RAS 9537

112 STATE STREET
DRAWER 20
MONTPELIER VT 05620-2601
TEL: (802) 828-2811

FAX: (802) 828-2342
TTY (VT): 1-800-734-8390
e-mail: vtdps@psd.state.vt.us
Internet: http://www.state.vt.us/psd

STATE OF VERMONT
DEPARTMENT OF PUBLIC SERVICE

DOCKETED
USNRC

March 7, 2005 (2:14 pm)

OFFICE OF SECRETARY
RULEMAKINGS AND
ADJUDICATIONS STAFF

March 7, 2005

Office of the Secretary of the Commission
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Attention: Rulemaking and Adjudications Staff

Re: Docket No. 50-271 - OLA
ASLBP No. 04-832-02-OLA
Extended Power Uprate at Vermont Yankee Nuclear Power Station

Dear Sir/Madam:

Please find enclosed for filing an original and two copies of the Vermont Department of Public Service Opposition to Entergy's Motion to Dismiss as Moot, or in the Alternative, for Summary Disposition of Department of Public Service Contention 6 with Attachments, Vermont Department of Public Service Response to Entergy's Statement of Material Facts of Which No Genuine Dispute Exists, and a Certificate of Service.

If you have any questions about this filing, please call me at 802-828-3088. Thank you for your assistance in making this filing.

Very truly yours,

Sarah Hofmann
Director for Public Advocacy

cc: As per Certificate of Service

Template = SECY-041

SECY-02

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	)	ASLBP No. 04-832-02-OLA
OPERATIONS, INC.	)	
(Vermont Yankee Nuclear Power Station)	)	

CERTIFICATE OF SERVICE

I hereby certify that copies of the Vermont Department of Public Service Vermont Department of Public Service Opposition to Entergy's Motion to Dismiss as Moot, or in the Alternative, for Summary Disposition of Department of Public Service Contention 6 with Attachments, Vermont Department of Public Service Response to Entergy's Statement of Material Facts of Which No Genuine Dispute Exists, and the accompanying cover letter in the above captioned proceeding has been served on the following by deposit in the United States Mail, first class, postage prepaid, and where indicated by asterisk by electronic mail, this 7th day of March, 2005.

Alex S. Karlin, Chair*
Administrative Judge
Atomic Safety and Licensing Board Panel
Mail Stop T-3 F23
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001
E-mail: ask2@nrc.gov

Lester S. Rubenstein*
Administrative Judge
Atomic Safety and Licensing Board Panel
4270 E. Country Villa Drive
Tuscon, AZ 85718
E-mail: lesrrr@comcast.net

Atomic Safety and Licensing Board
Mail Stop T-3 F23
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555-0001

Dr. Anthony J. Baratta*
Administrative Judge
Atomic Safety and Licensing Board Panel
Mail Stop T-3 F23
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001
E-mail: ajb5@nrc.gov

Office of the Secretary*
ATTN: Rulemaking & Adjudications Staff
Mail Stop: O-16 C1
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001
E-mail: HEARINGDOCKET@nrc.gov

Office of Commission Appellate Adj.
Mail Stop O-16 C1
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555-0001

Jay E. Silberg, Esq.*
Matias Travieso-Diaz, Esq.*
Douglas J. Rosinski, Esq.
Shaw Pittman, LLP
2300 N St., NW
Washington, DC 20037-1128
jay.silberg@shawpittman.com
matias.travieso-diaz@shawpittman.com

Brooke Poole, Esq.*
Robert Weisman, Esq.*
Marissa Higgins, Esq.*
Office of the General Counsel
Mail Stop 0-15 D21
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555-0001
bdp@nrc.gov
rmw@nrc.gov
Mch5@nrc.gov

Anthony Z. Roisman, Esq.*
National Legal Scholars Law Firm
84 East Thetford Rd.
Lyme, NH 03768
aroisman@valley.net

Jonathan M. Block, Esq.*
94 Main Street
P.O. Box 566
Putney, VT 05346-0566
jonb@sover.net

Raymond Shadis*
New England Coalition
P.O. Box 98
Shadis Road
Edgecomb, ME 04566
shadis@prexar.com

John M. Fulton, Esq.*
Assistant General Counsel
Entergy Nuclear Operations, Inc.
440 Hamilton Avenue
White Plains, NY 10601
jfulto1@entergy.com

Chris Wachter*
Atomic Safety and Licensing Board Panel
Mail Stop T-3F23
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001
cmw@nrc.gov

Jonathan Rund*
Atomic Safety and Licensing Board Panel
Mail Stop T-3F23
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001
Jmr3@nrc.gov

Respectfully submitted,

Sarah Hofmann
Director for Public Advocacy

UNITED STATES
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**
(Vermont Yankee Nuclear Power Station)	)	

VERMONT DEPARTMENT OF PUBLIC SERVICE OPPOSITION TO ENTERGY'S MOTION TO DISMISS AS MOOT, OR IN THE ALTERNATIVE, FOR SUMMARY DISPOSITION OF DEPARTMENT OF PUBLIC SERVICE CONTENTION 6

Although Entergy seeks dismissal of Contention 6 as moot or in the alternative for summary disposition, it is clear the relevant standards are those related to summary disposition motions. Indisputably Entergy has now submitted additional information but a dispute remains. First, the NRC Staff has not yet determined that the verification conducted by Entergy is the one it requires in order to comply with the requirements for a safe shutdown analysis (SSCA) for purposes of a 10 CFR Appendix R event. Second there remains a dispute as to whether the information submitted demonstrates that the "verification" required by the regulations of the effectiveness of Entergy procedures to cope with an Appendix R fire has been performed. As discussed below, the dispute arises because the operating procedures for which operators were trained (OP3126 (Rev. 17)) and under which a "verification" was conducted have been changed in a material way and are not the operating procedures which were identified by the NRC Inspection Team as requiring verification (OP3126 (Rev. 16). Since Vermont Department of

Public Service (DPS) Contention 6 is based, at least in part, on the information uncovered during the Inspection (see Vermont Department of Public Service Reply to Answer of Applicant to the Department's Request for Leave to File a New Contention at 3-4), the fact that Entergy has engaged in *a* "verification" under a materially different operating procedure, does not mean it has engaged in *the* "verification", the absence of which formed the basis for the Contention.

