, and complete in all material respects to demonstrate that the Vermont Yankee Nuclear Power Station Alternate Cooling System [ACS][1] in entirety, in its current actual physical condition (or in the actual physical condition [Entergy] will effectuate prior to commencing operation at EPU), will be able to withstand the effects of an earthquake and other natural phenomena without loss of capability to perform its safety functions.[2] [Entergy] must be able to demonstrate that the actual structures, systems and components comprising the ACS will perform satisfactorily in service at the requested increased plant power level.
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> [1] The ACS system includes, but is not limited to, towers, fill, structural members and bracing, shear pins and/or tie rods, basins, piping, pumps, valves and controls, fan motors, fan decks and fan gearing, emergency electrical supply, and all components vital to design basis objectives and licensing basis requirements intended to assure operability when the system is called upon in an emergency.
> [2] Under uprate conditions, in particular, the removal of additional decay heat generated by uprated reactor power, any seismically induced impairment of the ACS function is apt to eliminate already attenuated margins.

The contention, its bases and its "supporting evidence" attempt to raise new issues that go far beyond the adequacy of the Seismic Calculation:[19]

- The ability of the ACS "in its entirety" *including, "but . . . not limited to*, towers, fill, structural members and bracing, shear pins and/or tie rods, basins, piping, pumps, valves and controls, fan motors, fan decks and fan gearing, emergency electrical supply, and all components vital to design basis objectives and licensing basis requirements intended to assure operability when the system is called upon in an emergency" to "withstand the effects of an earthquake *and other natural phenomena* without loss of capability to perform its safety functions."[20]

- The risk that "[u]nder uprate conditions, in particular, the removal of additional decay heat generated by uprated reactor power, any seismically induced impairment of the ACS function is apt to eliminate already attenuated margins."[21]

- Entergy's failure to provide "analyses that are adequate, accurate, and complete in all material respects which contravene this assertion and demonstrate that the actual structures, systems and components comprising the ACS will perform satisfactorily in service at the requested increased plant power level."[22]

19 It should be kept in mind that the scope of NEC Contention 4 was a challenge to the seismic qualification of the Alternative Cooling System cell because of the lack of up-to-date structural and seismic analyses.

20 NEC Request at 1, emphasis added.

21 *Id.* at n. 2.

22 *Id.* at 2.

- Entergy's failure to "demonstrate that the entire Vermont Yankee Nuclear Power Station Alternate Cooling System [ACS] in its current actual physical condition (or in the actual physical condition [Entergy] effectuates prior to commencing operation at EPU) will be able to withstand the effects of a Safe Shutdown or Design Basis earthquake and other natural phenomena without loss of capability to perform its safety functions" and its failure to "demonstrate that the actual structures, systems and components comprising the ACS will perform satisfactorily in service at the requested increased plant power level."[23]

- The non-conservative nature of the design basis earthquake used to prepare the Seismic Calculation, when compared to the seismic hazard maps prepared for FEMA in 1988.[24]

- Entergy's failure to demonstrate "that the actual structures, systems and components comprising the ACS will perform satisfactorily in service at the requested increased plant power level."[25]

None of these alleged deficiencies was raised by the NEC in its original Request for Hearing, filed in August of last year, and NEC does not link these alleged deficiencies to any new information. Indeed, there has been no subsequently developed information that provided a basis for these claims. In the absence of subsequently developed information, NEC is not allowed to raise new issues in its attempt to frame a new contention on the seismic capabilities or the seismic performance of the Alternate Cooling System cell.[26]

The consultant on whom NEC relies in proffering its proposed new contention confirms that there is no subsequently developed information.[27] He asserts that "[a] diligent search of the

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23 *Id.* at 3-4, footnote omitted, emphasis in original.

24 *Id.* at 11. Notably, the Board has already rejected a contention proffered by the Department of Public Service that sought to impose later, more stringent seismic standards on VY. LBP-04-28, 60 NRC at 567.

25 NEC Request at 12.

26 *McGuire, supra,* 56 NRC at 386; *Philadelphia Electric Co.* (Limerick Generating Station, Units 1 and 2), ALAB-819, 22 NRC 681, 709 (1985).

27 NEC sought to oppose dismissal of NEC Contention 4 by filing a Declaration by its consultant Mr. Arnold Gundersen. *See* Declaration of Arnold Gundersen Opposing Summary Disposition of New England Coalition's Contention 4 (Aug. 2, 2005) ("Gundersen 2005 Declaration"). After NEC Contention 4 was dismissed as moot, NEC retained another consultant, Dr. Ross Landsman, to submit a Declaration in support of its new proposed contention. Declaration of Dr. Ross B. Landsman Supporting New England Coalition's Alternate Cooling System Contention, dated September 19, 2005 ("Landsman Declaration"). In his Declaration, Dr. Landsman

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Vermont Yankee Nuclear Power Station docket on ADAMS (05000271) from September 2003 to date uncovered no document other than the ABS Consulting report that [Entergy] produced to address seismic qualification of the Alternate Cooling System."[28] NEC's new claims, therefore, are untimely and NEC has made no attempt to explain their lateness, or sought to demonstrate that the factors enumerated in 10 C.F.R. §2.309(f)(2) warrant their consideration. Accordingly, these claims must be rejected as untimely attempts to raise new contentions.

NEC's attempts would be prohibited by the Commission rules even if NEC were only attempting to supplement an existing contention, let alone submit new ones. As the Commission stated in the *LES* proceeding:

> "Allowing contentions to be added, amended, or supplemented at any time would defeat the purpose of the specific contention requirements" . . . "by permitting the intervenor to initially file vague, unsupported, and generalized allegations and simply recast, support, or cure them later." The Commission has made numerous efforts over the years to avoid unnecessary delays and increase the efficiency of NRC adjudication and our contention standards are a cornerstone of that effort. We believe that the 60-day period provided under 10 C.F.R. § 2.309(b)(3) for filing hearing requests, petitions, and contentions is "more than ample time for a potential requestor/intervenor to review the application, prepare a filing on standing, and develop proposed contentions and references to materials in support of the contentions." Under our contention rule, Intervenors are not being asked to prove their case, or to provide an exhaustive list of possible bases, but simply to provide sufficient alleged factual or legal bases to support the contention, and to do so at the outset.[29]

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largely re-asserts the claims made in the Gundersen 2005 Declaration. Dr. Landsman's resume, attached as Exhibit A to his Declaration, does not reveal that he possesses any training, experience or other qualifications in the seismic design or analysis of cooling towers.

28 Landsman Declaration, ¶7.

29 *Louisiana Energy Services, L.P.* (National Enrichment Facility), CLI-04-35, 60 NRC 619, 622-23 (2004), footnote omitted; *McGuire*, 56 NRC at 386.

III. THE PROPOSED CONTENTION AND ITS ASSERTED BASES ARE IMPERMISSIBLY BROAD AND VAGUE

NEC's proposed new contention asserts that the EPU application "does not provide analyses that are adequate, accurate, and complete in all material respects to demonstrate that the Vermont Yankee Nuclear Power Station Alternate Cooling System [ACS] in entirety, in its current actual physical condition (or in the actual physical condition [Entergy] will effectuate prior to commencing operation at EPU), will be able to withstand the effects of an earthquake and other natural phenomena without loss of capability to perform its safety functions."[30] Neither the contention nor the bases asserted in its support identify which analyses are inadequate, inaccurate, or incomplete, or which components of the system are subject to these alleged deficiencies. Such broad brush allegations, coupled with the extremely expansive and vague definition of the ACS propounded by NEC (said to include, but not be limited to, "towers, fill, structural members and bracing, shear pins and/or tie rods, basins, piping, pumps, valves and controls, fan motors, fan decks and fan gearing, emergency electrical supply, and all components vital to design basis objectives and licensing basis requirements intended to assure operability when the system is called upon in an emergency"), do not satisfy the requirement that admissible contentions "must explain, with specificity, particular safety or legal reasons requiring rejection of the contested [application]." [31] Therefore, the contention must be rejected, as it "is not conducive to the fair and efficient management of this proceeding."[32]

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30 NEC Request at 1, footnotes omitted.

31 *Dominion Nuclear Connecticut, Inc.* (Millstone Nuclear Power Station, Units 2 and 3), CLI-01-24, 54 NRC 349, 359-60 (2001); 10 C.F.R. §2.309(f)(1)(vi).

32 LBP-05-24, slip op. at 5. *See also Arizona Public Service Co.* (Palo Verde Nuclear Generating Station, Units 1, 2, and 3), CLI-91-12, 34 NRC 149, 155-56 (1991); *Fansteel, Inc.* (Muskogee, Oklahoma Site), CLI-03-13, 58

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IV. THE PROPOSED CONTENTION LACKS FACTUAL BASIS

NEC asserts four bases in support of its proposed new contention: (1) The ACS and its components are not seismically qualified and [Entergy] has not provided analyses that are adequate, accurate, and complete in all material respects which contravene this assertion and demonstrate that the actual structures, systems and components comprising the ACS will perform satisfactorily in service at the requested increased plant power level.[33] (2) The ACS "is (and it comprised of) structures, systems and 'components important to safety' which must be able to withstand the effects of natural phenomena, such as earthquakes, without loss of capability to perform their safety functions. They must also be able to perform satisfactorily in service at the requested increased plant power level."[34] (3) Entergy "must provide documentation, per 10 CFR 50.9(a), that, e.g., the ACS under uprate condition will be in compliance with the original design basis as licensed by the Commission and that the actual structures, systems and components comprising the ACS will perform satisfactorily in service at the requested increased plant power level."[35] (4) The Seismic Calculation "is <u>not</u> adequate, accurate, and complete in all material respects, and does not demonstrate that the entire Vermont Yankee Nuclear Power Station Alternate Cooling System [ACS] in its current actual physical condition (or in the actual physical condition [Entergy] effectuates prior to commencing operation at EPU) will be able to withstand the effects of a Safe Shutdown or Design Basis earthquake and other natural phenomena without loss of capability to perform its safety

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NRC 195, 203 (2003); *GPU Nuclear, Inc.* (Oyster Creek Nuclear Generating Station), CLI-00-6, 51 NRC 193, 208 (2000).

33 NEC Request at 2.

34 *Id.* at 3.

35 *Id.*, emphasis in original.

functions. It does not demonstrate that the actual structures, systems and components comprising the ACS will perform satisfactorily in service at the requested increased plant power level."[36]

None of the four bases supports the proposed new contention.

A. Basis 1 Lacks Factual Support

Basis 1 claims that the ACS and its components "are not seismically qualified and [Entergy] has not provided analyses that are adequate, accurate, and complete in all material respects which contravene this assertion and demonstrate that the actual structures, systems and components comprising the ACS will perform satisfactorily in service at the requested increased plant power level."

It is unclear whether the allegations raised in Basis 1 are different from those in Basis 4 (discussed below). If Basis 1 (and Basis 4, to the extent that the two bases overlap) is alleging that the structures, systems and components comprising the ACS, *other than the Alternate Cooling System cell*, have not been demonstrated capable of performing adequately in service during EPU operations, those unsubstantiated assertions are new claims, not raised in NEC's original Petition. These new claims refer to matters discussed in the original EPU application and supplements thereto, which have been outstanding now for almost two years. For example, Entergy stated in Supplement 4 to the application, submitted under letter BVY 04-009 dated January 31, 2004, the following information:[37]

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36 *Id.* at 3-4, footnote omitted, emphasis in original.

37 Entergy letter BVY-009, dated January 31, 2004, Attachment 6, at 8-9, ADAMS Accession No. ML040360118 at 214-215, copy enclosed as Attachment 1.

SE 2.5.3.4 VY NOTE, Ultimate Heat Sink: VYNPS uses the Connecticut River as its Ultimate Heat Sink (UHS) to provide cooling water for both normal and accident conditions. This cooling water is delivered by both safety and non-safety related portions of the Service Water System (SWS). Additionally, an Alternate Cooling System (ACS) based on a dedicated portion of the VYNPS cooling towers and RHR Service Water (RHRSW) pumps, is available for the remote scenario where either the intake structure or the downstream dam is lost. All of the SWS and ACS have been evaluated for CPPU conditions. The evaluations have included the consideration of the most limiting environmental conditions for the Connecticut River or cooling tower including peak seasonal river and air temperatures. The increased decay heat load associated with CPPU reactor core post-shutdown conditions were included in the evaluations. As a result of the system and equipment analysis, a modification to re-circulate ACS (RHRSW) pump motor cooler water back to the cooling tower instead of discharging it to the river are planned to ensure adequate inventory is available to meet the 7 day requirement associated with the ACS design basis functional scenario. This modification is the result of the increased decay heat. The following conclusions were reached in the VYNPS CPPU UHS and ACS evaluations:

- No SW flow or supply temperature changes are required to support CPPU normal operation.
- No SW flow or SW supply temperature changes are required to support CPPU LOCA operation.
- No SW flow or SW supply temperature changes are required to support CPPU Shutdown Events operation.
- SW system pump NPSH required and available is unchanged.
- All heat exchangers remain within design temperatures including consideration of tube plugging.
- The ACS cooling tower (deep basin) inventory is assured with the modification to the ACS pump motor cooler flow.
- The ACS pump NPSH and capacity are adequate.

- ACS deep basin temperature remains below 130 °F to protect cooling tower fill.
- ACS will maintain required loads including its system components, spent fuel pool and torus within required limits.

Thus, it has been Entergy's position from the start that the ACS is adequate to perform its safety function, and that it does not need to be changed as part of the proposed uprate. That position had not been previously challenged by NEC, and any such challenge at this late date would be grossly untimely and should be rejected. In addition, the performance of the ACS under uprate conditions has been analyzed by Entergy and demonstrated to be adequate, so the analyses that NEC claims do not exist have been available in the record of this proceeding for over a year.[38] For that reason, the untimely claims of system inadequacy contained in Basis 1 are also without any factual support and should be rejected.[39]

B. Basis 2 Sets No Facts in Dispute

Basis 2 alleges no facts that need adjudication. It merely asserts that the ACS and the structures, systems and components that comprise it must be able to withstand the effects of

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[38] Entergy's position that the ACS in its existing, licensed configuration will perform adequately under EPU conditions was restated and expanded on July 30, 2004 in an analysis submitted in response to a Staff request for additional information. See Response to RAI SPLB-A-9, Attachment 2 to letter BVY 04-074, ADAMS Accession No. ML 042160195, copy enclosed as Attachment 2. NEC did not contest Entergy's analysis contained in this submission. Indeed, NEC's Request does not even acknowledge the existence of this analysis.

natural phenomena, such as earthquakes, without loss of capability to perform their safety functions, and must also be able to perform satisfactorily in service at the requested increased power level. Such assertions are merely restatements of the regulatory requirements governing the performance of the ACS and provide no support for the proposed contention.

C. Basis 3 Sets no Facts in Dispute

Basis 3 asserts that Entergy must provide documentation that the ACS, at the uprate conditions, will be in compliance with the original design basis licensed by the Commission and that the structures, systems and components comprising the ACS will perform satisfactorily in service at the requested increase power level. Again, those assertions are only restatements of the regulatory requirements governing the performance of the ACS and provide no support for the proposed contention.

D. Basis 4 Lacks Factual Support

Basis 4 contends that the Seismic Calculation is "not adequate, accurate, and complete in all material respects, and does not demonstrate that the entire Vermont Yankee Nuclear Power Station Alternate Cooling System [ACS] in its current actual physical condition (or in the actual physical condition [Entergy] effectuates prior to commencing operation at EPU) will be able to withstand the effects of a Safe Shutdown or Design Basis earthquake and other natural phenomena without loss of capability to perform its safety functions. It does not demonstrate

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[39] By the same token, any challenge to the seismic qualification of any other portion of the ACS besides the Alternate Cooling System cell must be rejected as untimely new contentions and as a challenge to the licensed basis of the system, which has not been changed as part of the proposed uprate.

that the actual structures, systems and components comprising the ACS will perform satisfactorily in service at the requested increased plant power level." [40]

NEC identifies several respects in which it claims that the Seismic Calculation is deficient. The deficiencies are generally not with the calculation itself; for the most part, NEC does not take exception to the analytical methods, modeling techniques, or computed results. Rather, most of the shortcomings alleged by NEC in the proposed new contention are, as was the case in former NEC Contention 4, errors of omission. NEC claims that:

- ABS Consulting failed to conduct a physical examination of the alternate cooling tower cell;
- The Seismic Calculation fails to provide adequate documentation of the breaking strength of the tie rods;
- The Seismic Calculation fails to use added conservatism in accounting for the effects of aging mechanisms and/or moisture and/or cooling system chemicals;
- The calculation's structural analysis fails to assign a negative value to the replacement rate for degraded members;
- The Seismic Calculation fails to account for changes to ACS after it was completed;
- ABS Consulting made incorrect and non-conservative assumptions concerning the condition of the concrete in the alternate cooling tower cell and failed to take into account the unanalyzed effects of recent modification including steel splices; and

[40] Basis 4 appears to be repetitive of Basis 1. Also, to the extent that Bases 1 through 4 imply that there is no evidence that the ACS will perform its intended safety function under uprate conditions for any reason not related to the seismic performance of the Alternate Cooling System cell, the implication is inadmissible as an untimely new claim. It is also unsupported and, as discussed above, factually incorrect.

- ABS Consulting failed to provide reasonable assurance of seismic qualification of the ACS.[41]

As will be demonstrated below, these "errors of omission" are non-existent. The alleged deficiencies in the Seismic Calculation are without factual basis.

1. **Lack of physical examination of the actual ACS**

NEC claims:[42]

> ABS consultants do not claim to have conducted a physical examination of the alternate cooling tower cell. The Vermont Yankee cooling towers are thirty-five year old wooden structures. The towers rest on and deliver water to substructure concrete basins. The towers operate in a caustic environment and are subject as well to other aging mechanisms including, e.g., vibration, biotic and chemical reductions, corrosion, and temperature extremes. Failure to collect and utilize field data indicating actual physical condition of these structures, as they would be affected under uprated loads, is not a sound engineering approach. The ABS Consultant report assumes that the "as is" condition of the cooling towers is accurately reflected in existing plant documentation.
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> [T]he ABS report I reviewed fails to take into account the conditions [Mr. Gundersen] describes, viz., operation in an unanalyzed safety condition due to the fact that although "the safety related seismic cooling tower had its fill replaced in the mid 1980's... that modification was never properly analyzed to determine if it effected the seismic qualification of the tower." It is apparent that Entergy Vermont Yankee will have to make additional fill modifications. Because the fill holds more water, there will be increased loading. Additional loading reduces seismic performance margin.

41 NEC Request at 5-6; Landsman Declaration, ¶7.

42 NEC Request at 6; Landsman Declaration, ¶¶7,8.

NEC's claim rests on the unwarranted assumption that no inspection of the VY cooling towers was performed in connection with the preparation of the Seismic Calculation. As this assumption is incorrect, the alleged deficiency is without basis.

On March 29 and 30, 2005 Paul Baughman and Richard Augustine of ABS Consulting conducted a contractually-required walk-through inspection of each cell in each cooling tower.[43] They inspected the towers to verify that the arrangement, member sizes, and connections details of the load bearing members were as shown on the drawings. They also verified that modeling assumptions were reasonable, and confirmed that the physical condition of the towers matched the calculation's assumptions.[44] For example, they inspected the anchor bolts that secure the tower to the foundation concrete and the concrete in the foundations and confirmed they were in good condition.[45]

The allegation that the fill replacement that was made in 1986 was never properly analyzed is not new. NEC raised the same claim in connection with the initial filing of NEC Contention 4. The Board rejected NEC's claim as irrelevant:

> Whether Entergy's prior seismic or structural analyses of the cooling towers, basins or fans are compliant with its <u>current</u> licensing basis is not relevant to this proceeding unless there is a clear and direct relationship to the alleged need for an analysis of these structures and systems under the <u>proposed</u> uprate conditions.

LBP-04-28, 60 NRC at 573, n. 30, emphasis in original. The basis for rejecting this claim as irrelevant is even stronger here, for there is no dispute that the Seismic Calculation uses the current values of cooling tower fill water loadings. Therefore, whatever the merits of the 1986

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43 Baughman Declaration, ¶8.

44 *Id.*, ¶¶8-9. Only one connection detail was found that did not agree with the drawings. This discrepancy was communicated to Entergy and was promptly corrected. *Id.*, ¶9.

45 *Id.*, ¶10.

analysis, it has been superseded by the Seismic Calculation, which does use the current fill parameters. NEC's claim is still irrelevant.

2. **Lack of adequate documentation of the breaking strength of the tie rods**

NEC claims:[46]

> [T]he ABS Consulting report fails to take into account the effects of lack of adequate documentation of the breaking strength of the tie rods connecting seismic and non-seismic cells. It also fails to take into account the effect of the absence of that data on seismic qualification of the alternate cooling system. Absent a complete analysis of the breaking strength of the tie rods, under both tensile and compressive loads, as well as horizontal loads transmitted through sixty-inch diameter heavy wall (1.2" thick) header pipes, ABS has no basis to conclude that the collapse of one or more cells would not propagate through additional cells.

This aspect of the proposed NEC contention appears to allege that the Seismic Calculation should have taken into account the forces that could be transmitted from the Seismic Class II cells in CT-2 to the Alternate Cooling System cell and the cell adjacent to it. Those forces, according to NEC, could be transmitted through "tie rods" and "header pipes". The design documents on the record, including the Seismic Calculation, show that the transmittal of earthquake loadings from the Seismic Class II cells to the Alternate Cooling System cell and the cell adjacent to it is not possible because the connections between them will break under seismic forces.

a. Tie Rods

NEC claims that the Seismic Calculation is deficient in that it fails to take into account the breaking strength of the tie rods connecting Seismic Class I and Seismic Class II cells. The tie rods in question are "breakaway ties" located in cell CT2-3 of the West Cooling tower.[47]

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[46] NEC Request at 7; Landsman Declaration, ¶¶10, 11.

[47] Baughman Declaration, ¶11.

They are not made out of steel, but of wood, and are not bolted to the members but attached to them with nails.[48] These nailed wood splices are designed to break in a seismic event prior to the failure of Seismic Class II cell CT2-3, thus detaching the Seismic Class I cells (CT2-1 and CT2-2) from the Seismic Class II portions of the cooling tower.[49]

The Seismic Calculation did not include these breakaway ties as load bearing elements, because it only considered bolted structural connections as load bearing.[50] The reason is that nails have small load carrying capacity as compared to bolted connections.[51] In addition, as their name implies, these breakaway ties will break loose at low seismic levels and separate the Seismic Class I cells from the Seismic Class II cells prior to the failure of any of the cells, and therefore will not transmit loadings from the Seismic Class II cells to the Seismic Class I cells.[52] Therefore, it was appropriate to exclude these breakaway ties from the seismic analyses. NEC has provided no evidentiary support to the contrary, but has limited itself to pointing out the existence of the tie rods without addressing their materials or design.

b. Header Pipe

NEC alleges that horizontal forces will be transmitted to the Alternate Cooling System cell "through sixty-inch diameter heavy wall (1.2" thick) header pipe." NEC provides no support for its claim that the header pipe is "heavy wall" and "1.2" thick." In fact, the Seismic Calculation makes it clear that the piping in question (the circulating water distribution header) is made of sections of fiberglass pipe connected together through bell and spigot joints, and has

[48] *Id.*

[49] *Id.*

[50] *Id.*

[51] *Id.*

[52] *Id.*, ¶ 12.

only a ½" wall thickness.[53] Thus, during a seismic event, the piping is not strong enough to transmit horizontal loads from one cell to another, and can be disregarded in the analysis.[54] In addition, since the pipe is constructed with bell and spigot type joints, during seismic conditions the pipe will pull apart at the joints rather than transferring longitudinal loads from one cell to another.[55] Thus, it was appropriate not to include in the calculation the transmission of seismic forces to the Seismic Class I cells through the header piping.[56]

3. **Failure to add conservatism in accounting for the effects of aging mechanisms and/or moisture and/or cooling system chemicals**

NEC claims:[57]

> Entergy's April 2005 ABS Consulting seismic evaluation and accompanying materials do not indicate that ABS took into account the actual "as-found" physical condition of the cooling towers at issue as there is an absence of additional conservatisms to account for the effects of aging and/or moisture and/or cooling system chemicals and/or biotic action on the wooden structural members, steel connecting hardware, reinforcement rods and concrete within tower basins.

The Seismic Calculation was performed in accordance with the provisions of the Cooling Tower Institute's ("CTI") "Standard Specifications for the Design of Cooling Towers with Douglas Fir Lumber", CTI Bulletin STD-114 November 1996 ("CTI Bulletin STD-114").[58] That standard provides for reductions in the computed strength of cooling tower members to account

[53] *See* Seismic Calculation, page 12, copy of which is included for convenience as Attachment 3.

[54] Baughman Declaration, ¶13.

[55] *Id.*

[56] *Id.*

[57] NEC Request at 7; Landsman Declaration, ¶12.

[58] CTI Bulletin STD-114 is cited as Reference 11 on page 181 of the Seismic Calculation.

for, *inter alia*, wet conditions and the operating temperatures of the cooling towers.[59] Further conservatisms were included in the Seismic Calculation; those are described on pages 8 and 9 of the calculation.[60] Accordingly, the calculation properly accounts of the effects of aging and other detrimental factors. NEC does not acknowledge that the Seismic Calculation incorporates the conservatisms called for in CTI Bulletin STD-114, and gives no evidence that NEC or its consultants are even familiar with this industry standard.

4. **Failure to assign a negative value to the replacement rate for degraded members**

NEC claims:[61]

> [T]he assumption in the ABS Consulting report, at 12 of 182, "that all lumber is capable of supporting the full design capacities based on ongoing inspection and replacement regime in place at VY" is intended to indicate that the material in the cooling towers is as sound, therefore as strong as new. However, the "replacement" regime following visual inspection verifies that some structural members are found to be substandard and therefore they are replaced.

The full credit given in the Seismic Calculation to the load bearing capacity of the tower members (as reduced by the conservative assumptions incorporated in the analysis) is validated by the fact that the actual conditions of the cooling tower cells match the design documents, as confirmed in the ABS Consulting walkdowns.[62] This is no happenstance. Entergy conducts twice-a-year inspections of the cooling towers in accordance with a "Cooling Tower Inspection

59 A copy of CTI Bulletin is included as Attachment 4. Section 11 of the Bulletin and associated tables list the conservatisms provided by the code.

60 For example, the Seismic Calculation conservatively assumes that the design snow/ice loads occur simultaneously with design summer temperature conditions, which results in a corresponding reduction in member strengths due to the high temperatures. Declaration of George S. Thomas, dated July 10, 2005 (submitted in support of Entergy's Motion to Dismiss), ¶10.

61 NEC Response at 8; Landsman Declaration, ¶13.

Guideline" that specifies the items to be inspected.[63] In particular, Sections III and IV (pp. 6-9) of the Guideline provide instructions for structural inspections. Section VI (p. 15) contains inspection instructions for the water basins under the towers. The Guideline includes a set of Classification Criteria that allow classification of the level of structural degradation at the time it is discovered so appropriate corrective action can be taken. Similar inspections are conducted of the cooling tower deep basin.[64] NEC fails to acknowledge the performance of these inspections.

Thus, it was appropriate for ABS Consulting to assume that the "as is" condition of the cooling towers is accurately reflected in existing plant documentation.

5. **Failure to account for changes to the cooling towers after the ABS Study**

NEC claims:[65]

> [Entergy] made changes, including the attachment of braces to the cooling towers[,] after the ABS Cooling Tower Seismic Evaluation was completed. In addition, NRC Inspection Staff noted degradation of cooling basin concrete. *See* NRC Integrated Inspection Report 05000271/2005003 (July 20, 2005) (ADAMS #ML052020003) (at 1R23 Temporary Plant Modifications (71111.23), Inspection Scope (one sample) (installation of structural steel splices in cooling tower CT2-1), at 1R15 Operability Evaluations (71111.15), Inspection Scope (seven samples) (visibly obvious degradation of the alternate cooling deep basin cement wall)).

Footnote continued from previous page

62 *See* Baughman Declaration, ¶9.

63 A copy of Entergy's "Cooling Tower Inspection Guideline" is included as Attachment 5. A copy of the most recent inspection, conducted in the spring of 2005, of the West Cooling Tower (which contains the Alternate Cooling System cell) is included as Attachment 6.

64 Attachment 7 documents the most recent deep basin inspection, conducted in 2002.

65 NEC Response at 8-9; Landsman Declaration, ¶14.

This claim by NEC involves two items referenced by the NRC resident inspectors at VY during a routine inspection conducted under the staff's oversight program for operating reactors.[66] Each is discussed separately below.

a. Installation of Temporary Splices

One inspection item, reported in the NRC Inspection Report under the heading "Temporary Plant Modifications (71111.23),"[67] reads:

> a. Inspection Scope (one sample)
>
> The inspectors reviewed temporary modification (TM) 2005-004, "Installation of Structural Steel Splices on Cooling Tower CT-2-1," and calculation VYC-2404, "Design of Structural Member Splices on Cooling Tower CT-2 for TM 2005-004," and discussed the modification with the responsible engineer to ensure that the modification did not adversely affect the availability or functional capability of the cooling tower. The inspectors also walked down the accessible portions of CT 2-1 to verify the TM was properly maintained and there were no obvious deficiencies.
>
> b. Findings No findings of significance were identified.[68]

The objective of this type of inspection is to "verify that temporary modifications have not affected the safety functions of important safety systems." [69] The inspection is to, *inter alia*: review the temporary modifications against the system design bases and verify that the modifications have not affected system operability/viability; verify that the installation and restoration of the temporary modifications are consistent with the modification documents; verify that the licensee has evaluated the combined effects of the outstanding temporary

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66 See Attachment 8, letter dated July 20, 2005 from Clifford J. Anderson (NRC) to Jay K. Thayer (Entergy), Enclosure, Report No. 05000271/2005003 ("Report No. 05000271/2005003") at iii. The inspection identified "no findings of significance." *Id.*

67 The designation "Temporary Plant Modifications (71111.23)" refers to NRC Inspection Procedure 71111.23, available online at http://www.nrc.gov.edgesuite.net/reading-rm/doc-collections/insp-manual/inspection-procedure/. A copy or this procedure is included as Attachment 9.

68 Report No. 05000271/2005003 at 7-8.

69 NRC Inspection Procedure 71111.23 at 1.

modifications in regard to mitigating systems and the integrity of radiological barriers. [70] Thus, the inspection verified that the temporary modifications did not affect the system's operability, and the inspectors determined that the temporary installation of structural member splices on Cooling Tower cell CT 2-1 identified no findings of significance.[71] This finding *confirms* that the temporary modification did not impair the safety function of the ACS. Thus, NEC's reliance on the NRC inspection to raise questions about the seismic capability of the system is without factual basis. [72]

b. Degradation of Cooling Basin Concrete

The other item from the NRC Inspection Report cited by NEC reads as follows:

> Operability Evaluations (71111.15)[73]
>
> a. Inspection Scope (seven samples)
>
> The inspectors reviewed seven operability determinations prepared by Entergy. The inspectors evaluated operability determinations against the requirements and guidance contained in NRC Generic Letter 91-18, "Resolution of Degraded and Nonconforming conditions," as well as Entergy procedure ENN-OP-104, "Operability Determinations." The inspectors evaluated the adequacy of the following evaluations of degraded or nonconforming conditions:
>
> * * *
>
> - Damage to alternate cooling deep basin cement wall;

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70 *Id.* at 1-2.

71 The temporary modification reviewed by the NRC, Temporary Modification 2005-004, "Installation of Structural Steel Splices on Cooling Tower CT2-1," is enclosed as Attachment 10.

72 In addition, NEC and its consultant ignore the findings by the NRC Staff that the two items they raise resulted in "[n]o findings of significance [being] identified." It is well established that a document cited in support of the admission of a proposed contention must be subject to scrutiny both as to those portions of it which support the intervenor's assertions and those portions which do not. *See Yankee Atomic Elec. Co.* (Yankee Nuclear Power Station), LBP-96-2, 43 NRC 61, 90 n.30, *rev'd in part on other grounds* CLI-96-7, 43 NRC 235 (1996). Here the NRC findings clearly refute NEC's allegations as to the significance of the reported conditions.

73 NRC Inspection Procedure 71111.15, available online at http://www.nrc.gov.edgesuite.net/reading-rm/doc-collections/insp-manual/inspection-procedure/. A copy or this procedure is included as Attachment 11.

* * *

b. Findings No findings of significance were identified.[74]

The objective of this Staff inspection procedure is to "review operability evaluations affecting mitigating systems and barrier integrity to ensure that operability is properly justified and the component or system remains available, such that no unrecognized increase in risk has occurred."[75] The inspection includes, *inter alia*, "[r]eview[ing] the technical adequacy of the licensee's operability evaluation, and verify[ing] that operability is justified."[76]

In the cited instance, the NRC inspectors reviewed Entergy's operability determination for the damage to the alternate cooling deep basin cement wall[77] and concluded that "[n]o findings of significance were identified." Thus, instead of lending support to NEC's claim, the NRC inspection shows the claim to be invalid.[78]

6. Improper accounting for the current, actual strength of the concrete

NEC claims:[79]

> ABS engineers assumed that in all cases concrete strength increases over time. *Id.* In this regard, he finds it significant that ABS failed to take into account the physical condition of the structures they were analyzing. Although "ideal" concrete may increase in strength over time, "given the age and caustic

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74 Report No. 05000271/2005003 at 5-6.

75 NRC Inspection Procedure 71111.15 at 1.

76 *Id.*

77 A copy of Entergy's operability determination for the damage to the wall, "ENVY System Engineering Initial Operability Recommendation, dated May 2, 2005," is enclosed as Attachment 12. It concludes, in relevant part, that "[t]he areas of degraded concrete are above ACS water level and perform no seismic structural function." *Id.* at 3.

78 Again, NEC and its consultant ignore this determination by the NRC Staff inspectors.

79 NEC Response at 9-10; Landsman Declaration, ¶15.

> environment within these towers, [such an assumption] in not properly conservative."
>
> * * *
>
> It is the case that "age does not improve the tension characteristics of reinforced concrete" because "rebar always degrades" and "[t]hat degradation [is] accelerated under the caustic conditions within the cells." *Id.*

This claim is based on two assumptions, both erroneous: (1) that the actual condition of the installed concrete in the cooling tower foundations is different from that assumed in the calculation due to the effects of "age and caustic environment," and (2) that the condition of the concrete rebar and its strength in tension are relevant to the seismic calculation.[80]

There is no evidence that the cooling towers are exposed to a "caustic" environment, and NEC offers none. To the contrary, the discharge from the Circulating Water System at VY is regulated by the State of Vermont Discharge Permit, which imposes strict limits on the pH of the water, temperature and chemical composition of the discharge.[81]

With respect to aging and its effects on the "tension characteristics" of the rebar in the concrete, those allegations are irrelevant, since the concrete strength is used in the calculation

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80 NEC goes on to argue that "this is a prime example of the need for an actual, physical inspection as the basis for any report prepared on the Appendix S qualification of the ACS (and its components) under extended power uprate conditions." NEC Response at 10. However, as discussed above, such an inspection was conducted in connection with the preparation of the Seismic Calculation. The walkdowns conducted by ABS Consulting established that the condition of the concrete at the cooling towers' foundations was acceptable. Baughman Declaration, ¶10.

81 See State of Vermont Discharge Permit No. 3-1199, enclosed as Attachment 13. The Circulating Water discharge is described in Section A.1 starting on page 2 of the permit. The permit sets an allowable pH of 6.5 to 8.5 (page 2) and defines the allowed temperatures at various times during the year (pages 4-5). When the Cooling Towers are in operation and the plant is discharging to the river, the chemical composition of the water at the discharge is the same as the water in the deep basin. Thus, operation in accordance with the discharge permit refutes the unfounded NEC claims that the towers "operate in a caustic environment and are subject as well to other aging mechanisms including, e.g., vibration, biotic and chemical reductions, corrosion, and temperature extremes." *See* NEC Request at 6; Landsman Declaration, ¶8. The only time periods that the Cooling Towers are in operation and the plant is not discharging to the river is during closed cycle operation, which is only a few hours per week. Attachment 13 at 2.

only for the purpose of determining the allowable anchor bolt capacity.[82] ABS Consulting inspected the concrete supporting the cooling tower anchor bolts and found it to be in sound condition.[83] NES provides no factual evidence to the contrary.

7. **Utilization of a particular seismic damping ratio**

NEC claims:[84]

> The ABS engineers generalized about the damping of this "type" of wooden structure due to "bolted connections" which will "absorb energy due to friction and slippage inherent in the connections and support point." *Dr. Landsman's Declaration* at ¶16. (citing ENN-DC-141, Design Input Record for ASS Calculations Nos. 1356711- 001 and 1356711- 002 for Vermont Yankee; ENN-DC-141 Design Input Record for ASS Calculations Nos. 1356711- 001 and 1356711- 002 for Vermont Yankee (April 8, 2005) at 2757 and page 3 of 9).
>
> 14. Again, the ABS engineers failed to take into account that "steel splices" (observed in the NRC Inspection) modify the damping characteristics of the wooden structures. *Dr. Landsman's Declaration* at ¶16. This failure undercuts the validity of the chosen seismic damping ratio and calls into question the conservatism of that choice. *Id.*
>
> * * *
>
> It is my professional opinion that where "structural steel splices" have been applied as identified in 1R23 above, these splices may add rigid nodes or fulcra to the structure. Credit for flexibility (friction and slippage) in bolted wooden joints must be re-examined following completion of any such modifications. It is not clear that ABS has ever reviewed the actual condition of the tower to identify all situations where "structural steel splices" have been applied.

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82 *See* Seismic Calculation, page 12, Attachment 3 hereto.

83 Baughman Declaration, ¶10.

84 NEC Response at 10-11; Landsman Declaration, ¶16-17.

This claim is based on the erroneous assumption that structural steel splices were installed in the Alternate Cooling System cell as part of the temporary modification. In reality, what was installed was a single splice made of Douglas fir (the same material as the remainder of the towers).[85] Since no structural steel splices were installed, the damping ratio used in the Seismic Calculation was not affected by the temporary modification. In particular, contrary to the erroneous conclusion reached by NEC's consultant, no rigid nodes or fulcra were added to the structure. The claim is without merit.

8. **Design basis earthquake used to prepare Seismic Calculation**

NEC claims:[86]

> The very design basis earthquake against which all of the calculations are measured, that is the Vermont Yankee design basis earthquake, is non-conservative. The FSAR for Vermont Yankee (VY) indicates that the Maximum Credible Event (MCE) for the design earthquake results in a 0.14g ground acceleration at the plant site. This acceleration appears to be the Safe Shutdown Earthquake (SSE) basis. However, seismic hazard maps prepared for FEMA (1988) appear to indicate that a 0.15g ground acceleration is consistent with a 2400-year return interval.
>
> * * *
>
> [T]he ABS evaluation relies on non-conservative assumptions that are neither properly supported nor supportable. The ABS evaluation also ignores the actual structural conditions of the cooling towers. ABS and Entergy invoke certain "conservations" throughout their filing that, in my professional opinion, must be put in perspective for the record. The very design basis earthquake against which all of the calculations are measured, that is the Vermont Yankee design basis earthquake, is non-conservative.

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85 The temporary splice is described as follows in the Temporary Modification: " The temporary splice process consists of removing the damaged section of 4" x 4" PT Douglas Fir diagonal brace (approximately 30") and inserting an equally sized section of new 4"x 4" Douglas Fir. The new section will be constructed or "spliced" to the existing brace member by adding two 4"x4" members of new PT Douglas Fir to the top and bottom of the joint." Temporary Modification 2005-004, Attachment 10 hereto, at 1.

86 NEC Response at 11-12; Landsman Declaration, ¶18-19.

* * *

> In a deterministic approach, the non-seismic towers would fail in an SSE. As I have previously pointed out, Vermont Yankee's towers have mixed seismic and non-seismic structures and components. If the worst-case single failure occurs during an SSE, it is not clear how Vermont Yankee survives. A failure modes and effects analysis with respect to the safety-related and non-safety-related cooling towers must be completed to provide this assurance. In my professional opinion, this remains a serious issue that is included in New England Coalition's new or revised alternate cooling system contention and that the Atomic Safety and Licensing Board should examine in this case.

In this claim, NEC and its consultant do not contend that the Seismic Calculation used an earthquake definition that was different from that in the VY licensing basis; in fact, that is precisely what ABS Consulting did in its analysis.[87] Instead, NEC disputes the validity of the VY licensing basis earthquakes, and thereby it challenges the Commission regulations regarding design and licensing basis maintenance, change, and approval processes; *see, e.g.,* 10 C.F.R. §§ 50.59, 50.90, 50.92, 50.109. Even more fundamentally, NEC is ignoring the prohibition against litigating Commission rules and regulations in a licensing proceeding. *See* 10 C.F.R. § 2.335(a). This portion of the NEC's proposed contention is, therefore, deficient and should be rejected, as similar claims have already been rejected in this proceeding.[88] It is also an impermissible new claim that could have been asserted in NEC's original Request for Hearing and was not.

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87 The Seismic Calculation states: "The models are analyzed using the Vermont Yankee design basis earthquake from Appendix A of the UFSAR (included as Attachment C). The curves in Attachment C have a peak ground acceleration of 0.07g, corresponding to the operating basis earthquake (OBE). Horizontal seismic input for this analysis is the maximum hypothetical earthquake (MHE) equal to two times the OBE (PGA of 0.14g)." Seismic Calculation at 6.

88 *See* LBP-04-28, 60 NRC at 566-67.

9. **Failure of the Seismic Calculation to adequately address the seismic qualification of the alternate cooling system and Entergy's failure to demonstrate the seismic resilience of the entire alternate cooling system**

NEC claims:[89]

> Dr. Landsman's final conclusion is that [Entergy's] ABS report is not adequate to address the seismic qualification of the alternate cooling system and that ENVY has not demonstrated the seismic resilience of the entire alternate cooling system.

This is clearly a conclusory statement by NEC and its consultant. It alleges no new facts and is apparently drawn from the previously discussed assessments. Since those assessments are faulty, the conclusions drawn from them are erroneous.

V. CONCLUSION

For the reasons stated above, the new contention proposed by NEC is inadmissible. Accordingly, the NEC Request should be denied.

Respectfully submitted,

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Counsel for Entergy Vermont Yankee, LLC and Entergy Nuclear Operations, Inc.

Dated: October 19, 2005

[89] NEC Response at 13; Landsman Declaration, ¶21.

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

Before the Atomic Safety and Licensing Board

In the Matter of	)	
	)	Docket No. 50-271
ENTERGY NUCLEAR VERMONT YANKEE, LLC and ENTERGY NUCLEAR OPERATIONS, INC.	)	ASLBP No. 04-832-02-OLA (Operating License Amendment)
(Vermont Yankee Nuclear Power Station)	)	

CERTIFICATE OF SERVICE

I hereby certify that copies of "Entergy's Response to the New England Coalition's Request for Leave to File a New Contention" and "Declaration of Paul D. Baughman" were served on the persons listed below by deposit in the U.S. Mail, first class, postage prepaid, and where indicated by an asterisk by electronic mail, this 19th day of October, 2005.

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January 31, 2004
BVY 04-009

U.S. Nuclear Regulatory Commission
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Subject: **Vermont Yankee Nuclear Power Station**
License No. DPR-28 (Docket No. 50-271)
Technical Specification Proposed Change No. 263 – Supplement No. 4
Extended Power Uprate – NRC Acceptance Review

By letter dated September 10, 2003[1], Vermont Yankee[2] (VY) proposed to amend Facility Operating License, DPR-28, for the Vermont Yankee Nuclear Power Station (VYNPS) to increase the maximum authorized power level from 1593 megawatts thermal (MWt) to 1912 MWt. The request for license amendment was prepared in accordance with the guidelines contained in the NRC-approved, licensing topical report NEDC-33004P-A[3] (referred to as the CLTR). Included with the license amendment request was NEDC-33090P[4] (referred to as the PUSAR), a summary of the results of the safety analyses and evaluations performed specifically for the VYNPS power uprate. Subsequent to the initial application, VY provided a supplement dated October 1, 2003 and two supplements dated October 28, 2003.

NRC's letter dated December 15, 2003[5], provided a status of the NRC staff's acceptance review of the extended power uprate (EPU) application for VYNPS and identified areas where additional details are needed. The attachments to this letter provide the additional information requested by the NRC to consider the application for extended power uprate acceptable.

Attachment 1 to this letter provides additional information describing how items stated in the VYNPS PUSAR were dispositioned based on the CLTR or will be dispositioned as part of the cycle-specific reload evaluation. In addition, information is provided as to the method used by VY to review and provide oversight of engineering products of GE Nuclear Energy (GENE). The information provided in Attachment 1 directly corresponds to those areas identified in paragraphs 1.a, 1.b, and 1.c of NRC's December 15, 2003 letter. The response to Item 1.a references a summary confirmation of PUSAR topics that is provided as Attachment 2 to this letter. Because the information provided in Attachment 2 is

[1] Vermont Yankee letter to U.S. Nuclear Regulatory Commission, "Extended Power Uprate," Proposed Change No. 263, BVY 03-80, September 10, 2003.

[2] Entergy Nuclear Vermont Yankee, LLC and Entergy Nuclear Operations, Inc. are the licensees of the Vermont Yankee Nuclear Power Station.

[3] GE Nuclear Energy, "Constant Pressure Power Uprate," Licensing Topical Report NEDC-33004P-A (Proprietary), July 2003, and NEDO-33004-A (Non-Proprietary), July 2003.

[4] GE Nuclear Energy, "Safety Analysis Report for Vermont Yankee Nuclear Power Station Constant Pressure Power Uprate," NEDC-33090P, September 2003.

[5] U.S. Nuclear Regulatory Commission letter to Entergy Nuclear Operations, Inc., "Vermont Yankee Nuclear Power Station – Extended Power Uprate Acceptance Review (TAC No. MC0761)," December 15, 2003.

AP01

deemed to contain proprietary information as defined by 10CFR2.790, that attachment has been designated in its entirety as proprietary information. The specific proprietary information is identified by double underline within double brackets. Attachment 3 to this letter is a non-proprietary version of Attachment 2 with the proprietary information removed.

Attachment 4 to this letter provides a revision to the template safety evaluation in NRC review standard RS-001[6] substituting the plant-specific design criteria and draft General Design Criteria of 10CFR50, Appendix A that constitute VYNPS' licensing basis. The revision will maintain consistency within VYNPS' licensing basis. Changes to the template are identified by change bars in the left-hand margins.

Attachment 5 to this letter is an update to the review matrix that cross-references the criteria of NRC review standard RS-001 for extended power uprates with the information in the VYNPS PUSAR and the NRC-approved CLTR for constant pressure power uprate. "VY Notes" have been added to the matrices to provide additional guidance to direct reviewers to the specific safety analyses and conclusions. Certain information in Matrix 8 is deemed to contain proprietary information as defined by 10CFR2.790. For that reason Attachment 5 has been designated in its entirety as proprietary information. The specific proprietary information is identified by double underline within double brackets. Attachment 6 to this letter is a non-proprietary version of Attachment 5 with the proprietary information removed.

Attachment 7 to this letter addresses steam dryer integrity issues. VY recognizes the importance of these issues and is planning to implement modifications to the dryer during the next refueling outage as described in the attachment. Based on discussions with NRC staff, VY understands that adequately addressing the scope of dryer issues and specific actions identified in GE SIL 644, Rev. 1 will provide sufficient information for the NRC staff to complete its acceptance review in this matter. VY will be responsive to additional information requests throughout the review process. Certain information in Attachment 7 is deemed to contain proprietary information as defined by 10CFR2.790. For that reason Attachment 7 has been designated in its entirety as proprietary information. The specific proprietary information is identified by double underline within double brackets. Attachment 8 to this letter is a non-proprietary version of Attachment 7 with the proprietary information removed.

General Electric Company, as the owner of the proprietary information in Attachments 2, 5, and 7 has executed three affidavits (provided as Attachment 9 to this letter). The enclosed proprietary information has been handled and classified as proprietary, is customarily held in confidence, and has been withheld from public disclosure. The proprietary information was provided to VY in GENE transmittals that are referenced in the affidavits. The proprietary information has been faithfully reproduced in attachments to this letter, such that the affidavits remain applicable. GENE requests that the enclosed proprietary information be withheld from public disclosure in accordance with the provisions of 10CFR2.790 and 9.17.

This supplement to the license amendment request does not change the scope or conclusions in the original application, nor does it change VY's determination of no significant hazards consideration.

If you have any questions, please contact Mr. James DeVincentis at (802) 258-4236.

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[6] U.S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, "Review Standard for Extended Power Uprates," (RS-001) Revision 0, December 2003.

Sincerely,

Jay K. Thayer
Site Vice President

STATE OF VERMONT)
)ss
WINDHAM COUNTY)

Then personally appeared before me, Jay K. Thayer, who, being duly sworn, did state that he is Site Vice President of the Vermont Yankee Nuclear Power Station, that he is duly authorized to execute and file the foregoing document, and that the statements therein are true to the best of his knowledge and belief.

SALLY A. SANDSTRUM NOTARY WINDHAM COUNTY, VERMONT

Sally A. Sandstrum, Notary Public
My Commission Expires February 10, 2007

Attachments (9)

cc: USNRC Region 1 Administrator (w/o attachments)
USNRC Resident Inspector – VYNPS (w/o attachments)
USNRC Project Manager – VYNPS (two copies/with attachments)
Vermont Department of Public Service (with non-proprietary attachments)

VERMONT YANKEE NOTES – MATRIX 5 (cont.)

SE 2.5.2.3 VY NOTE, Turbine Gland Sealing System: RS-001 Matrix 5 states that this review criterion is applicable to EPU's for which the turbine gland sealing system is modified. The turbine gland sealing system is not being modified for the VYNPS CPPU. The CPPU evalutation of the turbine gland seal system, taking into account the modification of the VYNPS main turbine to accept the increased steam flow at CPPU operating conditions, demonstrated that the system is capable of adequately performing its design function without modification. No increase in capacity or changes in any control settings are required for the VYNPS CPPU.

SE 2.5.3.1 VY NOTE, Spent Fuel Pool Cooling and Cleanup System: Attachment 4 of the VYNPS CPPU submittal, Section 6.3, summarizes analysis performed to demonstrate the adequacy of systems designed to cool the spent fuel pool for the CPPU under normal and accident scenarios. The existing fuel pool cleanup system is unaffected by CPPU conditions.

SE 2.5.3.4 VY NOTE, Ultimate Heat Sink: VYNPS uses the Connecticut River as its Ultimate Heat Sink (UHS) to provide cooling water for both normal and accident conditions. This cooling water is delivered by both safety and non-safety related portions of the Service Water System (SWS). Additionally, an Alternate Cooling System (ACS) based on a dedicated portion of the VYNPS cooling towers and RHR Service Water (RHRSW) pumps, is available for the remote scenario where either the intake structure or the downstream dam is lost. All of the SWS and ACS have been evaluated for CPPU conditions. The evaluations have included the consideration of the most limiting environmental conditions for the Connecticut River or cooling tower including peak seasonal river and air temperatures. The increased decay heat load associated with CPPU reactor core post-shutdown conditions were included in the evaluations. As a result of the system and equipment analysis, a modification to re-circulate ACS (RHRSW) pump motor cooler water back to the cooling tower instead of discharging it to the river are planned to ensure adequate inventory is available to meet the 7 day requirement associated with the ACS design basis functional scenario. This modification is the result of the increased decay heat. The following conclusions were reached in the VYNPS CPPU UHS and ACS evaluations:

- No SW flow or supply temperature changes are required to support CPPU normal operation.
- No SW flow or SW supply temperature changes are required to support CPPU LOCA operation.
- No SW flow or SW supply temperature changes are required to support CPPU Shutdown Events operation.
- SW system pump NPSH required and available is unchanged.
- All heat exchangers remain within design temperatures including consideration of tube plugging.
- The ACS cooling tower (deep basin) inventory is assured with the modification to the ACS pump motor cooler flow.
- The ACS pump NPSH and capacity are adequate.

VERMONT YANKEE NOTES – MATRIX 5 (cont.)

- ACS deep basin temperature remains below 130 °F to protect cooling tower fill.
- ACS will maintain required loads including its system components, spent fuel pool and torus within required limits.

SE 2.5.4.1 VY NOTE, Main Steam Supply System: The VYNPS main steam system evaluation at CPPU determined that the existing system design is acceptable for CPPU conditions. Capacity of the steam flow nozzles, steam control valves and steam bypass valves will remain within design specifications. The existing main steam piping is rated for CPPU conditions. Controls that function to admit steam to emergency equipment are unaffected by CPPU as are the associated supply and exhaust systems.

SE 2.5.4.2 VY NOTE, Main Condenser: The VYNPS main condenser system evaluation determined that the existing system design is acceptable for CPPU operating conditions. In addition to the information provided in Attachment 4 to the VYNPS CPPU submittal, Section 7.2, the evaluation also considered heater drain and extraction steam holdup times in the condenser hot well, since VYNPS does not have an MSIV leakage control system. The condenser hotwell inventory is adequate to provide a 2 minute holdup time for CPPU flow conditions.

SE 2.5.4.4 VY NOTE, Condensate and Feedwater System: The feedwater and condensate system was evaluated for capability to operate at CPPU conditions including normal, transient and accident conditions. It was determined that in order to maintain adequate system overpressure the high pressure feedwater heaters would be replaced. Operationally, the evaluation indicates that VYNPS must operate with all three of its feedwater pumps at rated CPPU conditions, a change from the current two pump operation at rated power. Since it was determined that VYNPS could not operate without condensate bypass during condensate demineralizer backwash and precoat, a filtered bypass is to be installed. With the described modifications and operation of three feedwater pumps, the condensate/feedwater system will perform adequately at CPPU conditions. To evaluate the feedwater and condensate systems capability at CPPU conditions, a thorough review of the system operation and equipment design was performed. Evaluation of CPPU process conditions indicate a slight increase in temperatures and flow velocities through the system. The expected increases are within the design of the condensate feedwater system piping and components. Adequate pressure margin will exist as well. The new high pressure feedwater heater design includes higher pressure shells to accommodate the higher extraction steam pressures for CPPU. CPPU feedwater flow requirements will be adequate with the operation of the VYNPS third feedwater pump. The existing arrangement of running all three condensate pumps was found to provide CPPU flow with sufficient NPSH margin. While the feedwater pumps will run within their nameplate ratings, the condensate pumps will exceed their nameplate but remain within the design service factor. The feedwater regulation valve

BVY 04-074
Docket No. 50-271

Attachment 2

Vermont Yankee Nuclear Power Station

Proposed Technical Specification Change No. 263 – Supplement No. 10

Extended Power Uprate

Response to Request for Additional Information

REDACTED AND NON-PROPRIETARY INFORMATION

Total number of pages in Attachment 2 (excluding this cover sheet) is 39.

NON-PROPRIETARY INFORMATION

RAI SPLB-A-9

Ultimate Heat Sink (UHS) / Alternate Cooling System (ACS):
(Reference 1, Attachment 6, Section 6.4.5)

a) In Section 6.4.5 of Attachment 6 to Reference 1, it is stated that:

"The ACS was evaluated for CPPU in a manner that is similar to the UHS evaluation for newer plants (e.g., inventory requirements and heat removal capability with increased decay heat)....The heat removal requirements of the following affected components during the ACS operating mode have been evaluated and found to be acceptable at CPPU...."

i) With regard to performance, heat-loads, heat transfer capabilities, flow rates, and flow velocities in the ACS for post CPPU conditions, please explain how the above conclusions were reached.

ii) Also, describe the analyses that have been performed, assumptions, and input parameters that were used; and explain the impact of the proposed EPU on UFSAR Section 10.8.2, Safety Design Bases, Items 1, 2, and 3.

b) In Reference 5, Attachment 6, MATRIX 5, Page 8, SE 2.5.3.4, it is stated that no SW flow or SW supply temperature changes are required to support the CPPU normal, LOCA or shutdown operations. Please explain.

c) Confirm that the analyses performed for the proposed EPU are consistent with the existing plant licensing basis and that the worst-case ultimate heat sink temperature was used in calculating flow requirements of the ACS for the proposed CPPU conditions.

d) In Reference 1, Attachment 6, Section 6.4.5, as well as in Reference 5, Attachment 6, MATRIX 5, Page 8, SE 2.5.3.4, it is stated that a modification to re-circulate ACS (RHRSW) pump motor cooler water back to the cooling tower, instead of discharging it to the river, is planned to ensure adequate inventory to meet the 7-day requirement associated with the ACS design-basis functional scenario. Please provide a description of the modification, including a flow diagram. In addition, discuss the regulatory requirements applicable to the modification.

Response to RAI SPLB-A-9

a)(i) For the alternate cooling system (ACS) mode of operation of the service water system the following are analytical constraints on thermal/hydraulic conditions in the system.

- Thermal Constraints:

  1. Return temperature to cooling tower ≤ 130°F to protect fill material.
  2. Spent fuel pool ≤ 150°F (higher limits are allowed under upset conditions, but for conservatism, this normal design limit is used for ACS).
  3. RHRSW ≤ 150°F (becomes a constraint on heat removal rate from RHR heat exchangers).

4. Torus temperature ≤ 176°F (conservatively set for margin in meeting NPSH requirements for ECCS pumps).
5. Reactor cooldown rate ≤ 90°F/hr (this is an administratively set limit to remain below the Tech Spec limit of 100°F/hr).
6. Be in safe shutdown condition, that is, subcritical with the ability to transfer decay heat (core and spent fuel pool) and primary system sensible heat to the ultimate heat sink. Although VYNPS' license does not require it to achieve cold shutdown condition following this event, for conservatism, the analysis was performed on the basis that following event initiation, it is desirable to be in cold shutdown condition within 24 hours.

- Hydraulic constraints:

  1. Total flow to the cooling tower must be within the limits for which test data are available to support performance projections. Total flowrate must be ≥ 3500 gpm and ≤ 8800 gpm.
  2. Maintain positive margin on basin water inventory for 7 days of continuous ACS operation.
  3. Maintain positive NPSH margin on RHRSW pumps.

- Analysis:

  The thermal and hydraulic analyses that are conducted to evaluate ACS operation against the criteria listed above are separate but related tasks that must be carried out in parallel because of the interplay between them. The following conclusions were reached as a result of this analysis:

  1. Initially, a large amount of cooling water is required to remove the amount of decay heat being generated and under worst case conditions, two pumps are required per train to provide this amount of cooling water without violating NPSH requirements.
  2. At CLTP, it was determined that after 48 hours of operation, the number of operating pumps had to be reduced to one per train to maintain positive inventory. Running only one pump per train reduced the water loss because there is no motor bearing cooling water loss for the isolated pump and the EDG load is reduced and thus the evaporative losses for the heat load due to EDG operation are reduced.
  3. Determination of the point when the system must be switched to two pump operation and the flowrate required per pump after this time step is an iterative process that balances the need for decay heat removal against the need for maintaining pump NPSH and basin inventory.
  4. At CPPU there is an increase in the decay heat rate for both the core and spent fuel pool, but analysis determined that for the worst case design conditions, no changes would be required in the values currently specified in the ACS operating procedures for total system flow rate, number of operating RHRSW pumps and time step for reduction in number/flow rate of operating RHRSW pumps.
  5. At CPPU, because the higher decay heat rates result in an increase in evaporative losses from the cooling tower basin, several design changes

were determined to be necessary to preserve both water inventory and pump NPSH margin.

a)(ii) Thermal performance of the SW system during the ACS mode of operation is evaluated using a computer model that was created on an Excel spreadsheet. For pre-specified incremental progressions in time over the postulated 7 day ACS event, the program performs a mass/energy balance to conservatively predict the effectiveness of the cooling tower as the ultimate heat sink for all heat rejected to the closed loop RHRSW system during this abnormal event. The program also calculates the reduction in basin inventory due to evaporative, drift and pump cooler losses. There are 40 user defined inputs to this spreadsheet. The inputs that change as a result of CPPU are as follows:

1. Q cooldown – 1.39×10^8 BTU - differential in sensible heat content of the reactor coolant system (RCS) and internals from hot shutdown condition to SDC point (50 psig). This assumes that entire RCS and internals are at saturation conditions for 550 °F. For CPPU conditions, the heat content is less due to differences in core design, but for conservatism, the pre-CPPU value is retained.
2. RRU heat load – 9.42×10^5 BTU/hr/train. Although the actual load for post-CPPU operation is greater than that for pre-CPPU operation, this value has not been changed since it already conservatively assumes post-LOCA operation conditions, which are approximately 3 times greater than ACS conditions.
3. Maximum spent fuel pool heat load – 1.48×10^7 BTU/hr. This is the heat load at the start of the ACS event and is based on the conservative assumption of the event occurring immediately after a short duration refueling outage of only 6 days. The pre-CPPU value for this input was 1.1×10^7 BTU/hr. For post-CPPU operation, the curve used for the 7-day, spent fuel pool heat load is based on the methodology in ANS 5.1, as opposed to the methodology of BTP ASB 9-2 which was used for the pre-CPPU analysis. As a result, total integrated heat load over 7 days is now slightly less than that in the pre-CPPU analysis (1.55×10^9 BTU vs. 1.59×10^9 BTU). However, the analysis is still very conservative, since it is based on the assumption of a 6 day refueling outage and does not take any credit for heat losses to the concrete or air above the pool. (Note: the decay heat rate is incorporated into the spreadsheet in the form of a curve fit formula for the design basis fuel pool decay heat rate developed by GE and as documented in GE-NE-0000-0015-1737-01. As such, it is not an input that can be varied by the program user.)
4. RHRSW pump motor bearing cooler loss – A value of 4 gpm/pump was used for the pre-CPPU analysis. Modifications reduce this to zero gpm/pump for post-CPPU operation.
5. Core decay heat is based on a maximum thermal power level of 1950 MWt for post-CPPU operation vs 1593 MWt for pre-CPPU operation. Total integrated decay heat load over the postulated seven day ACS event increases from 4.41×10^9 BTU to 5.44×10^9 BTU. (Note: this input is incorporated into the spreadsheet in the form of a curve fit formula for the design basis decay heat rate developed by GE and as documented in GE-VYNPS-AEP-146. As such, it is not an input that can be varied by the program user.)

For each time step in the thermal analysis, the program user first estimates the tower outlet (cold) temperature, from which the tower performance characteristic (BTUs removed per °F tower range per lbm air flow) is determined using the Merkel Theory and compared with the tower performance characteristic calculated using vendor supplied performance data. This process is iterated using different estimates of cold outlet temperature until the Merkel Number agrees with the tower vendor data. Once the cold outlet temperature is found, the heat removal and evaporative losses for each time step are determined using the standard equations for steady state heat transfer.

The hydraulic analysis was performed using Pipe-Flo, which is a commercially available computer program for calculating flow rates in fluid networks. The program also computes pressure in the system at any desired point, so by designating the pump suction connection as one such point, the available NPSH for the pump under any given set of flow conditions can be determined. The required inputs to this program are listed below:

1. Fluid – warm water having an average temperature of 85°F.
2. Piping materials, sizes, fittings and lengths – from as-built piping physical drawings.
3. Piping roughness – the roughness varies in different sections of the system due to differences in materials and flowrates, which in turn affect the amount of microbiological induced corrosion (MIC) that can be expected. To confirm that conservative roughness factors are being used in the model, benchmark testing was performed against several sets of field measurements of pressure drops for various flowrate conditions.
4. Pump curve – For conservatism, the vendor pump curve was uniformly degraded 20% for use in the calculations. Note that the ASME Code requires corrective action to be taken if the actual pump performance at any point drops 6% below the certified test curve. So use of a 20% degraded pump curve is very conservative.

Note that these inputs are unchanged for power uprate since the required flowrates for each SW user are the same as those required prior to EPU and since no modifications were required in the piping (other than pump suction barrel material and ¾ inch lines for cooling water to the RHRSW pump motor bearing coolers, which are not included in the model because of their small flowrates). The proposed EPU has no adverse impact on the UFSAR Section 10.8.2 Safety Design Bases, Items 1, 2 and 3.

b) The equipment supplied by the service water system include:

- RBCCW Heat Exchangers
- TBCCW Heat Exchangers
- Generator H_2 Coolers
- Generator Stator Water Coolers
- Generator ALTERREX Coolers
- Standby FPC heat Exchangers
- Reactor Feedwater Pump Area Coolers (TRU-1, 2, 3, 4)
- Condensate Pump Area Cooler (TRU-5)
- Turbine Lube Oil Coolers
- Reactor Recirc System MG Set Lube Oil Coolers

- Circulating Water Pump A, B, C, motor coolers and gland seals
- MS and Feedwater Pipe Tunnel Coolers (RRU-17A, RRU-17B)
- Reactor Building Air Handling Units RRU 10 through RRU 16
- Reactor Building Air Conditioning 1A through 1D
- Administrative Building Water Cooled Chiller SCH 2
- Standby Gas Treatment Loop Seals
- Sample Coolers for Heating Boiler
- RHRSW Pump Motor Coolers
- Emergency Diesel generator Coolers
- ECCS Pump Room Coolers RRU 5, 6, 7, and 8
- RHRSW supply to the RHR Heat Exchangers
- Fire Protection Pressurization Line

Normal Operation:

During Normal Operation, the following service water system loads can potentially be affected by CPPU:

- <u>RBCCW Heat Exchangers</u> – There is a slight increase in heat load of approximately 0.6%. See also discussion in PUSAR section 6.4.3. There is no change to the service water flow rate or supply temperature.
- <u>TBCCW Heat Exchangers</u> – There is no increase in heat load. See discussion in PUSAR section 6.4.4. There is no change to the service water flow rate or supply temperature.
- <u>Generator H2 Coolers</u> – There is a slight increase in heat load to the service water system of about 2%. The SW design supply temperature is 85°F, which bounds the required 92°F supply temperature to the Generator H2 Coolers. Also, the required SW flow decreases about 14% because of a change in design requirements.
- <u>Generator Stator Water Coolers</u> – Due to a design change, there is a decrease of about 13% in the heat loads from the Generator Stator Water Coolers. The SW flow rate decreases and the maximum allowed SW supply temperature of 95°F is higher than the SW design temperature of 85°F. Also, the SW required flow decreases about 14%.
- <u>Generator ALTERREX Coolers</u> – There is no change in the Generator ALTERREX Coolers heat load, SW flows or supply temperatures.
- <u>Standby FPC heat Exchangers</u> – No change to the service water flow rate or supply temperature. See discussion in PUSAR section 6.3 and related discussion regarding heat rates, flows and supply temperatures in response to RAI SPLB-A-7 above.
- <u>Reactor Feedwater Pump Area Coolers (TRU-1, 2, 3, 4)</u> – There is an increase of approximately 36% in the heat load at CPPU compared to CLTP. However, this increase in heat load does not result in adverse temperatures. The SW supply temperature and flow rates remain unchanged.
- <u>Condensate Pump Area Cooler (TRU-5)</u> – There is a small increase (i.e., approximately 9%) in the heat load at CPPU compared to CLTP. This increase is acceptable because area equipment is not adversely affected. The SW supply temperature and flow rates remain unchanged.
- <u>Turbine Lube Oil Coolers</u> – No change in heat load, flow rates, or temperatures.

NON-PROPRIETARY INFORMATION

- Reactor Recirc System MG Set Lube Oil Coolers – No change in heat loads, flow rates, or temperatures.
- Circulating Water Pump A, B, C, motor coolers and gland seals – No change to the service water heat load, flow rate, or supply temperature since there is no change to circulating water system flows at CPPU.
- MS and Feedwater Pipe Tunnel Coolers (RRU-17A, RRU-17B) – There is an insignificant increase in the area temperature of approximately a 0.6°F. No change in SW flow rates or supply temperature.
- Other Equipment Supplied by Service Water – The RHRSW pump motor coolers, the EDG coolers, and RRUs 5, 6, 7 and 8 were addressed in the response to RAI SPLB-A-8. The remaining equipment heat loads are not significantly affected by EPU and there is no change in the SW flow rate or supply temperature.

Conclusions for Normal Operation:

- The SW design temperature limit of 85°F bounds all of the equipment above for CPPU operation.
- There is a slight decrease in the total required SW flow.
- There is a slight decrease in the total heat removed by the SW system.

LOCA or Shutdown Events:

The limiting scenario is the LOCA scenario. As such, the conclusions reached in the response to RAI SPLB-A-8 above are applicable.

c) The service water supply temperature is in accordance with the plant design basis of 85°F as discussed in UFSAR section 10.6.5. For ACS operation, see the above response to part (a).

d) For purposes of the following discussion, refer to the SW system flow diagram included below as Figure SPLB-A-9-1. For each pump in each train of the RHRSW system, this minor modification involves the addition of a new 3-way ball valve in the motor bearing oil cooling water (MBOCW) return piping that will allow routing of the cooling water back to the pump suction line during ACS mode operation only to save cooling tower basin water inventory. This new line will connect to the existing 14-inch diameter pump suction piping. The second outlet port of the three-way ball valve will be connected to the existing piping that connects to the reactor building storm drains.

This change will have negligible impact on system hydraulics or the PRA model. The new ball valve is a full-ported type that offers minimal resistance to fluid flow. For normal plant operation and post-LOCA recovery, the system will be configured and operated in a manner that is identical to that called for by the current design, except that the cooling water will be routed through the three-way ball valve. Since the system will normally be set in this alignment, no additional valve manipulation is required and the increase in human error probability (HEP) for normal or post-LOCA operation is consequently very small. For ACS operation, the only new operator action required is to reposition the 3-way ball valve. Therefore, for ACS operation the increase in HEP is very small.

When switching to the ACS mode of operation, an additional procedural step will be required to re-position the three-way ball valve to align it with the branch line to the pump suction. The valve will be mounted in a convenient spot near the pump. Therefore, the two hour limit on set-up time for ACS operation will not be jeopardized. Set-up time was significantly reduced in 2001 when a permanent cross-tie to the standby fuel pool cooling system was installed, eliminating the labor-intensive and time-consuming work associated with installing the temporary spool piece originally required for making this cross-tie. Operators are expected to already be in the area for related tasks that can be accomplished in a few simple steps. Thus, there is currently considerable margin between the time that it actually takes to set-up the system and the two hour design limit. In addition, realignment of this ball valve can be done simultaneously with other required valve manipulations, rather than in series with them.

From a hydraulic performance point of view, aligning the MBOCW discharge to the pump suction rather than to the storm sewers actually represents a considerable improvement since the hydraulic resistance is significantly reduced (due to the shorter length of piping and lower discharge point back pressure).

The pipe routing for each new MBOCW return line will have no impact on other safety related SSCs since the RHRSW pump which it services is the only SSC in the vicinity of the new line.

NON-PROPRIETARY INFORMATION

Figure SPLB-A-9-1

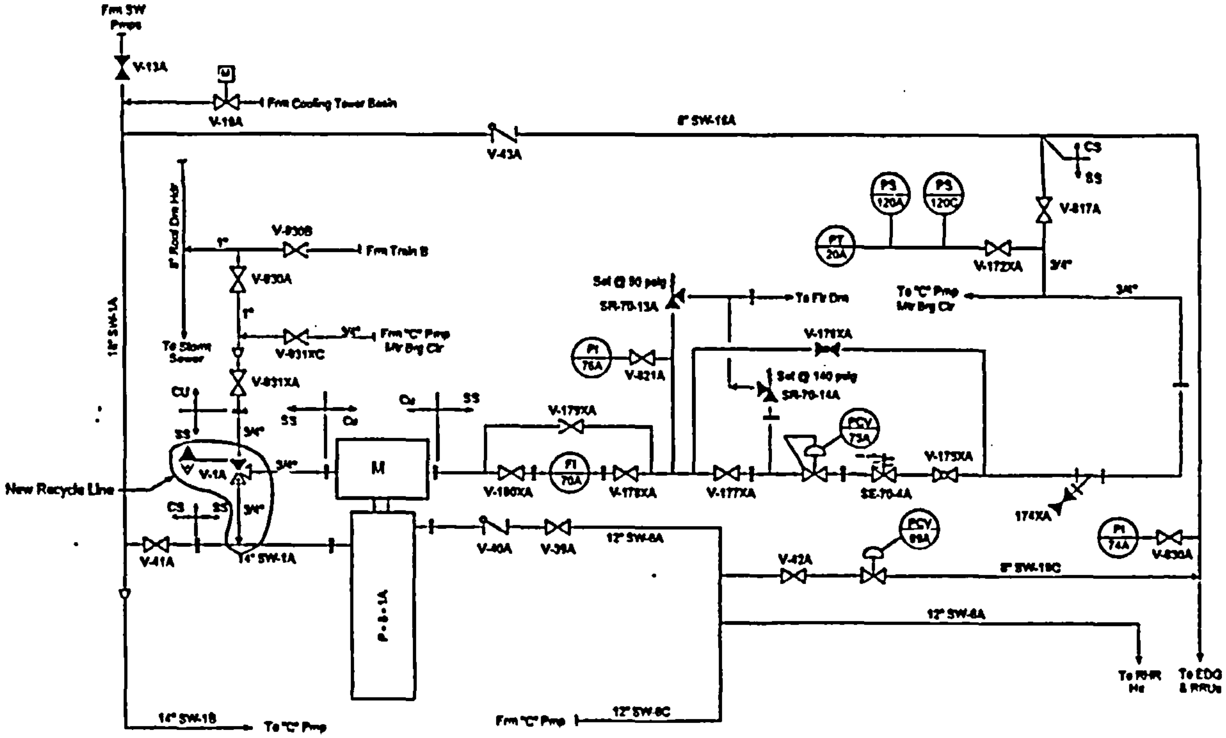

FIGURE 1 - Modification for RecyclingCooling Wtr to RHRSW Pump Motor Bearing Oil Coolers

5. ASSUMPTIONS

Assumptions are as follows:

- The weight of the circulating water distribution header is calculated assuming 60" OD fiberglass pipe with a wall thickness of 1/2". The density of the fiberglass material is assumed to be 120 pcf based on Reference 19.
- The concrete strength of the cooling tower foundation basin is assumed to be 3000 psi based on the notes on Drawing. G-200357 (Ref. 7.11). This is used for determining the allowable anchor bolt loads. This assumption is conservative since the value on the drawing is the minimum design strength (actual strength at the time the concrete is placed is normally much greater than the minimum design strength) and concrete strength increases with time.
- The moisture condition of all wood members is assumed saturated. This is conservative since not all members are continuously exposed to water.
- Lumber sizes are assumed to be equal to the minimum dry dressed size in accordance with NDS Supplement (Ref. 8) Table 1A.
- It is assumed that all lumber is capable of supporting the full design capacities based on ongoing inspection and replacement regime in place at VY (see sheet B7).
- The weight of the secondary distribution pipe in cell CT2-1 does not include the weight of water since the pipe is assumed to be normally empty (see Ref. 7.5). This system has to be activated manually by opening a manual valve. The weight of the empty pipe is determined assuming STD schedule wall thickness.
- The density of Douglas fir is assumed to be a minimum of 32 pcf from Reference 9 page 6-8.
- The density of the fan stack fiberglass is assumed to be 120 pcf based on Reference 19 (included in Attachment B) and Reference 27.

There are no unsubstantiated assumptions that require additional verification.

COOLING TOWER INSTITUTE

CTI CODE TOWER
Standard Specifications

For The Design Of Cooling Towers With Douglas Fir Lumber

Part 1: Scope, Abbreviations, Other Standards, and Definitions
Part 2: Grades of Douglas Fir Lumber
Part 3: Design Considerations

Revised November 1996

CTI Bulletin STD-114 (96)

CTI CODE TOWER

Standard Specifications

In the interest of obtaining uniform standards in the cooling tower industry, the Cooling Tower Institute has developed a series of individual Standards which taken together constitute a specification for a CTI CODE TOWER. Adherence to these standards is strictly on a voluntary basis. Any manufacturer may use them in whole or in part but their existence does not in any respect preclude any party who has approved of the standard from manufacturing or selling an industrial cooling tower not conforming to the standard. However, when reference to this CTI CODE TOWER Standard Specification is made in proposals, contracts, labels, invoices or advertising literature, the provisions of the standard are enforceable through usual legal channels as part of the sales contract.

Services of the Cooling Tower Institute may be arranged to assist any and all users and manufacturers of industrial cooling towers in the application of these Standard Specifications.

Printed copies of all CTI CODE TOWER Standard Specifications are available at nominal cost.

FOREWORD

This standard is based on accumulated knowledge and experience of manufacturers and users of timber structure cooling towers. The object of this publication is to provide a standard for design of timber cooling tower structures and for specification of timber grades with corresponding allowable stress values to be used for cooling tower structures.

Design criteria or rules given herein are recommended as minimum standards. Included in this standard are certain more restrictive criteria than those included in nationally recognized timber design standards, codes or specifications referenced herein. These more restrictive criteria, such as recommended allowable stresses, are considered necessary for the design of timber to be used in an environment with the temperature and moisture conditions found in wet cooling towers.

This publication may be referenced in purchase specifications to set basic requirements for design and construction and cooling tower manufacturers may use this standard as a basis for proposals.

Supercedes CTI Bulletins STD-114, dated May 1959, January 1971, October 1978, February 1983, October 1986 and July 1994

Approved by the
CTI Executive Board

CTI - Bulletin
STD-114 (96)

PART I
Scope, Abbreviations, Other Standards and Definitions

1.0 Scope

1.1 This standard sets forth recommended timber design parameters; the recommended grades; and the specifications and grading rules for Douglas Fir lumber to be used in construction of water cooling towers.

2.0 Abbreviations

ICBO International Conference of Building Officials, 5630 So. Workman Mill Rd, Whittier Ca.

NDS National Design Specification for Wood Construction, 1111 19th St., N.W. Washington D.C. 20036

AFPA American Forest and Paper Association, 1111 19th St., N.W. Washington D.C. 20036 (Formerly NFPA, National Forest Products Association)

WCLIB West Coast Lumber Inspection Bureau, Portland, Oregon

WWPA Western Wood Products Association, Portland Oregon

UBC Uniform Building Code.

3.0 Other Standards and Specifications

3.1 Other standards or specifications as listed below are referenced in the body of this standard.

- ASCE 7-88 (Formerly ANSI A58.1) American Society of Civil Engineers Standard Minimum Design Loads in Buildings and other Structures.
- National Design Specifications for Wood Construction. 1991, by NFPA with 1991 supplement, Design Values for Wood Construction.
- Standard Grading Rules for Western Lumber, 1991 by Western Wood Products Association, hereafter referenced as WWPA Grading Rules.
- Standard Grading and Dressing Rules for West Coast Lumber, Number 17, published by the West Coast Lumber Inspection Bureau, as revised 1991, hereafter referenced as WCLIB Grading Rules.
- Uniform Building Code, latest edition, with supplements, by ICBO.

4.0 Definitions of Members

Framework Members:

4.1 Water cooling tower framework members are those members which must be capable of supporting applicable loads and have published allowable stresses (or sufficient testing verifying structural integrity) and include the following:

Columns: Vertical or inclined supporting members in the tower framework, used to resist axial compression or tension stresses in combination with flexural or shear stresses that may exist.