Whether Contention 6 should be summarily disposed of depends upon whether, based on the undisputed facts, the party seeking summary disposition has met its burden of demonstrating the lack of a genuine issue of material fact, construing the evidence submitted in favor of the non-moving party. *See Sequoyah Fuels Corp. and General Atomics Corp. (Gore, Oklahoma Site Decontamination and Decommissioning Funding*), LBP-94-17, 39 NRC 359, 361, aff'd, CLI-94-11, 40 NRC 55 (1994). The central issue of fact raised by Contention 6 is whether "Entergy completed the verification by individually training its six VY operator crews, and then having each of the crews perform the required actions, *all in accordance with documented procedures*". Entergy Motion at 6 (citations omitted, emphasis added).[1]

The issue underlying this Contention arose out of an NRC Inspection:

> During the period from August 9 through September 3, 2004, the US Nuclear Regulatory Commission (NRC) conducted a team inspection in accordance with Temporary Instruction 2515/158,

---

[1] DPS believes this articulation of the issue raised by Contention 6 is consistent with the Board's January 11, 2005 Memorandum and Order admitting the Contention and noting the scope of the Contention was limited to "the absence of the verification, not its quality". *Id.* at 7. If the verification procedures had been followed but done in a sloppy way or if the verification procedures, although met, are not sufficient assurance that in the event of an Appendix R fire, protective actions can be taken in a timely manner, DPS would have to amend the existing contention to raise those issues. But, an amendment is unnecessary because DPS and Entergy agree that unless *the* verification performed by Entergy followed "documented procedures", it was not *the* "verification", the absence of which formed the basis for the Contention.

> "Functional Review of Low Margin/Risk Significant Components and Human Actions," at the Vermont Yankee Nuclear Power Station.

NRC Inspection Report 05000271/2004008 (12/2/04)(Report) at i. Attached as Exhibit A. The portion of the Report relevant to Contention 6 found "the licensee did not adequately coordinate between the operations department and the engineering organization procedure revisions that increased the length of time required to place the reactor core isolation cooling system in service from the alternate shutdown panels. As a consequence, the licensee did not revise its Vermont Yankee Safe Shutdown Capability Analysis (SSCA)." *Id.* at 18.

During the Inspection, the NRC found:

> the team found that the licensee had not revised the December 1999 Vermont Yankee SSCA to reflect the June 2001 time estimate or present day version of the procedure to place RCIC in service from the alternate shutdown panels. The team also determined that the licensee's engineering organization was unaware that the time to complete the task had increased from approximately 15 to 21 minutes and had effectively reduced the time margin available for event mitigation from about 10 minutes to 4 minutes at the current full power level.
>
> ***
>
> the team concluded that for the proposed EPU, the ability to place the RCIC in service from the alternate shutdown panels (21 minutes) prior to reactor water level reaching the top of active fuel (21.3 minutes) is questionable..

Id. at 18-19.

In apparent response to the Inspection team concerns and even before the Report was issued, Entergy filed a notification to the NRC that it had "revised the procedure governing operator actions" in the event of an Appendix R fire and "is in the process of verifying" that it can meet Appendix R requirements under its new procedures. Letter of 9/30/04 (Exhibit 1 to

Entergy Motion).

On December 8, 2004, Entergy advised the NRC by letter that it had completed verifying compliance with Appendix R fire requirements and represented that it had now demonstrated it can comply with Appendix R if the proposed 20% uprate is approved. In correspondence between NRC Staff personnel and the Department, the Department has been advised that NRC review of the December 8 submittal by Entergy should be complete the week of March 21, 2005, and the Staff will be in a position to indicate whether it believes the concerns raised by the 2004 Inspection have been addressed. Affidavit of William Sherman (Attached as Exhibit B with NRC letter attached).

Entergy recognizes that a critical part of Contention 6 is the final acceptance by the NRC of the revised procedures and Entergy's proof that it can comply with the SSCA action in an Appendix R event by following those procedures. In its Statement of Material Facts On Which No Genuine Dispute Exists Entergy lists the following as one of the material facts:

> Entergy completed the verification program by the December 1, 2004 deadline it had committed to the NRC.

Id. at ¶ 9. NRC has yet to confirm that the information submitted to it by Entergy meets the commitment made to NRC by Entergy and until that confirmation is provided, there is no basis to conclude that Contention 6 has been resolved.

In light of these considerations and because the NRC Staff Inspection is the primary source of the expertise which underlies the concerns raised by Contention 6, DPS requests the Board postpone final action on the pending motion until the Staff has completed its review of Entergy's claimed Appendix R compliance. DPS is willing to agree that if the Staff concludes that Entergy has now demonstrated it has verified it can meet Appendix R requirements with regard to the length of time to place the RCIC in service from alternate shutdown panels, that summary disposition may be granted as to Contention 6. DPS is also willing to extend the stay of all discovery obligations under §2.336 until a final resolution of this issue by the Board.

There is good reason for the Board to stay its decision on Entergy's Motion. First, the amount of delay in reaching a decision will be small and does not come at a time in the case when any critical path item will be affected by the delay. Second, there are some highly technical questions raised by Entergy's submittal of its "verification" as to which the special expertise of the NRC Staff will be uniquely valuable. For example:

> 1. Entergy's Training Module for its operators included an actual timed walk-through. Licensed Operator Requal Training Program Instructor Guide (LOR-24-405-2, Rev. 0 10/04 at 2 ("Be able to conduct a walkthrough of the actions of OP 3126 with the goal of restoring AC power and starting RCIC injection to the vessel within 21 minutes."). Exhibit 3 to Entergy Motion. Entergy used this timed event, not one separate from the training program, as its proof that its operators could meet Appendix R.[2] The NRC Staff is most knowledgeable regarding the proper procedures to be used in conducting operator tests and can best determine whether the test results submitted qualify as "verification" of operator capability or merely evidence that the operators passed their training course.
>
> 2. Entergy revised the operating procedure OP 3126, Shutdown Using Alternate Shutdown Method (Rev. 17 (eff. date 9/30/04)) from the version which the Inspection Team reviewed during August 9 through September 3 site inspection. The revised