Horizontal Ties and Struts: The main horizontal members interconnecting columns or bracing elements.

Braces: Members in the framework whose primary function is to provide lateral stability to the structure or individual members. These usually consist of diagonal members between columns or beams.

Joists and Beams: Horizontal members used to support gravity loads such as supports for fan deck flooring, fill, drift eliminators, cold and hot water collection and distribution basins, flumes, piping and mechanical equipment. Also included are beam-type members which resist wind or seismic forces.

Decking

4.2 Horizontal planking, typically 50.8mmx152.4mm (2x6) tongue and groove material used for fan deck flooring which must be capable of sustaining live loads, construction and maintenance loads, environmental loads, concentrated loads and any applicable dynamic loads due to equipment.

Non-Framework Members:

4.3 Non framework members of water cooling towers are all parts of subassemblies not included in paragraph 4.1 above.

PART II
Grades of Douglas Fir Lumber

5.0 Purpose

5.1 Structural grades of lumber defined in this standard are applicable for all structural framework members of the tower. Proper application of principles of design as outlined herein may be used for structural grades other than those indicated in this document, providing the reductions in design allowable stress are made in accordance with the NDS and this standard.

5.2 Industrial clear grades of lumber defined in this standard are intended only for the non-framework members in a tower.

6.0 Applications of WCLIB and WWPA Specifications

6.1 Grades of Douglas Fir to be used for the framework members in cooling tower construction shall be in accordance with the WCLIB grading Rules or WWPA Grading Rules, except that boxed heart shall not be permitted.

7.0 Definition of grades For Framework Members

7.1 Definitions of grades for framework members shall be as described in WCLIB or WWPA Grading Rules paragraphs for each particular grade description as listed below.

7.2 Members 50.8mm to 101.6mm (two to four inches) thick and 50.8mm to 101.6mm (two to four inches wide):

(a) Select Structural Light Framing shall conform to WCLIB para. 124-a, or WWPA, Section 42.10.

(b) No. 1 Light Framing shall conform to WCLIB, para. 124-b or WWPA, Section 42.11.

(c) No. 2 Light Framing shall conform to WCLIB, para. 124-c or WWPA, Section 42.12.

7.3 Members 50.8mm to 101.6mm (two to four inches) thick and 152.4mm (six inches) and wider:

(a) Select structural - Joists and Planks shall conform to WCLIB, para. 123-a, or WWPA Sections 62.10.

(b) No. 1 - Structural Joists and Planks shall conform to WCLIB, para. 123-b, or WWPA, Section 62.11

(c) No 2. - Structural Joists and Planks shall conform to WCLIB, para. 123-c, or WWPA 62.12.

8.0 Definitions of Grades for Non-Framework Members

8.1 Grades for non-framework members shall be as described in WCLIB Grading Rules paragraphs as listed below for each indicated grade description.

(a) B & BTR Industrial Clear: Para. 151-b.

(b) C Industrial Clear: Para. 151-c.

(c) D Industrial Clear: Para. 151-d.

(d) Construction Boards: Para. 118-b.

9.0 Preservative Treatment

9.1 All Douglas Fir lumber used in cooling tower construction shall be pressure treated with suitable preservative material. Pressure treatment shall conform to the requirements of CTI Bulletin WMS-112.

PART III
Design Considerations

10.0 Scope

10.1 This part establishes allowable design values for structural framework members and design criteria.

10.2 Structural grades of lumber shall conform to the definitions of grades as set forth in paragraphs 7.1 through 7.3 of this standard.

11.0 Design Criteria and Allowable Design Values

11.1 Except where more restrictive design requirements are indicated herein, or by the final user, timber design shall be in accordance with provisions of the National Design Specification for Wood Construction, 1991, by the National Forest Products Association.

11.2 The recommended design values for the structural grades of Douglas Fir described in paragraphs 7.1 through 7.3 above are shown in Table 114-A of this standard. The recommended design values are derived from Table 4A of the NDS Supplement.

11.3 Cooling towers should be designed to provide for a 50-year duration of operational loads in structural framework members (NDS Figure B1 Appendix B), therefore values shown in table 114-A have been multiplied by appropriate values to acquire a 50 year load duration. For loads of lesser duration, the values in Table 114-A, except for modulus of elasticity, may be multiplied by the following factors:

1.21 for two months cumulative duration as for snow or construction

1.32 for seven days cumulative duration

1.68 for wind & earthquake

2.10 for impact NOTE: The impact load duration does not apply to connections.

11.4 When loads of different durations are applied simultaneously, the design of structural members shall be based on the critical load combination per the National Design Specifications.

11.5 For members in cooling towers which are subjected to extended periods of operation at temperatures greater than 20°C (68°F), the allowable design values of Tables 114-A shall be reduced to account for reduced properties at the higher temperatures. These reduced design values shall be obtained by multiplying the Table

114-A stresses by the temperature-moisture correction factors, (C_t) listed in Table 114-C. The temperature to be used is the actual temperature to which the member under consideration is exposed when the tower is at design heat load at design wet-bulb temperature. An acceptable option is to use the design hot-water temperature in the top half of the flooded portion of the tower and the average of the design hot-water and cold-water temperature in the lower half. A statement indicating the design temperature distribution shall be included as part of the manufacturers proposal.

Values for all timber fastenings indicated in NDS shall be reduced by the 50-year load duration factor of .95, the temperature modification factor, C_t listed in tables 114-C, in addition to any reduction factors for wet use listed in part VII of the NDS. The temperature to be used is the same as described in the preceding paragraph. (Refer to STD-119 for complete details) NOTE: If the design wet bulb is lower than the 5% summer design data wet bulb, the owner must be warned against operation of the cooling tower at higher wet bulb temperatures with design heat load.

11.6 Values in table 114-A must be multiplied by the appropriate size adjustment factor, (C_F) provided in table 114-B, depending on the thickness and width of each piece of lumber. Stresses provided in table 114-A are considered Base Values (base value is defined as the allowable unit working stress for a reference size of lumber). The reference size is set at nominal 50.8mm by 304.8mm (2 inches by 12 inches) in lumber for grades of Structural Light framing and Structural Joist and Plank. To determine the allowable design values for other sizes of dimension lumber, the Base Value must be multiplied by the appropriate size adjustment factor.

11.7 Values in table 114-A must be multiplied by the appropriate moisture adjustment factor, (C_M) provided in table 114-D. When dimension lumber is used where moisture content will exceed 19% for an extended period of time, design values shall be multiplied by the appropriate wet service factors from the table. This includes all cooling tower members and members used in an unenclosed stair.

11.8 Compression members such as columns or bracing to resist axial loads shall be restrained from buckling by ties, struts, or other suitable bracing. Such bracing shall be capable of resisting at least three percent of the compression member axial load in addition to any forces resulting from induced flexural stresses.

11.9 Design of axially loaded members shall take into account the stresses and the long-term deflection effects resulting from eccentricity of load application.

Bow and crook permitted by WCLIB and WWPA Grading Rules for the grade used shall be included in determining such eccentricity except that smaller bow and crook than limited by these grading rules may be used if such smaller bow or crook is assured by cooling tower manufacturer's quality control.

11.10 Design of axially loaded members shall take into account flexure resulting from the eccentricity of axial load application from bolted or other kinds of connection-joined shear connections, where shear transfer to another member is accomplished by connection at only one side of the member considered. Such eccentricity shall be taken as not less than one-sixth the member cross sectional dimension along the bolt axis and perpendicular to the load direction for bolted connections or, for other kinds of connections, from the center of gravity of the shear connector bearing area within the considered member to the neutral axis of such member parallel to the side connected. Shear connector, as use herein, shall mean shear plate timber connector, split ring timber connector, or toothed ring. Nails or spikes shall not be used for connecting structural framework members.

11.11 The designer shall take into account the effects of any lack of end restraint on effective column length; the effect of the location of column splices; the effect of eccentricity due to connection, framing and material tolerances; and the effect of field construction tolerances on the overall column performance.

11.12 The designer shall take into account the effects of simple, continuous and cantilevered beams, beam splice locations, concentrated loads, beam stability (depth of a bending member compared to is breadth as for intermediate joists) and deflection of bending members.

11.13 If mechanical incising is performed, then allowable stresses in Table 114-A shall be adjusted as specified in the current edition of WMS-112.

12.0 Design Data

12.1 Wind: Unless otherwise specified, wind pressure design shall be in accordance with ASCE 7-88, 1990. In design of the component portions of the structure, consideration of positive and negative pressures on windward and leeward surfaces shall be taken into account. Design shall provide for the maximum forces which would result from any wind direction. There shall be no reduction of wind force taken for the possible shielding effect of structures adjacent to the cooling tower. Design shall take into account the various geometric shapes with corresponding shape factors to be applied for wind force calculations.

The dry weight of the tower shall be used in determining uplift forces. Adequate anchorage to foundations or the supporting structure shall be provided in accordance with the specified or local building code.

12.2 **Seismic:** Design for seismic forces should be in accordance with UBC latest edition unless specified otherwise. The specified seismic loading and the wind load shall be considered separately and design of the structure and its components shall provide for the maximum forces resulting from either.

12.3 **Gravity Loads:** Such loads used for design of tower, framing, cold water basin, and foundations shall include wet weight of lumber; operating weight of tower including water in the distribution system; snow and ice loads; and an allowance for construction loads on the horizontal floor or deck surfaces.

12.3.1 Unless otherwise specified by the Purchaser, the water weight load in the hot water distribution basin shall be based on the overflow depth of the basin. The water weight load in distribution troughs shall be based on the overflow depth of the troughs. All piping water weight loads shall be based on pipes completely full.

12.3.2 For design, the wet operating weight of Douglas Fir lumber shall be calculated on the basis of 737kg/m^3 (46 pounds per cubic foot) (G=.50 and M.C.= 150%). Dry weight to be used for uplift force calculations shall not be greater than 545kg/m^3 (34 pounds per cubic foot) (G=.50 and M.C.=15%).

12.3.3 Unless greater design snow loads are specified by Purchaser or required by codes or regulations applicable to the cooling tower site, the basic snow load on the fan deck or other similar exposed areas shall be per ASCE 7-88 1990 for a 100 year mean recurrence interval with no reduction. For areas where snow loads are not indicated per ASCE 7-88 1990 or specified by the Purchaser or local code, the design snow loads shall be determined by research and analysis of the effect of local climate and topography. The design shall provide for loading requirements per ASCE 7-88 1990 as applied to roofs of buildings except that the basic snow load coefficient, C_s, shall not be less than 1.0.

12.3.4 Construction and Maintenance Loads: Design shall take account of construction and maintenance requirements which necessitate loading of fan deck or other areas with equipment or materials during initial construction or for maintenance operations. Unless otherwise approved by the Purchaser, the minimum design load for such construction or maintenance shall be taken as 2.87kPa (60 pounds per square foot) over the whole fan deck area, or as approved by the Purchaser on those areas to be clearly defined on the manufacturer's design drawings. Unless otherwise specified by the Purchaser, such construction or maintenance load need not be combined with snow load, and the cumulative duration of such construction or maintenance load shall not be less than two months. Design loads shall consider necessity for removing tower components such as motors and gear boxes across the fan deck or other surface, with resultant local concentrated loads, during maintenance or repair.

12.4 **Member Sizes**

12.4.1 Calculations to determine required member properties shall be based on net dimensions (actual size) and not on nominal dimensions.

12.4.2 Sizes of dressed boards, strips, and dimension lumber identified by nominal sizes shall not be less than the dressed dimension in inches shown in the WCLIB Grading Rules, para. 250-d, or in WWPA Grading rules, in the introduction to each grade section.

12.4.3 Manufacturing tolerances for nominal rough and dressed sizes shall be in accordance with the grading rules.

TABLE 114-A

GRADE	STRESS (kPa)(1)(3)(4) STRESS (psi)(1)(3)(4)					
	F_b(2)	F_t	F_v	$F_c$per	$F_c$par	E
Select Structural Douglas Fir	9,500 1,377	6,552 950	622 90	4,095 594	11,138 1,615	$1.31x10^7$ $1.9x10^6$
No. 1 & Better Douglas Fir	7,535 1,093	5,078 736	622 90	4,095 594	9,828 1,425	$1.24x10^7$ $1.8x10^6$
No. 1 Douglas Fir	6,552 950	4,422 641	622 90	4,095 594	9,500 1,377	$1.17x10^7$ $1.7x10^6$
No. 2 Douglas Fir	5,732 831	3,767 546	622 90	4,095 594	8,518 1,235	$1.10x10^7$ $1.6x10^6$

NOTES:
1. Values must be multiplied by table 114B, 114C & 114D to obtain adjusted size, temperature, and wet conditions.
2. Value shown is for single use, to obtain repetitive member use multiply value shown by 1.15..
3. Values shown have been adjusted for a 50 year load duration
4. Tabulated values are derived from Douglas Fir-Larch in the NDS.

TABLE 114-B: Size Adjustment Factor C_f

GRADES	WIDTH	F_b THICKNESS 50.8mm & 76.2mm (2" & 3")	F_b 101.6mm (4")	F_t	F_c
Select Structural Douglas Fir, No. 1 & Better Douglas Fir, No. 1 Douglas Fir, No. 2 Douglas Fir.	50.8mm,76.2mm &101.6mm (2", 3" & 4")	1.5	1.5	1.5	1.15
	127mm (5")	1.4	1.4	1.4	1.10
	152.4mm (6")	1.3	1.3	1.3	1.10
	203.3mm (8")	1.2	1.3	1.2	1.05
	254mm (10")	1.1	1.2	1.1	1.00
	304.8mm (12")	1.0	1.1	1.0	1.00
	355.6mm (14") & UP	.90	1.0	.90	.90

TABLE 114-C: Temperature Adjustment Factor C_t

CORRECTION FACTORS FOR TEMPERATURES IN COOLING TOWERS					
PROPERTY	TEMPERATURE °C / TEMPERATURE °F				
	20 / 68	32.2 / 90	43.3 / 110	54.4 / 130	65.5 / 150
MOE AND TENSION PARALLEL TO GRAIN	1.0	.96	.93	.91	.88
OTHER PROPERTIES	1.0	.87	.76	.64	.53

NOTES: 1. Correction factors for temperatures intermediate to table values may be obtained by linear interpolation.

2. Tabulated correction factors are based on 24% moisture content for Douglas Fir lumber. Factors are also in accordance with 1991 NDS table 7.3.4. For intermediate values temperature adjustment equation found in the 1986 NDS may be used.

TABLE 114-D: Moisture Adjustment Factor C_m

When dimension lumber is used where moisture content will exceed 19% for an extended period of time, design values shall be multiplied by the appropriate wet service factors from the following table:

WET SERVICE FACTORS, C_m

F_b	F_t	F_v	F_cPer	F_cPar	E
.85*	1.0	.97	.67	.8	.9

* When $(F_b)(C_F)$ 7,931kPa (1150psi), C_m = 1.0

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COOLING TOWER INSPECTION GUIDELINE

Tower Designation:_ Work Order No.:______________________

Surveillance No.:______________________

Inspection Category (Check Category of Inspection Required)

☐ I) Operational... Page 2 and 3 .

☐ II) Rotating Equipment.................................. Pages 4 and 5 .

☐ III) Structural...(SPRING)............................... Pages 6 and 7 .

☐ III) Structural....(FALL).................................. Pages 8 and 9

☐ IV) Non-structural... Pages 10,11 and 12 .

☐ V) Distribution System.................................. Pages 13 and 14 .

☐ VI) Cold Water Basin...................................... Pages 15 .

Inspection Results

Category II findings recorded on ________ pages of C.T. Inspection Form - "A".

Categories I, III, IV and V findings recorded on ________ pages of C.T. Inspection Form - "B".

Inspection performed by ______________________

Date of Inspection ______________________

I) **OPERATIONAL CATEGORY (TROUBLE SHOOTING) (Inspection frequency: Annual, or as needed):**

1. Thermal Performance Test requested : Yes _____, No _____ (As needed).

   Clue: Increase in cooled water temperatures.

   If yes, state reason requested:

   Results of test on attached ______ Pages.

2. Level of drift loss:

   Clue: Is water splashing into plenum through air seal, or is drift eliminator section intact?

   Acceptable _____, Unacceptable _____.

   If unacceptable, determine cause: ____

   ____

   Recommended correction: ____

   ____

3. Level of splash out:

   Clue: Are there broken louvers or louver structure?

   Acceptable _____, Unacceptable _____.

   If unacceptable, determine cause: ____

   ____

   Recommended correction: ____

   ____

4. Water level in distribution pans:

   Clue: Is there water splashing over the curbs, or dry areas? (Ideal level is between 5" to 6").

   Acceptable _____, Unacceptable _____.

   If unacceptable, indicate problem areas ____

Recommended correction: ____________________

____

5. Observe for presence of algae, mold, white rots, brown rots or iron rot.

<u>Clue:</u> Rotted timber under protected areas.

Acceptable: _____, Unacceptable _____.

If unacceptable, indicate problem and areas affected ____________________

____

____

6. Observe for loss of thermal performance due to air "by-passing" the fill area.

<u>Clue:</u> This would pertain to the condition of the fan deck, access doors, partitions walls, partition doors, fan stacks, plenum air seals and end wall siding.

Acceptable _______ Unacceptable ________.

If unacceptable, indicate problem and areas affected ____________________

____

____

Recommended correction____________________

____

II) **ROTATING EQUIPMENT CATEGORY Inspection frequency: Monthly during operational mode, or annual as noted:**

1. Abnormal movement or shaking: (Defined as any movement in the support structure).

   Yes _____, No _____.

   If yes, indicate cell number and possible cause ________________________________

   ____

2. Abnormal noise: (Defined as any noise other than normal gear, motor or wind noise).

   Yes _____, No _____.

   If yes, indicate cell number and possible cause ________________________________

   ____

3. Abnormal vibration: Yes _____, No _____.

   If yes, indicate cell number _______ (The taking of vibration readings on this equipment is controlled by AP-0211, Predictive Maintenance Program).

4. Gear oil level: Okay _____, Correction required _____.

   If correction required, indicate cell number: ________________________________

   ____

5. Oil fill, drain lines, and gear box vents: Okay _____, Correction required _____.

   If correction required, indicate cell number: ________________________________

   ____

6. Condition of gear reducers: Okay _____, Correction required _____.

   If correction required, indicate cell number: ________________________________

   ____

7. Condition of coupling assemblies: Okay _____, Correction required _____.

   If correction required, indicate cell number: ______________________________

   ____

8. Condition of motors: Okay _____, Correction required _____.

   If correction required, indicate cell number: ______________________________

   ____

9. Condition of fan assemblies: Okay _____, Correction required _____.

   If correction required, indicate cell number: ______________________________

   ____

10. Fan blade tracking, and tip clearance **(<u>Inspection frequency: Annual</u>)**:

    Check each blade for tracking position. Maximum 1" deviation between all blades

    Check tip clearance from blade to stack. ¾" to 1" is acceptable

    Okay ______, Correction required ______.

    If correction required, indicate cell number: ______________________________

    ____

    Record findings of tip clearances on C.T. Inspection Form "A".

11. Fan blade pitch angle **(<u>Inspection frequency: Annual</u>)**:

    Check each blade for pitch angle setting and uniformity of each assembly. Record findings on C.T. Inspection Form "A".

III) <u>STRUCTURAL CATEGORY</u> (Inspection frequency: Annual): Spring inspection will be conducted to determine the towers fitness for the start of the cooling season. It will include manlift inspection, walk down of distribution deck and plenum areas. Also a review of the identified work list will be updated to indicate current priority level for repairs.

1. **COMPONENTS:**

Components included are those critical to the structural frame, and are as follows:

Timber Components

- 4 x 4 vertical tower columns.
- 4 x 4 sloping louver columns.
- 4 x 4 diagonal braces (transverse and longitudinal).
- 2 x 4 horizontal ties (transverse and longitudinal).
- 2 x 4 horizontal distribution basin supports.
- 2 x 6 horizontal fan deck joists.
- 2 x 6 horizontal manifold supports.
- 2 x 8 horizontal deck joist supports.
- 2 x 8 manifold supports
- 2 x 10 manifold supports
- All splice blocks

Non-Timber Components:

- Structural anchor castings.
- Structural joint connectors.
- Structural connection bolts, nuts and washers.
- Structural steel supports including companion post stanchion.

2. **INSTRUCTIONS:**

While inspecting structural components, every effort, (within economic limits) shall be made to observe them up close. In some cases, this will require removal and re-installation of "Non-structural" components. A representative sampling of all critical areas will be inspected, (i.e., top columns supporting the manifold pipes, header supports and etc.). Where damage is encountered, the inspection shall continue in depth, until undamaged or sound components are again continuously observed.

3. **PROCEDURE:**

The procedure for inspecting timber components shall be as follows:

- Observe for any obvious fan deck sagging or water ponding.
- Observe for any obvious out-of-alignment, twisting, bowing or crushing. Describe problem and location of component.
- Observe for any bowing or crushing distribution header supports.
- Observe for stress relating to location of large knots or bolt holes too close to small knots.
- Observe for any broken component or cracks that extend continuously from two surfaces. (Surface "checks" or "splits" are not cause for replacement). Describe problem and location of component.
- Observe for evidence of rot by physically probing or tapping with a blunt object. Some clues are discoloration, surface pelling (fuzzy look), blisters, or accumulation of mold.

Describe problem and location of components.

- Check material for compliance with published specification, (i.e., stainless steel hardware and pressure treated Douglas Fir). Any non-compliance material must be noted on form CTIF-B.
- Record all unacceptable findings on form CTIF-B, and mark the component for future reference.

4. **PROCEDURE:**

Procedure for inspecting non-timber components shall be as follows:

- Observe for evidence of corrosion or rust on steel components.
- Observe protective coatings on steel components.
- Record all unacceptable findings on form CTIF-B.

IV) STRUCTURAL CATEGORY (Inspection frequency: Annual): Fall inspection will be conducted to discover any problems resulting from operations. It will include manlift inspection, walk down of distribution deck and plenum areas, and behind drift eliminators ("B" column) also fan blade inspection

1. COMPONENTS:

Components included are those critical to the structural frame, and are as follows:

Timber Components

- 4 x 4 vertical tower columns.
- 4 x 4 sloping louver columns.
- 4 x 4 diagonal braces (transverse and longitudinal).
- 2 x 4 horizontal ties (transverse and longitudinal).
- 2 x 4 horizontal distribution basin supports.
- 2 x 6 horizontal fan deck joists.
- 2 x 6 horizontal manifold supports.
- 2 x 8 horizontal deck joist supports.
- 2 x 8 manifold supports
- 2 x 10 manifold supports
- All splice blocks

Non-Timber Components:

- Structural anchor castings.
- Structural joint connectors.
- Structural connection bolts, nuts and washers.
- Structural steel supports.

2. INSTRUCTIONS:

While inspecting structural components, every effort, (within economic limits) shall be made to observe them up close. In some cases, this will require removal and re-installation of "Non-structural" components. A representative sampling of all critical areas will be inspected, (i.e., top columns supporting the manifold pipes, header supports and etc.). Where damage is encountered, the inspection shall continue in depth, until undamaged or sound components are again continuously observed.

3. **PROCEDURE:**

The procedure for inspecting timber components shall be as follows:

- Observe for any obvious fan deck sagging or water ponding.
- Observe for any obvious out-of-alignment, twisting, bowing or crushing. Describe problem and location of component.
- Observe for any bowing or crushing distribution header supports.
- Observe for stress relating to location of large knots or bolt holes too close to small knots.
- Observe for any broken component or cracks that extend continuously from two surfaces. (Surface "checks" or "splits" are not cause for replacement). Describe problem and location of component.
- Observe for evidence of rot by physically probing or tapping with a blunt object. Some clues are discoloration, surface pelling (fuzzy look), blisters, or accumulation of mold.

Describe problem and location of components.

- Check material for compliance with published specification, (i.e., stainless steel hardware and pressure treated Douglas Fir). Any non-compliance material must be noted on form CTIF-B.
- Record all unacceptable findings on form CTIF-B, and mark the component for future reference.

4. **PROCEDURE:**

Procedure for inspecting non-timber components shall be as follows:

- Observe for evidence of corrosion or rust on steel components.
- Observe protective coatings on steel components [redacted].
- Record all unacceptable findings on form CTIF-B.

V) NON-STRUCTURAL CATEGORY (Inspection frequency: 2 Years):

1. COMPONENTS:

Components included are those not critical to the structural frame, and are as follows:

Timber Components

- Entire stairway.
- Fan deck and toe boards.
- Walkways and supports.
- Partition walls.
- Partition doors.
- Fill support timbers.
- Drift eliminator supports.
- Drift eliminator air-seals.
- Louver arms.
- Ladders.
- Hand and knee rails.
- Access hatches.

Non-Timber Components

- Wetting system and it's supports.
- Fill battens.
- Fill hangers.
- Drift eliminators.
- Walkway platforms.
- Fan deck cover.
- Fan stacks.
- Ladder extensions.
- Conduit and conduit supports.
- Plenum air seals.
- End wall siding.
- Sidewall siding.
- Louver blades.
- Bird screens.

2. INSTRUCTIONS:

While inspecting non-structural components, every effort (within economic limits) shall be made to observe them close up. Where damage is encountered, the inspection shall continue until undamaged or sound components are again continuously observed.

3. **PROCEDURE:**

The procedure for inspecting timber components shall be as follows:

- Observe for any obvious out-of-alignment, twisting, bowing or crushing. Describe problem and location of component.
- Observe for any broken component or cracks that extend continuously from two surfaces. (Surface "checks" or "splits" are not cause for replacement). Describe problem and location of component.
- Observe for evidence of rot by physically probing or tapping with a blunt object. Some clues are discoloration, surface pelling (fuzzy look), blisters, or accumulation of mold. Describe problem and location of components.
- Check material for compliance with published specification, (i.e., stainless steel hardware and pressure treated Douglas Fir). Any non-compliance material must be noted on form CITF-B.
- Check to see if plywood drift eliminator air-seals are in place, and bottom seals extend below normal basin water level.
- Record all unacceptable findings on form CTIF-B, and mark the component for future reference.

PROCEDURE:

3. Procedure for inspecting non-timber components shall be as follows:

- Observe for evidence of corrosion or rust on steel components.
- Observe protective coatings on steel components.
- Exterior fill areas are to be inspected by use of a man-lift. Interior fill areas are to be inspected by the removal (and re-installation) of drift eliminator panels. While

inspecting the fill and fill hanging system, a representative sampling of all areas will be conducted. Where damage is encountered, the inspection shall continue in depth until undamaged or sound components are again continuously observed. The inspection shall include observing for broken or dislocated components, and a solids build-up on the heat transfer surfaces.

- Record all unacceptable findings on form CTIF-B.

VI) DISTRIBUTION SYSTEM CATEGORY (Inspection frequency: Annual):

1. COMPONENTS:

Components included are those making up the distribution system, and are as follows:

Timber Components

- Plywood basin floor (pan).
- 2 x 8 basin sides.
- 2 x 8 basin partitions.
- 2 x 2 water diverters, 2 x 6 water brakes.
- Walkways.

Non-Timber Components

- Fiberglass pipe.
- Control valves.
- Flow diffusion shrouds.
- Flow diffusion deflectors.
- Pressure relief standpipes.
- Nozzles.

2. PROCEDURE:

The procedure for inspecting timber components shall be as follows:

- Observe for any obvious out-of-alignment, twisting or bowing. Describe problem and location of component.
- Observe for any broken component or cracks that extend continuously from two surfaces. (Surface "checks" or "splits" are not cause for replacement). Describe problem and location of component.
- Observe for evidence of rot by physically probing or tapping with a blunt object. Some clues are discoloration, surface pelling (fuzzy look), blisters, or accumulation of mold. Describe problem and location of components.
- Check material for compliance with published specification, (i.e., stainless steel hardware and pressure treated Douglas Fir).

- Observe for debris on the plywood basin floor (distribution deck). Because this area is not 100% visible, a representative area shall be observed. Evaluate and or identify the source of any foreign objects or debris.
- Insure all nozzles are installed and are cleaned.
- Record all unacceptable findings on form CTIF-B, and mark the component for future reference.

3. **PROCEDURE:**

Procedure for inspecting non-timber components shall be as follows:

- Observe for evidence of corrosion or rust on steel components.
- Observe for evidence of pipe - cracks, leaks, etc.
- Observe protective coatings on steel components.
- Observe for broken or missing distribution nozzles. Because these components are not 100% visible, a representative area shall be observed.
- Record all unacceptable findings on form CTIF-B.

VII) **COLD WATER BASIN (Inspection frequency: Annual):**

1. **Exterior:**

Clue: Are there heavy areas of ground water near the tower basin?

- Observe for spalling surfaces, leaking expansion joints and cracks.
- Record all unacceptable finds on form CTIF - "B".

2. **Interior:**

- Observe for spalling surfaces, loose expansion joints and cracks.
- Observe for level of silt and debris in the East tower and the shallow end of the West Tower.
- To observe the level of silt and debris in the deep end of the West tower, refer to OP-5265 (this may require the use of divers).
- Observe the condition of the structure below the normal water level, as directed in Category III.
- Record depth of silt.
- Record all unacceptable finds on form CTIF - "B".

SAMPLE OF FORM 'A'

SPRING COOLING TOWER MECHANICAL EQUIPMENT INSPECTION

CT-1 CELL 1

Work Order No. 03-5706
Date: 03-04

NOTE

Document As-Found information - Note minor corrections to make UNSAT - SAT or notify Maintenance Support Engineer if extensive work is required to resolve.

GEARBOX

➢ Check input shaft backlash	☑ Satisfactory	☐ Unsatisfactory	
➢ Check output shaft backlash	☑ Satisfactory	☐ Unsatisfactory	
➢ Check output key tight	☑ Satisfactory	☐ Unsatisfactory	
➢ Check input shaft seal	☑ Satisfactory	☐ Unsatisfactory	Minor oil leak 3-S
➢ Check output shaft seal	☑ Satisfactory	☐ Unsatisfactory	

FAN BLADES

➢ Fan blade condition	☑ Satisfactory	☐ Unsatisfactory	
➢ Blade tip clearance min 1/4"	☑ Satisfactory	☐ Unsatisfactory	Not uniform
➢ Blade tracking max 1"	☐ Satisfactory	☑ Unsatisfactory	

MISCELLANEOUS

Provide additional information that may be relevant to the maintainability of this cooling tower cell and to insure continued operability:

Minor oil leak at the inspection plate of the gearbox(11-02)
Fan Stack cracks inside

AS FOUND I[illegible]TION RESULTS

C.T. INSPECTION FORM "I

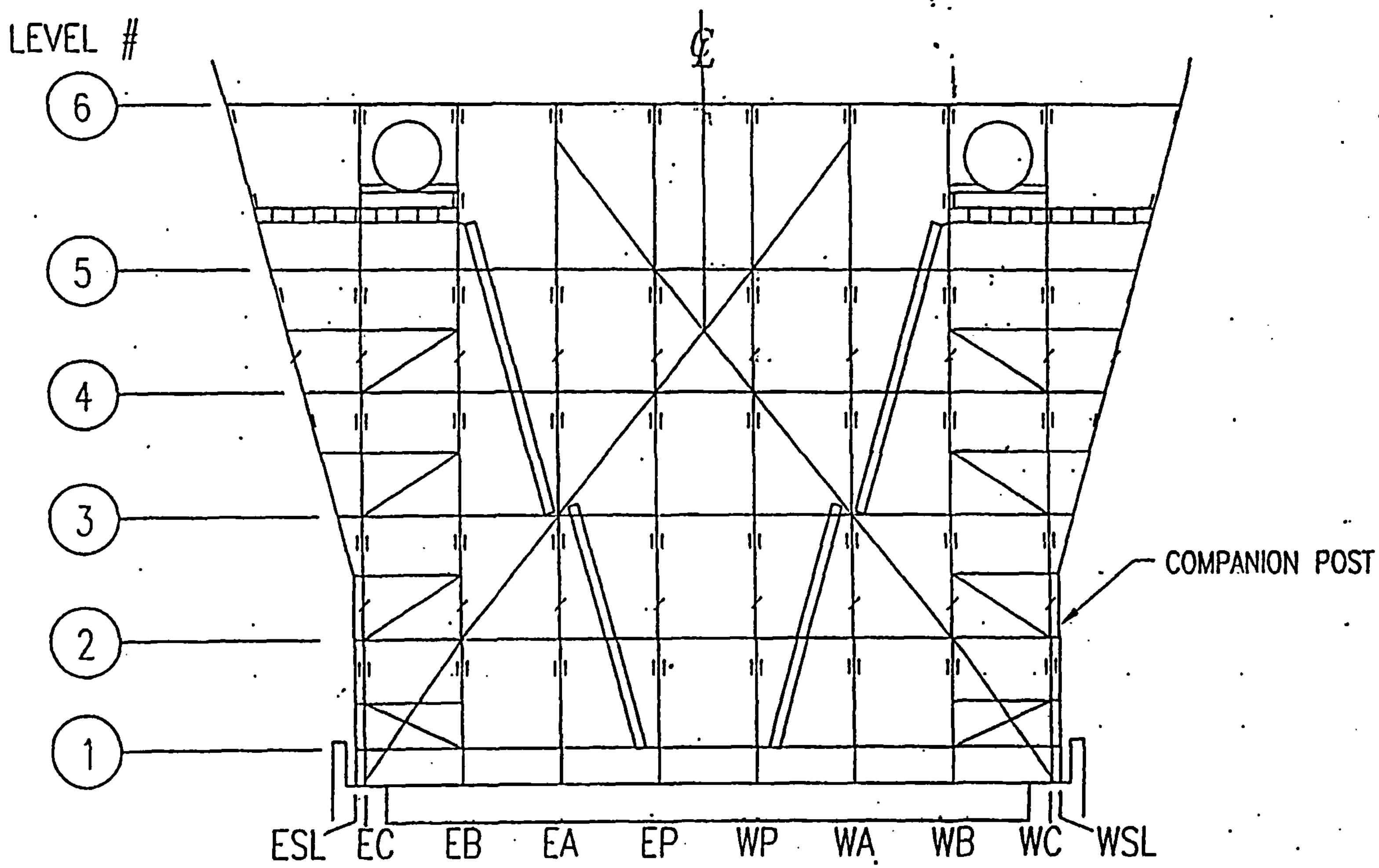
GENERAL

INSPECTION FINDINGS BY CELL: DATE:__________ TOWER:______________

CELL	LOCATION	MATERIALS EFFECTED	BRIEF DESCRIPTION	CLASSIFICAT

Classifications:

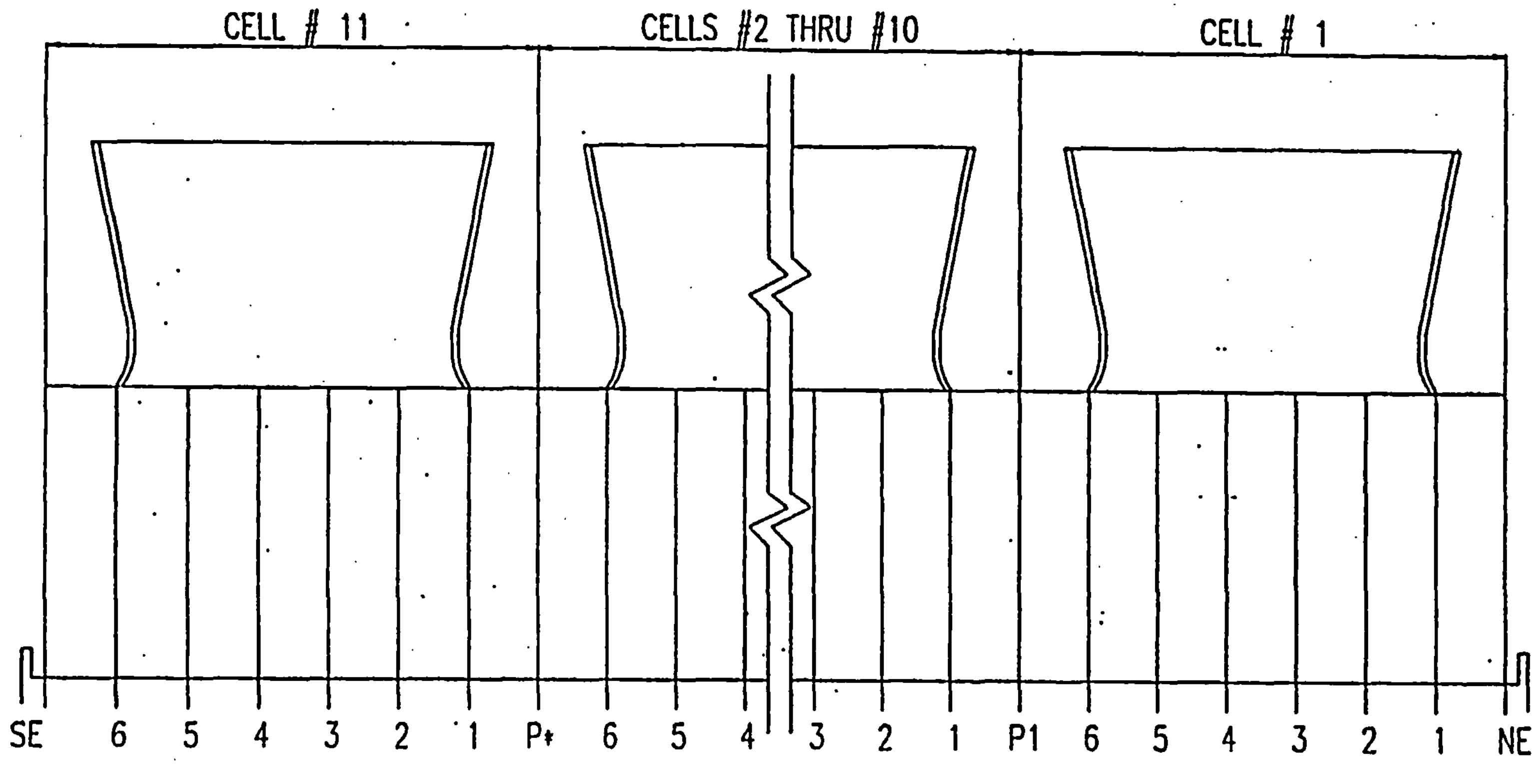
1. Degradation which could result in a structural failure
2. Condition presenting a safety risk
3. Degradation which could result in a structural failure in 3 years.
4. Degradation which could result in a lose of thermal performance.



TRANSVERSE ELEVATION, LOOKING SOUTH.