[2] Two documents submitted by Entergy as part of the record on Contention 6 provide evidence that Entergy operators may have difficulty demonstrating proficiency in tests under OP3126 where the timing of the tests is not closely coordinated with training programs they have passed: Vermont Yankee Training Change Request 04-0155 (TCR 04-0155) and Vermont Yankee Training Change Request 04-0160 (TCR 04-0160). Attached as Exhibits D and E. TCR 04-0155 identifies that three questions related to alternate shutdown (OP 3126) on operator biennial exams had high miss rates. TCR 04-0160 identifies that two operators failed job performance measures (JPM's) on the initial actions of OP 3126 on annual exams.

version removed several features designed to protect workers[3] and apparently, at least in part as a result of such modifications, the timed walk-through dropped from the 21 minutes observed by the Inspectors to 15 minutes. NRC Staff, particularly the Inspection Team, is best able to evaluate whether verifying compliance with the modified operating procedure satisfies its concerns with Appendix R compliance under uprate conditions

A summary disposition motion is to be decided pursuant to the provisions of §2.710. §2.1205(c). As indicated in the attached Affidavit of William Sherman, DPS cannot fully respond to Entergy's claim that what it has accomplished is *the* "verification" required by the NRC Inspection Report and intended by DPS Contention 6, until it has the benefit of disclosure of the portion of the NRC Staff Hearing File which contains the Staff review of the documents submitted by Entergy in support of their claim that they have accomplished the required

[3] At OP 3126, Rev. 17, page 6 of 8, the following two Precautions, which appear in OP3126, Rev. 16 (Attached as Exhibit C) are removed:

> 5. Exercise caution prior to entry into an unoccupied area since conditions associated with the emergency may dictate that protective equipment should be used.
>
> 6. Exercise caution and use protective equipment when replacing fuses or operating knife switches.

At OP 3126, Rev. 17, Appendix D, page 3 of 7, the words, "Don rubber gloves and", that appear in Rev. 16 (Attached as Exhibit C), are removed from the following procedural steps:

> 5. Don rubber gloves and, if necessary use a step stool and place the ALTERNATE/NORMAL control power knife switch for 480V Bus 9 (located inside the upper left-hand compartment of Bus 9) to ALTERNATE.
>
> 6. Don rubber gloves and, if necessary use a step stool and place the ALTERNATE/NORMAL control power knife switch for 480V Bus 4 (located inside the box behind Bus 4) to ALTERNATE.

"verification". Pursuant to §2.710(c) a basis for denial of summary disposition motion can be the absence of information needed by the party to fully respond to the motion. Recognizing the general rule that contentions may not be based upon the failure of NRC Staff to carry out their duties, DPS submits that this is not such a situation. In this case Contention 6 primarily exists because of an NRC inspection finding and Entergy's current filing is only valid evidence in opposition to that Contention if it in fact satisfies the Inspection concerns. Otherwise, Entergy will be back where it was in September of last year without an acceptable "verification" of compliance with Appendix R under uprate conditions. Entergy recognizes as much when it includes acceptance by NRC of its filing in December 2004 as one of the material facts upon which the Motion for Summary Disposition is based.

For these reasons, DPS requests the Board hold in abeyance its decision on whether to grant Entergy's Motion pending availability of the Staff's review of the Entergy submittal on its alleged compliance with the "verification" of its ability to meet Appendix R requirements.

Respectfully submitted,

Sarah Hofmann
Director for Public Advocacy
Department of Public Service
112 State Street - Drawer 20
Montpelier, VT 05602-2601

Anthony Z. Roisman
National Legal Scholars Law Firm
84 East Thetford Rd.
Lyme, NH 03768

Dated this 7th day of March 2005 at Montpelier, Vermont.

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

12/13/04

December 2, 2004

NVY 04-130

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 INSPECTION REPORT 05000271/2004008

Dear Mr. Thayer:

On September 3, 2004, the US Nuclear Regulatory Commission (NRC) completed an inspection at the Vermont Yankee Nuclear Power Station. The enclosed inspection report documents the inspection findings, which were discussed with members of your staff on September 3, October 27, and November 23, 2004.

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. In conducting the inspection, the team examined the adequacy of selected components and operator actions to mitigate postulated design basis accidents, both under current licensing and planned power uprated conditions. The inspection also reviewed Entergy's response to selected operating experience issues, and assessed the adequacy of Vermont Yankee's design and engineering processes.

The team concluded that the components and systems reviewed would be capable of performing their intended safety functions. The team also concluded that sufficient design controls had been implemented for design and engineering work, including that related to Entergy's extended power uprate. The team did identify several deficiencies related to design control at Vermont Yankee; however, sample based extent-of-condition reviews indicated the original problems were not widespread or programmatic in nature. In addition, some of the specific findings included topics that were within the scope of the NRC's power uprate review, and thus, will require the submittal of additional information to the NRC's technical staff to support that review.

The enclosed report documents eight findings of very low safety significance (Green), all of which were determined to involve a violation of NRC requirements. Because of their very low safety significance and because the findings were entered into your corrective action program, the NRC is treating them as non-cited violations (NCVs), consistent with Section VI.A of the NRC's Enforcement Policy. If you contest these non-cited violations, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555-0001; with copies to the Regional Administrator Region I; the Director, Office of Enforcement,

Exhibit A
NRC Docket No. 50-271
ASLBP No. 04-832-02-OLA
DPS Opposition Motion to Dismiss Contention 6
March 7, 2005

United States Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the NRC Resident Inspector at the Vermont Yankee Nuclear Power Station.

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 NRC's document system (ADAMS). ADAMS is temporarily unavailable due to an ongoing security review; therefore, this document will also be posted on the NRC Web site at http:\\www.nrc.gov\reactors\plant-specific-items\vermont-yankee-issues.html.

Sincerely,

Wayne D. Lanning, Director
Division of Reactor Safety

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

Enclosure: Inspection Report 05000271/2004008 w/Attachments

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
D. L. Pace, Vice President, Engineering
B. O'Grady, Vice President, Operations Support
J. M. DeVincentis, Manager, Licensing, Vermont Yankee Nuclear Power Station
Operating Experience Coordinator - Vermont Yankee Nuclear Power Station
J. F. McCann, Director, Nuclear Safety Assurance
M. J. Colomb, Director of Oversight, Entergy Nuclear Operations, Inc.
J. M. Fulton, Assistant General Counsel, Entergy Nuclear Operations, Inc.
S. Lousteau, Treasury Department, Entergy Services, Inc.
Administrator, Bureau of Radiological Health, State of New Hampshire
Chief, Safety Unit, Office of the Attorney General, Commonwealth of Mass.
D. R. Lewis, Esquire, Shaw, Pittman, Potts & Trowbridge
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
J. Sniezek, PWR SRC Consultant
R. Toole, PWR SRC Consultant
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
License No.	DPR-28
Report No.	05000271/2004008
Licensee:	Entergy Nuclear Vermont Yankee, LLC
Facility:	Vermont Yankee Nuclear Power Station
Location:	320 Governor Hunt Road Vernon, Vermont 05354-9766
Dates:	August 9 - 20 and August 30 - September 3, 2004
Inspectors:	J. Jacobson, Team Leader, Inspection Program Branch, NRR F. Bower, Senior Reactor Inspector, DRS, Region I G. Bowman, Reactor Inspector, DRS, Region I S. Dennis, Senior Operations Engineer, DRS, Region I M. Snell, Reactor Engineer, DRP, Region I C. Baron, NRC Contractor S. Spiegelman, NRC Contractor G. Skinner, NRC Contractor
Observer:	W. Sherman, Vermont State Nuclear Engineer
Approved by:	Wayne D. Lanning, Director Division of Reactor Safety Region I

Enclosure

CONTENTS

EXECUTIVE SUMMARY

During the period from August 9 through September 3, 2004, the US Nuclear Regulatory Commission (NRC) conducted a team inspection in accordance with Temporary Instruction 2515/158, "Functional Review of Low Margin/Risk Significant Components and Human Actions," at the Vermont Yankee Nuclear Power Station. The team was comprised of eight inspectors, including a team leader from the NRC's Office of Nuclear Reactor Regulation, four inspectors from the NRC's Region I Office, and three contractors. All of the inspectors and contractors met strict independence criteria developed for this inspection. Specifically, the NRC inspectors had not performed engineering inspections at Vermont Yankee within the last two years and had not been assigned as resident inspectors at Vermont Yankee. The contractors had never been directly employed by Entergy or Vermont Yankee, had not performed contract work for Entergy or Vermont Yankee in the past two years, and had not performed inspections for the NRC at Vermont Yankee within the past two years. The inspection was the first of four planned pilot inspections to be conducted throughout the country to assist the NRC in determining whether changes should be made to its Reactor Oversight Process (ROP) to improve the effectiveness of its inspections and oversight in the design/engineering area.

In selecting samples for review, the team focused on those components and operator actions that contribute the greatest risk to an accident that could involve damage to the reactor core. Additional consideration was given to those components and operator actions impacted by the licensee's request for a 20 percent extended power uprate (EPU) license amendment. The team focused its reviews on those components and operator actions contained in the reactor core isolation cooling (RCIC), main feedwater, safety relief valve, onsite electrical power, and off-site electrical power systems. In addition, inspection samples were added based upon operational experience and issues previously identified by the NRC's technical staff during the course of their reviews associated with the licensee's request for an EPU. A complete listing of all components, operator actions, and operating experience issues reviewed by the inspection team is contained in Attachment A to this report.

For each sample selected, the team reviewed design calculations, corrective action reports, maintenance and modification histories, associated operating procedures, and performed walkdowns of material conditions (as practical). The team concluded that the components and systems reviewed would be capable of performing their intended safety functions. The team also concluded that sufficient design controls had been implemented for engineering work, including that related to Entergy's EPU. The overall material condition of the plant and of the specific components reviewed was also noted as being good. The team identified eight findings of very low safety significance, one unresolved item, and one minor finding. The eight findings are listed in the "Summary of Findings" section of this report.

The team assessed the safety significance of each of the findings using the NRC's Significance Determination Process (SDP). Using this process, each of the findings was determined to be of very low safety significance. Also, for each of the findings where current operability was in question, the licensee provided a basis for operability and entered the issue into their corrective action program, as necessary to complete a more comprehensive assessment of the issue, including any programmatic oversight weaknesses that might have prevented self-identification. In addition, for the findings associated with a design vulnerability of an RCIC pressure control valve, the control of the condensate storage tank (CST) temperature to the limits of transient analysis assumptions, and the updating of the Safe Shutdown Capability Analysis, the team performed sample-based extent-of-condition reviews during the inspection to determine the breadth of the issues identified. No additional findings were identified during these reviews, indicating the original problems identified were not widespread, and were likely not programmatic in nature. Additional licensee extent-of-condition reviews of the issues were ongoing at the conclusion of the inspection.

Some of the findings also concern topics that are within the scope of the NRC's power uprate review and therefore will require the submittal of additional information to the NRC's technical staff.

SUMMARY OF FINDINGS

IR 05000271/2004008; 08/09/2004-09/03/2004; Vermont Yankee Nuclear Generating Station; Functional Review of Low Margin/Risk Significant Components and Human Actions.

This inspection was conducted by five inspectors and three NRC contractors. Eight Green non-cited violations, one unresolved item, and one minor finding were identified. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process." Findings for which the SDP does not apply may be "Green" or be assigned a severity level after NRC management review. 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 Findings

Cornerstone: Mitigating Systems

- Green. The team identified a non-cited violation of 10 CFR Part 50.63, "Loss of All Alternating Current Power," because the licensee had not completed a coping analysis for the period of time the alternate alternating current (AC) source (the Vernon Hydro-Electric Station) would be unavailable and had not demonstrated by test the time required to make the alternate source available for a station blackout involving a grid collapse. This issue was more than minor because it was associated with the Mitigating Systems Cornerstone attribute of Equipment Performance and affected the cornerstone objective of ensuring availability, reliability, and capability of systems needed to respond to a station blackout. The issue screened as very low safety significance in Phase I of the SDP because it was a design deficiency that was not found to result in a loss of function. Specifically, the team found that the licensee's preliminary coping analysis, performed during the inspection, demonstrated a four-hour coping time which should be sufficient to envelope the time required to start and align the Vernon Station. (Section 4OA5.2.1.1)