5 018

PROJECT:	TPI	DATE:	REV.
TITLE: KEY SHEET 1 OF 3	DWG. NO:		



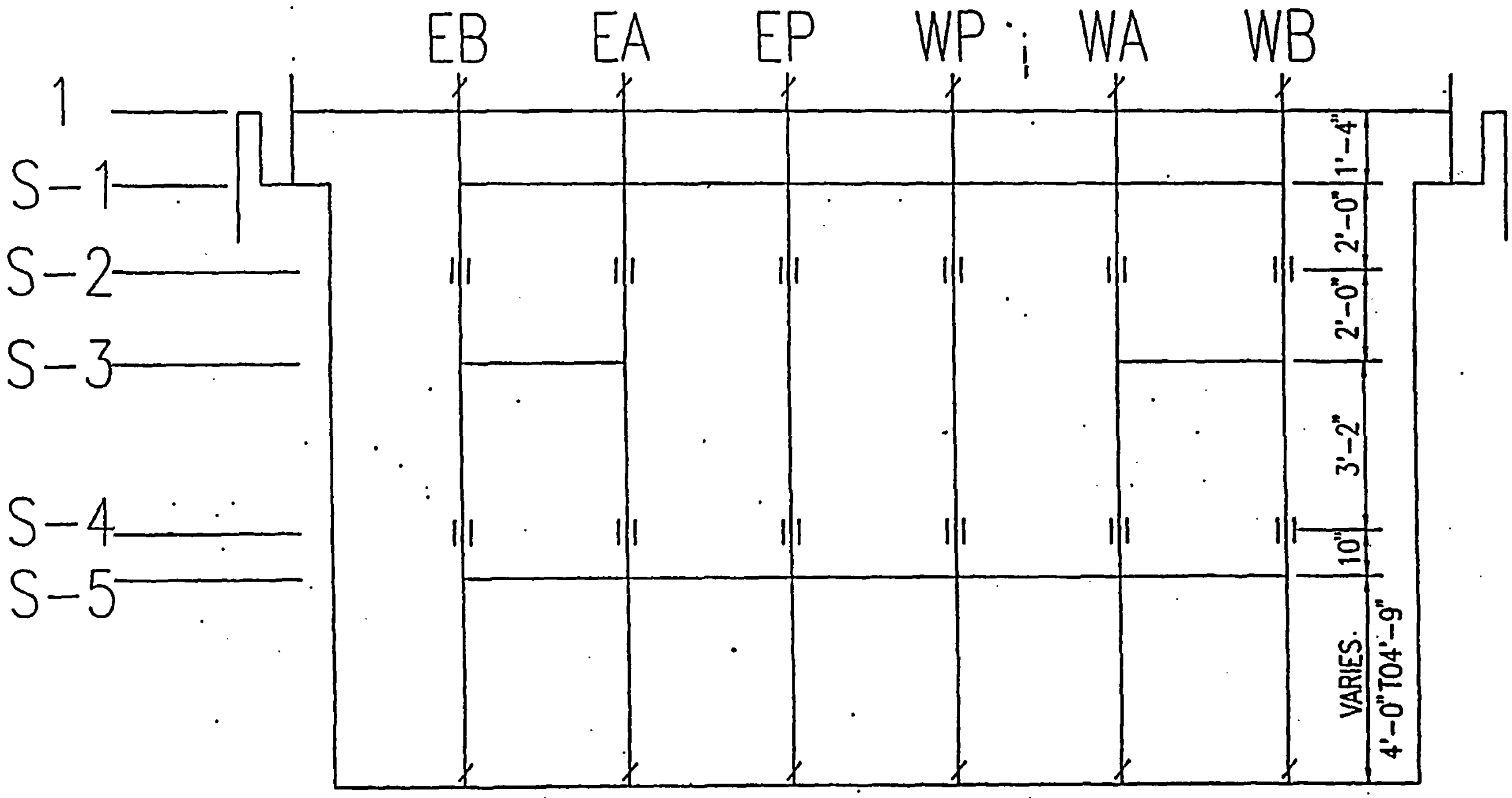
BENT #

*ENTER CELL #

LONGITUDINAL ELEVATION, LOOKING WEST

NORTH

PROJECT:	TPI	DATE:	REV.
TITLE: KEY SHEET 2 OF 3	DWG. NO:		



5 020

DEEP BASIN TRANSVERSE ELEVATION, LOOKING SOUTH(WEST TOWER)

PROJECT:	TPI	DATE:	REV.
TITLE: KEY SHEET 3 OF 3	DWG. NO:		

ENTERGY NUCLEAR
VERMONT YANKEE, LLC
Vernon, VT
No. 2 West Cooling Tower Inspection
Spring 2005

Cooling Tower Designation: CT-2 (West Tower)

Work Order : 04-005655-000(P)
Work Order : 04-005776-000(P)

Type of Inspection Performed

Inspection Category (Check Category of Inspection Performed)

☐	I	Operational	(Per Cooling Tower Inspection Guideline Pages 2 and 3)
☐	II	Rotating Equipment	(Per Cooling Tower Inspection Guideline Pages 4 and 5)
☑	III	Structural (SPRING)	(Per Cooling Tower Inspection Guideline Pages 6 and 7)
☐	IV	Structural (FALL)	(Per Cooling Tower Inspection Guideline Pages 8 and 9)
☑	V	Non-Structural	(Per Cooling Tower Inspection Guideline Pages 10, 11 and 12)
☑	VI	Distribution System	(Per Cooling Tower Inspection Guideline Pages 13 and 14)
☐	VII	Cold Water Basin	(Per Cooling Tower Inspection Guideline Page 15)

Inspection performed by Ernie Benne / Frank Foster

Date of Inspection March 7 thru March 10, 2005

GENERAL COMMENTS

1. All of the end wall hardware and most of the partition wall hardware must eventually be changed to stainless steel. 3-F, 4-S, 5S.
2. Most base anchor castings are showing heavy rust. 3-F, 4-S, 5S.
3. White Mold and Brown Mold is appearing in the Distribution Basin area again. Spraying should be considered. 3-F, 4-F, 5S.
4. All mechanical equipment being replaced with the exception of CT2, Cell 1.
5. CT 2 - Several mechical equipment walkways platform in the upper plenum have a slope at the end under the gear. We are not sure if this is the way they were installed or if it's a developmental condition. In either case, it does not appear to be a safety concern but is noteworthy, 4-F, 5S.

AS FOUND INSPECTION RESULTS

C.T. Inspection Form - "B"

March, 2005 | West Cooling Tower (CT-2)

Location					Materials Affected	Component Description	Classification
Cc.	?nt	Column	Level	Inspection Area			
1	NE	EP	TOP	Upper Plenum	1-4"x4"x18'	Split Vertical Column	3-4S
1	2	ESL	5A	ManLift/HWBasin	1-2"x4"x4'	Split Louver Arm	3-4F
1	5	ESL	TOP	ManLift/HWBasin	1-4"x4"x18'	Split Sloping Column	3-4S
1	4	WC	2	ManLift	1-4"x6"x12'	Split Longitudinal Diagonal Brace	3-3F
1	5	WC	INT	ManLift/Behind DE's	1-4"x4"x18'	Split Vertical Column	3-3F
1	5	WSL	2	ManLift	1-2"x4"x2'	Split Louver Support	3-4S
1	5	WSL	4	ManLift	1-2"x "4x4'	Split Louver Arm	3-3F
1	6	WSL	4	ManLift	1-2"x4"x14'	Split Transverse Tie	3-3F
1	4	WSL	3	ManLift	1-2"x4"x4'	Split Louver Arm	2-5S
1	4	WSL	4	ManLift	1-2"x4"x4'	Split Louver Arm	2-5S
1	4	WC	4	ManLift/Behind DE's	1-2"x4"x4'	Split Louver Arm	2-5S
1	3	WC	5A	HWBasin	1-2"x10"x8'	Split Header Support	3-5S
1	3	WC	5A	HWBasin	Ladder	Rungs 1"x4" Nailed (OSHA Violation)	5-5S
1	P1	WSL	5	ManLift	1-2"x4"x14'	Split Transverse Tie	3-5S
1	4	WB	5A	HWBasin	1-2"x10'x14'	Split Horizontal Tie	3-5S
1	2	WB	5A	HWBasin	FRP	Loose Plenum Wall	4-5S
1	5	WC	5A	HWBasin	1-2"x10"x8'	Split Header Support	3-5S
1	6	WC	5A	HWBasin	1-2"x10"x8'	Split Header Support	3-5S
1	2	WC	BOT	ManLift	1-4"x4"x10'	Split Vertical Column	3-5S
1	3	WC	BOT	ManLift	1-4"x4"x10'	Split Vertical Column	3-5S
1	1	WSL	TOP	ManLift/HWBasin	1-4"x4"x18'	Split Sloping Column	3-5S

Classifications:

First number represents description of condition followed by the year (3=03) and the season (S=Spring & F=Fall)

1 = [illegible]adation which could result in a structural failure. Immediate attention recommended.

2 = [illegible]adation which could result in a structural failure. Replace as schedule permits.

3 = Degradation and/or progressing degradation, which could result in a structural failure within 3 years.

4 = Degradation which could result in a loss of thermal performance and/or operating efficiency of the cooling tower.

5 = Condition presenting safety risk.

AS FOUND INSPECTION RESULTS

C.T. Inspection Form - "B"

March, 2005 West Cooling Tower (CT-2)

	Location				Materials		
Cell	Bent	Column	Level	Inspection Area	Affected	Brief Description	Classification
2	5	ESL	4	ManLift	1-2"x4"x4'	Split Louver Arm	3-3F
2	5	ESL	TOP	ManLift/HWBasin	1-4"x4"x18'	Split Sloping Support	3-4S
2	5	ESL	4	ManLift	1-2"x4"x4'	Split Louver Arm	3-4F
2	5	WP	INT	Lower & Upper Plenum	1-4"x4"x18'	Split Vertical Column	3-3F
2	4	WSL	3	ManLift	1-2"x4"x14'	Split Transverse Tie	3-3F
2	4	WSL	4	ManLift	1-2"x4"x4'	Split Louver Arm	3-3F
2	4	WSL	TOP	ManLift/HWBasin	1-4"x4"x18'	Split Sloping Column	3-3S
2	5	WSL	3	ManLift	1-2"x4"x14'	Split Transverse Tie	3-3F
2	6	WSL	5	ManLift	1-2"x4"x14"	Split Transverse Tie	3-4S
2	P2	WSL	1	ManLift	1-4"x4"x10'	Split Transverse Brace	3-4S
2	P2	WSL	4	ManLift	1-4"x4"x2'	Split Splice Block	3-4S
2	2	WSL	5	ManLift	1-2"x4"x2'	Leaning Louver Support	2-5S
2	6	WSL	5	ManLift	1-2"x4"x4'	Split Louver Arm	2-5S
2	6	WSL	5	ManLift	1-2"x8"x14'	Split Longitudinal Tie	3-5S
2	6	WSL	5	ManLift	1-2"x4"x14'	Split Transverse Tie	3-5S
2	6	WSL	5	ManLift	1-2"x4"x4'	Split Louver Arm	2-5S
2	1	WSL	BOT	ManLift	1-4"x4"x10'	Split Sloping Column	3-5S

Classifications:

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AS FOUND INSPECTION RESULTS

C.T. Inspection Form - "B"

March, 2005 West Cooling Tower (CT-2)

	Location				Materials		
Cell	Bent	Column	Level	Inspection Area	Affected	Brief Description	Classification
3	4	EB	INT	Behind DE's	1-4"x4"x18'	Split Transverse Brace	3-3F
3	6	EB	INT	Behind DE's	1-4"x4"x10'	Split Transverse Brace	3-3F
3	1	EC	5A	HWBasin	Fill	Top 16" of Fill Missing	4-4F
3	2	EC	5A	HWBasin	Fill	Top 16" of Fill Missing	4-4F
3	3	EC	5A	HWBasin	Fill	Top 16" of Fill Missing	4-4F
3	4	EC	5A	HWBasin	Fill	Top 16" of Fill Missing	4-4F
3	5	EC	5A	HWBasin	Fill	Top 16" of Fill Missing	4-4F
3	6	EC	5A	HWBasin	Fill	Top 16" of Fill Missing	4-4F
3	1	ESL	TOP	ManLift/HWBasin	1-4"x4"x18'	Split Top Column	3-4S
3	3	ESL	BOT	ManLift	1-4"x4"x8'	Split Transverse Brace	3-4S
3	4	ESL	BOT	ManLift	1-4"x4"x8"	Split Transverse Brace	3-4F
3	4	ESL	TOP	ManLift/HWBasin	Louver	Loose Louver	2-4F
3	3	WA	6	Upper Plenum	1-2"x8"x14'	Split Fan Deck Joist Support	3-3S
3	4	WA	6	Upper Plenum	1-4"x4"x10'	Split Transverse Brace	3-4F
3	4	WA	6	Upper Plenum	1-2"x8"x14'	Split Horizontal Tie	3-4F
3	1	WB	5	Behind DE's	1-4"x4"x10'	Split Transverse Brace	3-3F
3	P3	WC	5A	HWBasin	2-2"x10"x8'	Split Header Support	3-3F
3	1	WSL	INT	ManLift	1-4"x4"x18'	Split Intermediate Column	3-3F
3	2	WSL	2	ManLift	1-4"x4"x8'	Split Transverse Brace	3-4S
3	6	WSL	INT	ManLift	1-4"x4"x18'	Split Intermediate Column	3-4S
3	P3	WSL	3	ManLift	1-2"x4"x8'	Split Transverse Tie	3-3F
3	P3	WSL	TOP	ManLift/HWBasin	1-4"x4"x18'	Split Sloping Column	2-3F
3	3	WA	TOP	Upper Plenum	1-4"x4"x18'	Split Column	3-5S
3	3	WA	TOP	Upper Plenum	1-2"x8"x6'	Split Fan Deck Joist Support	3-5S
3	1	WP	BOT	Lower Plenum	1-4"x4"x12'	Split Vertical Column	3-5S
3	4	WC	5A	HWBasin	1-2"x4"x14'	Split Fan Deck Joist Support	3-5S
3	4	WSL	5A	ManLift/HWBasin	1-2"x2"x5'	Basin Curb Seal Strip	4-5S
3	3	WSL	INT	ManLift	1-2"x4"x14'	Missing Nut	3-5S

Classifications:

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2 = Degradation which could result in a structural failure. Replace as schedule permits.

3 = Degradation and/or progressing degradation, which could result in a structural failure within 3 years.

4 = Degradation which could result in a loss of thermal performance and/or operating efficiency of the cooling tower.

5 = Condition presenting safety risk.

AS FOUND INSPECTION RESULTS

C.T. Inspection Form - "B"

March, 2005

West Cooling Tower (CT-2)

Location					Materials		
Cell	Bent	Column	Level	Inspection Area	Affected	Brief Description	Classification
4	4	EC	5	ManLift/Behind DE's	1-2"x6"x14'	Bowing Basin Support	3-4F
4	5	EC	INT	ManLift/Behind DE's	1-4"x4"x18'	Split Vertical Column	3-3F
4	3	ESL	INT	ManLift	1-4"x4"x18'	Split Sloping Column	3-4S
4	5	ESL	INT	ManLift	1-4"x4"x18'	Split Sloping Column	3-3F
4	5	ESL	TOP	ManLift/HWBasin	1-4"x4"x18'	Split Sloping Column	3-4F
4	2	WA	5	Upper Plenum	1-2"x4"x14'	Split Transverse Tie	3-4F
4	3	WP	TOP	Upper Plenum	1-4"x4"x18'	Split Vertical Column	3-3F
4	4	WP	INT	Lower & Upper Plenum	1-4"x4"x18	Split Vertical Column	3-4S
4	6	WSL	3	ManLift	1-2"x4"x14'	Split Transverse Tie	3-3F
4	6	WSL	INT	ManLift	1-4"x4"x18'	Split Sloping Column	3-4F
4	6	WSL	5	ManLift	1-2"x4"x2'	Split Splice Block	3-3S
4	6	WSL	INT	ManLift	1-4"x4"x2'	Split Sloping Column	3-4F
4	3	WSL	INT	ManLift	1-4"x4"x18'	Split Sloping Column	3-5S
4	3	WP	BOT	Lower Plenum	1-2"x4"x8'	Weak Walkway Support	3-5S
4	5	WP	BOT	Lower Plenum	1-4"x4"x10'	Split Vertical Column	3-5S
4	P4	WC	5A	HWBasin	1-2"x10"x8'	Split Header Support	3-5S

Classifications:

First number represents description of condition followed by the year (3=03) and the season (S=Spring & F=Fall)

1 = Degradation which could result in a structural failure. Immediate attention recommended.

2 = Degradation which could result in a structural failure. Replace as schedule permits.

3 = Degradation and/or progressing degradation, which could result in a structural failure within 3 years.

4 = Degradation which could result in a loss of thermal performance and/or operating efficiency of the cooling tower.

5 = Condition presenting safety risk.

AS FOUND INSPECTION RESULTS

C.T. Inspection Form - "B"

March, 2005

West Cooling Tower (CT-2)

Location					Materials	Brief Description	Classification
Cell	Bent	Column	Level	Inspection Area	Affected		
5	1	ESL	INT	ManLift	1-4"x4"x18'	Split Sloping Column	3-4S
5	3	ESL	INT	ManLift	1-4"x4"x18'	Split Sloping Column	3-3F
5	3	ESL	TOP	ManLift/HWBasin	1-4"x4"x18'	Split Sloping Column	3-4S
5	5	ESL	1	ManLift	1-2"x4"x14'	Split Transverse Tie	3-4S
5	5	ESL	INT	ManLift	1-4"x4"x18'	Split Sloping Column	3-4S
5	P5	ESL	BOT	ManLift	1-2"x4"x2'	Split Louver Support	3-4F
5	P5	ESL	TOP	ManLift/HWBasin	1-4"x4"x18'	Split Sloping Column	3-4S
5	4	WSL	BOT	ManLift	1-2"x4"x4'	Split Louver Arm	3-4F
5	4	WA	5A	ManLift/HWBasin	1-4"x4"x10'	Split Diagonal Brace	3-4F
5	P5	WC	5A	HWBasin	1-2"x6"x10'	Split Header Support	3-4F
5	1	WSL	3	ManLift	1-2"x4"x14'	Split Transverse Tie	3-3F
5	2	WSL	INT	ManLift	1-4"x4"x18'	Split Sloping Column	3-4S
5	4	WSL	INT	ManLift	1-4"x4"x18'	Split Sloping Column	3-4S
5	6	WSL	TOP	ManLift/HWBasin	1-4"x4"x18'	Split Sloping Column	3-4S
5	4	WP	TOP	Upper Plenum	1-4"x4"x18'	Split Vertical Column	3-5S
5	4	WP	TOP	Upper Plenum	1-4"x4"x10'	Split Diagonal Brace	3-5S
5	4	WP	TOP	Upper Plenum	1-4"x6"x5'	Split Splice Block	3-5S
5	5	EB	TOP	HWBasin/Behind DE's	1-4"x4"x18'	Split Vertical Column	3-5S
5	5	EB	TOP	HWBasin/Behind DE's	1-2"x4"x14'	Split Scarf Joints	3-5S
5	2	WSL	TOP	ManLift/HWBasin	1-2"x4"x4'	Split Louver Arm	3-5S
5	3	WC	4	ManLift/Behind DE's	Drift Eliminators	Collapse Drift Eliminator Blades	4-5S
5	4	WP	2	Lower Plenum	1-4"x4"x12'	Split Vertical Column	3-5S

Classifications:

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1 = Degradation which could result in a structural failure. Immediate attention recommended.
2 = Degradation which could result in a structural failure. Replace as schedule permits.
3 = Degradation and/or progressing degradation, which could result in a structural failure within 3 years.
4 = Degradation which could result in a loss of thermal performance and/or operating efficiency of the cooling tower.
5 = Condition presenting safety risk.

AS FOUND INSPECTION RESULTS
C.T. Inspection Form - "B"

March, 2005 — West Cooling Tower (CT-2)

Location					Materials		
Cell	Bent	Column	Level	Inspection Area	Affected	Brief Description	Classification
6	1	ESL	INT	ManLift	1-4"x4"x18'	Split Sloping Column	3-4S
6	5	ESL	5	ManLift	1-2"x10"x18'	HW Basin Curb Split	3-3F
6	P6	ESL	INT	ManLift	1-4"x4"x18'	Split Sloping Column	3-4S
6	2	WSL	BOT	ManLift	1-4"x4"x14'	Split Transverse Tie	3-4F
6	3	EB	5A	HWBasin	1-2"x6"x14'	Split Deck Joist Support	3-5S
6	2	WC	5A	HWBasin	1-2"x10"x14'	Split Longitudinal Tie	3-5S
6	P6	WP	BOT	Lower Plenum	1-2"x4"x12'	Loose Handrail	5-5S
6	4	WC	5A	HWBasin	1-2"x10"x14'	Split Longitudinal Tie	3-5S

Classifications:

First number represents description of condition followed by the year (3=03) and the season (S=Spring & F=Fall)

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3 = Degradation and/or progressing degradation, which could result in a structural failure within 3 years.
4 = Degradation which could result in a loss of thermal performance and/or operating efficiency of the cooling tower.
5 = Condition presenting safety risk.

AS FOUND INSPECTION RESULTS

C.T. Inspection Form "B"

March, 2005 — West Cooling Tower (CT-2)

Cell	Location: Bent	Location: Column	Location: Level	Location: Inspection Area	Materials Affected	Brief Description	Classification
7	1	ESL	INT	ManLift	1-4"x4"x18'	Split Sloping Column	3-4S
7	2	ESL	TOP	ManLift/HWBasin	1-4"x4"x18'	Split Sloping Column	3-4S
7	3	ESL	INT	ManLift	1-4"x4"x18'	Split Sloping Column	3-4S
7	5	ESL	5	ManLift	1-4"x4"x18'	Split Sloping Column	3-4F
7	5	ESL	TOP	ManLift/HWBasin	1-4"x4"x18'	Split Sloping Column	3-3F
7	P7	ESL	2	ManLift	1-2"x4"x14'	Split Transverse Tie	3-3F
7	P7	ESL	INT	ManLift	1-4"x4"x18'	Split Sloping Column	3-3S
7	2	WA	6	Upper Plenum	1-4"x4"x18'	Split Vertical Column	3-4F
7	3	WA	6	Upper Plenum	1-2"x4"x14'	Split Horizontal Tie	3-4F
7	4	WA	3	Lower Plenum/Behind DE's	Drift Eliminators	DE Seal Missing	4-3A
7	2	WB	5A	HWBasin	Drift Eliminators	Missing Drift Eliminator Seal	3-4F
7	1	WSL	5A	ManLift/HWBasin	1-2"x4"x4'	Split Louver Arm	2-3F
7	3	WSL	1	ManLift	1-4"x4"x10'	Split Transverse Brace	3-4S
7	3	WSL	TOP	ManLift/HWBasin	1-4"x4"x18	Split Sloping Column	3-4S
7	4	WSL	2	ManLift	1-2"x4"x2'	Broken Louver Arm	3-3S
7	5	WSL	1	ManLift	1-4"x4"x10'	Split Transverse Brace	3-4S
7	6	WSL	4	ManLift	1-2"x4"x4'	Split Louver Arm	3-4F
7	P7	WSL	1	ManLift	1-2"x4"x14'	Split Transverse Tie	3-3F
7	P7	WSL	5A	ManLift/HWBasin	1-2"x4"x10'	Split Transverse Tie	3-3F
7	1	EB	TOP	HWBasin/Behind DE's	1-4"x4"x18'	Split Vertical Column	3-5S
7	1	EB	TOP	HWBasin/Behind DE's	1-2"x8"x14'	Split Horizontal Joist	3-5S
7	4	EB	TOP	HWBasin/Behind DE's	1-4"x4"x18'	Split Vertical Column	3-5S
7	7	WSL	INT	ManLift	1-2"x4"x2'	Split Louver Support	2-5S
7	P7	WSL	INT	ManLift	1-2"x4"x4'	Split Louver Arm	2-5S
7	5	WSL	TOP	ManLift/HWBasin	1-4"x4"x18'	Split Sloping Column	3-5S
7	4	WSL	INT	ManLift	1-4"x4"x18'	Split Sloping Column	3-5S
7	P7	WP	BOT	Lower Plenum	1-2"x4"x14'	Loose Handrail	5-5S
7	5	WB	5A	HWBasin	1-2"x10"x14'	Split Longitudinal Tie	3-5S
7	P7	WC	5A	HWBasin	1-2"x10"x6'	Split Header Support	3-5S

Classifications:

First number represents description of condition followed by the year (3=03) and the season (S=Spring & F=Fall)

1 = Degradation which could result in a structural failure. Immediate attention recommended.
2 = Degradation which could result in a structural failure. Replace as schedule permits.
3 = Degradation and/or progressing degradation, which could result in a structural failure within 3 years.
4 = Degradation which could result in a loss of thermal performance and/or operating efficiency of the cooling tower.
5 = Condition presenting safety risk.

AS FOUND INSPECTION RESULTS

C.T. Inspection Form - "B"

March, 2005 West Cooling Tower (CT-2)

Location					Materials	Brief Description	Classification
Cell	Bent	Column	Level	Inspection Area	Affected		
8	1	EP	TOP	Upper Plenum	1-4"x4"x18'	Split Vertical Column	3-3F
8	2	ESL	INT	ManLift	1-4"x4"x18'	Split Sloping Column	3-4F
8	4	ESL	TOP	ManLift/HWBasin	1-4"x4"x18'	Split Sloping Column	3-4S
8	5	ESL	2	ManLift	1-2"x4"x10'	Split Transverse Tie	3-3F
8	5	ESL	INT	ManLift	1-4"x4"x18'	Split Sloping Column	3-4F
8	3	WC	INT	ManLift/Behind DE's	1-4"x4"x18'	Split Vertical Column	3-4F
8	3	WSL	INT	ManLift	1-4"x4"x18'	Split Sloping Column	3-4F
8	3	WSL	TOP	ManLift/HWBasin	1-4"x4"x18'	Split Sloping Column	3-4S
8	4	WSL	4	ManLift	1-2"x4"x4'	Split Louver Support	3-4S
8	4	WSL	BOT	ManLift	1-4"x4"x10'	Split Transverse Brace	3-4S
8	5	WSL	5	ManLift	1-2"x4"x14'	Split Transverse Tie	3-4S
8	6	WSL	2	ManLift	1-2"x4"x14'	Split Transverse Tie	3-4S
8	6	WSL	5	ManLift	1-2"x4"x14'	Split Transverse Tie	3-4S
8	8	WSL	BOT	ManLift	1-4"x4"x10'	Split Transverse Brace	3-4S
8	5	WA	TOP	Upper Plenum	1-2"x8"x6'	Split Fan Deck Joist Support	3-5S
8	5	EA	TOP	Upper Plenum	1-2"x8"x14'	Split Fan Deck Joist Support	3-5S
8	2	WSL	TOP	ManLift/HWBasin	1-2"x4"x2'	Split Louver Support	3-5S
8	P8	WSL	BOT	ManLift	1-2"x4"x14'	Split Transverse Tie	3-5S
8	6	ESL	5	ManLift	Louvers	Bottom Portion Unsecure	2-5S
8	5	ESL	5	ManLift	Louvers	Bottom Portion Unsecure	2-5S
8	4	ESL	5	ManLift	Louvers	Bottom Portion Unsecure	2-5S
8	P8	ESL	5	ManLift	Louvers	Bottom Portion Unsecure	2-5S
8	1	ESL	5	ManLift	1-2"x4"x4'	Missing Louver Support	2-5S

Classifications:

First number represents description of condition followed by the year (3=03) and the season (S=Spring & F=Fall)

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3 = Degradation and/or progressing degradation, which could result in a structural failure within 3 years.

4 = Degradation which could result in a loss of thermal performance and/or operating efficiency of the cooling tower.

5 = Condition presenting safety risk.

AS FOUND INSPECTION RESULTS

C.T. Inspection Form - "B"

March, 2005

West Cooling Tower (CT-2)

	Location				Materials		
Cell	Bent	Column	Level	Inspection Area	Affected	Brief Description	Classification
9	1	EP	BOT	Lower Plenum	1-4"x4"x18'	Split Vertical Column	3-4S
9	3	ESL	4	ManLift	1-2"x4"x14'	Split Transverse Tie	3-4S
9	3	ESL	BOT	ManLift	1-4"x4"x10'	Split Transverse Brace	3-4S
9	5	ESL	INT	ManLift	1-4"x4"x18'	Split Sloping Column	3-3S
9	P9	ESL	INT	ManLift	1-4"x4"x18'	Split Sloping Column	3-2F
9	1	WSL	INT	ManLift	1-4"x4"x18'	Split Sloping Column	3-4S
9	3	WSL	TOP	ManLift/HWBasin	1-4"x4"x18'	Split Sloping Column	3-3S
9	5	WSL	BOT	ManLift	1-4"x4"x10'	Split Transverse Brace	3-4S
9	1	WSL	BOT	ManLift	1-4"x4"x10'	Split Transverse Brace	3-4F
9	5	WSL	2	ManLift	2-2"x4"x14'	Split Transverse Tie	3-4F
9	2	WA	5	Upper Plenum	1-2"x4"x14'	Split Transverse Tie	3-4F
9	4	WA	5	Upper Plenum	1-2"x4"x14'	Split Transverse Tie	3-4F
9	3	ESL	INT	ManLift	1-4"x4"x18'	Split Sloping Column	3-4F
9	2	ESL	BOT	ManLift	1-4"x4"x10'	Split Transverse Brace	3-4F
9	3	EA	TOP	Upper Plenum	1-4"x4"x18'	Split Vertical Column	2-5S
9	5	WSL	TOP	ManLift/HWBasin	1-2"x4"x4'	Split Louver Arm	3-5S
9	2	ESL	TOP	ManLift/HWBasin	1-4"x4"x18'	Split Sloping Column	3-5S

Classifications:

First number represents description of condition followed by the year (3=03) and the season (S=Spring & F=Fall)

1 = Degradation which could result in a structural failure. Immediate attention recommended.

2 = Degradation which could result in a structural failure. Replace as schedule permits.

3 = Degradation and/or progressing degradation, which could result in a structural failure within 3 years.

4 = Degradation which could result in a loss of thermal performance and/or operating efficiency of the cooling tower.

5 = Condition presenting safety risk.

AS FOUND INSPECTION RESULTS
C.T. Inspection Form - "B"

March, 2005 West Cooling Tower (CT-2)

	Location				Materials		
Cell	Bent	Column	Level	Inspection Area	Affected	Brief Description	Classification
10	P10	ESL	INT	ManLift	1-4"x4"x18'	Split Sloping Column	3-3F
10	3	WC	4	ManLift/Behind DE's	1-4"x4"x10'	Split Long Brace	3-4S
10	1	WSL	3	ManLift	Drift Eliminators	Broken DE Ledge	4-3F
10	1	WSL	5	ManLift	1-2"x4"x14'	Split Transverse Tie	3-3F
10	4	WSL	BOT	ManLift	1-4"x4"x10'	Split Transverse Brace	3-4S
10	P10	WSL	5	ManLift	1-2"x4"x14'	Split Transverse Tie	3-4S
10	P10	WSL	TOP	ManLift/HWBasin	1-2"x4"x14'	Split Transverse Tie	3-3F
10	3	WA	TOP	Upper Plenum	1-4"x4"x18'	Split Vertical Column	3-5S
10	3	WA	TOP	Upper Plenum	1-2"x8"x6'	Split Mechanical Support	3-5S
10	5	WP	TOP	Upper Plenum	1-4"x4"x10'	Split Diagonal Brace	3-5S
10	3	WSL	TOP	ManLift/HWBasin	1-4"x4"x18'	Split Sloping Column	3-5S
10	1	WA	BOT	Behind DE's	Drift Eliminators	Air Seal Off	4-5S
10	4	ESL	TOP	ManLift/HWBasin	1-4"x4"x18'	Split Sloping Column	3-5S

Classifications:
First number represents description of condition followed by the year (3=03) and the season (S=Spring & F=Fall)
1 = Degradation which could result in a structural failure. Immediate attention recommended.
2 = Degradation which could result in a structural failure. Replace as schedule permits.
3 = Degradation and/or progressing degradation, which could result in a structural failure within 3 years.
4 = Degradation which could result in a loss of thermal performance and/or operating efficiency of the cooling tower.
5 = Condition presenting safety risk.

AS-FOUND COOLING TOWER DEEP BASIN INSPECTION

PREREQUISITES | Initial / Date

1. WO No.: 01-5040-000 | TER 10/7/02
2. Shift Supervisor's permission to start work. | RK 10/7/02 SS
4. QC Peer inspection required: YES or NO (Circle One). | TER 10/7/02

I LPC 4

PROCEDURE

5.2 As-found average silt depth. Indicate most appropriate below

- 2" average or less: ______
- 4" average or less: X
*- 5.5" average or more: ______

*If average silt depth is 5.5" or more, initiate ER and notify SW System Engineer immediately.

JKA / 10/7/02

- 12" or less in the suction pit: X
*- 12" or greater in the suction pit: ______

*If average suction pit silt depth is 12" or more, initiate ER and notify SW System Engineer immediately.

JKA / 10/7/02

5.3 Evidence of clams, mussels and debris.

*Yes: _____ No: X

*If clams, mussels or debris is found, initiate an ER and notify SW System Engineer.

JKA / 10/7/02

AS-FOUND COOLING TOWER DEEP BASIN INSPECTION (Continued)

5.4 As-found deep basin physical condition.

- Cracks with leakage: *Yes ____ No X
- Leaks: *Yes ____ No X
- Structural Failure: *Yes ____ No X

*If deep basin has cracks, leaks or other structural failures, initiate ER and notify SW System Engineer immediately.

10/7/02

COMMENTS: ______________________

FINAL CONDITIONS

4. Copy of completed form forwarded to System Engineering Records Clerk.

TER 10/22

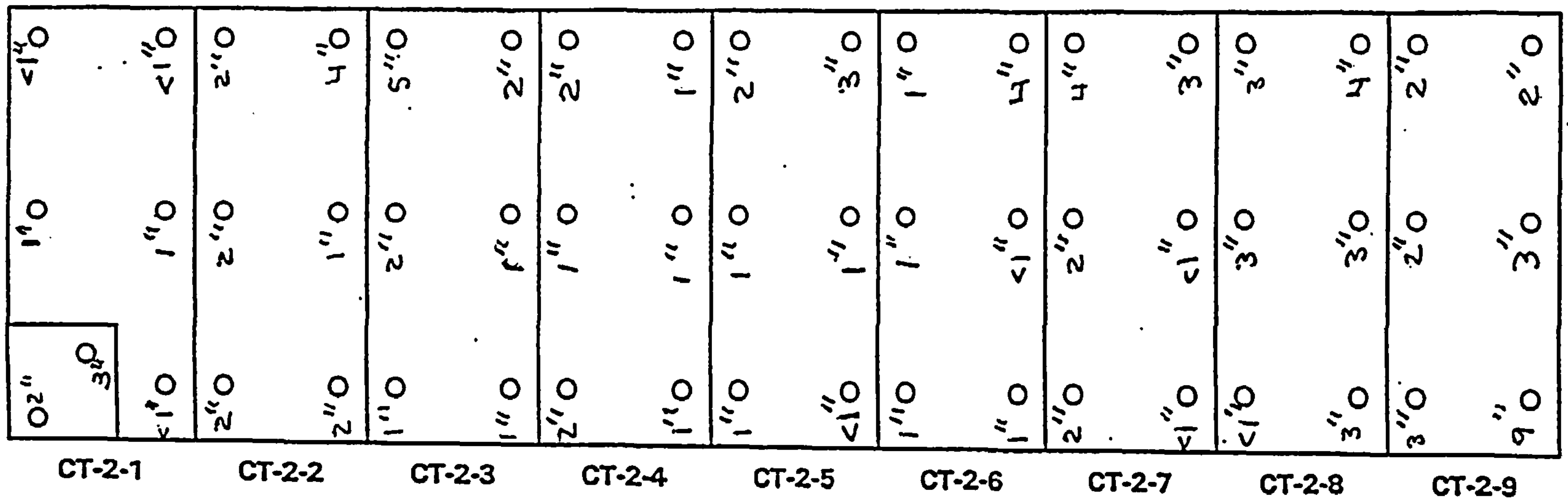
Inspection Completed By: ______ 10/7/02 Date Inspection Reviewed By: TER 10/22/02 Maint. Supv. Date

These Readings were taken on 10/7/02
Actual silt removal indicates slightly higher levels than recorded.
T E Ryan
10/17/02

TABLE 2

Cooling Tower Deep Basin Silt Depth Measurement Locations

Measure and record silt depth at each location indicated on the basin floor map below (O = location).



UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
475 ALLENDALE ROAD
KING OF PRUSSIA, PA 19406-1415

July 20, 2005

Mr. Jay K. Thayer
Site Vice President
Entergy Nuclear Operations, Inc.
Vermont Yankee Nuclear Power Station
P.O. Box 0500
185 Old Ferry Road
Brattleboro, VT 05302-0500

SUBJECT: VERMONT YANKEE NUCLEAR POWER STATION - NRC INTEGRATED INSPECTION REPORT 05000271/2005003

Dear Mr. Thayer:

On June 30, 2005, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Vermont Yankee Nuclear Power Station (VY). The enclosed report documents the inspection findings which were discussed on July 11, 2005, with members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel. Based on the results of this inspection, no findings of significance were identified.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of the NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

Clifford J. Anderson

Clifford J. Anderson, Chief
Projects Branch 5
Division of Reactor Projects

Docket No. 50-271
License No. DPR-28

Enclosure: Inspection Report 05000271/2005003
w/Attachment: Supplemental Information

cc w/encl:
M. R. Kansler, President, Entergy Nuclear Operations, Inc.
G. J. Taylor, Chief Executive Officer, Entergy Operations
J. T. Herron, Senior Vice President and Chief Operating Officer
C. Schwarz, Vice-President, Operations Support
O. Limpias, Vice President, Engineering
J. M. DeVincentis, Manager, Licensing, Vermont Yankee Nuclear Power Station
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J. E. Silberg, Pillsbury, Winthrop, Shaw, Pittman LLP
G. D. Bisbee, Esquire, Deputy Attorney General, Environmental Protection Bureau
J. Block, Esquire
J. P. Matteau, Executive Director, Windham Regional Commission
M. Daley, New England Coalition on Nuclear Pollution, Inc. (NECNP)
D. Katz, Citizens Awareness Network (CAN)
R. Shadis, New England Coalition Staff
G. Sachs, President/Staff Person, c/o Stopthesale
Commonwealth of Massachusetts, SLO Designee
State of New Hampshire, SLO Designee
State of Vermont, SLO Designee

U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket No.	50-271
Licensee No.	DPR-28
Report No.	05000271/2005003
Licensee:	Entergy Nuclear Operations, Inc.
Facility:	Vermont Yankee Nuclear Power Station
Location:	320 Governor Hunt Road Vernon, Vermont 05354-9766
Dates:	April 1, 2005 - June 30, 2005
Inspectors:	David L. Pelton, VY Senior Resident Inspector Beth E. Sienel, VY Resident Inspector James D. Noggle, Senior Health Physicist Steven W. Shaffer, Seabrook Resident Inspector
Approved by:	Clifford J. Anderson, Chief Projects Branch 5 Division of Reactor Projects

CONTENTS

SUMMARY OF FINDINGS

IR 05000271/2005003; 04/01/05 - 06/30/05; Vermont Yankee Nuclear Power Station; Routine Integrated Report.

This report covered a 13-week period of inspection by resident inspectors and a regional senior health physicist. No findings of significance were identified. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

No findings of significance were identified.

B. Licensee-Identified Findings

None.

REPORT DETAILS

Summary of Plant Status

Vermont Yankee Nuclear Power Station began the inspection period operating at or near full power. On April 25, 2005, operators reduced reactor power to approximately 80% at the request of the electrical grid operator. Power was restored to approximately 100% later that day and, with the exception of power reductions for control rod pattern adjustments and turbine valve testing, continued at or near full power for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

1. Readiness for Impending Adverse Weather Conditions

a. Inspection Scope (one sample)

On June 6, the inspectors reviewed actions taken by Entergy in response to a tornado watch for the area. The inspectors reviewed Vermont Yankee Operating Procedure (OP) 3127, "Natural Phenomena," and emergency action levels (EALs) to ensure any applicable actions were taken. The inspectors also discussed the weather situation and status of safety related equipment with the operations shift manager to ensure he was aware of the potential for severe weather and equipment was available, if needed.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

1. Complete Equipment Alignment (71111.04S)

a. Inspection Scope (one sample)

The inspectors performed a complete equipment alignment walkdown of accessible portions of the reactor building closed cooling water system, with a focus on the portions of the system that would be required for alternate cooling. The inspectors compared the actual equipment alignment to approved piping and instrumentation drawings, operating procedures, and the system description in the Updated Final Safety Analysis Report (UFSAR). The inspectors observed valve positions, the availability of power supplies, and the general condition of the system to verify any deficiencies were identified and did not affect the operability of the system.

b. Findings

No findings of significance were identified.