- Green. The team identified a non-cited violation of Technical Specifications 6.4.C, "Procedures," because the licensee failed to establish adequate procedures for determining the operability of the 115 kilovolt (kV) Keene line, which is designated as an alternate immediate access power source if the 345/115 kV auto transformer is lost. This issue was more than minor because it was associated with the Mitigating Systems Cornerstone attribute of Procedural Quality and affected the cornerstone objective of ensuring availability, reliability, and capability of systems needed to respond to a loss of off-site power. The issue screened as very low safety significance in Phase I of the SDP because it was a design deficiency that was not found to result in a loss of function. Specifically, the team did not identify any instances where the lack of procedural guidance had resulted in an inadequate assessment of off-site power operability or the inoperability of the electrical system or any components. (Section 4OA5.2.1.1)

- Green. The team identified a non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," because the licensee used incorrect and non-conservative voltage values in calculations performed to assure that electrical equipment would remain operable under degraded voltage conditions. This issue was more than minor because it was associated with the Mitigating Systems Cornerstone attribute of Equipment Performance and affected the cornerstone objective of ensuring availability, reliability, and capability of systems needed to respond to a design basis accident. The issue screened as very low safety significance in Phase I of the SDP because it was a design deficiency that was not found to result in a loss of function. Specifically, the team did not identify any instances where using the Technical Specification degraded voltage allowable setpoint values would have resulted in inoperable equipment.. (Section 4OA5.2.1.1)

- Green. The team identified a non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," because the licensee did not implement measures to ensure that the design basis for the cooling water supply to the lube oil cooler of RCIC was correctly translated into the specifications, drawings, procedures, or instructions. Specifically, the installed pressure control valve in the lube oil cooler water supply line was not independent of air systems, and the installed piping between the pressure control valve and lube oil cooler did not contain a restricting orifice. This issue was more than minor because it was associated with the Mitigating Systems Cornerstone attribute of Equipment Performance and affected the cornerstone objective of ensuring the reliability of the RCIC system. The issue screened as very low safety significance in Phase I of the SDP because it was a design deficiency that was not found to result in a loss of function. This deficiency would not have resulted in the RCIC system becoming inoperable due to a loss of air to the lube oil cooler pressure control valve. (Section 4OA5.2.1.2).

  A contributing cause of this finding is related to the cross cutting area of Problem Identification and Resolution. The licensee had previously reviewed the failure positions of air-operated equipment and issued a report, "Compressed Air Systems," dated July 16, 1989. During this review, the licensee did not identify that the pressure control valve was not independent of the instrument air system.

- Green. The team identified a non-cited violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," because the licensee failed to correct a longstanding non-conformance in the operation of pressure control valve PCV-13-23. The team determined through interviews with Vermont Yankee staff that during initial start-up testing, problems were identified with the automatic operation of this valve which affected its ability to properly supply cooling flow to the RCIC lube oil cooler. This issue was more than minor because it was associated with the Mitigating Systems attribute of Equipment Performance and affected the cornerstone objective of ensuring the reliability of the RCIC system. The issue screened as very low safety significance in Phase I of the SDP because it was a design deficiency that was not found to result in a loss of function. The licensee had implemented manual actions as a compensatory measure for the operation of PCV-13-23 through the addition of procedural steps. (Section 4OA5.2.1.2)

- Green. The team identified a non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," because the licensee had neither established the correct condensate storage tank (CST) temperature limit for use in the plant transient analyses nor translated the CST temperature limit into plant procedures. This issue was more than minor because it was associated with the Mitigating Systems Cornerstone attribute of Equipment Performance and affected the cornerstone objective of ensuring the reliability of the core spray system. The issue screened as very low safety significance in Phase I of the SDP because it was a design deficiency that was not found to result in a loss of function. Although available net positive suction head (NPSH) margin for the core spray pumps was lowered, adequate margin remained due to the conservatism that existed in other aspects of the licensee's NPSH analysis. (Section 4OA5.2.1.7)

  A contributing cause of this finding is also related to the cross-cutting area of Problem Identification and Resolution. The licensee identified this issue in December 2002, but concluded that the non-conservative CST temperature had little to no effect on the transient analyses.

- Green. The team identified a non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," because between June 2001 to September 2004, the licensee did not adequately coordinate between the operations department and the engineering organization regarding procedure revisions that increased the length of time required to place the reactor core isolation cooling system in service from the alternate shutdown panels. This issue was more than minor because it was associated with the Mitigating Systems Cornerstone attribute of Human Performance and affected the cornerstone objective of ensuring the availability of the RCIC system. Furthermore, this finding resulted in the use of the December 1999 value of time to place RCIC in service from the alternate shutdown panel in documents submitted to the NRC as part of the Vermont Yankee Power Uprate Safety Analysis Report. The issue screened as very low safety significance in Phase I of the SDP because it was a design deficiency that was not found to result in a loss of function. Although the available time margin was lowered, sufficient margin remained to allow operator action to manually start the RCIC system prior to reactor level reaching the top of active fuel. (Section 4OA5.2.2)

- Green. The team identified a non-cited violation of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control," because the licensee had conducted motor-operated valve (MOV) diagnostic tests using procedures that did not include acceptance limits, which were correlated to and based on applicable (stem thrust and torque) design documents. Additionally, MOV diagnostic testing had been conducted solely from the motor control centers using test instrumentation that had not been validated to ensure its adequacy. The finding was more than minor because it affected the Mitigating Systems Cornerstone attribute of Equipment Performance and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems and components that respond to initiating events. Specifically, the unvalidated test method had the potential to affect the reliability of safety-related motor-operated valves. The issue screened as very low safety significance in Phase I of the SDP because it was a qualification deficiency that was not found to result in a loss of function. The team did not identify any examples of degraded or inoperable valves during the inspection and noted that the design basis calculations for the MOVs reviewed had available thrust margin of greater than 60 percent. (Section 4OA5.2.3)

B. Licensee Identified Violations

None.

REPORT DETAILS

4OA2 Problem Identification and Resolution (PI&R)

1. Annual Sample Review

Not applicable.

2. Cross Reference to PI&R Findings Documented Elsewhere

Section 2.1.2 (b) 1 of this report describes a finding associated with a design vulnerability of the reactor core isolation cooling (RCIC) system lube oil cooling pressure control valve in that the valve design was not independent of station service air as described in the Updated Final Safety Analysis Report. The licensee had previously reviewed the failure positions of air-operated equipment and issued a report, "Compressed Air Systems," dated July 16, 1989. This longstanding deficiency was not identified by this review or by other station service air reviews.