2. Partial Equipment Alignments (71111.04)

a. Inspection Scope (three samples)

The inspectors performed three partial system walkdowns of risk-significant systems to verify system alignment and to identify any discrepancies that could impact system operability. Observed plant conditions were compared to the standby alignment of equipment specified in Entergy's system operating procedures. The inspectors also observed valve positions, the availability of power supplies, and the general condition of selected components to verify there were no obvious deficiencies. The inspectors evaluated the alignment of the following systems:

- The reactor core isolation cooling (RCIC) system during planned high pressure coolant injection (HPCI) maintenance on May 24, 2005;
- The HPCI, main feedwater, control rod drive, and automatic depressurization systems during RCIC system valve packing replacement on June 3; and
- The "A" train of the standby liquid control (SLC) system during planned maintenance on the "B" train of SLC on June 21.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05Q)

a. Inspection Scope (twelve samples)

The inspectors identified twelve fire areas and zones important to plant risk based on a review of Entergy's Safe Shutdown Capability Analysis for Vermont Yankee and the Individual Plant Examination External Events (IPEEE). The inspectors toured these plant areas in order to verify the suitability of Entergy's control of transient combustibles and ignition sources, and to evaluate the material condition and operational status of fire protection systems, equipment, and barriers. In addition, the inspectors discussed attributes of several of the areas with the fire protection engineer. The following fire areas (FAs), fire zones (FZs) and combustion free zones (CFZs) were inspected:

- Torus room, 213 foot elevation, North (FZ RB1);
- Torus room, 213 foot elevation, South (FZ RB2);
- Reactor building, 252 foot elevation, North (FZ RB3);
- Reactor building, 252 foot elevation, South (FZ RB4);
- Reactor building, 252 foot elevation - S1 cable trays (CFZ-3/4);
- Reactor building, 252 foot elevation - S2 cable trays (CFZ-3/4);
- Reactor building, 280 foot elevation, North (FZ RB5);

- Reactor building, 280 foot elevation, South (FZ RB7);
- Reactor building, 280 foot elevation, recirc motor generator area (SZ RB-MG)
- Reactor building, 303 foot elevation (FZ RB7);
- Turbine building, all areas (FA TB); and
- Relay house - 345 KV (No fire designation).

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope (one sample)

The inspectors reviewed Entergy's established flood protection barriers and procedures for coping with external flooding events. The inspectors reviewed external flooding information contained in Entergy's IPEEE and compared it to required flooding actions delineated in OP 3127, "Natural Phenomena." The inspectors performed walkdowns of flood-vulnerable areas and ensured equipment needed to mitigate an external flooding event (e.g., sump pumps, floor drain plugs, sand bags, etc.) was available and in working order. The inspectors also reviewed a sample of problems identified in Entergy's corrective action program to verify that Entergy identified and implemented appropriate corrective actions.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11Q)

a. Inspection Scope (one sample)

The inspectors observed a simulator examination for one operating crew to assess the performance of the licensed operators and the ability of Entergy's Training and Operations Department staff to evaluate licensed operator performance. Crew performance was evaluated during simulated events involving an anticipated transient without a scram and a loss of all high pressure injection to the reactor vessel.

The inspectors evaluated the crew's performance in the areas of:

- Clarity and formality of communications;
- Ability to take timely actions;
- Prioritization, interpretation, and verification of alarms;
- Procedure use;
- Control board manipulations;
- Oversight and direction from supervisors; and
- Group dynamics.

Crew performance in these areas was compared to Entergy management expectations and guidelines as presented in the following documents:

- Vermont Yankee Administrative Procedure (AP) 0151, "Responsibilities and Authorities of Operations Department Personnel";
- AP 0153, "Operations Department Communication and Log Maintenance"; and
- Vermont Yankee Department Procedure (DP) 0166, "Operations Department Standards."

The inspectors evaluated whether the crew completed the critical tasks identified in the simulator evaluation guide. The inspectors also compared simulator configurations with actual control board configurations. For any weaknesses identified, the inspectors observed Entergy evaluators to verify that they also noted the issues to be discussed with the crew.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12Q)

a. Inspection Scope (two samples)

The inspectors performed one issue/problem-oriented inspection of actions taken by Entergy in response to "B" SLC pump packing leakage. The inspectors also performed one system/function performance history-oriented inspection of the containment continuous air monitor (CAM) system. The inspectors reviewed the UFSAR, system design basis documents, operating procedures, system maintenance rule scoping documents, list of historical condition reports written for the CAM and SLC systems, applicable maintenance rule functional failure determinations, and corrective actions taken in response to the equipment problems in accordance with station procedures and the requirements of 10 CFR 50.65.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessment and Emergent Work Evaluation (71111.13)

a. Inspection Scope (six samples)

The inspectors evaluated on-line risk management for five planned maintenance activities and one emergent condition. The inspectors reviewed maintenance risk evaluations, work schedules, recent corrective actions, and control room logs to verify that other concurrent or emergent maintenance activities did not significantly increase plant risk. The inspectors compared reviewed items and activities to requirements listed in procedures AP 0125, "Plant Equipment," and AP 0172, "Work Schedule Risk Management - Online." The inspectors reviewed the following on-line work activities:

- (Emergent) Trip of the Scobie 345 kilovolt (KV) offsite power line coincident with the Coolidge line being in a degraded condition during inclement weather;
- Planned limiting condition for operation (LCO) maintenance on the "B" service water pump;
- Planned LCO maintenance on cooling tower CT 2-1;
- Planned LCO maintenance on the HPCI system;
- Replacement of the five volt power supply for the rod position indicating system (RPIS); and
- Planned work, designated as high risk, in the 115 KV switchyard.

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Non-routine Plant Evolutions (71111.14)

a. Inspection Scope (two samples)

The inspectors assessed the control room and in-plant operators' performance during an April 25, 2005, power reduction to approximately 80% that was requested by the electrical grid operator and a June 28 power reduction to approximately 65% to support a planned control rod sequence exchange and turbine valve testing. The inspectors evaluated the adequacy of personnel performance, procedure compliance, and use of the corrective action process against the requirements and expectations contained in the following station procedures:

- AP 0091, "Risk Assessment Procedure - Temporary Configuration Changes";
- AP 0151, "Responsibilities and Authorities of Operations Department Personnel";
- AP 0153, "Operations Department Communication and Log Maintenance"; and
- DP 0166, "Operations Department Standards."

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope (seven samples)

The inspectors reviewed seven operability determinations prepared by Entergy. The inspectors evaluated operability determinations against the requirements and guidance contained in NRC Generic Letter 91-18, "Resolution of Degraded and Nonconforming Conditions," as well as Entergy procedure ENN-OP-104, "Operability Determinations."

The inspectors evaluated the adequacy of the following evaluations of degraded or non-conforming conditions:

- Electrical grounds identified while running the cooling fan for the West cooling tower cell 2-1 (This cooling tower cell supports the alternate cooling system.);
- Low residual heat removal service water system pump motor bearing cooling water flow;
- Damage to alternate cooling deep basin cement wall;
- Potential for certain safety related breakers to fail to close electrically;
- RCIC steam line pressure switch root valve packing leak;
- Two broken bolts on control side vertical drive inspection cover of "B" emergency diesel generator (EDG); and
- Licensee identified that reactor protection system testing was not being performed as required by the Technical Specifications (TS).

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing (71111.19)

a. Inspection Scope (seven samples)

The inspectors reviewed seven post-maintenance testing (PMT) activities on risk-significant systems. The inspectors either directly observed or reviewed completed PMT documentation to verify that the test data met the required acceptance criteria contained in the TS, UFSAR, and in-service testing program. Where testing was directly observed, the inspectors evaluated whether installed test equipment was appropriate and controlled and that the test was performed in accordance with applicable station procedures. The inspectors also evaluated whether the test activities were adequate to ensure system operability and functional capability following maintenance; that systems were properly restored following testing; and that any discrepancies were appropriately documented in the corrective actions program. The inspectors reviewed the PMTs performed after the following maintenance activities were completed:

- Cooling tower fan CT 2-1 cable re-routing;
- Replacement of control side sections of the "B" EDG fuel oil injector camshaft;
- HPCI planned LCO maintenance;
- Planned maintenance on the "A" train of the standby gas treatment system;
- Replacement of the diesel driven fire pump;
- Replacement of the five volt power supply for the RPIS system; and
- Troubleshooting and repair of the feedwater master level controller.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope (seven samples)

The inspectors observed surveillance testing to evaluate whether each test was performed in accordance with the written procedure, the acceptance criteria specified for each test was consistent with the requirements of the TS and UFSAR, test data was complete and met procedural requirements, and the system was properly returned to service following the completion of testing. The inspectors observed selected pre-job briefings supporting testing. The inspectors also evaluated whether discrepancies identified were entered into the corrective action program. The inspectors evaluated whether testing in accordance with the following procedures met the above requirements:

OP 4105	Fire Protection Systems Surveillance; Section D, "Eighteen Month Fire Pump Operational Performance, Capacity Check and Diesel Fire Pump Alarm/Shutdown Test"
OP 4114	Standby Liquid Control System Surveillance; Section B, "Pump Operability and Comprehensive Tests and Discharge Check Valve Test"
OP 4116	Secondary Containment Surveillance; Section A, "Secondary Containment Capability Test"
OP 4121	Reactor Core Isolation Cooling System Surveillance; Section C, "RCIC Pump Operability and Full Flow and Comprehensive Test"
OP 4126	Diesel Generator Surveillance; Section B, "Monthly ["B"] Diesel Generator Slow Start Operability Test"
OP 4152	Equipment and Floor Drain Sump and Totalizer Surveillance, and
OP 4400	Calibration of the Average Power Range Monitoring System to Core Thermal Power

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope (one sample)

The inspectors reviewed temporary modification (TM) 2005-004, "Installation of Structural Steel Splices in Cooling Tower CT 2-1," and calculation VYC-2404, "Design of Structural Member Splices on Cooling Tower CT-2 for TM 2005-004," and discussed the modification with the responsible engineer to ensure that the modification did not adversely affect the availability or functional capability of the cooling tower. The inspectors also walked down the accessible portions of CT 2-1 to verify the TM was properly maintained and there were no obvious deficiencies.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope (one sample)

The inspectors observed an operating crew evaluate a simulator-based event using the station EALs during licensed operator requalification training activities. The inspectors discussed the performance expectations and results with the lead instructor. The inspectors focused on the ability of licensed operators to perform event classification and make proper notifications in accordance with the following station procedures and industry guidance:

- AP 0153, "Operations Department Communications and Log Maintenance";
- AP 0156, "Notification of Significant Events";
- AP 3125, "Emergency Plan Classification and Action Level Scheme";
- DP 0093, "Emergency Planning Data Management";
- OP 3540, "Control Room Actions During an Emergency"; and
- Nuclear Energy Institute (NEI) 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 2.

b. Findings

No findings of significance were identified.

2. **RADIATION SAFETY**

Cornerstone: Public Radiation Safety

2PS1 Gaseous and Liquid Effluents (71122.01)

a. Inspection Scope (one sample)

The inspectors performed an in-office review of the following documents to evaluate the effectiveness of the licensee's radioactive gaseous and liquid effluent control programs. In addition, telephone interviews were conducted with Entergy chemistry staff and their contractors. The criteria for this review were the requirements for radioactive effluent controls as specified in the TS and the Offsite Dose Calculation Manual (ODCM).

Changes to the ODCM, Revision 29, Section 6.11, concerning direct dose calculation methodology were reviewed. This included a review of bases documents including: Summary Report, "In Situ Measurements Performed at Vermont Yankee Nuclear Power

Station," published February 13, 2002, by Duke Engineering & Services Environmental Laboratory; ANSI/ANS-6.1.1-1991, "Neutron and Gamma-Ray Fluence-to-Dose Factors"; and NISTIR 5632, "Tables of X-Ray Mass Attenuation Coefficients and Mass Energy-Absorption Coefficients."

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA2 Identification and Resolution of Problems (71152)

1. Routine Review of Identification and Resolution of Problems

a. Inspection Scope

The inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify they were being entered into Entergy's corrective action system at an appropriate threshold and that adequate attention was being given to timely corrective actions. Additionally, in order to identify repetitive equipment failures and/or specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into Entergy's corrective action program. This review was accomplished by reviewing selected hard copies of condition reports (a listing of CRs reviewed is included in the Attachment to this report) and/or by attending daily screening meetings.

b. Findings

No findings of significance were identified.

2. Annual Sample Review - Risk Assessment Program Implementation

a. Inspection Scope (one sample)

The inspectors selected Entergy's implementation of the risk assessment program for review based on several NRC and licensee-identified issues in the past year. The issues occurred both online and during the refueling outage and included both incorrect outage risk determinations and failures to hang a portion of critical plant equipment signs when maintenance was performed on safety-related equipment. A listing of reviewed CRs is included in the Attachment to this report. The CRs were reviewed to ensure the issues were identified accurately, appropriate evaluations were performed, and adequate corrective actions were specified and properly prioritized.

b. Findings and Observations

No findings of significance were identified. However, the inspectors identified one corrective action, a procedure change, that was closed in the corrective action program but was not completed. The licensee subsequently wrote CR 2005-1763 to identify this issue and track the procedure change to completion. Entergy's failure to complete the procedure change before closing the item in the corrective action program is a violation of Entergy procedure AP 0009, "Condition Reports." The procedure violation is of minor significance because the procedure change was an improvement item which related to risk reviews performed during outages. Entergy did not have an outage in the time between the due date for the corrective action and the time the error was discovered. In addition, the issue was entered into the corrective action program. Therefore, the finding is not subject to enforcement in accordance with Section VI of the NRC's Enforcement Policy.

3. Semi-Annual Trend Review

a. Inspection Scope

As required by Inspection Procedure 71152, "Identification and Resolution of Problems," the inspectors performed a semi-annual trend review to identify trends, either Entergy or NRC identified, that might indicate the existence of a more significant safety issue. Included within the scope of this review were:

- CRs generated from January through June 2005;
- Corrective maintenance backlog listings from January through June 2005;
- The corrective action program 4th Quarter 2004 and 1st Quarter 2005 trend reports; and
- Daily review of main control room operating logs.

b. Findings

No findings of significance were identified.

4OA5 Other Activities

1. Temporary Instruction (TI) 2515/163: Operational Readiness of Offsite Power

The inspectors reviewed Entergy procedures and supporting information pertaining to offsite power availability and operability. The inspectors evaluated these procedures against the requirements of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants;" 10 CFR 50.63, "Loss of All Alternating Current Power;" 10 CFR 50, Appendix A, Criterion 17, "Electric Power Systems;" and TS. The results of this inspection were forwarded to NRR for further review. Entergy procedures and supporting information reviewed by the inspectors are listed in the Attachment to this report.

4OA6 Meetings, Including Exit

Resident Exit

On July 11, the resident inspectors presented the inspection results to Messrs. William Maguire and John Dreyfuss and members of their staff. The inspectors asked whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Entergy Personnel

J. Callaghan, Design Engineering Manager
P. Corbett, Maintenance Manager
J. Dreyfuss, Director of Engineering
J. Devincentis, Licensing Manager
M. Gosekamp, Superintendent of Operations Training
M. Hamer, Licensing
M. Metell, Engineering
W. Maguire, General Plant Manager
J. Thayer, Site Vice President
C. Wamser, Operations Manager
R. Wanczyk, Director of Nuclear Safety
S. Wender, Chemistry Superintendent

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

None.

LIST OF DOCUMENTS REVIEWED

Section 4OA5.1: Temporary Instruction (TI) 2515/163

Vermont Yankee/Entergy Procedures

AP 0156, "Notification of Significant Events"
AP 0172, "Work Schedule Risk Management - On Line"
AP 3125, "Vermont Yankee Emergency Action Levels, Section 6, "Loss of Power""
Vermont Yankee Off-Normal (ON) Procedure 3172, "Loss of Bus 4"
ON 3171, "Loss of Bus 3"
ON 3155, "Loss of Auto Transformer"
ON 3150, "Loss of Startup Transformer"
Operational Transient Procedure (OT) 3122, "Loss of Normal Power"
OP 2140, "345 KV Electrical System"
Annunciator Response Sheet (ARS) for annunciator 8-J-9, "Safety Bus Voltage Low"
Timeline for Alternate AC Source Startup and Alignment for Station Blackout Conditions.
Entergy Procedure ENN-PL-158, "Transmission Grid Interface"

ISO New England Procedures

Master/LCC Procedure #1, "Nuclear Plant Transmission Operations"
Operating procedure #4, "Action During a Capacity Deficiency"

Section 4OA2: Review of Problem Identification and Resolution

Condition Reports

2004-3000	"A" SLC Pump Leakage Increasing Trend
2004-3521	Containment CAM particulate warning alarm in
2005-0004	Containment CAM particulate alarming
2005-0226	Containment CAM particulate high readings
2005-0520	Containment CAM operability adverse trend
2005-0569	Containment CAM particulate level caused unexpected alarm
2005-0591	Procedure requirements not met for Quarterly Trend Report
2005-0621	Containment CAM paper tear switch damaged
2005-0700	Unexpected rod blocks
2005-0819	Containment CAM paper tear indication cam is broken
2005-0878	"B" EDG control side fuel oil injector cam lobe excessive wear
2005-0924	High fuel filter differential pressure on the "B" EDG
2005-0925	"B" EDG exhaust for #10 cylinder reading low
2005-0926	Unexpected Containment CAM alarm
2005-0991	Loss of flow through containment CAM with no low flow alarm
2005-0996	Containment Air Monitor detector gasket not seated properly
2005-1011	RHRSW pump motor bearing cooling flows found out of spec low
2005-1022	Diesel driven fire pump gear backlash found out of tolerance
2005-1165	NODES discharge permit limit exceeded
2005-1190	Isotopic analysis of reactor coolant surveillance interval missed
2005-1201	Recirc pump "A" outboard seal pressure oscillations
2005-1219	Adverse trend on no-go badge detector operation at Gate 2
2005-1224	Piping leak on containment CAM
2005-1230	Paper tear alarm in for containment CAM
2005-1232	Adverse trend (2) for containment CAM
2005-1278	Containment CAM low flow alarm NOT received as
2005-1317*	Internal flooding design basis document discrepancy
2005-1318*	Fire Hazards Analysis compliance issue regarding coated cables
2005-1367*	Potential Rework WR#05-64474 was written against Level Transmitter
2005-1368*	Large quantities of mercury in plant
2005-1392	CT-2 deep basin damage
2005-1427	Containment rad monitor failure
2005-1502	Ground detected on cooling tower fan CT 2-1
2005-1605*	Some critical plant equipment signs not hung during HPCI LCO maintenance
2005-1623	Multiple rod drift alarms
2005-1633*	Fire hazards analysis discrepancy noted by NRC
2005-1641	A cutoff switch on an AK-50 breaker could not be reset
2005-1655*	Post job critique item for RPIS jumper replacement documentation
2005-1685	Steam leakage from RCIC valve 800C
2005-1740*	HPCI quad equipment funnel overflows periodically
2005-1763*	Commitment Closure not in accordance with EN-LI-102
2005-1783*	Potential spread of radioactive material from HPCI room floor scupper

2005-1884	Two broken bolts on control side vertical drive inspection cover of "B" EDG
2005-1893	SLC Pump has packing leakage from 2 of 3 cylinders
2005-1953	Feedwater master controller not responding to operator input

*Inspector-identified issues

Section 4OA2.2: Review of Risk Assessment Program Implementation

Condition Reports

2003-0155*	Not all critical plant equipment signs required by "B" RHR LCO plan were hung
2003-1512*	Critical plant equipment sign not posted as required
2004-0596*	ORAM color change made after equipment tagged out
2004-0840*	Incorrect status of decay heat removal logged on the critical outage system status form
2004-0897*	Incorrect start dates used in ORAM risk assessment for alternate decay heat removal capability determinations
2004-2345*	Posting critical plant equipment signs process needs to be formalized
2004-3474*	Critical plant equipment signs not posted as required
2004-3719	Critical plant equipment not properly identified in the "A" core spray LCO plan
2005-1033	Critical plant equipment sign not hung in advance of electric fire pump
2005-1458	Outage risk assessment per AP 0173 results in missed contingency
2005-1605*	Some critical plant equipment signs not hung during HPCI LCO maintenance
2005-1763*	NRC identified that a commitment closure was inappropriately closed

*Inspector-identified issues

LIST OF ACRONYMS

ADAMS	Automated Document Access Management System
ANSI	American National Standard Institute
AP	Vermont Yankee Administrative Procedure
CAM	Continuous Air Monitor
CFR	Code of Federal Regulations
CFZ	Combustion Free Zones
DP	Vermont Yankee Department Procedure
EAL	Emergency Action Level
EDG	Emergency Diesel Generator
FA	Fire Area
FIN	Finding
FZ	Fire Zone
HPCI	High Pressure Coolant Injection
IPEEE	Individual Plant Examination External Events
LCO	Limiting Condition for Operation
KV	Kilovolt
NEI	Nuclear Energy Institute
NRC	Nuclear Regulatory Commission

NRR	Nuclear Reactor Regulation
ODCM	Offsite Dose Calculation Manual
ON	Vermont Yankee Off-Normal Procedure
OP	Vermont Yankee Operating Procedure
PMT	Post Maintenance Testing
RCIC	Reactor Core Isolation Cooling
RHRSW	Residual Heat Removal Service Water
RPIS	Rod Position Indicating System
SLC	Standby Liquid Control
TI	Temporary Instruction
TM	Temporary Modification
TS	Technical Specifications
UFSAR	Updated Final Safety Analysis Report
VY	Vermont Yankee
VYC	Vermont Yankee Calculation

ATTACHMENT 71111.23

INSPECTABLE AREA: Temporary Plant Modifications

CORNERSTONES: Mitigating Systems (90%)
Barrier Integrity (10%)

INSPECTION BASES: Temporary modifications to risk-significant SSCs may adversely affect their availability, reliability or functional capability. A temporary modification may result in a departure from the design basis and system success criteria. Temporary or unrecognized risk changes due to the modification may evolve into high risk configurations. This inspectable area verifies aspects of the associated cornerstones for which there are no indicators to measure performance.

LEVEL OF EFFORT: Periodically screen active temporary modifications on systems which are ranked high in risk. Review the details of 4 to 6 temporary modifications a year for a 1-unit site; 5 to 7 for a 2-unit site; or 6 to 8 for a 3-unit site, respectively. Although the sample sizes are an annual goal, the inspection effort can be distributed on a quarterly basis.

71111.23-01 INSPECTION OBJECTIVE

This inspection will verify that temporary modifications have not affected the safety functions of important safety systems.

71111.23-02 INSPECTION REQUIREMENTS

02.01 Selection of Temporary Modifications. Select temporary modifications to risk-significant systems. For purposes of this inspection, temporary modifications include jumpers, lifted leads, temporary systems, repairs, design modifications and procedure changes which can introduce changes to plant design or operations. Although the focus of this inspection is on active modifications, inspectors may choose to review a recently removed temporary modification for adequate restoration and testing.

02.02 Inspection

a. Review the temporary modifications and associated 10 CFR 50.59 screening against the system design bases documentation, including Updated Final Safety Analysis Report (UFSAR) and Technical Specifications (TS). Verify that the modifications have not affected system operability/availability. See Inspection Procedure 71111.17, "Permanent Plant Modifications," for additional attributes which may be considered for review. Inspect only those attributes which are significant for the particular modification being reviewed.

b. Verify that the installation and restoration of the temporary modifications (if accessible) are consistent with the modification documents. Verify configuration control of the modification is adequate by verifying that the plant documents, such as drawings and procedures are updated including adequacy of operating and maintenance procedures.

c. Review post-installation test results to confirm that the tests are satisfactory and the actual impact of the temporary modifications on the permanent systems and interfacing systems have been adequately verified by test. Also, review planned testing after removal of the temporary modifications.

d. Verify that temporary modifications are identified on Control Room drawings and at that appropriate tags are placed equipment being affected by the temporary modifications.

e. Verify that licensee has evaluated the combined effects of the outstanding temporary modifications in regard to mitigating systems and the integrity of radiological barriers.

f. Examine drawings, design and operating procedures, operations logs for evidence of temporary modifications that have not been so evaluated or categorized.

02.03 Problem Identification and Resolution. Verify that problems associated with temporary modifications are being identified by the licensee at an appropriate threshold and are properly addressed for resolution in the licensee corrective action program. See Inspection Procedure 71152, "Identification and Resolution of Problems," for additional guidance.

71111.23-03 INSPECTION GUIDANCE

03.01 General Guidance

For inspection guidance, see Table A below.

TABLE A

Cornerstone	Inspection Objective	Risk Priority	Example
Mitigating Systems	Identify temporary modifications which could affect the design basis or the functional capability of plant mitigating systems Emphasize modifications which affect high safety significant Maintenance Rule SSCs/functions or modifications which affect SSCs/functions with high PRA rankings	Temporary modifications which could affect the design bases and functional capability of interfacing systems Multiple temporary modifications to a single system or train, especially during outages Temporary modifications which require operator workarounds.	Use of alternate material when specified replacement parts are not available During outages: Temporary electrical power to equipment required to minimize shutdown risk Alternate water sources for equipment cooling or fire protection of equipment required to minimize shutdown risk

Cornerstone	Inspection Objective	Risk Priority	Example
Barrier Integrity	Identify temporary modifications which could affect the design basis or the functional capability of containment or reactor coolant system boundaries		Temporary changes to containment isolation motor operated valve designs. During outages: Temporary power improperly routed into containment when the ability to establish containment integrity is still required

03.02 Specific Guidance

a. The review of the design aspects of a temporary modifications should focus on conformance to relevant design criteria not the programmatic elements of licensee programs.

b. The review of both the installation of and the restoration from a temporary modification is necessary to ensure that the impact on the operation of other equipment is what is expected and previously analyzed, and to verify all other unexpected effects were subsequently evaluated with the results being there is no significant impact on the safe operation of plant or equipment.

c. The review of the post-installation test results is to ensure that the parent system remains operable and that its safety function has not been impaired.

d. Identification of temporary modifications on drawings and at placement of appropriate tags equipment being affected by the temporary modification should make operators aware of their impact on the operation of plant equipment and components.

e. The synergistic effects of outstanding temporary modifications is best judged based on whether there are new impediments to the safety functions of mitigating safety systems, degradation of radiological barriers, and an increase in the consequences of pertinent analyses in Chapter 15 of the FSAR.

f. Focus more attention on identifying temporary modifications not previously identified by the licensee if there is no existing program tasked with making interested parties aware of the existence of all temporary modifications.

71111.23-04 RESOURCE ESTIMATE

The annual resource expenditure for this inspection procedure at a site is estimated to be on average: 31 to 41 hours for one unit; 34 to 46 hours for two units; and 41 to 55 hours for three units.

71111.23-05 COMPLETION STATUS

Inspection of the minimum sample size will constitute completion of this procedure in the Reactor Programs Systems (RPS). That minimum sample size will consist of the review of 4 temporary modifications for one unit; 5 temporary modifications for two units; and 6 temporary modifications for three units.

71111.23-06 REFERENCES

Inspection Procedure 71111, Attachment 17, "Permanent Plant Modifications"

Inspection Procedure 71152, "Identification and Resolution of Problems"

END

COPY

VERMONT YANKEE

TM No. 2005 - 004

TEMPORARY MODIFICATION PACKAGE

TM intended to be replaced by a permanent Design Change? ☐ Yes ☒ No

SAFETY CLASSIFICATION:

☐ SC-1 ☐ SC-2 ☒ SC-3 ☐ SCE ☐ All NNS SSCs ☐ OQA/Vital Fire

TITLE: Installation of Structural Splices in Cooling Tower CT2-1

ORIGINATOR/DEPARTMENT: (Print Legibly) M. Selling / J. Fitzpatrick / M/S - DE

PURPOSE/REASON FOR CHANGE: (See Note 1)

The purpose of this temporary modification is to restore the integrity of the degraded diagonal brace located on the north wall of Cooling Tower 2 (CT2-1). The degraded brace was identified during routine inspections in support of the March 2005 LCO (CR-VTY-2005-0710) see attached mark-up for actual location. The degraded condition is described as longitudinal cracking at the end of a main diagonal brace member in the vicinity of the brace plate connection bolts. This condition causes a reduction in the load carrying capacity of that individual brace. The preferred fix is a complete replacement of the brace, but because the upper section of the brace is inaccessible without significant prep-work to clear interferences, replacement of the entire brace during the current LCO is not practical. A temporary "splice" of new bracing material will be utilized to repair only the degraded end piece of the brace to return the brace to full load carrying capacity. The full brace replacement will be scheduled for a later date when more time is available (RFO-25).

SCOPE/DESCRIPTION OF CHANGES: (See Note 2)

The scope of the temporary modification is to install a temporary "splice" of new bracing material at the degraded end of the CT2-1 north wall diagonal brace.

The temporary splice process consists of removing the damaged end section of the 4"x4" PT Douglas Fir diagonal brace (approximately 30") and inserting an equal sized section of new 4"x4" PT Douglas Fir. The new section will be connected or "spliced" to the existing brace member by adding two 4"x4" members of new PT Douglas Fir to the top and bottom of the joint. The 4x4 splice pieces will be securely attached to the brace by through-bolting with high strength threaded steel rods.

The above described bracing splice repair has been evaluated and qualified by VYC- 2404.

The splice has been designed and qualified to support the full capacity of the bracing member. The intention of this temporary modification is restore the degraded diagonal brace to its original load carrying capacity with minimal impact to the overall structure and LCO schedule.

The proposed change restores the brace to its original capacity and function and does not affect operation of any existing systems or components. The Mechanical Data Sheet, VYAPF 0020.05, and attached sketches provide the conceptual details of the temporary repair with a description of the materials required.

EVALUATION OF TM CHANGES:

1. Indicate the mode(s) of operation for which the TM is allowable:

☒ Shutdown ☒ Refuel ☒ Startup ☒ Run

2. Evaluation: (See Note 3)

Degradation of the 4x4 wooden diagonal brace at the north wall of the west Cooling Tower (CT2-1) necessitates temporary modification of that brace to return the structural component to original load carrying capacity. The proposed temporary change (new bracing section to replace degraded section) provides a means to quickly return the seismic section of the Cooling Tower (CT2 to original configuration and does not create any potential hazards (Fire, Flooding, Radiation, etc.). The temporary modification does not interact with any other systems or modifications and the added weight of the repair/splicing members is insignificant. The use of high strength carbon steel threaded rods for this application is qualified in VYC-2404. Minimal corrosion of the threaded rod is expected and will have no impact on the integrity of the repair splice and is acceptable. The proposed temporary changes are acceptable.

INSTALLATION/RESTORATION REQUIREMENTS: (May be provided as attachments and identified here)

General Precaution: If an unexpected action results during installation, do not proceed with uncertainty. Place the system or component in a safe condition, if possible. Notify the Shift Manager if plant equipment is impacted. (ER991225_02)

1. Prerequisites (RWPs, Housekeeping, Fire Permits, Barrier Control Permits, etc.):

If an unexpected action results during the installation, do not proceed with uncertainty. Exercise judgment, experience and training to:

- Place the system or component in a safe condition so as to preclude a potential transient, equipment damage or personal injury.
- Notify the VYICE
- Notify the SM if the situation impacts plant equipment

1.1 Verify TM 2005-004 has been approved by the VY General Manager.
1.2 Verify Work Order 03-1243-037 (installation) for this Temp Mod has been released for implementation.
1.3 Verify all personnel involved have been properly indoctrinated to the installation requirements of this Temp Mod prior to implementation.
1.4 Request permission from the SM to install the TM.
1.5 SM sign the TM for release.

2. Precautions:

2.1 Ensure all work areas are well lighted in accordance with the VY Safety Manual and the work platform is built in accordance with AP-0019.
2.2 Ensure all precautions in the Vermont Yankee Safety Manual are observed as required.

3. Installation Instructions:

3.1 Ensure the Circulation Water System is secured.

3.2 Repair of the diagonal wooden brace located at the north wall of the CT2-1;

3.2.1 The attached mark-up of 5920-6451 Sht. 3 of 5 showns the general location of the temporary splice. Remove the degraded section of 4x4 bracing by making a perpendicular cut at a point of sound, non-degraded bracing material. Ensure that the cut line will not interfere with any existing thru-bolts for existing metal brace plates. Also, ensure that the location of the cut will allow installation of the repair splice pieces (4x4's) to each side of the cut-joint without interference or modification to the repair design. See Attachment #1; "Temp Mod 2005-004 Sketch #1" for the required cut location, fit-up dimensions, and installation details.

3.2.2 Cut from a new section of PT Douglas Fir 4x4 material, a single section to fit and match the original angle and cut-joint of the degraded bracing section to return the brace to its original alignment and configuration. Note: if the section of degraded bracing is removed intact, it may be used as a template for cutting proper angles in the replacement bracing section.

3.2.3 Cut from a new section of treated PT Douglas Fir 4x4 material, two splice sections with dimensions as shown on the Attachment #1; "Temp Mod 2005-004 Sketch #1".

3.2.4 Install the new replacement 4x4 bracing section into the space that was occupied by the degraded bracing section along with the two new repair splice sections placed at top and bottom of the cut joint aligned with the 4x4 bracing section and "centered" on the cut-joint as shown on the Attachment #1; "Temp Mod 2005-004 Sketch #1" and temporarily clamp/secure the four piece assembly together.

3.2.5 Drill in-place, thru-holes, as shown on Attachment #1; "Temp Mod 2005-004 Sketch #1" through the 4x4 brace section in a continuous, smooth, straight, and perpendicular manner. Care should be taken to avoid damage to the existing brace member.

3.2.6 Install the new high strength threaded rods as shown on the Attachment #1; "Temp Mod 2005-004 Sketch #1" to be snug-tight and remove the temporary clamps. Tighten each threaded rod to a snug-tight condition plus a ¼ turn or until the washer begins to cut or crush the repair splice member. Ensure all rods remain tight at completion.

4. Installation Verification/Testing Requirements (See Note 4):

4.1 Verify that the installation is correct and in accordance with Mechanical Data Sheet (VYAPF 0020.05), Attachment #1; "Temp Mod 2005-004 Sketch #1", and that the bracing member is in the original alignment and configuration.

Performed by: S. H. Deyo / STEVE DEYO Date: 3/10/05

VY ICE or Const. Supervisor : Tom Regan T E Ryan Date: 3/10/05
(Print/Sign)

4.2 Verify the work area is free of construction damage.

VY ICE or Const. Supervisor : STEVE DEYO S H Deyo / Tom Regan T E Ryan Date: 3/10/05 3/10/05
(Print/Sign)

4.3 Verify all temporary equipment has been removed.

VY ICE or Const. Supervisor: STEVE DEYO S N. Deyo / Tom Regan T E Ryan Date: 3/10/05 3/10/05
(Print/Sign)

4.4 Verify VYC-2404 Rev. 0 has been approved prior to return to service.

VY ICE : Jim Calchera J F Calchera Date: 3/10/05
(Print/Sign)

4.5 Verify any non-conforming issues are resolved.

VY ICE or Const. Supervisor : Jim Calchera J F Calchera Date: 3/10/05
(Print/Sign)

4.6 Notify the SM that TM 2005-004 is installed and VYAPF 0020.05 is signed.

VY ICE or Const. Supervisor : Jim Calchera J F Calchera Date: 3/10/05
(Print/Sign)

5. Restoration Instructions:

5.1 Verify Work Request 05-64077 for restoration of this Temp Mod has been released for implementation.

5.2 Request permission from the SM to remove the TM.

5.3 Remove the entire diagonal brace which has the temporary repair splice installed.

VY ICE or Const. Supervisor :__________ Date:______
(Print/Sign)

5.4 Install a new PT Douglas Fir 4x4 brace in the same space, alignment, and configuration as the existing brace (one piece, full length as required). Install new stainless steel fasteners and brace plates as required to ensure a sound complete brace is operational and functioning as originally intended.

VY ICE or Const. Supervisor :__________ Date:______
(Print/Sign)

5.5 Paint over or remove the "TM 2005-004" STENCIL from the wall panels.

VY ICE or Const. Supervisor :__________ Date:______
(Print/Sign)

6. Restoration Verification/Testing Requirements:

6.1 Verify the work area is free of construction damage.

VY ICE or Const. Supervisor :______________________ Date:________
(Print/Sign)

6.2 Verify all temporary equipment has been removed.

VY ICE or Const. Supervisor :______________________ Date:________
(Print/Sign)

6.3 Verify any non-conforming issues are resolved.

VY ICE or Const. Supervisor :______________________ Date:________
(Print/Sign)

6.4 Verify that the STENCIL "TM 2005-004" has been removed from the wall panels.

VY ICE or Const. Supervisor :______________________ Date:________
(Print/Sign)

6.5 Notify the SM that TM 2005-004 is complete and VYAPF 0020.05 is signed.

VY ICE or Const. Supervisor :______________________ Date:________
(Print/Sign)

7. Describe When TM will be restored: (e.g. during outage, following job activity, change via design # xx-xxx, etc)

This TM will be restored prior to Start-up from RFO-25.

8. Approximate date TM will be closed: 11/15/05

VERMONT YANKEE TEMPORARY MODIFICATION PACKAGE TM No. 2005-004 (Continued)

DOCUMENTATION REQUIRED & PROCEDURES/PROGRAMS AFFECTED	
1.	**List affected Control Room/TSC drawings:**
	None
2.	**List all other affected drawings:**
	5920-6451 Sht. 3 Rev 2
3.	**List affected procedures:**
	None
4.	**List affected/new calculations:**
	VYC-2404 Rev. 0 "Design of Structural Member Splices on Cooling Tower CT-2 for Temp Mod 2005-004"
5.	**If the TM intended to be replaced by a permanent Design Change, prepare and attach any applicable DBD and UFSAR markups and initiate pending changes as required.**
6.	**List recommendations for new or revised PMs.** None
7.	**Attach markups of all affected drawings, procedures, and other plant documents listed above. Handle safeguards information in accordance with ENN-OM-121.**
8.	**Attach completed Appendix R review form.**
9.	**Attach Installation/Restoration Instructions:** *Included in Text* ☐ Yes ☒ N/A
10.	**Attach Installation Verification/Testing Instructions:** *Included in Text* ☐ Yes ☒ N/A
11.	**Attach Restoration Verification/Testing instructions:** *Included in Text* ☐ Yes ☒ N/A
12.	**Attach 10CFR50.59 Applicability Determination, Screening or Evaluation.**
13.	**Attach AP 0091 Risk Management Screen.**
Originator (As required by procedure Section B)	
1.	**Customer contacted to confirm desired outcome of TM.**
2.	**Operations, Implementing Department, System Engineering, Design Engineering E/I&C, ALARA Engineer, ISI Program Manager, Reactor Engineering, and Chemistry contacted for input/concurrence, as applicable.**
3.	**Systems/PRA Group contacted for PRA model impacts, and ORAM SENTINEL change requirements are indicated in the Implementation and Restoration sections of this form.**
4.	**New equipment EMPAC asset IDs obtained and safety classification work sheets initiated as needed for TMs which will be permanent.**
5.	**All applicable elements of Appendix A considered and addressed.**
6.	**Impact of ongoing work (VYDCs, TMs, MMs, WOs) factored into the design/installation.**
7.	**Any additional training requirements discussed with affected Department Heads and documented in the TM package.**
8.	**All pending change notifications initiated: drawing pending changes (all TMs), DBD and UFSAR pending changes (TMs, which will be permanent).**
Originator: Michael Selling / James Fitzpatrick [signatures] Print/Sign	**Date:** 3/9/05

VERMONT YANKEE TEMPORARY MODIFICATION PACKAGE TM No. 2005-004 (Continued)

REVIEWS (Print, sign, date)

1. System Engineering: ☒ N/A
2. Design Engineering, Electrical/I&C: ☒ N/A
3. Design Engineering, Fluid Systems/Nuclear: ☒ N/A
4. Design Engineering, Mechanical/Structural: T.M O'Connor 3/9/05 ☐ N/A
5. Fire Protection: ☒ N/A
6. Appendix J Testing: ☒ N/A
7. ISI & IST: ☒ N/A
8. Setpoint Coordinator: ☒ N/A
9. Reactor Engineering: ☒ N/A
10. Chemistry: ☒ N/A
11. Probabilistic Safety Assessment : ☒ N/A
12. ALARA Christine Eyre per telecon w/ Calchera 3/9/05 ☐ N/A
13. Other: PSO: Ken Swanger Steve Nack for Swanger per telecon Calchera 3/9/05 ☐ N/A
14. Project Engineering: Jim Calchera 3/9/05 ☐ N/A
15. Maintenance: Maint. Suppt. Eng.; M. McKenney Mike Tessier per telecon w/ Calchera 3/9/05 ☐ N/A
16. MOV Program Coordinator: ☒ N/A
17. AOV Program Coordinator: ☒ N/A
18. Independent Reviewer: T.M. O'Connor 3/9/05

APPROVALS (Print, sign, date)

1. Implementing Department Head: SDG for PMM per telecon 3-9-05
2. Manager of Operations:
   - Verify operations procedures affected and determine procedures requiring revision prior to implementation.
   - Identify any additional operational controls.
   - Initiate any required Operations training.