Section 2.1.7 (b) of this report describes a finding associated with maintaining the condensate storage tank temperature within limits assumed in the facility's transient analysis. The licensee had identified conditions where the tank temperature had exceeded the transient analysis assumptions but had not taken sufficient corrective actions.

4OA5 Other Activities - Temporary Instruction 2515/158

1. Inspection Sample Selection Process

In selecting samples for review, the team focused on the most risk-significant components and operator actions. The team selected these components and operator actions by using the risk information contained in the licensee's Probabilistic Risk Assessment (PRA) and the US Nuclear Regulatory Commission's (NRC's) Simplified Plant Analysis Risk (SPAR) models. An initial sample was chosen from those components and operator actions that had a risk achievement worth factor greater than two. These components and operator actions are important to safety since their assumed failure would result in at least doubling the risk of an accident that could result in core damage. Consideration was also given to those components and operator actions most impacted by the licensee's request for a 20 percent extended power uprate (EPU) license amendment.

Many of the samples selected were located within the reactor core isolation cooling, main feedwater, safety relief valve, onsite electrical power, and off-site electrical power systems. In addition, inspection samples were added based upon operational experience reviews. The team was also briefed by the NRC's technical staff conducting the EPU licensing review on issues that had arisen during their reviews, indicating areas that might warrant additional inspection. A complete listing of all components, operator actions and operating experience issues reviewed by the inspection team is contained in Attachment A to this report. A total of 91 samples were chosen for the team's initial review.

A preliminary review was performed on the 91 samples to determine whether any low-margin concerns existed. For the purpose of this inspection, margin concerns included original design issues, margin reductions due to the proposed EPU or margin reductions identified as a result of material condition issues. Consideration was also given to the uniqueness and complexity of the design, operating experience, and the available defense-in-depth margins. Based upon the above considerations, 45 of the original 91 samples were selected for a more detailed review. An overall summary of the reviews performed and the specific inspection findings identified is included in the following sections of the report.

2. Results of Detailed Reviews

The team performed detailed reviews on the 45 components, operator actions and operating experience issues. For components, the team reviewed the adequacy of the original design, modifications to the original design, maintenance and corrective action program histories, and associated operating and surveillance procedures. As practical, the team also performed walkdowns of the selected components. For operator actions, the team reviewed the adequacy of operating procedures and compared design basis time requirements against actual demonstrated timelines. For the operating experience issues chosen for detailed review, the team assessed the issues' applicability to Vermont Yankee and the licensee's disposition of the issue. The following sections of the report provide a summary of the detailed reviews, including any findings identified by the inspection team.

2.1 Detailed Component and System Reviews

2.1.1 Electrical Power Sources

a. Inspection Scope

The team reviewed the adequacy of the onsite and off-site electrical power sources that supply power to the safety-related components chosen for detailed review. Particular focus was paid to the off-site power sources and grid stability, to the extent they would be impacted by an EPU. The team's review encompassed the licensee's plans to limit the initial power increase to 15 percent, as a capacitor bank necessary to provide reactive power to the grid to ensure stability had yet to be installed. Other attributes of the electrical systems reviewed during the inspection were operating procedures, setpoints for degraded voltage relays, battery capacity, circuit breaker coordination, fast and slow transfer schemes, Technical Specifications (TS) and other related calculations.

The team conducted a walkdown of the safety-related switchgear rooms and the electrical controls in the main control room with station engineering personnel. The review was conducted to identify any alignment discrepancies or visible signs of significant deficient material conditions.

The team also performed a detailed, focused review of the ability of the Vernon Hydro-Electric Station to supply emergency power to Vermont Yankee in the event of a station blackout (SBO) caused by a grid disturbance, as required by 10 CFR Part 50.63, "Loss of all Alternating Current Power," and as clarified by Regulatory Guide 1.155, Station Blackout, and NUMARC 87-00, Revision 1. The team reviewed procedures associated with the operator actions necessary to tie in the Vernon Station, procedures associated with the operation and maintenance of the Vernon Station, and regional grid operator system restoration procedures. The team also visited the remote control location for the Vernon Station, and interviewed station personnel. Lastly, the team conducted a conference call with the regional grid operator responsible for controlling the operation of circuit breakers and switches in the Vernon switchyard.

b. Findings

(1) Availability of Power from Vernon Station

Introduction. The team identified a Green non-cited violation of 10 CFR Part 50.63, "Loss of All Alternating Current Power," because the licensee had not completed a coping analysis and had not demonstrated, by test, the time required to make the alternate alternating current (AC) source available for an electrical grid collapse resulting in a station blackout.

Description. 10 CFR Part 50.63 requires that licensees be able to recover from an SBO that results from a loss of all AC electrical power (both the normal off-site power sources and the on-site emergency diesel generators). In Section C.2, "Offsite Power," Regulatory Guide 1.155 defines the minimum potential causes to be considered for a loss of off-site power that results in an SBO. One listed cause is grid undervoltage and collapse. For SBO scenarios where the licensee cannot demonstrate by test that an alternate AC source would be available within 10 minutes, 10 CFR Part 50.63 requires the licensee to complete a coping analysis for the period of time it would take for power to be restored.

At Vermont Yankee, the licensee credits the Vernon Hydro-Electric Station as its alternate AC source to respond to a station blackout within 10 minutes. If a grid collapse occurs, the Vernon Station would trip offline and have to be restarted. The Vernon Station is considered a "black start" facility by the regional grid operator. As such, the Vernon Station is required to certify it can be ready to supply power within 90 minutes after tripping off line. However, in order to supply power to Vermont Yankee under such conditions, the Vernon switchyard would have to be configured to isolate the Vernon Station from the rest of the grid. The operation of the circuit breakers necessary to complete such actions is not controlled by either the licensee or the Vernon Station, but is controlled by the regional grid operator. The team held a conference call with the grid operators. During the call, the team learned that no specific procedures or communication protocols had been set up to deal with a station blackout at Vermont Yankee. The only reference to Vermont Yankee was a general statement in a procedure that said that nuclear generators should receive critical priority. During the call, the team also learned that the grid operator did not differentiate between situations where normal off-site power was lost to a nuclear unit but emergency diesels remain available, and those situations where the emergency diesel generators failed to start and the station was in a true blackout condition. The team learned that no specific training, testing, or simulations had been conducted to simulate the actions that would have to be taken to respond to an SBO at Vermont Yankee caused by a grid collapse.