   Manager of Operations: Date 3/9/05
3. Cognizant DS: SDGoodwin 3-9-05
4. Manager of Design Engineering: JH Callaghan 3/9/05

PORC APPROVAL (If required) / GENERAL MANAGER, PLANT OPERATIONS APPROVAL AND DISTRIBUTION

PORC Review at Meeting No. N/A Date:
General Manager, Plant Operations Approval: W. MAGUIRE / W Maguire Date: 3-9-05
(Print/Sign)
Forwarded to DEAA: Jim Calchera / J F Calchera Date: 3-9-05
(Print/Sign)

Distribution of Approved TM:
- Implementing Department Head, original copy
- Manager of Training & Development, 1 Copy
- QA Manager, 1 Copy
- Operations Procedure Writer, 1 Copy with Attachments
- Planning Supervisor, 1 Copy with Attachments
- Maintenance Rule Coordinator, 1 Copy
- DEAA, 2 Copies with marked up drawings

DEAA or Originating Department: Jim Calchera / J F Calchera Date: 3/9/05
(Print/Sign)

INSTALLATION AND TESTING:

~~Work Request~~/Work Order No. 03-1243-037
Controls established to ensure required Procedure changes will be in place prior to system operation.
Implementing Department: Project Engineering. Calchera / J F Calchera Date: 3/9/05
(Print/Sign)

SHIFT MANAGER (OR DESIGNEE)
1. TM reviewed.
2. Installation and Testing Requirements reviewed.
3. Plant conditions reviewed for compatibility with installation.
4. Special actions or Tech Spec requirements implemented, if required.
5. Tag outs reviewed, if required.
6. Operating procedures revised or controls in place to ensure revised procedures are issued prior to operation, if required.

Shift Manager (or Designee): Bob Kaupel / Robert Kaupel Date: 3/9/05
(Print/Sign)
Authorization to start installation, Shift Manager: Bob Kaupel / Robert Kaupel Date: 3/9/05
(Print/Sign)

IMPLEMENTING DEPARTMENT
Copy of the TM is placed in the Control Room book, and original is in the field with the J.O./W.O. package for installation.
DEAA notified via e-mail of Shift Manager authorization.
Implementing Department: Jim Calchera / J F Calchera Date: 3/9/05
(Print/Sign)
DEAA notified via e-mail within one week prior to beginning implementation. Installation initiated within 30 days of Shift Manager authorization. If not, contact the originator prior to implementation.
Implementing Department: Tom Regan / Thomas E Regan Date: 3/9/05
(Print/Sign)
Installation complete, Testing complete (N/A) and satisfactory, TM tags installed, Shift Manager notified, DEAA notified via e-mail, original TM returned to control room, and UFSAR (N/A) and DBD (N/A) markups submitted, if applicable. Calchera / J F Calchera 3/10/05

IMPLEMENTING DEPARTMENT (Continued)

ORAM SENTINEL change required ? ☒ No ☐ Yes If yes, PSA group notified.

List Location of all TM Tags: No tags required. STENCIL *"TM 2005-004"* onto the wall panel(s) that cover the area of the splice repair. STENCILED ON ADDITIONAL PANEL & SCREWED TO END WALL PANELS.

Implementing Department: JIM CALCHERA [signature] Date: 3/10/05
(Print/Sign)

SHIFT MANAGER

Post Installation Testing complete and satisfactory.

Shift Manager (or Designee): A. King [signature] Date: 3/10/05
(Print/Sign)

RESTORATION AND TESTING

Shift Manager

1. Plant conditions compatible with restoration.
2. Operating procedures revised or controls in place to ensure revised procedures are issued prior to operation.

Authorization to start restoration, Shift Manager:____________ Date:________
(Print/Sign)

Implementing Department

1. Copy of TM placed in Control Room book while original is in the field for restoration.
2. ORAM SENTINEL change required? ☒ No ☐ Yes If yes, PSA group notified.
3. Restoration complete and verified, all tags removed, Shift Manager notified and DEAA notified via e-mail that TM has been restored, copy of TM removed from Control Room Book and discarded.
4. VYAPF 0020.04/.05 completed if required.
5. Drawing Pending Change Notifications cancelled, if required.

Implementing Department:____________ Date:________
(Print/Sign)

Shift Manager

1. TM restoration complete and post installation retest performed.
2. Verify all caution tags, temporary instructions, temporary labels, etc. are removed.
3. Original TM forwarded to DEAA.

Shift Manager:____________ Date:________
(Print/Sign)

NOTES:

1. Briefly describe the need for this Temporary Modification.
2. Fully describe the proposed modification and how the proposed change may affect operation of existing systems or components. Include a description of materials to be used. Attach VYAPF 0020.04/.05 as required.
3. Provide an assessment of the proposed changes, including any potential hazards (Fire, Flooding, Radiation, etc.) (UND9302TP1) and/or interaction with other changes and provide a conclusion that these changes are acceptable.
4. Any verification steps that do not specify the person performing the verification must be performed by someone who did not actually perform the work but is familiar with the nature of the work being performed. (ER2001-1292_01)

MECHANICAL DATA SHEET

DESCRIPTION: Provide a sketch or other suitable description

See Attachment # 1; "Temp Mod 2005-004 Sketch #1"
for installation details, dimensions, and materials.

Tom Regan 3/10/05

*Installed By Rick Rautlier [signature] [signature] Date 3/10/05
(Print/Sign)

3/10/05 Steve Deyo per telecon [signature] after this signature

*Verified By ~~Jim Calchera~~ JFC JIM CALCHERA [signature] Date 3/10/05
(Print/Sign)

Restored By__________ Date______
(Print/Sign)

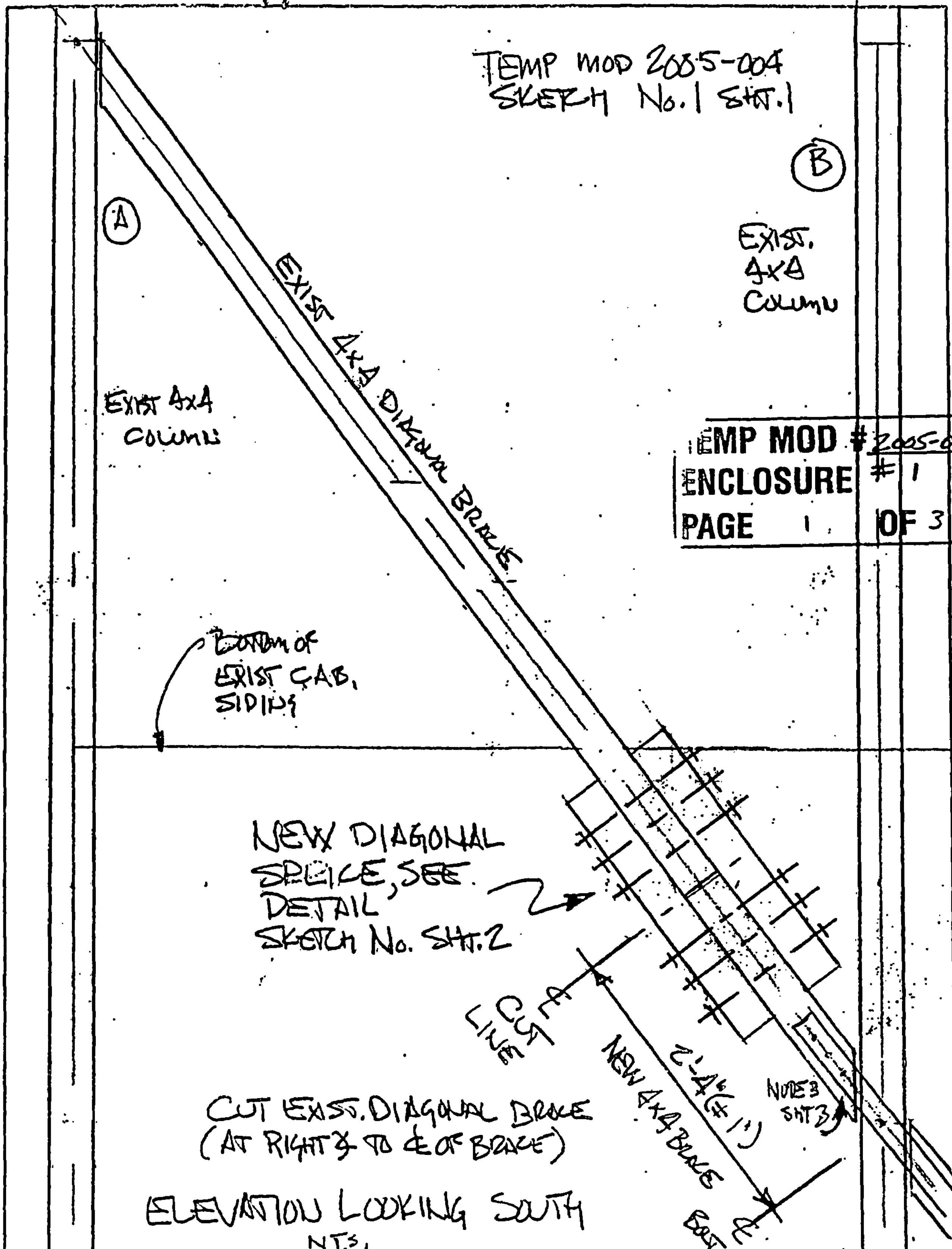
Verified By__________ Date______
(Print/Sign)

*Per discussion w/ Regan & Deyo and per sign-offs on Page 4 of 18 of the TM.

ENGINEERING ORGANIZATION CALC. NO. ________ REV. ____ DATE ________

TITLE TEMP MOD 2005-004 SKETCH No.1 SHT. 1 of 3

PREPARED BY JCB 3/8/05 REVIEWED BY MRS 3/8/05 TFC 3/8/05 PAGE ____ OF ____



ELEVATION LOOKING SOUTH

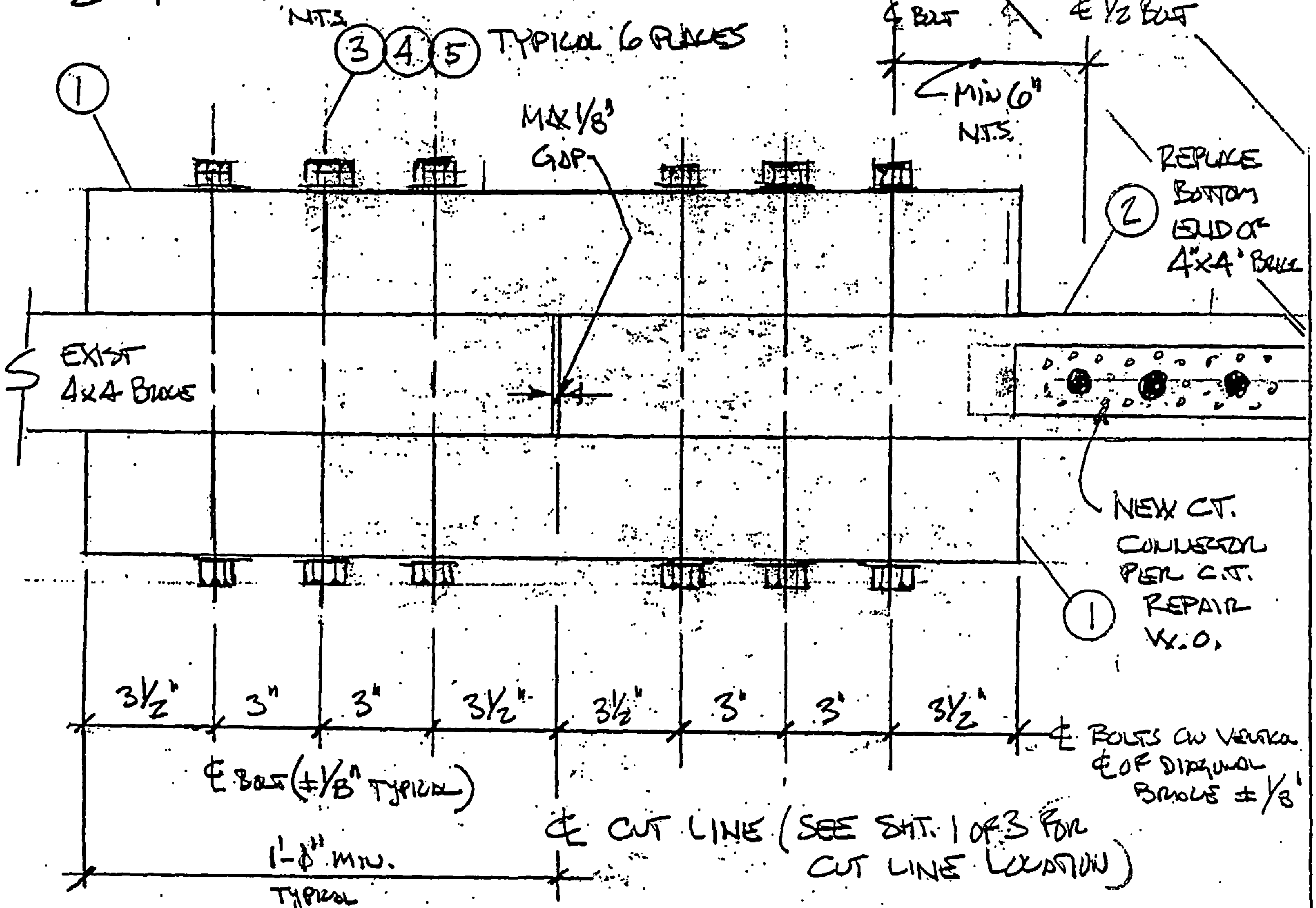
N.T.S.

TEMP MOD # 2005-004
ENCLOSURE # 1
PAGE 1 OF 3

TEMP MOD # 2005-004
ENCLOSURE #1
PAGE 2 **OF** 3

ENGINEERING ORGANIZATION
TITLE TEMP MOD 2005-004 SKETCH No1 SHT 2 of 3
CALC. NO. ______ REV. ______ DATE ______
PREPARED BY DRB 3/8/05 REVIEWED BY MWS 3/8/05 PAGE ______ OF ______

DETAIL NEW SPLICE BLOCK



ENGINEERING ORGANIZATION CALC. NO. ______ REV. ______ DATE ______

TITLE TEMP MOD 2005-004 SKETCH No. 1 ~~SHT~~ 3 of 3

PREPARED BY JCR/TE 3/8/05 REVIEWED BY WRS 3/8/05 3/9/05 PAGE ______ OF ______

SPLICE BLOCK BILL OF MATERIAL

ITEM	QTY	DESCRIPTION
1	2	~~4~~"x4" NOM. x 2'-2" LG MIN. TREATED DOUGLAS FIR NO. 1 OR BETTER
2	1	4"x4" NOM. x LENGTH AS REQ. TO MATCH EXISTING. TREATED DOUGLAS FIR No. 1 OR BETTER
3	6	3/4"Φ x 14" LG. THREADED ROD (3/4"-10-UNC-2A) A193 GR B7
4	12	3/4" HEAVY HEX NUT A194 GR 2H
5	12	3/4"Φ HARDENED STEEL FLAT WASHER F436 OR EQUAL

NOTES

1. ITEMS 1, 2, 3, 4 SAFETY CLASS 3 OR BETTER
2. TORQUE BOLTS: ~~SNUG TIGHT + 1/4 TURN~~ OR UNTIL WASHER BEGINS TO CRUSH OR CUT INTO THE 4x4. REPAIR SPLICE MEMBERS ITEM 2.
3. DO NOT COUNTER SINK SIDE OF ITEM 2 AT 1/2"Φ BOLT LOCATIONS ON COOLING TOWER S.S. HARDWARE AT COLUMN B

MP MOD # 2005-004
NCLOSURE #1
AGE 3 OF 3

ATTACHMENT 9.1 **PROCESS APPLICABILITY DETERMINATION**

Page 1 of 7

Part I ☐IP1 ☐IP2 ☐IP3 ☐JAF ☐PNPS ☒VY Nuclear Power Plant Activity No: TM 2005-004 Preparer (Print/Sign): M. SELLING / J. FITZPATRICK 3/9/05

Does the Activity affect?		If "Yes", process per indicated procedure or Contact Manager of:					
		IP1	IP2	IP3	JAF	PNPS	VY
☐ Yes ☒ No	Tech Spec or Facility Operating License (10CFR50.90)	Licensing	Licensing	Licensing	Licensing	Licensing	Licensing
☐ Yes ☒ No	Tech Spec Bases (or TRM) (10CFR50.59)	LI-101	LI-101	LI-101	LI-101	LI-101	LI-101
☐ Yes ☒ No	Security Plan (10CFR50.54(p))	Security	Security	Security	Security	Security	Security
☐ Yes ☒ No	QA Plan (10CFR50.54(a))	QA	QA	QA	QA	QA	QA
☒ Yes ☐ No	UFSAR (10CFR50.59)	LI-101	LI-101	LI -101	LI-101	LI -101	LI-101
☐ Yes ☒ No	Emergency Plan (10CFR50.54(q))	E-Plan	E-Plan	E-Plan	E-Plan	E-Plan	E-Plan
☐ Yes ☒ No	Environmental Impact	Environmental	Environmental	Environmental	Chemistry	Environ Prot/ Chem Manager	Chemistry
☐ Yes ☒ No	Exemptions (10CFR50.12)	Licensing	Licensing	Licensing	Licensing	Licensing	Licensing
☐ Yes ☒ No	Chemistry/Effluents	Chemistry	Chemistry	Chemistry	Chemistry	Chemistry/ Environ Pro	Chemistry
☐ Yes ☒ No	Rad Waste/Process Control Program	Radwaste	Radwaste	Radwaste	Operations	Rad Protection	Rad Prot.
☐ Yes ☒ No	Radiation Protection/ALARA program	Rad Protection	Rad Protection	Rad Protection	Rad Protection	Rad Protection	Rad Prot.
☐ Yes ☒ No	Fire Protection Program (10CFR50.48 & Appendix R)	Fire Protection	Fire Protection	Fire Protection	Fire Protection	Fire Protection	Fire Protection
☐ Yes ☒ No	ASME Code Program (10CFR50.55a)	N/A	Code Program	ISI Program	ISI Program	Code Program	Code Program
☐ Yes ☒ No	Containment Leakage Testing or IST Program	N/A	Code Program	Prog & Comp	IST Program	Code Program	Code Program
☐ Yes ☒ No	Maintenance Rule (10CFR50.65)	N/A	Work Control	System Eng	System Eng	MRule Coord	MRule Coord
☐ Yes ☒ No	Core Operating Limits Report (COLR) (10CFR50.59)	Rx Engineering	Rx Engineering	Rx Engineering	Rx Engineering	Rx Engineering	Rx Engineering
☐ Yes ☒ No	Commitments	Licensing	Licensing	Licensing	Licensing	Licensing	Licensing
☐ Yes ☐ No	ISFSI CFSAR / UFSAR Change (10CFR72.48)	LI-112	LI-112	LI-112	LI-112	N/A	N/A
☐ Yes ☐ No	ISFSI Program Review (10CFR72.48)	Licensing	Licensing	Licensing	Licensing	N/A	N/A
☐ Yes ☐ No	ISFSI Cask CofC, TS (Appendix A), or Approved Contents & Design Features (Appendix B) change required or received?	Licensing	Licensing	Licensing	Licensing	N/A	N/A

The Preparer should answer all questions in Part II of this Attachment. Part II provides a basis for the Determination results in Part I. All questions in Part II should be answered "No" in order to check "No" as a corresponding summary response in Part I. A "Yes" answer to any question in Part II must result in a "Yes" summary response in Part I.

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ENCLOSURE #2
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Part II: LBD/Program Questions (Department or Program Owner)	
	<u>Technical Specifications or Facility Operating License</u> (Licensing Manager)
	Does the proposed activity:
☐Yes ☒ No	Invalidate, render incorrect or otherwise require a change to an existing Technical Specification or the Facility Operating License?
	<u>Tech Spec Bases, Technical Requirements Manual</u> (Licensing Manager)
	Does the proposed activity:
☐Yes ☒ No	1. Invalidate or render incorrect an existing Technical Specification Bases?
☐Yes ☒ No	2. Require a change to the Technical Specification Bases?
☐Yes ☒ No	3. Affect the Technical Requirements Manual (TRM) or programs described in the TRM?
	<u>Security Plan</u> (Security Manager)
	Does the proposed activity:
☐Yes ☒ No	1. Add, delete, modify or otherwise affect Security department responsibilities?
☐Yes ☒ No	2. Modify or otherwise affect installed Protected Area or Vital Area barriers (i.e., breach walls, floors, ceilings, fencing, intake structures, etc.)?
☐Yes ☒ No	3. Cause materials or equipment to be placed or installed within the Security Isolation Zone?
☐Yes ☒ No	4. Modify or otherwise affect installed exterior lighting within the Protected Area?
☐Yes ☒ No	5. Modify or otherwise affect the facility's land vehicle barriers including access roadways?
☐Yes ☒ No	6. Modify or otherwise affect primary or secondary power supplies to access control equipment or intrusion detection equipment or to the Central Alarm Station or the Secondary Alarm Station?
☐Yes ☒ No	7. Modify or otherwise affect (block, move or alter) installed access control equipment, CCTV equipment or intrusion detection equipment?
☐Yes ☒ No	8. Modify or otherwise affect the facility's telephone or security radio system?
	<u>QA Program</u> (Quality Assurance Manager)
	Does the proposed activity:
☐Yes ☒ No	1. Affect the authority, independence, or management reporting levels previously established for organizations performing quality assurance functions as described in the QAPM?
☐Yes ☒ No	2. Reduce commitments or the effectiveness of the Quality Assurance functions specifically described in the QAPM?
☐Yes ☒ No	3. Reduce the level of QA activities, controls, or oversight activities as described in the QAPM?
☐Yes ☒ No	4. Delete or contradict any regulatory requirement listed in the QAPM as modified by Table 1 of the QAPM?
☐Yes ☒ No	5. Require a "Quality-Related" procedure revision, which would delete or reduce, a Section 8.0 "Requirements and Commitment Cross-Reference" listed QAPM reference?

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ENCLOSURE #2
PAGE 2 OF 7

Part II: LBD/Program Questions (Department or Program Owner)

	UFSAR (Licensing Manager)
	Does the proposed activity involve:
☒Yes ☐No	1. An SSC, whose design, function or operation is described in the UFSAR?
☐Yes ☒No	2. Any text, figure or table contained in the UFSAR?
	Emergency Plan (Emergency Planning Manager)
	Does the proposed activity:
☐Yes ☒No	1. Change responsibilities described in the Emergency Plan or Emergency Plan Implementing Procedures?
☐Yes ☒No	2. Affect or cause a modification (permanent or temporary) in structures, systems components or software or equipment use that affects or is described in the Emergency Plan?
☐Yes ☒No	3. Affect offsite assistance or agreements or any offsite facilities used in the Emergency Plan?
☐Yes ☒No	4. Affect On-Site staffing, Emergency staffing, equipment or operations referred to in the Emergency Plan?
☐Yes ☒No	5. Affect the design or operation of the meteorological system, public alert/notification system, effluent radiological monitoring systems, ventilation systems or communication systems?
☐Yes ☒No	6. Affect the data reporting activities or peripherals of the following electronic data systems? o Meteorological Information Data Acquisition System o Safety Parameter Display System (SPDS) (or Emergency Response Facility Information System (ERFIS) for VY o Data Point Library (DPL), if applicable
☐Yes ☒No	7. Affect any Emergency Action Level (EAL) bases or values?
☐Yes ☒No	8. Affect any changes or additions to external structures surrounding the plant that may create radiological, security, toxic, or explosive concerns?
☐Yes ☒No	9. Affect protective actions, equipment, evacuation, accountability, exposure control, for onsite personnel?
☐Yes ☒No	10. Affect emergency public information programs and/or capabilities?
☐Yes ☒No	11. Affect Emergency Response Organization training, Drills/exercises, Emergency Plan reviews and updates?

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ENCLOSURE #2
PAGE 3 OF 7

Part II - EBD/Program Questions (Department or Program Owner)

	Environmental Impact (RadPro/Chem/Environmental Manager as applicable) Does the proposed activity affect or produce a change in:
☐Yes ☒ No	1. Meteorological Monitoring or Air Quality including painting, organic solvents, fuel combustion, fuel dispensing sites, general process emissions/new air contamination source or emission points?
☐Yes ☒ No	2. Water Quality including Discharge Permit (Water discharge), chemical and petroleum bulk storage, storm water run-off, endangered or threatened species or protection of waters and structures?
☐Yes ☒ No	3. Hazardous Substance Regulation including new or existing chemical usage, pesticide use, hazardous waste generation, hazardous materials use, mixed waste generation, or asbestos removal?
☐Yes ☒ No	4. Land and forest (disturbs more than 5 acres)?
☐Yes ☒ No	5. Wetlands (any construction or digging within 100 feet of wetlands or shoreline)?
	Exemptions (Licensing Manager) Does the proposed activity:
☐Yes ☒ No	1. Require an exemption from any applicable NRC requirements?
☐Yes ☒ No	2. Invalidate the bases for any existing exemptions from NRC requirements?
	Chemistry/Effluents (RadPro/Chem/ Environmental Manager as applicable) Does the proposed activity affect or produce a change in:
☐Yes ☒ No	1. Effluent releases or paths (including Discharge Permit or Wastewater Treatment concerns)?
☐Yes ☒ No	2. Installed or portable chemical monitoring systems?
☐Yes ☒ No	3. Any radioactive effluent or monitoring process or system?
☐Yes ☒ No	4. New or existing chemical usage?
☐Yes ☒ No	5. Radioactivity/chemical vapor pathway affecting Control Room habitability?
	Rad Waste/Process Control Program (Ops/RadPro/Chem/ Environmental Manager as applicable) Does the proposed activity:
☐Yes ☒ No	1. Cause a major change to the solid radioactive waste processing system?
☐Yes ☒ No	2. Adversely affect the current capacity of the solid radioactive waste processing system?
☐Yes ☒ No	3. Involve or change calculations or assumptions concerning liquid or solid radioactive waste processing systems?
☐Yes ☒ No	4. Affect systems described in the UFSAR as governed by the PCP?

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ENCLOSURE #2
PAGE 4 OF 7

Part II.B Program Questions (Department or Program Owner)	
	Radiation Protection/ALARA (Radiation Protection Manager)
	Does the proposed activity
☐Yes ☒ No	1. Cause a change in the radiological conditions inside or outside radiologically controlled areas?
☐Yes ☒ No	2. Adversely affect the monitoring of radiological conditions?
☐Yes ☒ No	3. Involve or change calculations or assumptions concerning plant radiological conditions following a design basis accident?
☐Yes ☒ No	4. Affect ALARA issues such as change of radiation sources; increase time in radiation area; change containment of a radiation source; or change shielding of a radiation source?
☐Yes ☒ No	5. Involve establishing a Radiological Controlled Area outside of the restricted area?
	Fire Protection (Fire Protection Engineer)
	Does the proposed activity:
☐Yes ☒ No	1. Affect any fire protection systems, components or features including fire pumps, tanks, piping, valves, hydrants, extinguishers, hose stations, sprinklers/nozzles, smoke/heat/flame detectors, control panels, cables, fire seals, fire barriers, fire doors, heat or smoke vents, fire dampers, etc.?
☐Yes ☒ No	2. Affect any Appendix R credited components including cables, cable wraps, separation barriers, communication equipment, Appendix R repair kits, portable ventilation equipment, (RCP Oil Collection System at IPEC) or emergency lights?
☐Yes ☒ No	3. Affect any physical changes to areas protected by fire suppression or detection systems which could adversely impact system performance such as changes to, ceiling configuration, air distribution patterns, addition or deletion of openings into a gaseous protected enclosure, addition of obstructions below sprinklers/nozzles which may impact spray patterns, etc.?
☐Yes ☒ No	4. Permanently change the combustible load due to the addition or removal of flammable or combustible materials?
☐Yes ☒ No	5. Affect spill control features such as dikes, curbs or floor drains?
☐Yes ☒ No	6. Affect the administrative elements of the fire protection program such as the safe shutdown strategy, fire brigade training or equipment, fire protection surveillance procedures, etc?
☐Yes ☒ No	7. Block access/egress to any fire protection equipment including obstruction of emergency lights or safe shutdown pathways?

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ENCLOSURE #2
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ATTACHMENT 9.1 PAGE 6 OF 7

Part II LBD/Program Questions (Department or Program Owner)	
	ASME Code Program (WPO Engineering Programs Director or Site ASME Group)
☐Yes ☒ No	Does the proposed activity affect any ISI pressure boundary (piping, supports, components, valves, flanges, etc.) within the ISI Class 1, 2 or 3/3A boundary as detailed on the ISI drawings or affect the containment structure?
	Containment Leakage Rate Testing or IST Program (Programs and Component Engineering Manager)
	Does the proposed activity affect the:
☐Yes ☒ No	1. Components serving as Containment Isolation barriers that are in the Containment Leakage Rate Testing Program?
☐Yes ☒ No	2. Pumps and/or valves in the IST Program?
☐Yes ☒ No	3. Does the activity involve changes to testing frequencies specified in Surveillance Tests?
	Maintenance Rule (Maintenance Rule Coordinator)
	Does the proposed activity add or remove:
☐Yes ☒ No	1. A safety-related system, structure, or component (SSC)?
☐Yes ☒ No	2. Non safety-related SSCs that mitigate accidents and transients?
☐Yes ☒ No	3. Non safety-related SSCs that are used in the Emergency Operating Procedures (EOP) or EOP support procedures?
☐Yes ☒ No	4. Non safety-related SSCs whose failure could prevent safety-related SSCs from fulfilling their safety-related function?
☐Yes ☒ No	5. Non safety-related SSCs whose failure could cause a reactor scram or safety-system actuation?
	COLR (Systems Engineering Manager or RE Manager)
☐Yes ☒ No	Does the proposed activity involve changes, tasks or evolutions that could potentially affect the control of core reactivity or affect calorimetric or core monitoring instrumentation?
☐Yes ☒ No	Commitments (Licensing Manager) Does the proposed activity modify or delete any commitments?

TEMP MOD # 2005-009
ENCLOSURE #2
PAGE 6 OF 7

ATTACHMENT 9.1

	Check one - ☐JAF or IPEC (Complete Questions below), or ☒ N/A (For Pilgrim and VY)
	Independent Spent Fuel Storage Facility (ISFSI) (Licensing Manager)
	Does the proposed activity involve:
☐Yes ☐ No	1. An ISFSI SSC, whose design, function or operation is described in the CFSAR or UFSAR?
☐Yes ☐ No	2. Any text, figure or Table contained in the CFSAR or UFSAR?
	Independent Spent Fuel Storage Facility (ISFSI) (Licensing Manager)
	Does the proposed activity involve:
☐Yes ☐ No	1. Fire Protection Program – Introduction of ignition sources or combustibles within the ISFSI pad fenced area or involve the introduction of significant combustibles or explosion hazards within 50 feet of the ISFSI pad or ISFSI transfer route? (Fire Protection/Safety Coordinator)
☐Yes ☐ No	2. Security Program – Security procedures related to ISFSI operations, or ISFSI related security features such as Protected Area barriers, lighting, or intrusion detection equipment? (Security Manager)
☐Yes ☐ No	3. Emergency Plan – Any ISFSI EAL, any ISFSI EAL bases, modification of the JAF Exclusion area boundary, or any procedure used for controlling access to the exclusion area? (Emergency Planning Manager)
☐Yes ☐ No	4. Quality Assurance Program – ISFSI augmented quality assurance program implementation, or ISFSI record retention requirements? (Quality Assurance Manager)
☐Yes ☐ No	5. Training – Program requirements related to ISFSI? (Training Manager)
☐Yes ☐ No	6. Radiation Protection / ALARA – Program requirements related to the ISFSI? (Radiation Protection Manager)
☐Yes ☐ No	7. Radiological Effluents - Radiological Effluent Controls (REC), or Offsite Dose Calculation Manual (ODCM) requirements related to ISFSI? (Chemistry Manager)
☐Yes ☐ No	8. Cask Transport Pathway – Alteration of the ISFSI pad area, or alteration or obstruction of the pathway used during storage cask movements between the ISFSI pad and the reactor building?
☐Yes ☐ No	9. ISFSI Exemptions – A new or existing exemption from any applicable NRC ISFSI requirement?
☐Yes ☐ No	10. Transportation Packaging Current Licensing Basis – Alteration or any text, figure, or Table contained in the 10CFR71 CofC or SAR?
	ISFSI Cask CofC, TS (Appendix A), or Approved Contents & Design Features (Appendix B) change required or received? (Licensing Manager)
	Does the proposed activity involve:
☐Yes ☐ No	1. A change to the ISFSI Cask CofC, Technical Specification or Approved Contents and Design Features?

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ATTACHMENT 9.1 **50.59 SCREEN CONTROL FORM**

Sheet 1 of 1

☐ IP1 ☐ IP2 ☐ IP3 ☐ JAF ☐ PNPS ☒ VY Nuclear Power Plant

Activity ID/No. TM 2005-004 Activity: ☐ Design Change; ☐ Procedure; ☐ Test; ☐ Experiment; ; ☒ Other

Description: The purpose of this Temporary Modification (TM) is to restore the integrity of the diagonal bracing located in the Cooling Tower CT2-1 north wall area. Degraded bracing material was identified during the scheduled march 2005 Cooling Tower LCO. Cracking at the end section of the bracing near the bolted connection for the tie-plates caused a reduction in the capacity of the brace and should be restored in a manner that will return the brace to intended capacity and function as soon as possible.

Part I

Can the activity be excluded from 10CFR50.59 Review (Screening/Evaluation)? ....☐ Yes, ☒ No
(See NEI-96-07 Sections 4.1.2, 4.1.3, and 4.1.4 for examples of changes that may be excluded from 10CFR50.59 Review)

If Yes, provide reason in Part III, complete Part IV and exit ENN-LI-101 as 10CFR50.59 Review is not required.

Does the activity:

1. Involve a *change to the "facility as described in the UFSAR" (as defined in Section 3.0[5]),- which adversely affects (a) a design function, or (b) method of performing or controlling the design function, or (c) an evaluation for demonstrating that the intended design function will be accomplished ?*................. ☐ Yes, ☒ No
2. Involve changes to *"procedures as described in the UFSAR" (as defined in Section 3.0[9]),- which adversely affects (a) a design function, or (b) a method of performing or controlling the design function, or (c) an evaluation for demonstrating that the intended design function will be accomplished?* .... ☐ Yes, ☒ No
3. Involve *"a test or experiment not described in the UFSAR" (as defined- in Section 3.0[11])?*.......................................☐ Yes, ☒ No
4. *Result in changing or replacing an UFSAR "method of evaluation" described in the UFSAR (as defined in Section 3.0[8]) that is used in establishing the design bases or in the safety analysis?*... ....☐ Yes, ☒No

Part II UFSAR Sections reviewed:

A review of the UFSAR and the Technical Specifications was conducted to determine if the proposed TM adversely affects any described function or method of function performance as defined by the 10 CCFR 50.59 Resource Manual. The following sections were researched using a combination of manual search techniques and the Adobe document search function applied to the UFSAR and Technical Specification.

Electronically scanned documents for "cooling tower", reviewed UFSAR sect. 1.6.5, .10.8.3, 11.6, 11.9, 12.2, Appendix A.7.

Part III Justification (Attach additional pages as necessary): TM 2005-004 is a interim condition that maintains/restores the original configuration and capacity.

Part IV 50.59 Evaluation is NOT required:

PREPARER: James Fitzpatrick SIGNATURE: [signature] DATE: 3/9/05

REVIEWER: T. M. O'Connor SIGNATURE: [signature] DATE: 3/9/05

# of pages attached: [N/A]

EMP MOD # 2005-004

ENCLOSURE #3

INITIAL RISK ASSESSMENT SCREEN

NOTE

Activities that fall within the guidelines of the following procedures need not be assessed. (See Appendix B for examples of activities that may be excluded from assessment).

Procedures:
AP 0019, Control of Temporary and/or Portable Materials
AP 0042, Plant Fire Prevention and Fire Protection
OP 0046, Installation and Repair of Fire Barriers, Penetration Seals, Fire Breaks and Flood Seals
AP 0077, Barrier Control Process
AP 0140, Vermont Yankee Local Control Switching Rule
AP 0536, ALARA Implementation for Design Changes and Work Analysis

Reference Doc. #: TM 2005-004/SWO 03-1243-037 Implementation

List temporary configurations to be evaluated (see Appendix C for examples):
Partial removal of damaged diagonal~~(s)~~ etc and installation of splice ~~s~~ etc. Work to be performed from scaffolding or man-lift through open endwall. Scaffolding/man lift controlled by AP 0019 and man-lift operators are all trained/qualified. CT-2-1 is tagged out per AP 0140. FINAL TM configuration is evaluated in the TM.

With consideration of the credible failure modes associated with the above temporary configurations, answer the following risk assessment screening questions. The originator should provide a response to "No" answers that are potentially applicable to provide a basis for the conclusion.

1. Does this configuration render any risk-significant SSC(s) functions degraded? (See Maintenance Rule IG-3, Appendix B for information regarding risk-significant functions of SSCs) ☐ Yes ☒ No
   CT-2-1 is tagged OOS per AP0140 and will be restored ~~(with~~ after TM (and other modifications) are installed. No other risk-significant functions could be degraded.
2. Does this configuration increase the likelihood of a plant transient (Reactor/Turbine Trip, LOCA, LOOP, ATWS, HELB)? ☐ Yes ☒ No
3. Does this configuration increase the likelihood of a special initiators (Loss of DC Bus, Loss of AC Bus, Loss of SW)? ☐ Yes ☒ No
   Work is well away from SW piping and header in CT-2-1.