As a result of the team's concerns, the licensee issued condition reports (CRs) CR-VTY-2004-2677 and 2004-2738. The licensee also created a preliminary timeline which estimated the time to restore power under such conditions as being between 20 minutes and 2 hours. The licensee also performed an operability evaluation in accordance with Generic Letter 91-18, which included a preliminary four-hour coping analysis. The licensee provided the team a copy of the preliminary coping analysis and copies of the original NRC Safety Evaluation Report (SER) for the station blackout rule dated September 1, 1992. The team reviewed the preliminary coping analysis and found the methodology used to be reasonable. Review of the NRC SER indicated that questions were asked by the NRC staff regarding a regional grid disturbance during the original station blackout review, and that the licensee's response was that power would be restored within one hour. Based upon the above facts, the team determined that the one hour time stated in the SER could no longer be ensured. Furthermore, contrary to 10 CFR Part 50.63, the licensee had not completed a coping analysis for the period of time it would take to restore the alternate source.

Analysis. The team determined that this issue was a performance deficiency since the licensee had not demonstrated by test that the Vernon Station could supply power to Vermont Yankee within one hour after the onset of a station blackout and had not completed a coping analysis for the period of time the Vernon Station would be unavailable, as required by 10 CFR Part 50.63. Also, the licensee did not remain cognizant of how design changes, made by the operator of the Vernon Station, affected the ability of the Vernon Station to supply emergency power to Vermont Yankee in a timely manner. This issue was more than minor because it was associated with the Mitigating Systems Cornerstone attribute of Equipment Performance and affected the cornerstone objective of ensuring availability, reliability, and capability of systems needed to respond to a station blackout resulting from a grid collapse. The issue screened as very low safety significance (Green) in Phase I of the SDP because it was a design deficiency that was not found to result in a loss of function. Specifically, the team found that the licensee's preliminary coping analysis, performed during the inspection, demonstrated a four-hour coping time that should be sufficient to envelope the time required to start and align the Vernon Station.

Enforcement. 10 CFR Part 50.63(c)(2), requires that a coping analysis be performed if the designated alternate AC source cannot be made available within 10 minutes. It also requires that the time required to make the alternate AC source available be demonstrated by test. Contrary to the above, the licensee had not completed a coping analysis for the period of time the alternate AC source would be unavailable and had not demonstrated by test the time required to make the alternate source available for a station blackout involving a grid collapse. Because this finding is of very low safety significance and the licensee entered this issue into its corrective action program (CR-VTY-2004-2677 and 2004-2738), it is considered a non-cited violation consistent with Section VI.A.1 of the NRC's Enforcement Policy. **(NCV 05000271/2004008-01 Availability of Power from Vernon Station)**

(2) Procedures for Assessing Off-site Power Operability

Introduction. The team identified a Green non-cited violation of Technical Specifications 6.4, "Procedures," because the licensee did not establish adequate procedures for assessing the operability of the 115 kilovolt (kV) Keene line.

Description. At Vermont Yankee, the immediate access off-site power source is normally derived from the 345 kV switchyard through the 345/115 kV transformer T-4-1A. The 115 kV Keene line may also be conditionally used as an alternate immediate access source for satisfying TS requirements for off-site power supplies, depending on grid and plant conditions. Specifically, Technical Specification Bases 3.10.A, states that the availability of the Keene line is dependent on its pre-loading which must be limited by the system dispatchers prior to it being declared an immediate access source.

The team reviewed Procedure ON 3155, "Loss of Auto Transformer," and noted that Step 2b, instructs operators to contact ISO New England to determine the 115 kV Keene line load limit but does not provide explicit criteria for evaluating the line's operability. The team also noted Note 5 on the load nomograph included in procedure ON 3155, Reference D, "Guidelines for Operating the Vermont Yankee 115 kV System with the VTY4 Auto Transformer Out of Service," stated the assumption that, "All Vermont Yankee motor startups performed sequentially, not simultaneously." During accident loading with off-site power available, all safety loads are designed to block start simultaneously, so this assumption would never be met.

The team noted the procedure also contained invalid criteria for assessing the operability of the downstream safety buses. Step 11 allowed operation of bus 3 or 4 with voltages as low as 3600 volts (V) AC. This voltage was below the TS allowable setting of 3660 VAC for the degraded voltage relays. Under non-accident conditions, operation of the buses at this minimum voltage would result in automatic actuation of the degraded voltage relays, separating the buses from off-site power. Under post-accident conditions, the degraded voltage protection relays are locked out and operation of the buses at 3600 VAC could result in equipment mis-operation or damage.

Analysis. The team determined this to be a performance deficiency since the operating procedures did not provide adequate guidance for determining operability of the 115 kV Keene line. This issue was more than minor because it was associated with the Mitigating Systems Cornerstone attribute of Procedure Quality and affected the cornerstone objective of ensuring availability, reliability, and capability of systems needed to respond to a loss of off-site power. The issue screened as very low safety significance (Green) in Phase I of the SDP because the failure to translate design requirements into operating procedures was a design deficiency that was not found to result in a loss of function. Specifically, the team did not identify any instances where the lack of procedural guidance had resulted in an inadequate assessment of off-site power operability or the inoperability of the electrical system or any components.

Enforcement. Technical Specifications 6.4.C, "Procedures," requires that written procedures be established, implemented, and maintained for actions to be taken to correct specific and unforeseen potential malfunctions of systems or components. Contrary to the above, the licensee did not establish adequate procedures for assessing the operability of the 115 kV Keene line. Since this finding is of very low safety significance and has been entered into the licensee's corrective action program (CR-VTY-2004-2803 and CR-VTY-2004-2804), it is considered a non-cited violation, consistent with Section VI.A.1 of the NRC Enforcement Policy. **(NCV 05000271/2004008-02 Procedures for Assessing Off-site Power Operability)**

(3) Degraded Voltage Relay Setpoint Calculations

Introduction. The team identified a Green non-cited violation of 10 CFR Part 50 Appendix B, Criterion III, "Design Control," because the licensee did not use the Technical Specification allowed voltage value in the calculations used to ensure the degraded voltage relay dropout function would provide adequate voltage to safety-related electrical equipment.