TEMP MOD # 2005-004
ENCLOSURE #4
PAGE 1 OF 2

INITIAL RISK ASSESSMENT SCREEN (Continued)

4. Does this configuration increase the potential for, or consequences of, internal flooding that may impact risk-significant SSCs? ☐ Yes ☒ No

5. Does the configuration impact the seismic qualification of any SSCs? ☐ Yes ☒ No
CT-2-1 is Seismic Class I but as noted previously is tagged OOS per AP0140 while in Interim configurations. The TM final configuration has been evaluated as acceptable in the TM & supporting calculation.

6. Does the configuration impact the EQ of any SSCs (radiation, temperature, pressure, humidity)? ☐ Yes ☒ No

7. Does the configuration increase the potential for a primary containment bypass event such as an interfacing systems LOCA or a LOCA outside of containment? ☐ Yes ☒ No

8. Does the configuration increase the potential for an inadvertent safety-system actuation? There is no equipment that will activate a safety-system in the area of this work. ☐ Yes ☒ No

If any of the above questions is answered "YES", an Engineering Risk Assessment (VYAPF 0091.02) is required.

Engineering Risk Assessment Required? ☐ Yes ☒ No

Initial Risk Assessment Screen Performed by*: Jim Calchera / J Calchera / 3/9/05
Print/Sign Date

Initial Risk Assessment Screen Approved by: S A Goodwin / S A Goodwin / 3-9-05
Department Head (Print/Sign) Date

* The preparer of the Initial Risk Assessment Screen shall be 50.59 Screen qualified and trained in this procedure.

TEMP MOD # 2005-004
ENCLOSURE # 4
PAGE 2 OF 2

PENDING CHANGE NOTIFICATION FORM

Notification of a pending revision to the drawing(s) listed.

VYDC/EDCR #______ MM #______ ER ____ OTHER: *TM 05-004* CANCELLATION ______

JO FILE # and/or WO # (if applicable) *W.O. 05-1243-037*

TITLE/DESCRIPTION OF CHANGE: *Installation of Structural Splice in Cooling Tower CT2-1*

[illegible]	[illegible]
5920-6451 Sht. 3 of 5	2

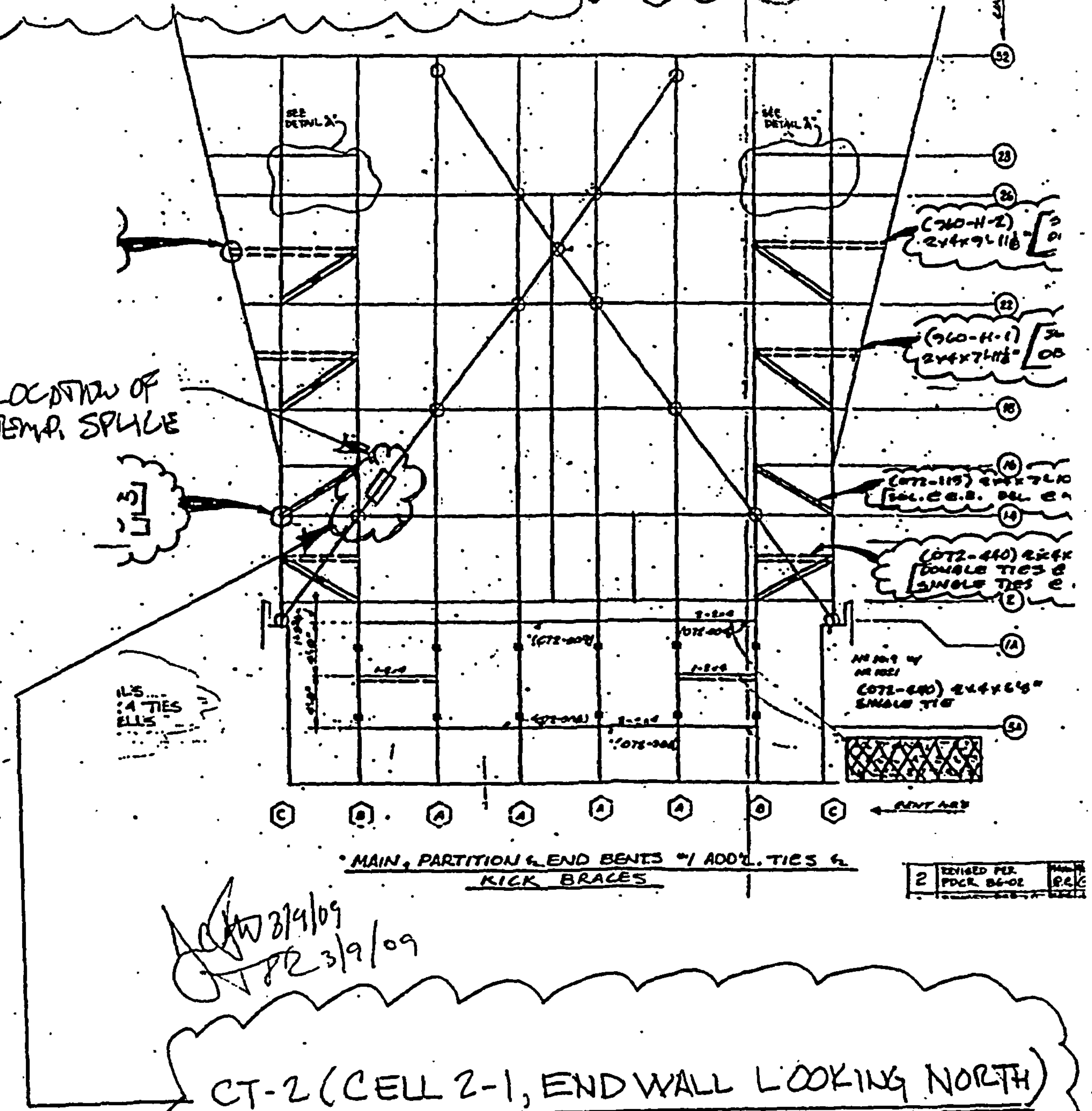
Originator: JAMES C FITZPATRICK DATE: 3/9/05
(Please Print)

DELIVERED TO RIMS
3/9/05 @ 15:45

VYAPF 6802.01
AP 6802 Rev. 24
Page 1 of 1

TEMP MOD # 2005-004
ENCLOSURE #5
PAGE 1 OF 2

PARTIAL
MARKUP OF DWG 5920-6451 SHT 3 OF 5 REV. 2
FOR TEMP MOD 2005-004



3/9/09
3/9/09

CT-2 (CELL 2-1, END WALL LOOKING NORTH)

TEMPORARY SPLICE INSTALLED ON DIAGONAL BRACE. SEE TEMP MOD 2005-004 SKETCH No1 SHTS 1 TO 3 FOR DETAILS.

TEMP MOD # 2005-004
ENCLOSURE #5
PAGE 2 OF 2

APPENDIX R REVIEW
(INS9526_01, ER960433_01)

~~MM~~/TM No.: 2005-004

Title: INSTALLATION OF STRUCTURAL SPLICES IN COOLING TOWER CT2-1

Plant System Affected: ____________________ Safety Class: 3

Cognizant: M. SELLING / JAMES FITZPATRICK

Appendix R Review Items to be Considered:
[If any question is answered YES, additional Appendix R specialist review is required. However, if the document is a TM which will be implemented and restored while the plant is in cold shutdown during a single outage, Appendix R specialist review is not required.]

1.	Does change involve electrical components or wiring?	☐ YES	☒ NO ✓
2.	Does change involve Appendix R Safe Shutdown components, including any support system components [Refer to EMPAC Programs Page]?	☐ YES	☒ NO ✓
3.	Will change impact any Appendix R lighting or visibility therefrom?	☐ YES	☒ NO ✓
4.	Will change impact any Appendix R fire barrier, CFZ, or Suppression zone?	☐ YES	☒ NO ✓
5.	Will change require revision/update of CWDs? (List below)	☐ YES	☒ NO ✓
6.	Will change require revision/update of CCLs? (List below)	☐ YES	☒ NO ✓
7.	Does change impact an Appendix R Safe Shutdown Strategy?	☐ YES	☒ NO ✓
8.	Will change require an update/modification of Appendix R documentation (including cable list database)?	☐ YES	☒ NO ✓

Review Comments: THIS TEMP. MOD IS FOR A STRUCTURAL / MECHANICAL COMPONENT; THERE ARE NO ELECTRICAL IMPACTS.

TEMP MOD # 2005-004
ENCLOSURE # 6
PAGE 1 OF 1

CWDs: NONE

CCL: NONE

N/A M. Selling / [signature] 1/3/05

Design Engineering Reviewer (if applicable) (Print/Sign) Date

VYAPF 0020.09
AP 0020 Rev. 28
Page 1 of 1

ATTACHMENT 71111.15

INSPECTABLE AREA: Operability Evaluations

CORNERSTONES: Mitigating Systems (90%)
Barrier Integrity (10%)

INSPECTION BASES: Improperly evaluated degraded and/or non-conforming conditions may result in continued operation with a structure, system, or component (SSC) that is not capable of performing its design function.

This inspectable area verifies aspects of the Mitigating Systems and Barrier Integrity cornerstones for which there are no performance indicators.

LEVEL OF EFFORT: Review the following sample sizes of operability evaluations of degraded and non-conforming conditions which impact mitigating systems and barrier integrity: 15 to 21 per year at one reactor unit sites; 19 to 25 per year at two reactor unit sites; and 22 to 30 per year at three reactor unit sites. Although the number of required samples is an annual goal, available operability evaluation samples should be inspected each quarter to ensure a reasonable distribution throughout the year.

71111.15-01 INSPECTION OBJECTIVE

01.01 To review operability evaluations affecting mitigating systems and barrier integrity to ensure that operability is properly justified and the component or system remains available, such that no unrecognized increase in risk has occurred.

71111.15-02 INSPECTION REQUIREMENTS

02.01 Operability Evaluation Review

a. Select operability evaluations involving risk significant SSCs. Selection of operability evaluations can emerge from the inspector's review of plant status documents such as operator shift logs, emergent work documentation, deferred modifications, and standing orders to determine if an operability evaluation is warranted for a degraded component.

b. Review the technical adequacy of the licensee's operability evaluation, and verify if operability is justified. Verify that the licensee considered other degraded conditions and their impact on compensatory measures for the condition being evaluated. Refer to the FSAR and other design basis documents during the review. If operability is justified, no further review is required.

c. If the operability evaluation involves compensatory measures, determine if the measures are in place, will work as intended, and are appropriately controlled.

d. If operability is not justified:

1. Determine impact on any Technical Specification LCOs.

2. Use the Significance Determination Process to evaluate the risk significance of the equipment inoperability.

02.02 Identification and Resolution of Problems. Verify that the licensee is identifying problems with operability evaluations at an appropriate threshold and entering them in the corrective action program. For a sample of significant operability evaluations issues documented in the corrective action program, verify that the licensee has identified and implemented appropriate corrective actions. See Inspection Procedure 71152, "Identification and Resolution of Problems," for additional guidance.

71111.15-03 INSPECTION GUIDANCE

The licensee's process of ensuring operability is continuous and consists of the verification of operability by surveillances and continuous monitoring of plant systems. Formal determinations of operability are performed whenever a verification or other indication calls into question the SSC's ability to perform its specified function. Licensees are obligated to ensure the continued operability of SSCs as specified by TS, or to take the remedial actions addressed in the TS. The intent of this inspection is to sample licensee's operability evaluations for risk significant SSCs to verify if operability is justified, such that availability is assured, and no unrecognized increase in risk has occurred. Also, the inspections should verify that operability concerns associated with plant issues and events are being identified.

Where there is a reason to suspect that the licensee's operability determination is not, or was not correct based on the information reviewed, the inspector should discuss the issue with regional management for resolution. Depending on the complexity and risk significance of the issue, in some cases, the inspector may need to consult with regional specialists to complete verification of licensee's operability evaluation. The regional specialist's time spent on reviewing the issue should be charged to this procedure. The inspectors are not required to spend additional time in reviewing an issue if the discrepancies identified do not change the outcome of the operability evaluation.

Generic Letter 91-18, "Resolution of Degraded and Non-Conforming Conditions" and NRC Inspection Manual Part 9900 "Operable/Operability - Ensuring the Functional Capability of a System or Component" provides additional guidance in this area. In particular, as stated in section 4.5.4 of Generic Letter 91-18, some licensees may refer to documents or processes that establish operability of SSCs as JCOs or Justification for Continued Operation. The NRC has defined a JCO as the licensee's technical basis for requesting authorization to operate in a manner that is prohibited absent such authorization. This procedure is not intended to review formal JCOs as defined by the NRC but does cover evaluations referred to by licensees as JCOs which establish operability of structures, systems or components.

See table below for inspection guidance to assist the inspector in selecting inspection activities to achieve each cornerstone objective and to those activities that have a risk priority.

Cornerstone	Inspection Objective	Risk Priority	Example
Mitigating Systems Barrier Integrity	Identify any improperly evaluated degraded and/or nonconforming conditions which could potentially impact SSCs availability and result in an unrecognized increase in risk.	Operating - mitigating system as determined by plant-specific information or RIM2. Shutdown - Mitigating systems that perform key safety functions during shutdown (decay heat removal, inventory control, electrical power availability, reactivity control, and containment)	Improper conclusion on operability of the HPCI system such that the system could not perform its' function during a station blackout event concurrent with planned unavailability of the RCIC system.

71111.15-04 RESOURCE ESTIMATES

The annual resource expenditure for this inspection procedure is estimated to be 54 to 72 hours for sites with one reactor unit; 66 to 88 hours for sites with two reactor units; and 78 to 106 hours for sites with three reactor units.

71111.15-05 COMPLETION STATUS

Inspection of the minimum sample size will constitute completion of this procedure in the Reactor Programs Systems (RPS). That minimum sample size will consist of 15, 19, and 22 operability evaluations of degraded and non-conforming conditions in a year at 1-unit, 2-unit, and 3-unit sites respectively.

71111.15-06 REFERENCES

Generic Letter 91-18, "Resolution of Degraded and Nonconforming Conditions"

Inspection Manual Part 9900, "Operable/Operability - Ensuring the Function Capability of a System or Component"

Information Notice 97-78, "Crediting of Operator Actions in Place of Automatic Actions and Modification of Operator Actions, including Response Times"

Inspection Procedure 71152, "Identification and Resolution of Problems"

END

ENVY System Engineering Initial Operability Recommendation

System: BLD and ACS **Asset:** CT-2

Problem Description:

A small section of the concrete freeboard atop the deep basin foundation wall has failed on the west side of CT-2.

Condition Report Number: CR-VTY-2005-1392

Work Request Number (If Applicable): WO 05-0737

Initial Operability Recommendation:

System Engineering recommends that the Alternate Cooling system be considered Operable.

Basis for Recommendation:

Condition:

As stated in the referenced CR, a degraded condition in the west cooling tower deep basin was discovered in 2/05. CR-VTY-2005-0540 was written at that time to describe an 8" X 10" hole in the deep basin freeboard on the west side of CT-2, near the south end of CT-2-2. The freeboard is the non-structural curb at the top of the deep basin wall. The evaluation of that CR indicated that the cause of the event was a pocket of unconsolidated concrete containing insufficient cement. It was attributed to an original construction defect. The evaluation at that time indicated that there was no operability concern since the defective concrete was located a few inches above the normal alternate cooling water level and no inventory was being lost.

Since that event, WO 05-0737 was written as an S0 outage WO to repair the freeboard. The foundation wall below the failed area appears sound, but water level will need to be lowered in the deep basin to support forming the location for a proper concrete repair. No additional deterioration occurred in the winter since, with only SW discharging to the deep basin, the water level remained several inches below the defect location. CW flow to the cooling towers was initiated today to support cooling tower testing. The additional volumetric flow of CW added to the deep basin inventory raised the deep basin water level to a couple inches above the hole in the freeboard, allowing water to pour out and pond in the local area west of CT-2. CR-VTY-2005-1392 was written to document this condition.

Operability Recommendation:

There are no structural concerns with the existing condition. The freeboard extends above the deep basin foundation wall with the purpose of retaining a few inches of water head. The hole in the freeboard has no impact on the seismic capabilities of CT-2. The areas of degraded concrete are above ACS water level and perform no seismic structural functions.

The loss of water to the west of the tower has resulted in some ponding, however, there is no evidence of soil erosion outside the failed area with maximum CW flow present. The ponding is minor, does not undermine the deep basin and has no effect on the seismic ability of the deep basin.

Although water level in the cooling towers is currently a few inches higher than the bottom of the failed section of the freeboard, this is only occurring because the CW system is currently discharging to the deep basin. If alternate cooling operation was required, the CW system would not be discharging to the deep basin, and water level would return to the winter condition where water level was observed to be a few inches lower than the failed area. This condition is the same as would occur if alternate cooling were required due to the loss of the Vernon dam or due to a fire in the intake structure. If alternate cooling were required due to the design basis flood, the current configuration would actually be an improvement, since the hole in the freeboard would allow the flood to replenish the deep basin earlier than it normally would when flood waters must exceed the height of the freeboard to replenish the deep basin.

The fact that the size of the failed area has increased is not an operability concern. When CT-2005-0540 was written in 2/05, the defect was found to be a hole, with the very top of the freeboard above the hole still intact. This piece atop the whole has now failed and fallen out on the ground outside the deep basin. When the defect was first observed in 2/05, it was evident that there was potentially soft concrete outside the failed area which looked degraded. These areas were all above the required inventory level for alternate cooling. The fact that another small section of this known soft concrete has now failed does not change the evaluation that alternate cooling is not affected. There is no indication of any failed concrete or potentially failed concrete below the required alternate cooling inventory elevation.

Conclusion:

Based on the above, there is no impact on Alternate Cooling System inventory, operability or seismic support due to the failed concrete on the freeboard of CT-2. System Engineering recommends that the Alternate Cooling system be considered Operable.

Function Potentially Affected: Functions potentially affected by this event include loss of seismic/structural ability of the cooling towers and loss of ACS inventory.
Potential Adverse Effects: Questions considered in the operability recommendation include the potential for further degradation, impact on seismic operability of the cooling towers, and impact on the ACS system inventory and operability.
Limitations/Restrictions (If Applicable): None
Additional Actions to Consider (If Applicable): The defective area is being sandbagged to limit loss of water to the area west of CT-2, which should eliminate the nuisance ponding currently occurring.

Prepared by (Name/Date): Stephen A. Vekasy 5/2/05
Reviewed by (Name/Date): Mark Lefrancois 5/2/05

State of Vermont

NPDES

AGENCY OF NATURAL RESOURCES
Department of Environmental Conservation
Wastewater Management Division
103 South Main Street - Sewing Bldg.
Waterbury, Vermont 05671-0405

Telephone: (802) 241-3822
Fax: (802) 241-2596

Department of Fish and Wildlife
Department of Forests, Parks and Recreation
Department of Environmental Conservation
State Geologist
RELAY SERVICE FOR THE HEARING IMPAIRED
1-800-253-0191 TDD>Voice
1-800-253-0195 Voice>TDD

May 14, 2002

RECEIVED
MAY 16 2002
By Lynn DeWald

Michael R Kansler
Entergy Nuclear Vermont Yankee, LLC
440 Hamilton Avenue
White Plains, NY 10601

Re: **Amended (Transferred) Discharge Permit #3-1199**

Dear Mr Kansler:

Enclosed is your copy of the above referenced permit, which I have signed for the Commissioner of the Department of Environmental Conservation. Please read the permit carefully and familiarize yourself with all its terms and conditions. Your attention is particularly directed to those conditions which may require written responses by certain dates.

If you have any questions concerning your permit, please contact Carol Carpenter at 241-3828.

Sincerely,

Marilyn J Davis

Marilyn J Davis, Director
Wastewater Management Division

Enclosure

cc: Barbara Williams, Vermont Yankee
Elise Zoli, Goodwin Procter, LLP
EAC members

Permit No. 3-1199
File No. 13-17
NPDES No. VT0000264
Project ID No. NS75-0006

AGENCY OF NATURAL RESOURCES
DEPARTMENT OF ENVIRONMENTAL CONSERVATION
WASTEWATER MANAGEMENT DIVISION
103 SOUTH MAIN STREET
WATERBURY, VERMONT 05671-0405

AMENDED (TRANSFERRED) DISCHARGE PERMIT

In compliance with the provisions of the Vermont Water Pollution Control Act, as amended, (10 V.S.A. Chap. 47 1251 et. seq;) and the Federal Clean Water Act, as amended (33 U.S.C. §1251 et seq),

Entergy Nuclear Vermont Yankee, LLC
185 Old Ferry Road
Brattleboro, VT 05302

(hereinafter referred to as the "permittee") is authorized, by the Secretary, Agency of Natural Resources, to discharge from a facility located at:

320 Governor Hunt Road
Vernon, Vermont

to the Connecticut River, Class B at the point of discharge

in accordance with effluent limitations, monitoring requirements, and other conditions set forth in Parts I, II, III hereof.

This permit shall become effective as described under Part I.A9.

This permit and the authorization to discharge shall expire on March 31, 2006.

Signed this 14th day of May , 2002.

Christopher Recchia, Commissioner
Department of Environmental Conservation

By Marilyn J. Davis
Marilyn J. Davis, Director
Wastewater Management Division

Part I

A. EFFLUENT LIMITATIONS, MONITORING REQUIREMENTS, AND SPECIAL CONDITIONS

1. Through March 31, 2006, the permittee is authorized to discharge from outlet serial number S/N 001: Circulating water discharge - main condenser cooling water and service water. Such discharges shall be limited by the permittee as specified below:

EFFLUENT CHARACTERISTIC	DISCHARGE LIMITATIONS lbs/day Monthly Avg.	Daily Max.	Other units (specify) Monthly Avg.	Daily Max.	MONITORING REQUIREMENTS Measurement Frequency	Sample Type
Flow: Open/Hybrid-Cycle				543 MGD	Daily	Calculated Flow
Closed Cycle				12.1 MGD	Daily	Calculated Flow
Temperature	see Part 1.6.a-e, pp.4-5					
Free Residual Chlorine	(b)		0.2 mg/l		(c)	Grab
Total Residual Oxidant	(a)(b)		Monitor Only		(c)	Grab
pH	6.5 to 8.5 Standard Units				1 x daily	Grab (d)

There shall be no discharge of floating solids or visible foam in other than trace amounts.

Samples taken in compliance with the monitoring requirements specified above shall be collected at locations which are representative of the effluents discharged.

(a) Where "Total Oxidant" is chlorine, chlorine plus bromine, or bromine.
(b) Oxidant or chlorine injection is limited to discharge during closed cycle only and detectable residuals are not to exceed 2 hours/day with the exception that the service water system may be treated during open/hybrid cycle provided that treatment does not exceed 2 hours/day with no detectable oxidant being measured at the discharge structure.
(c) Monitoring is required during the period that oxidant, or chlorine, treatment is occurring. The duration of the treatment shall be reported for each treatment day in the monthly discharge monitoring report.
(d) A daily grab represents the minimum monitoring frequency. Continuous pH monitoring is acceptable and if utilized will require reporting daily minimum and maximum values on the monthly monitoring report.

2. Through March 31, 2006, the permittee is authorized to discharge from outfall serial number S/N 002: Radioactive liquid. Such discharges shall be limited by the permittee as specified below:

EFFLUENT CHARACTERISTIC	DISCHARGE LIMITATIONS		MONITORING REQUIREMENTS	
	Monthly Avg.	Daily Max.	Measurement Frequency	Sample Type
Flow		0.01 MGD	(a)	Estimate
Radioactivity	see Part 1.10.a-f., pp.6-7		(a)	see Part 1.10.a-f.
pH	6.5 to 8.5 Standard Units		(a)	Grab

There shall be no discharge of floating solids or visible foam in other than trace amounts.

Samples taken in compliance with the monitoring requirements specified above shall be collected at locations that are representative of the radioactive effluent discharge.

(a) Shall be monitored daily when the discharge occurs. When it is determined that a discharge of radioactive liquid wastewater is necessary, the permittee shall notify the Wastewater Management Division prior to the discharge or, if necessary, within 24 hours following the discharge.

3. Through March 31, 2006, the permittee is authorized to discharge from outfall serial number S/N 003: Plant Heating Boiler Blowdown. Such discharges shall be limited by the permittee as specified below:

EFFLUENT CHARACTERISTIC	DISCHARGE LIMITATIONS		MONITORING REQUIREMENTS	
	Monthly Avg.	Daily Max.	Measurement Frequency	Sample Type
Flow		0.001 MGD (a)	Each discharge	Estimate
BetzDearborn Cortrol OS7700	(b)		No Monitoring Required	

There shall be no discharge of floating solids or visible foam in other than trace amounts.

Samples taken in compliance with the monitoring requirements specified above shall be collected before combining with other waste streams.

(a) Each of the two boilers may be drained of 0.002 MGD at the end of the heating season.
(b) See Part I.15.

4. Through March 31, 2006, the permittee is authorized to discharge from outfall serial number S/N 004: Water treatment carbon filter backwash. Such discharges shall be limited by the permittee as specified below:

EFFLUENT CHARACTERISTIC	DISCHARGE LIMITATIONS		MONITORING REQUIREMENTS	
	Monthly Avg.	Daily Max.	Measurement Frequency	Sample Type
Flow		0.010 MGD	(a)	Estimate
Total Suspended Solids		8.3 lbs.	No Monitoring Required	

There shall be no discharge of floating solids or visible foam in other than trace amounts.

(a) Shall be monitored daily when the discharge occurs.

5. Through March 31, 2006, the permittee is authorized to discharge from outfall serial number S/N 005: Cooling water discharge from the four RHR-Service Water pumps.

The permittee may discharge up to 14,000 gpd. No effluent limits or monitoring is required for this waste stream.

6. The permittee is required to operate its circulating water cooling facilities whether closed, open, or in a hybrid mode as follows:

a. During the period **October 15 through May 15**:

(1). The temperature at Station 3 shall not exceed 65°F.

(2). The rate of change of temperature at Station 3 shall not exceed 5°F per hour. The rate of change of temperature shall mean the difference between consecutive hourly average temperatures.

(3). The increase in temperature above ambient at Station 3 shall not exceed 13.4°F. The increase in temperature above ambient shall mean plant induced temperature increase as shown by equation 1.1 (defined on page 1-8 of Vermont Yankee's 316 Demonstration: Engineering, Hydrological and Biological Information and Environmental Impact Assessment (March 1978).

b. During the period **May 16 through October 14**, the increase in temperature above ambient at Station 3 shall not exceed the limits set forth in the following table:

Station 7 Temperature	Increase in Temperature Above Ambient at Station 3
Above 63°F	2°F
>59°F, ≤63°F	3°F
≥55°F, ≤59°F	4°F
Below 55°F	5°F

The increase in temperature above ambient shall mean plant induced temperature increase as shown by equation 1.1 (defined on page 1-8 of Vermont Yankee's 316 Demonstration: Engineering, Hydrological and Biological Information and Environmental Impact Assessment (March 1978).

c. Experimental open/hybrid cycle test programs with alternative thermal limits (to 6a. and 6b. above) may be administered as approved by the Vermont Yankee Environmental Advisory Committee (defined in Part I.12) and which receive written authorization from the Secretary of the Agency of Natural Resources.

d. During power operation, if an unexpected failure results in a complete loss of the cooling tower system, the above restrictions may be modified for a period not to exceed 24 hours to allow an orderly shutdown by utilizing the main condenser as a heat sink and operating in an open-cycle mode. The cooling tower system includes all auxiliary components required for cooling tower operation.

e. Notwithstanding the above, the Secretary may reopen and modify the permit to incorporate more stringent effluent limitations for control of the thermal component of Entergy Nuclear Vermont Yankee's discharge, including the requirements of closed-cycle operation, if the Secretary determines that open-cycle operation is having an adverse effect in resident or anadromous fish species in the river. Entergy Nuclear Vermont Yankee will be given notice and opportunity for a hearing prior to the imposition of such more stringent effluent limitations.

7. Through March 31, 2006, the permittee is authorized to discharge from outfall serial numbers S/N 006, 007, 008, 010, 011: Stormwater runoff; and demineralized trailer rinse down water (S/N 006 only).

006 - North Storm System Discharge Point: to the north of the intake structure.
007 - South Storm System Discharge Point: to the forebay of the discharge structure; includes discharges from S/N 003, S/N 004 and S/N 005.
008 - Southeast Storm System Discharge Point: to the southeast of the east cooling tower.
010 - 345 kV Switchyard Storm System Discharge Point: about 300 yards north of the intake structure.
011 - 115kV Switchyard Storm System Discharge Point: about 350 yards north of the intake structure.

Effluent limits and monitoring are not required for the stormwater discharges; however, future storm drain and manhole construction shall conform to the Agency's policy for stormwater treatment.

The permittee is authorized to discharge demineralized trailer rinse down water to the storm drain system (S/N 006). The permittee may discharge up to 10,000 gpd. No effluent limits or monitoring is required for this waste stream..

8. Through March 31, 2006, the permittee is authorized to discharge from outfall serial number S/N 009: Strainer and traveling screen backwash.

EFFLUENT CHARACTERISTIC	DISCHARGE LIMITATIONS		MONITORING REQUIREMENTS	
	Monthly Avg.	Daily Max.	Measurement Frequency	Sample Type
Flow		0.050 MGD	(a)	Estimate
Bulab 8006	(b)		No Monitoring Required	

There shall be no discharge of floating solids or visible foam in other than trace amounts.

Samples taken in compliance with the monitoring requirements specified above shall be collected before combining with other waste streams.

(a) Shall be monitored daily when the discharge occurs.
(b) See Part I.15.

9. **This amended permit shall become effective on the date of sale of the facility from Vermont Yankee Nuclear Power Corporation to Entergy Nuclear Vermont Yankee, LLC and shall then supersede Permit No. 3-1199, signed August 29, 2001. The permittee shall submit to the Department written notification of sale within 24 hours of the closing date.**

10. The permittee will conduct an environmental monitoring program to measure and record physical, chemical, and biological data to assure compliance with the requirements of this permit in accord with Part IV of this permit: Environmental Monitoring Studies, Connecticut River. The permittee shall submit an annual report by May 31 of each year to the Secretary of the Agency of Natural Resources and the Environmental Advisory Committee.

11. All radioactive liquid waste collected in the plant will be processed through a treatment system, including filtering and/or demineralization, and the liquid will be processed and disposed of in accordance with the Nuclear Regulatory Commission Regulations. Low level radioactive wastes may be released to the Connecticut River after treatment pursuant to Final Safety Analysis Report, Volume 111, Section 9.2: Station Radioactive Liquid Waste System, Vermont Yankee Nuclear Power Station, as amended, subject to the following restrictions:

    a. The maximum instantaneous concentration of radionuclides in liquid effluents released to the unrestricted environment shall not exceed the limits specified in 10 CFR Part 20.1001 - 20.2401, Appendix B, Table 2, including applicable notes thereto.

    b. The maximum annual quantity of radionuclides, except tritium, in liquid effluents released to the unrestricted environment shall not exceed five (5) curies.

    c. The maximum annual quantity of tritium in liquid effluents released to the unrestricted environment shall not exceed five (5) curies.

d. The dose or dose commitment to a member of the public from radionuclides in liquid effluents released to the unrestricted environment shall be limited to the following:

i. During any calendar quarter: less than or equal to 1.5 millirems to the total body, and less than or equal to 5 millirems to any organ.

ii. During any calendar year: less than or equal to 3 millirems to the total body, and less than or equal to 10 millirems to any organ.

e. The permittee shall report to the Agency of Natural Resources any abnormal releases of radioactivity in liquid effluents in a manner and timeframe consistent with Nuclear Regulatory Commission requirements.

f. The permittee shall monitor and report concentrations, quantities, and calculated doses of gamma radionuclides and tritium in liquid effluents released to the Connecticut River and report such data to the Agency of Natural Resources. Other radionuclides shall be reported to the Agency of Natural Resources in a manner consistent with the reports submitted to the Nuclear Regulatory Commission.

12. An Environmental Advisory Committee (EAC) is comprised of one individual each representing (1) Vermont Department of Environmental Conservation; (2) Vermont Department of Fish and Wildlife; (3) New Hampshire Fish and Game Department; (4) New Hampshire Department of Environmental Services; (5) Massachusetts Office of Watershed Management; (6) Massachusetts Division of Fisheries and Wildlife; and, (7) Coordinator of the Connecticut River Anadromous Fish Program, U.S. Fish and Wildlife Service. The EAC shall be advisory in function and Entergy Nuclear Vermont Yankee, LLC shall meet with the EAC as often as necessary, but at least annually, to review and evaluate the aquatic environmental monitoring and studies program. The Entergy Nuclear Vermont Yankee, LLC Chemistry Manager or designee will serve as the administrative coordinator and Secretary for the EAC.

13. The temperature probe in the Vernon fishway shall be compatible with the temperature monitoring system utilized at Stations 3 and 7 in the Connecticut River.

14. Racks and screens preventing fish and other wildlife from entering the condenser water intake must be operated and maintained in a manner as previously approved by the Vermont Water Resources Board. Solids collected on the traveling screen shall not be returned to the Connecticut River.

15. The permittee is authorized to pump river silt, as necessary, that deposits in the intake structure and cooling tower basins, in the form of a silt-water slurry to be deposited on land on the plant site in the sedimentation area. Slurry volumes to be pumped shall not exceed 0.500 MGD or 350 gpm. River sediment/silt will be pumped from the West Cooling Tower into the existing spray pond where it will be passively filtered to reduce turbidity before the water portion is routed to the discharge structure. The remaining sediment will be removed form the spray pond and disposed of properly in accordance with state and federal statutes and regulations.

16. The permittee is authorized to use either the following chemicals, or chemicals which are similar in composition, concentration, and toxicity, to the maximum concentrations indicated below. An increase in dosage rate or a substantial change in the chemicals identified must be reviewed and approved by the Department to assure that no adverse impact will occur. A substantial change in chemicals shall be defined as chemicals that are not similar in composition, concentration, and toxicity to those identified. A change of chemical vendors will require, as a minimum, a submittal of the appropriate MSDS, prior to use of the chemical, to the Wastewater Management Division of the Department.

Bulab 8006: penetrant/biodispersant for use in minimizing and removing fouling within the Service Water System; maximum concentration 20 ppm.

Bulab 7034 or Depositrol BL5303: general corrosion inhibitors for use in service water or circulating water; maximum concentration 30 ppm.

Bulab 9027 or Inhibitor AZ8103: copper corrosion inhibitors for use in the circulating water for condenser corrosion control. Maximum concentration for Bulab 9027 is 10 ppm. Maximum concentration for Inhibitor AZ8103 is 50 ppm (used monthly for a 10 minute period).

Dianodic DN2301: a dispersant for use in the circulating and service water systems; maximum concentration 20 ppm.

Bulab 6002 or Spectrus NX-1104: a biocide for use in the circulating and service waters as an alternative or in addition to bromine/chlorine. Maximum concentration for Bulab 6002 is 5 ppm. Maximum concentration for Spectrus NX-1104 is 30 ppm for the service water system and 2 ppm for the circulating water system.

Cortrol OS7700: an oxygen scavenger and pH control agent containing hydroquinone as the oxygen scavenger. Use concentration varies from approximately 100 ppm to 2,000 ppm. Boiler discharges are limited to 15 ppm as hydroquinone.

Ferroquest FQ7101: a chemical for use in the service water system to correct biological/corrosion fouling with the service water pumps. The maximum concentration is 96 ppm for one minute approximately eight times per year.

Ferroquest FQ7102: a pH control agent. Less than two gallons are used to maintain a neutral pH when using FQ 7101. The maximum concentration is 7 ppm for one minute approximately eight times per year.

Oxidizing biocides (chlorine or chlorine with bromine) for treatment of the Service Water System (SWS)

a.. Open/hybrid cycle, treatment of the SWS shall not exceed 2 hours per day with no detectable free residual oxidant being measured at the discharge structure (S/N 001).

b. Closed cycle, free residual oxidant as measured at the discharge structure (S/N 001) is limited to 0.2 mg/l and detectable residual oxidant shall not exceed 2 hours per day.

17. There shall be no discharge of polychlorinated biphenyl compounds, such as those commonly used for transformer fluids.

18. There shall be no discharges of metal cleaning waste including wastewater from chemical cleaning of boiler tubes, air preheater washwater, and boiler fireside washwater.

B. REAPPLICATION

If the permittee desires to continue to discharge after the expiration date of this permit, the permittee shall apply on the application forms then in use at least 180 days before the permit expires.

Reapply for a Discharge Permit by **September 30, 2005.**

C. OPERATING FEES

This discharge is subject to operating fees. The permittee shall submit the operating fees in accordance with the procedures provided by the Secretary.

D. MONITORING AND REPORTING

1. **Sampling and Analysis**

The sampling, preservation, handling, and analytical methods used shall conform to regulations published pursuant to Section 304(g) of the Clean Water Act, under which such procedures may be required. Guidelines establishing these test procedures have been published in the Code of Federal Regulations, Title 40, Part 136 (Federal Register, Vol. 56, No. 195, July 1, 1999 or as amended).

Samples shall be representative of the volume and quality of effluent discharged over the sampling and reporting period. All samples are to be taken during normal operating hours. The permittee shall identify the effluent sampling location used for each discharge.

2. **Reporting**

The permittee is required to submit monitoring results as specified on a Discharge Monitoring Report (Form WR-43). Reports are due on the 15th day of each month, beginning with the month following the effective date of this permit.

If, in any reporting period, there has been no discharge, the permittee must submit that information by the report due date.

Signed copies of these, and all other reports required herein, shall be submitted to the Secretary at the following address:

Agency of Natural Resources
Department of Environmental Conservation
Wastewater Management Division
103 South Main Street

Waterbury, Vermont 05671-0405

All reports shall be signed:

a. In the case of corporations, by a principal executive officer of at least the level of vice president, or his/her duly authorized representative, if such representative is responsible for the overall operation of the facility from which the discharge described in the permit form originates;

b. In the case of a partnership, by the general partner;

c. In the case of a sole proprietorship, by the proprietor;

d. In the case of a municipal, state, or other public facility, by either a principal executive officer, ranking elected official, or other duly authorized employee.

3. **Recording of Results**

The permittee shall maintain records of all information resulting from any monitoring activities required including:

a. The exact place, date, and time of sampling;
b. The dates and times the analyses were performed;
c. The person(s) who performed the analyses;
d. The analytical techniques and methods used including sample collection, handling, and preservation techniques;
e. The results of all required analyses;
f. The records of monitoring activities and results, including all instrumentation and calibration and maintenance records;
g. The original calculation and data bench sheets of the operator who performed analysis of the influent or effluent pursuant to requirements of Section I.A of this permit.

The results of monitoring requirements shall be reported (in the units specified) on the Vermont reporting form WR-43 or other forms approved by the Secretary.

4. **Additional Monitoring**

If the permittee monitors any pollutant at the location(s) designated herein more frequently than required by this permit, using approved analytical methods as specified above, the results of such monitoring shall be included in the calculation and reporting of the values required in the Discharge Monitoring Report. Such increased frequency shall also be indicated.

PART II

A. MANAGEMENT REQUIREMENTS

1. Facility Modification / Change in Discharge

All discharges authorized herein shall be consistent with the terms and conditions of this permit. Such a violation may result in the imposition of civil and/or criminal penalties as provided for in Section 1274 and 1275 of the Vermont Water Pollution Control Act. Any anticipated facility expansions, production increases, or process modifications which will result in new, different, or increased discharges of pollutants must be reported by submission of a new permit application or, if such changes will not violate the effluent limitations specified in this permit, by notice to the permit issuing authority of such changes. Following such notice, the permit may be modified to specify and limit any pollutants not previously limited.

2. Noncompliance Notification

In the event the permittee is unable to comply with any of the conditions of this permit due among other reasons, to:

a. breakdown or maintenance of waste treatment equipment (biological and physical-chemical systems including, but not limited to, all pipes, transfer pumps, compressors, collection ponds or tanks for the segregation of treated or untreated wastes, ion exchange columns, or carbon absorption units),

b. accidents caused by human error or negligence, or

c. other causes such as acts of nature,

the permittee shall notify the Secretary within 24 hours of becoming aware of such condition or by the next business day and shall provide the Secretary with the following information, in writing, within five (5) days:

i. cause of non-compliance

ii. a description of the non-complying discharge including its impact upon the receiving water;

iii. anticipated time the condition of non-compliance is expected to continue or, if such condition has been corrected, the duration of the period of non-compliance;

iv. steps taken by the permittee to reduce and eliminate the non-complying discharge; and

v. steps to be taken by the permittee to prevent recurrence of the condition of non-compliance.

3. **Operation and Maintenance**

All waste collection, control, treatment. And disposal facilities shall be operated in a manner consistent with the following:

a. The permittee shall, at all times, maintain in good working order and operate as efficiently as possible all treatment or control facilities or systems installed or used by the permittee to achieve compliance with the terms and conditions of this permit; and

b. The permittee shall provide an adequate operating staff which is duly qualified to carry out the operation, maintenance, and testing functions required to insure compliance with the conditions of this permit.

4. **Quality Control**

The permittee shall calibrate and perform maintenance procedures on all monitoring and analytical instrumentation at regular intervals to ensure accuracy of measurements or shall ensure that both activities will be conducted.

The permittee shall keep records of these activities and shall provide such records upon request of the Secretary.

The permittee shall analyze any additional samples as may be required by the Agency of Natural Resources to ensure analytical quality control.

5. **Bypass**

The diversion or bypass of facilities necessary to maintain compliance with the terms and conditions of this permit is prohibited, except where authorized under terms and conditions of an emergency pollution permit issued pursuant to 10 V.S.A. Section 1268.

6. **Duty to Mitigate**

The permittee shall take all reasonable steps to minimize or prevent any adverse impact to waters of the State resulting from non-compliance with any condition specified in this permit, including accelerated or additional monitoring as necessary to determine the nature and impact of the non-complying discharge.

7. **Records Retention**

All records and information resulting from the monitoring activities required by this permit including all records of analyses performed, calibration and maintenance of instrumentation, and recordings from continuous monitoring instrumentation shall be retained for a minimum of three (3) years, and shall be submitted to Department representatives upon request. This period shall be extended during the course of unresolved litigation regarding the discharge of pollutants or when requested by the Secretary.

8. **Solids Management**

Collected screenings, sludges, and other solids removed from liquid wastes shall be stored, treated and disposed of in accord with the terms and conditions of any certification, interim or final, transitional operation authorization or order issued pursuant to 10 V.S.A., Chapter 159 that is in effect on the effective date of this permit or is issued during the term of this permit.

9. **Emergency Pollution Permits**

Maintenance activities, or emergencies resulting from equipment failure or malfunction, including power outages, which result in an effluent which exceeds the effluent limitations specified herein, shall be considered a violation of the conditions of this permit, unless the permittee immediately applies for, and obtains, an emergency pollution permit under the provisions of 10 V.S.A., Chapter 47, Section 1268. The permittee shall notify the Department of the emergency situation within 24 hours.

10 V.S.A., Chapter 47, Section 1268 reads as follows:

"When a discharge permit holder finds that pollution abatement facilities require repairs, replacement, or other corrective action in order for them to continue to meet standards specified in the permit, he may apply in the manner specified by the Secretary for an emergency pollution permit for a term sufficient to effect repairs, replacements or other corrective action. The permit may be issued without prior public notice if the nature of the emergency will not provide sufficient time to give notice; provided that the Secretary shall give public notice as soon as possible but in any event no later than five days after the effective date of the emergency pollution permit. No emergency pollution permit shall be issued unless the applicant certifies and the Secretary finds that:

(1) there is no present, reasonable alternative means of disposing of the waste other than by discharging it into the waters of the State during the limited period of time of the emergency;

(2) the denial of an emergency pollution permit would work an extreme hardship upon the applicant;

(3) the granting of an emergency pollution permit will result in some public benefit;

(4) the discharge will not be unreasonably harmful to the quality of the receiving waters;

(5) the cause or reason for the emergency is not due to willful or intended acts or omissions of the applicant."

Application shall be made to the Secretary of the Agency of Natural Resources, Department of Environmental Conservation, Wastewater Management Division, 103 South Main Street, Waterbury, Vermont 05671-0405.

10. **Power Failure**

In order to maintain compliance with the effluent limitations and prohibitions of this permit, the permittee shall either:

a. Provide an alternative power source sufficient to operate the wastewater control facilities; or, if such alternative power source is not in existence,

b. Halt, reduce, or otherwise control production and/or all discharges upon the reduction, loss, or failure of the primary source of power to the wastewater control facilities.

B. RESPONSIBILITIES

1. Right of Entry

The permittee shall permit the Secretary or authorized representative, upon presentation of proper credentials:

a. to enter upon the permittee's premises where an effluent source or any records required to be kept under the terms and conditions of this permit are located; and

b. to have access to and copy any records required to be kept under the terms and conditions of this permit;

c. to inspect any monitoring equipment or method required in this permit; or

d. to sample any discharge of pollutants.

2. Transfer of Ownership or Control

This permit is not transferable without prior written approval of the Secretary. All application and operating fees must be paid in full prior to transfer of this permit. In the event of any change in control or ownership of facilities from which the authorized discharges emanate, the permittee shall provide a copy of this permit to the succeeding owner or controller and shall send written notification of the change in ownership or control to the Secretary. The permittee shall also inform the prospective owner or operator of their responsibility to make an application for transfer of this permit. This application must include as a minimum; a written statement from the prospective owner or operator certifying:

a. The conditions of the operation that contribute to, or affect, the discharge will not be materially different under the new ownership.

b. The prospective owner or operator has read and is familiar with the terms of the permit and agrees to comply with all terms and conditions of the permit.

c. The prospective owner or operator has adequate funding to operate and maintain the treatment system and remain in compliance with the terms and conditions of the permit.

d. The date of the sale or transfer of the business.

The Department may require additional information dependent upon the current status of the facility operation, maintenance, and permit compliance.

3. **Confidentiality**

Pursuant to 10 V.S.A. 1259(b):

"Any records, reports or information obtained obtained under this permit program shall be available to the public for inspection and copying. However, upon a showing satisfactory to the secretary that any records, reports or information or part thereof, other than effluent data, would, if made public, divulge methods or processes entitled to protection as trade secrets, the secretary shall treat and protest those records, reports or information as confidential. Any records, reports or information accorded confidential treatment will be disclosed to authorized representatives of the state and the United States when relevant to any proceedings under this chapter."

4. **Permit Modification**

After notice and opportunity for a hearing, this permit may be modified, suspended, or revoked in whole or in part during its term for cause including, but not limited to, the following:

a. Violation of any terms or conditions of this permit;

b. Obtaining this permit by misrepresentation or failure to disclose fully all relevant facts; or

c. A change in any condition that requires either a temporary or permanent reduction or elimination of the authorized discharge.

5. **Toxic Effluent Standards**

If a toxic effluent standard or prohibition (including any schedule of compliance specified in such effluent standard or prohibition) is established under Section 307 (a) of the Federal Clean Water Act for a toxic pollutant which is present in the discharge, and such standard or prohibition is more stringent than any limitation for such pollutant in this permit, the secretary shall revise or modify the permit in accordance with the toxic effluent standard or prohibition and so notify the permittee.

6. **Oil and Hazardous Substance Liability**

Nothing in this permit shall be construed to preclude the institution of legal action or relieve the permittee from any responsibilities, liabilities, or penalties to which the permittee is or may be subject under 10 V.S.A. Section 1281.

7. **Civil and Criminal Liability**

Except as provided in permit conditions on <u>Bypass</u> (Part II, A. 5.), <u>Power Failure</u> (Part II, A. 10.), and <u>Emergency Pollution Permits</u> (Part II, A. 9.), nothing in this permit shall be construed to relieve the permittee from civil or criminal penalties for noncompliance. Civil penalties as authorized under 10 V.S.A. §1274 and 10 V.S.A. §8010, shall not exceed $10,000 a day for each day of violation. Criminal penalties, as authorized under 10 V.S.A. §1275, shall not exceed $25,000 for each day of violation, imprisonment for up to six months, or both.

8. **State Laws**

Nothing in this permit shall be construed to preclude the institution of any legal action or relieve the permittee from any responsibilities, liabilities, or penalties established pursuant to any applicable State law or regulation under authority preserved by Section 510 of the Clean Water Act.

9. **Property Rights**

Issuance of this permit does not convey any property rights in either real or personal property, or any exclusive privileges, nor does it authorize any injury to private property or any invasion of personal rights, nor any infringement of Federal, State, or local laws or regulations.

10. **Severability**

The provisions of this permit are severable, and if any provision of this permit, or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby.

11. **Authority**

This permit is issued under authority of 10 V.S.A. Section 1259 which states that: "No person shall discharge any waste, substance, or material into waters of the State, nor shall any person discharge any waste, substance, or material into an injection well or discharge into a publicly owned treatment works any waste which interferes with, passes through without treatment, or is otherwise incompatible with those works or would have a substantial adverse effect on those works or on water quality, without first obtaining a permit for that discharge from the Secretary", and under the authority of Section 402 of the Clean Water Act, as amended.

PART III

A. OTHER REQUIREMENTS

This permit shall be modified, suspended or revoked to comply with any applicable effluent standard or limitation issued or approved under Sections 301(b)(2)(C) and (D), 304(b)(2), and 307(a)(2) of the Clean Water Act, if the effluent standard or limitation so issued or approved:

1. Contains different conditions or is otherwise more stringent than any effluent limitation in the permit; or

2. Controls any pollutant not limited in the permit.

The permit as modified or reissued under this paragraph shall also contain any other requirements of the Vermont Water Pollution Control Act then applicable.

B. DEFINITIONS

For purposes of this permit, the following definitions shall apply:

The Act - The Vermont Water Pollution Control Act, 10 V.S.A. Chapter 47.

Average - The arithmetic mean of values taken at the frequency required for each parameter over the specific period.

The Clean Water Act - The federal Clean Water Act, as amended.

Composite Sample - A sample consisting of a minimum of one grab sample per hour collected over a normal operating day and combined proportional to flow, or a sample continuously collected proportional to flow over a normal operating day.

Daily Discharge - The discharge of a pollutant measured during a calendar day or any 24 hour period that reasonably represents the calendar day for purposes of sampling.

For pollutants with limitations expressed in pounds, the daily discharge is calculated as the total pounds of pollutants discharged over the day.

For pollutants with limitations expressed in mg/l, the daily discharge is calculated as the average measurement of the pollutant over the day.

Grab Sample - An individual sample collected in a period of less than 15 minutes.

Maximum Day (maximum daily discharge limitation) - The highest allowable "daily discharge" (mg/l, lbs., or gallons).

Mean - The mean value is the arithmetic mean.

Monthly Average (average monthly discharge limitation) - The highest allowable average of daily discharges (mg/l, lbs., or gallons) over a calendar month, calculated as the sum of all daily discharges (mg/l, lbs.,or gallons) measured during a calendar month, divided by the number of daily discharges measured during that month.

NPDES - The National Pollutant Discharge Elimination System.

Secretary - The Secretary of the Agency of Natural Resources

Closed-Cycle Operation and Blowdown - The circulating water system mode in which water is circulated through the cooling towers to dissipate condenser heat. The only water discharged to the River during closed-cycle operation is the blowdown from the cooling towers except for minor leakage through the intake gates which is less than 1% of the circulating water flow. Blowdown refers to the water continuously removed from the cool side of the cooling tower collection basins to rid cooling towers of dissolved solids.

Instantaneous Maximum - A value not to be exceeded in any grab sample.

PART IV

ENVIRONMENTAL MONITORING STUDIES, CONNECTICUT RIVER

The environmental monitoring and studies specified in Part IV are intended to assure that the discharges authorized by this permit do not violate applicable Vermont Water Quality Standards and are not adverse to fish and other wildlife that inhabit the Connecticut River in and around the vicinity of Vernon.

In the event the US Fish and Wildlife Service determines that the field sampling activities as required in the **Larval Fish, Fish, Anadromous Fish,** and **Fish Impingement** sections of this permit may violate the applicable provisions of Endangered Species Act of 1973 as amended (16 USC 1531-43) the Agency, after consultation with other appropriate governing agencies, may direct the permittee to make changes and/or substitutions in the sampling protocol as required in this permit.

CONNECTICUT RIVER MONITORING

River Flow Rate

Frequency/Date: Once per hour - All months
Location: Vernon Dam
River flow data shall be tabulated based on data supplied by the Wilder Station.

Temperature

Frequency/Date: Once per hour - All months
Location: Stations 3 and 7
Water temperature shall be measured to within 0.1°F.

Frequency/Date: Once per hour - During fishway operation
Location: Vernon Fishway
Water temperature shall be measured to within 0.1°F. These data shall be collected only when the fishway is officially operating. Data shall be reported as hourly, daily, monthly means.

Water Quality Parameters

Frequency/Date: Once per month - All months
Location: Stations 3 and 7, and the Plant discharge
Water quality parameters shall be grab samples collected via monitor pumps or directly from the River for the following:

	Location		
Parameter	**Station 7**	**Discharge**	**Station 3**
Copper	*	*	*
Iron	*	*	*
Zinc	*	*	*

* Monitoring required only if Entergy Nuclear Vermont Yankee is operating during the specified sample period.

Macroinvertebrates

Macroinvertebrates shall be collected according to the following schedule:

Frequency/Date: June, August, and October (once each month)
Locations: Stations 2 and 3

Cage samplers shall be deployed in June, August, and October. Multiple samplers (minimum of three) should be set at each deployment. Physical characteristics at deployment sites should be standardized between stations to the greatest extent possible. Final sampling plan to be approved by the DEC.

Larval Fish

Larval fish shall be collected when the plant cooling water intake is operating in open/hybrid cycle according to the following schedule and methods:

Frequency/Date: Weekly - May through July 15
Location: Connecticut River adjacent to the plant intake

Collect three plankton net samples on the same day in each week. The net shall be deployed as close as possible to the intake allowing each sample to be representative of the water column, bottom to surface. The volume sampled shall be measured with a flow meter mounted near the net mouth and used to calculate the density of larval fish in each tow. Larval fish shall be identified to the lowest distinguishable taxonomic level and enumerated.

With the written concurrence of the Agency, the sampling method may be modified or replaced.

Fish

Fish shall be collected according to the following schedule and methods:

Frequency/Date: Monthly - May, June, September, and October
Locations: Connecticut River at Rum Point; Station 5; N.H. Setback; 0.1 mile south of the Vernon Dam; Station 3; Stebbin Island; and, Station 2

Fish shall be collected at each location with boat mounted electrofishing gear. All fish caught shall be identified, enumerated to the lowest distinguishable taxonomic level, and measured for length and weight. A representative sample of American Shad and Atlantic Salmon shall be scaled for annuli determination of age. Catch-per-unit-of-effort (CPUE) shall be calculated for each species sampled.

Anadromous Fish

Juvenile and adult American shad shall be monitored according to the following schedule:

Frequency/Date: Twice monthly - July through October
Locations: Connecticut River 0.1 mile south of Vernon Dam; Station 3; and Stebbin Island

Juvenile shad shall be collected at each location with boat mounted electrofishing gear. All captured juvenile American shad shall be identified, enumerated, and measured for length and weight. Catch-per-unit-of-effort shall be calculated.

Frequency/Date: Twice monthly - July through October
Location: Connecticut River between Vernon Dam and the confluence of the West River

Collect 20 beach seine hauls and 12 surface trawl tows (utilizing midwater trawl tow gear) per sampling event. All fish caught shall be identified, enumerated to the lowest distinguishable taxonomic level, and measured for length and weight. Catch-per-unit-of-effort shall be calculated for American shad.

Frequency/Date: Weekly - May 15 through June
Location: Vernon Fish Ladder

Adult American shad shall be sampled in the fish trap and enumerated, measured for length and weight and evaluated for sex and sexual condition. Scale samples shall be taken from each fish and used for annuli determination of age.

All sampling activities at the Vernon Fish Ladder are under the direction of the Vermont Department of Fish & Wildlife.

Fish Impingement

Impingement samples shall be collected when the plant cooling water intake is operating in open/hybrid cycle according to the following schedule and methods:

Frequency/Date: Weekly - April 1 through June 15; August 1 through October 31
Locations: Circulating water traveling screens

Prior to the start of each weekly sample, the three circulating water screens shall be backwashed and the debris removed. Debris shall be examined for American shad and Atlantic salmon. On the following day, the three circulating water screens shall be backwashed and the debris shall be sorted to remove all impinged fish. Fish shall be identified to the lowest distinguishable taxonomic level, enumerated, measured for total length and weighed.

Standard Operating Procedures

Field sampling required as specified in the **Macroinvertebrates, Larval Fish, Fish, Anadromous Fish,** and **Fish Impingement** sections shall be performed according to approved Standard Operating Procedures. A Standard Operating Procedures Manual describing the field sampling activities shall be provided to the Agency for review and approval prior to the start of field sampling.

Atlantic salmon: The plant shall revert to closed cycle if the annual Atlantic salmon impingement limit as determined by the U.S. Fish and Wildlife Service, is exceeded and shall remain on closed cycle until June 15 of the current calendar year. If any anadromous Atlantic salmon are impinged, the Vermont Department of Fish and Wildlife shall be notified.

1. If Atlantic salmon are impinged, the frequency of impingement sampling shall increase to daily sampling when either of the following criteria are met:

   a. when any daily impingement of Atlantic salmon exceeds 10% of the annual impingement limit or,

   b. when 50% or more of the annual limit have been exceeded during the current year.

   Daily impingement sampling shall continue until three consecutive daily samples have been collected and no Atlantic salmon obtained. Sampling frequency shall then revert to weekly sampling.

2. If the criteria listed above are not met, impingement sampling will remain on a weekly schedule.

The maximum number of Atlantic salmon which can be impinged by Entergy Nuclear Vermont Yankee, LLC during a calendar year is determined by:

Impinged Atlantic salmon limit = 0.001 x (smolt equivalents)

Smolt equivalents (SE) are defined as:

$$SE = SE_F + SE_P + SE_S + SE_N$$

where:

SE_F is defined as the total number of smolt equivalents available from fry plants upstream of Vernon Dam. This number is calculated by:

$$SE_F = 0.0675 \times (\text{two year previous fry})$$

Two year previous fry is defined as the total number of fry stocked upstream of the Vernon Dam two years previous.

SE_P is defined as the total number of smolt equivalents available from parr plants upstream of the Vernon Dam. This number is calculated by:

SE_P = [(0.25 x (yearling parr)) + (0.11 x (two-year previous under yearling)]

Yearling parr is defined as the total number of 1+ parr stocked upstream of the Vernon Dam during the previous calendar year.

Two-year previous under yearling parr is defined as the total number of 0+ parr stocked two years previous.

SE_S is defined as the total number of smolt equivalents available from smolt stocked upstream of Vernon Dam. This number is calculated by:

SE_S = 1 x (smolts stocked)

Smolts stocked is defined as the total number of smolts stocked upstream during the current monitoring year.

SE_N is defined as the total number of smolt equivalents available from natural reproduction upstream of Vernon Dam. This number is calculated by:

SE_N = 0.58 x 7000 x 0.01 x (adult salmon)

0.58 represents 58% of the run as female.
7000 represents the average number of eggs per female.
0.01 represents a 1% survival of eggs to the smolt stage.
Adult salmon is defined as the number of adult salmon passed through the Vernon Fishway three years previous.

American shad: The plant shall revert to closed cycle if the annual American shad impingement limit, as determined by the U.S. Fish and Wildlife Service, is exceeded and shall remain on closed cycle until November 15 of the current calendar year. If any anadromous American shad are impinged, the Vermont Department of Fish and Wildlife shall be notified.

1. If 50% or more of the annual limit have been exceeded during the current year, impingement sampling frequency shall increase to daily sampling upon the impingement of any American shad and continue until three consecutive daily samples not containing these fishes are obtained. Sampling would then revert back to weekly sampling.

2. If the above criterion is not met, impingement sampling shall remain on a weekly schedule.

The maximum number of American shad which can be impinged by Entergy Nuclear Vermont Yankee, LLC during a calendar year is determined by:

Impinged American shad limit = 1 x number of American shad

The number of American shad is defined as the number of American shad passed at the Vernon fish ladder or otherwise introduced above Vernon Dam during the calendar year.

No Adverse Impact on Biota Evaluation:

The above task-oriented monitoring program defines a minimal data collection study on the water quality and biota adjacent to the plant. In order to demonstrate that the operation of the plant does not result in an adverse effect on fish and other wildlife, including their value as fish and game and their habitat and ecology, additional objective specific studies and data evaluation may be required. These additional study topics would be as a result of changes observed during the task-oriented program and/or Environmental Advisory Committee (EAC) concerns raised for fish or other biota.

The EAC (in conjunction with the Vermont Department of Fish and Wildlife) may modify the fish sampling protocol if it has been determined that the impact on biota adjacent to the plant may be adversely affected. The modifications shall be made in writing and submitted to the DEC and Entergy Nuclear Vermont Yankee, LLC.

Objective specific investigations would be defined and reviewed by the EAC annually. A draft proposal for the following years studies, if any, would be submitted by Entergy Nuclear Vermont Yankee, LLC to the EAC for review by October 1 of the current year. A progress report on studies conducted during the current year would be submitted by Entergy Nuclear Vermont Yankee, LLC to the EAC by February 1. Proposed changes to the draft proposal would by submitted by March 1.

Macroinvertebrate Investigation - During 2002-03 Entergy Nuclear Vermont Yankee, LLC shall complete a study on the macroinvertebrate populations in the Vernon Pool. Specifics of the study shall be coordinated between the Department of Environmental Conservation and Entergy Nuclear Vermont Yankee, LLC prior to commencement of the study.

The Department may amend this permit to include other specific EAC investigations.

DOCKETED
USNRC

October 19, 2005 (12:47pm)

OFFICE OF SECRETARY
RULEMAKINGS AND
ADJUDICATIONS STAFF

UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

Before the Atomic Safety and Licensing Board

In the Matter of	)	
	)	Docket No. 50-271
ENTERGY NUCLEAR VERMONT YANKEE, LLC and ENTERGY NUCLEAR OPERATIONS, INC.	)	ASLBP No. 04-832-02-OLA (Operating License Amendment)
(Vermont Yankee Nuclear Power Station)	)	

DECLARATION OF PAUL D. BAUGHMAN

Paul D. Baughman states as follows under penalties of perjury:

I. Introduction

1. I am currently employed as a Senior Consultant by ABSG Consulting Inc. ("ABS Consulting"). ABS Consulting provides risk assessment and mitigation services to government, corporate and energy clients worldwide. Our work includes, among other things, performing engineering assessments of the effects of extreme loadings – such as earthquake, high wind and explosion loadings – on facility structures and systems.

2. My professional and educational experience is summarized in the *curriculum vitae* attached as Exhibit 1 to this declaration. Briefly summarized, I have engaged in earthquake engineering activities related to commercial and nuclear structures and systems for over 35 years. I received B.S. and M.S. Degrees in Civil Engineering from Northeastern University and am a registered professional structural engineer in Massachusetts.

3. I am providing this declaration in support of the response of Entergy Nuclear Vermont Yankee LLC and Entergy Nuclear Operations, Inc. ("Entergy") to the "New England Coalition's Request for Leave to File a New Contention" in the above captioned proceeding

regarding the proposed extended power uprate ("EPU") of the Vermont Yankee Nuclear Power Station ("VY").

4. In September 2004 ABS Consulting was engaged by Entergy to perform a seismic evaluation of the Seismic Class I cooling tower cells at the VY site. (Seismic Class I structures are those designed to withstand the loadings produced by a design basis earthquake.) The scope of the evaluation included reviewing drawings, documentation and previous analyses furnished by Entergy; recommending an appropriate analysis methodology; determining cooling tower properties, method of construction and design details; preparing finite element models of the cooling tower wood framing; performing dynamic seismic analysis of the cooling tower cells for the VY design basis earthquake loadings; and evaluating loads and stresses in framing members and connections and comparing them against allowable limits. In April 2005 ABS Consulting was engaged by Entergy to perform a seismic evaluation of the Seismic Class II cooling tower cells. The scope of this evaluation was similar to the evaluation of the Seismic Class I cells except that the analysis was a static coefficient Uniform Building Code analysis as per the VY Seismic Class II requirement.

5. There are two cooling towers at VY, designated as the "East" and "West" towers or Cooling Tower No. 1 and Cooling Tower No. 2, located at the south end of the VY site. Each cooling tower contains two large pipes running along its length that distribute heated water from the plant condenser among the cells. The water drains down through plastic fill material to a basin underneath each tower, where it is piped to the plant discharge structure. As the water falls through the fill, it is broken up into small droplets and is cooled by ambient air. An induced draft fan located on the top center of each cell draws air through the fill to obtain maximum cooling of the water.

6. One cell in the north end of the West Cooling Tower (cell CT2-1) is known as the "Alternate Cooling System cell" because it houses a portion of the Alternate Cooling System ("ACS"), a system that provides an alternate means of cooling in the event that the Service Water pumps become unavailable. The Alternate Cooling System cell, the cell adjacent to it (CT2-2), and the Cooling Water Deep Basin in the West Cooling Tower are designated as

Seismic Class I and as such are designed to withstand the design basis earthquake loadings. The remaining cooling tower cells are designed as Seismic Class II structures.

7. ABS Consulting performed separate structural and seismic analyses of the Seismic Class I cells and the remaining cells in the towers. The analyses include the loads associated with the 200 HP fans and their associated support equipment that Entergy installed in 21 of the 22 cells as part of the EPU modifications. The structural and seismic analysis of the cooling tower Seismic Class I cells is contained in Calculation No. 1356711-C-001, *Cooling Tower Seismic Calculation* (Rev. 1), which was approved by Entergy on April 12, 2005, as VYC-2413, Rev. 0 ("Seismic Calculation"). I understand that a copy of the Seismic Calculation has been filed by Entergy in this proceeding. A separate calculation describes our analysis of the remaining (Seismic Class II) cells in the West and East Cooling Towers. *See* Calculation No. 1356711- C-002, *Non Safety Cooling Tower Seismic Evaluation* (Rev. 0), performed by ABS Consulting and approved by Entergy on April 28, 2005, as VYC-2412, Rev. 0.

8. Our scope of work included performing a walkdown inspection of the cooling towers to confirm their physical condition and validate our modeling assumptions. Richard Augustine, Principal Engineer of ABS Consulting, and I visited the VY site on March 29-30, 2005. The purpose of our site visit was to perform a visual inspection of each cell in each cooling tower. We inspected the towers to verify that the arrangement, member sizes, and connections details of the load bearing members were as shown on the drawings. Other purposes of the inspection were to verify that the modeling assumptions in our calculations were reasonable, and to verify the general condition of the tower structures.

9. Our inspection verified that, in all but one instance, the installed configuration matched that shown in the cooling tower design drawings. One connection detail was found that did not agree with the drawings. This finding was communicated to Entergy for correction. Project records (Corrective Action Report CR-VTY-2005-01299) document that this condition was corrected in April 2005, shortly after we identified it.

10. Our inspection of the condition of the structural components of the cooling towers and the accessible portions of the concrete foundations determined that these structures and components were in acceptable physical condition. In particular, we confirmed that the concrete

in the tower foundations showed no signs of degradation and that the anchor bolts securing the towers to the foundations were in sound condition.

11. I understand that NEC questions the failure to include in the Seismic Calculation the loadings on the tie rods connecting seismic and non-seismic cells. The tie rods in question are multiple "breakaway ties" located in cell CT2-3 of the West Cooling tower. They are not tie rods made out of steel, but are wooden splice blocks connected across cut-through joints in the horizontal members in the longitudinal bents. They are not bolted to the members but attached to them with nails. These nailed wood splices are designed to break in a seismic event, thus detaching the Seismic Class II cells CT2-3 to CT2-11 from the Seismic Class I cells CT2-1 and 2-2 of the west cooling tower.

12. The Seismic Calculation did not include these breakaway ties as load bearing elements, because it only considered bolted structural connections as load bearing. The reason for excluding these nailed connections is that they have small load carrying capacity compared to bolted connections. As their name implies, these breakaway ties will break loose at the onset of a seismic event and will not transmit loadings from the Seismic Class II cells to the Seismic Class I cells.

13. NEC also alleges that horizontal forces will be transmitted to the Alternate Cooling System cell "through sixty-inch diameter heavy wall (1.2" thick) header pipe." However, this statement is technically incorrect. The piping in question (the circulating water distribution header) is made of fiberglass (not steel), and has only a ½" wall thickness. Thus, the piping is not strong enough to transmit horizontal loads from one cell to another, and can be disregarded in the analysis. In addition, the pipe is constructed with bell and spigot type joints, such that during seismic conditions the pipe will pull apart at the joints rather than transferring longitudinal loads from one cell to another. Thus, it was appropriate not to include in the Seismic Calculation the transmission of seismic forces to the Seismic Class I cells through the header piping.

14. The Seismic Calculation demonstrates that there is no need for structural modifications to the Alternate Cooling System cell or the cell adjoining it, and that these two cells are adequate for the design basis earthquake loadings under EPU conditions.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on October 17, 2005.

Paul D. Baughman

ABS Consulting

PAUL D. BAUGHMAN

PROFESSIONAL HISTORY

ABS Consulting (formerly EQE International), Stratham, New Hampshire, Vice President and Senior Consultant, 1987-present

Cygna Energy Services, Boston, Massachusetts, Vice President Engineering Mechanics, 1980-1987

Yankee Atomic Electric Company, Westboro, Massachusetts, Senior Structural Engineer, 1976-1980

Stone & Webster Engineering Corp., Boston, Massachusetts, Mechanical/Structural Engineer, 1969-1976

SUMMARY

Mr. Baughman has 35 years of professional engineering and project management experience with industrial and power plant structures, systems and equipment. He has held a variety of positions encompassing structural and mechanical design, safety and risk evaluations, and regulatory interface. He has actively participated in research into the effects of earthquakes on structures, piping and equipment.

PROFESSIONAL EXPERIENCE

Mr. Baughman is a senior consultant in ABS Consulting's Northeast Regional Office. He manages structural engineering and evaluation programs, safety and reliability assessments, earthquake verification programs, and risk evaluations. He is the ABS Consulting program manager for the EPRI Seismic Qualification Utility Group (SQUG), which sponsors the application of earthquake experience data for seismic verification of nuclear power plant piping and equipment. He serves as a subject matter expert for training programs given by SQUG. He has also participated in post-earthquake reconnaissance at several earthquake sites, and in development of the electronic earthquake experience database. He has acted as project manager for seismic PRA/margins assessments at Indian Point 2, Three Mile Island, Oyster Creek, Calvert Cliffs, Pickering A and Bruce A nuclear power plants, and was a peer reviewer for the Oconee, Vermont Yankee and Maine Yankee plants. International projects have included seismic margin reviews of Pickering A and Bruce A in Canada, Kozloduy in Bulgaria, Paks in Hungary and Bohunice in Slovakia.

Piping assessments have included seismic analyses of reactor primary coolant piping, vessels and components at Pickering A, Bruce A, TMI Unit 2 and Seabrook. Other piping assessment projects have included the D.C. Cook Small Bore Piping Confirmation Program, the Connecticut Yankee Piping Seismic Margins project, the Princeton Tokamak Fusion Test Reactor Tritium Handling Systems Review, EDF Bugey VD3 Piping Assessment, Bruce A High Energy Piping, Pickering A Moderator Piping, Darlington Non-Qualified Piping Review, Paks Feedwater Piping Assessment, and MSIV Alternate Leakage Path Assessments for Vermont Yankee, Hatch, Duane Arnold Peach Bottom, Brunswick, and Oyster Creek.

He has performed mechanical equipment seismic evaluations for Boston Edison, Maine Yankee, Public Service of New Hampshire, Consolidated Edison, Gulf States Utilities, Rochester Gas and Electric, Southern Electric International, Virginia Power, Ontario Hydro, Public Service Electric and Gas, and GPU Nuclear; electrical equipment seismic evaluations for Vermont Yankee, Boston Edison, Maine Yankee, GPU Nuclear, Philadelphia Electric, Virginia Power, Rochester Gas and Electric, and Consolidated Edison; and piping seismic evaluations for Vermont Yankee, Tennessee Valley Authority, Ontario Hydro, Princeton Plasma Physics Laboratory, Westinghouse Savannah River, Rochester Gas and Electric, Public Service Electric and Gas, American Electric Power, Northeast Utilities, and Mesquite Lake Resource Recovery Center.

He has performed seismic verifications of cable tray, conduit, instrument tubing, and ductwork for Southern Nuclear, Princeton Plasma Physics Laboratory, Tennessee Valley Authority, Public Service of New Hampshire, Consolidated Edison, GPU Nuclear, and Rochester Gas and Electric.

He has prepared procedures for seismic technical evaluation of replacement items (STERI) for Bruce Power, Maine Yankee, GPU Nuclear and Virginia Power, and presented training in STERI at Virginia Power, GPU Nuclear and Rochester Gas and Electric. He is a SQUG trainer for the SQUG New and Replacement Equipment course.

At Cygna Energy Services, Mr. Baughman managed structural and mechanical activities for the eastern United States. He directed technical activities at more than 30 nuclear plants, including seismic evaluations of critical structures, piping, and equipment. Assignments included failure modes and effects analysis (FMEA) for high energy piping, probabilistic risk evaluation of the reactor containment and code reconciliation of Class 1,2 and 3 piping systems at Seabrook Station, resolution of Bulleting 80-11 (masonry walls) at Pilgrim, Millstone 1, Vermont Yankee and Maine Yankee, and FMEA of spent fuel cask handling systems at Yankee Rowe. He also provided licensing consultation services related to structural and mechanical issues for Yankee Rowe, Vermont Yankee, Maine Yankee, Pilgrim, Millstone Units 1 and 2, Seabrook, Three Mile Island Unit 1, Davis-Besse, and R. E. Ginna.

While at Yankee Atomic, Mr. Baughman was responsible for many structural and mechanical issues, including seismic upgrade of structures and equipment, spent fuel pool modifications at Yankee Rowe, and spent fuel storage expansions at Vermont Yankee, Pilgrim, and Maine Yankee. Spent fuel pool modifications at Yankee Rowe required FMEA of the 75-ton overhead crane and evaluation of smaller cranes used during construction or operation. Spent fuel storage expansions required FMEA of the spent fuel storage pools, fuel handling systems, and movement of heavy loads near stored fuel. Mr. Baughman also performed a structural safety evaluation of the polar crane in the reactor containment at Maine Yankee. He was a member of the Nuclear Safety Audit and Review Committee for Maine Yankee.

With Stone & Webster, Mr. Baughman carried out a variety of design assignments on nuclear plants under construction in the Mechanical Analysis and Structural Mechanics groups, including containment design, building seismic analysis, generation of floor response spectra, and equipment seismic qualification.

EDUCATION

Northeastern University: M.B.A., 1984

Northeastern University: M.S. Civil Engineering, 1978

Northeastern University: B.S. Civil Engineering, 1972

AFFILIATIONS

American Society of Civil Engineers

REGISTRATION

Structural Engineer: Massachusetts

TRAINING EXPERIENCE

EPRI SQUG Walkdown Training:

May 16-20, 2005, Ontario Power, Canada
May 3-7, 2004, Bruce Power, Canada
Feb 18-23, 2002, Rolls-Royce, UK
Jul 19-23, 1999, OPG, Canada

EPRI SQUG NARE Training:

Sep 23-24, 2003, Raleigh, NC
Nov 12-13, 2002, Alexandria, VA
Dec 6-7, 2001, Orlando, FL
Jul 23-24, 2001, Alexandria, VA
Nov 16-17, 2000, Atlanta, GA
Apr 10-11, 2000, Myrtle Beach, SC

Seismic Margins/Seismic PRA Training:

Nov 19-20, 1998, Point Lepreau, Canada
May 6-7, 28-29, 1998, AECL, Canada
Jun 17-21, 1997, KOPEC, ROK

Seismic Awareness Training:

Jun 8, 2004, Bruce Power, Canada

SMA Project Review Seminar:

Jul 21, 2004, Bruce Power, Canada
Jun 8, 2004, Bruce Power, Canada
Jul 24, 2002, Bruce Power, Canada
Nov 23, 1999, OPG Pickering, Canada

Earthquake Experience Database Training:

Aug 12, 1999, KEPRI, ROK

Tornado Analysis:

May 27, 1999, AECL, Canada

SELECTED PUBLICATIONS

With J. White, et.al., "Experience-Based Seismic Verification Guidelines for Piping Systems," EPRI 1012023, June 2005.

With S. Yim, et. al., "Experience Based Seismic Verification Guidelines for Overhead Crane Systems," EPRI 1012022, June 2005.

With F. Beigi, et. al., "Seismic Evaluation Guidelines for HVAC Duct and Damper Systems," EPRI 1007896, April 2003.

With K. Campbell, et. al., "Procedure for Derivation of Database Ground Motion," 8th NRC/ASME Symosium on Pump and Valve Testing, Washington, D.C., July 2004

With T. Adams, et. al., "An Update on the Implementation of Experience Based Seismic Equipment Qualification in the QME-1 Standard," ASME PVP Conference, Cleveland, Ohio, July 2003.

"RISC-3 EPRI Seismic Special Treatment Requirements Exemption Program," Panel Session: Performance Based Seismic Design of Equipment and Components, ASME PVP Conference, Cleveland, Ohio, July 2003.

With K.M. Sickles, "Application of Seismic Margin Methodology for Modification of Piping Systems," ASME Pressure Vessel and Piping Conference, Orlando, Florida, July, 1997.

With R.D. Campbell, P.J. Arnold, H. Schlund, T. Grief, "Application of GIP to Eastern European Reactors," ASME Pressure Vessel and Piping Conference, Orlando, Florida, July, 1997.

With S.A. Usmani, "Recommendations for Damping and Treatment of Modeling Uncertainty in Seismic Analysis of CANDU Nuclear Power Plant," ASME Pressure Vessel and Piping Conference, Montreal, Quebec, July, 1996.

With R. Campbell, T. Roche, S. Eder, R. Hookway. 1995. "Use of Seismic Experience Data for Seismic Verification of VVER Reactors." International Atomic Energy Agency Coordinated Research Program.

With J. Stoessel, M. Wright, L. Villani, L. Bragagnolo, R. Knott. 1994. "Test-Based Strength Criteria for Nonserrated Cable Tray Strut Nuts and Embedded Strut." Fifth Symposium on Current Issues Related to Nuclear Power Plant Structures, Equipment, and Piping with Emphasis on Resolution of Seismic Issues in Low-seismicity Regions.

With M. Aggarwal. 1989. "Seismic Evaluation of Piping Using Experience Data." ASME Pressure Vessels and Piping Conference, July 1989.

With H. Johnson, G. Hardy, and N. Horstman. 1989. "Use of Seismic Experience Data for Replacement and New Equipment." Second Symposium on Current Issues Related to Nuclear Power Plant Structures, Equipment, and Piping with Emphasis on Resolution of Seismic Issues in Low-seismicity Regions, May 1989.

With M. Aggarwal, S. Harris, and R. Campbell. 1990. "Seismic Evaluation of Piping Using Experience Data." Second Symposium on Current Issues Related to Nuclear Power Plant Structures, Equipment, and Piping with Emphasis on Resolution of Seismic Issues in Low-seismicity Regions.