Description. As described in Section 8.5 of the Vermont Yankee Updated Final Safety Analysis Report (UFSAR), the licensee has installed degraded voltage relays, which are designed to protect the station's electrical equipment from damage that could occur due to degraded voltage. The licensee's Technical Specifications (TS) allow a minimum degraded voltage relay setpoint of 3660 VAC; however, the licensee's analysis of record, VYC-1088 "Vermont Yankee 4160/480 Volt Short Circuit/ Voltage Study," did not evaluate the operability of the connected electrical components at this minimum TS value. Instead, the lowest voltage evaluated by VYC-1088 was based on the minimum expected switchyard voltages, which were 3951 VAC for bus 3 and 3809 VAC for bus 4. Consequently, motors were evaluated for voltage considerably above the minimum voltage that could occur based on the TS value.

As a result, calculation VYC-1053 and VYC-1314, which determine worst-case motor-operated valve (MOV) and motor control center (MCC) voltages, were also non-conservative. In response to the team's concerns, the licensee initiated CR-VTY-2004-2596. The operability determination (OD) for CR-VTY-2004-2596 identified two motors that did not meet calculation acceptance criteria and provided justification for their operability. This OD also provided justification for lower MCC control circuit voltages than previously analyzed. The licensee also initiated CR-VTY-2004-2734 to address the effects of the postulated lower voltage on MOV operation. The effect on the MOVs was not expected to be significant due to the otherwise generally conservative approach used for MOV calculations.

Analysis. The team determined this to be a performance deficiency because the licensee's calculations did not ensure the operability of electrical equipment at the minimum TS value for the degraded voltage relay dropout setting. This issue was more than minor because it was associated with the Mitigating Systems Cornerstone attribute of Equipment Performance and affected the cornerstone objective of ensuring availability, reliability, and capability of systems needed to respond to a design basis accident. The issue screened as very low safety significance (Green) in Phase I of the SDP because it was a design deficiency that was not found to result in a loss of function. Specifically, the team did not identify any instances where using the Technical Specification degraded voltage allowable setpoint values would have resulted in inoperable equipment.

Enforcement. 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires that measures be established to assure that applicable regulatory requirements and the design basis for structures, systems and components are correctly translated into specifications, drawings, procedures and instructions. Contrary to the above, the licensee used incorrect and non-conservative voltage values in calculations performed to ensure that electrical equipment would remain operable under degraded voltage conditions. Since this finding is of very low safety significance and has been entered into the licensee's corrective action program (CR-VTY-2004-2596 and CR-VTY-2004-2734), it is considered a non-cited violation, consistent with Section VI.A.1 of the NRC Enforcement Policy. **(NCV 05000271/2004008-03 - Degraded Voltage Relay Setpoint Calculations)**

(4) Ungrounded 480 VAC Electrical System.

The team identified an unresolved item (URI) associated with the 480 VAC circuit-breakers designed to detect and interrupt electrical malfunctions. An unresolved item is an issue requiring further information to determine if it is acceptable, if it is a finding or if it constitutes a deviation or violation of NRC requirements. In this case, additional review will be required to determine if the facility is in accordance with its design and/or licensing basis, since this was part of the original design of the facility. Also, additional review will be required to determine the safety significance of this issue.

The Vermont Yankee 480 VAC system consists of two 480 VAC load center buses supplied through separate 4160/480 V transformers from the redundant

4160 VAC safety buses. The transformers are connected delta-delta and the 480 VAC system is ungrounded. Several non-safety related loads are supplied from the safety-related load center buses and from safety-related MCCs. These non-safety loads are not automatically disconnected during postulated accidents but rather are shed manually depending on the specific accident scenario. The load centers are equipped with 600 ampere circuit-breakers with long-time and short-time, or long-time and instantaneous trip devices. The MCCs are equipped with magnetic breakers with thermal overloads or thermal/magnetic breakers. Each bus is provided with a ground detection system which consists of three ground detection voltmeters and three potential transformers. The system only provides local indication at the MCCs and does not annunciate in the control room. The control room relies on the auxiliary operator round sheet voltage recordings of the ground detection voltmeters to be informed of any ground fault on the 480 V system. The ground detector does not actuate any protective devices or indicate the location of the fault.

The team identified that since the 480 VAC electrical system at Vermont Yankee is ungrounded, an arcing/intermittent ground fault could cause excessive voltages to be impressed upon the system. Such a ground could begin on non-safety related equipment that is unprotected from the effects of a postulated high energy line break or seismic event. The installed electrical protective devices designed to provide isolation between the safety and non-safety related loads may not open during this scenario because the ungrounded system may not provide a return current path until a second ground was formed. While such a ground could possibly be detected with the installed ground detection instrumentation, there would likely be insufficient time to detect and isolate the ground before damage could occur to safety-related motors due to the possible excessive voltages. **(URI 05000271/2004008-04 - Ungrounded 480 VAC Electrical System)**

2.1.2 Reactor Core Isolation Cooling (RCIC) System

a. Inspection Scope

During the inspection, the team reviewed selected RCIC system components to ensure they would be capable of performing their required design functions for both current licensing basis conditions and the proposed EPU conditions. The team reviewed the RCIC pump and turbine, auxiliary equipment, various system valves, and instrumentation and controls. The team conducted plant equipment walkdowns, reviewed plant operating and test procedures, condition reports, test results, maintenance history, vendor manuals, drawings, design calculations and applicable sections of the UFSAR and the TS.

b. Findings

(1) Control Valve for RCIC Lube Oil Cooler

Introduction. The team identified a Green non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," because the cooling water supply to the lube oil cooler of the RCIC system was not installed as described in the RCIC system design basis. Specifically, the pressure control valve for the lube oil cooler water supply was not independent of air systems, and the piping between the pressure control valve and lube oil cooler did not contain a restricting orifice.

Description. During a review of drawing G-191174, Sheet 2, "Flow Diagram - Reactor Core Isolation Cooling," Revision 23, the team noted that a pressure control valve, PCV-13-23, was shown as having a connection to station instrument air. The team noted that USFAR Section 4.7.5 stated that all components necessary for initiating operation of RCIC were completely independent of auxiliary ac power and station service air. The station instrument air and service air systems are interconnected and are supplied from four AC powered air compressors connected in parallel. Both the station instrument air and service air systems are classified as non-nuclear safety related. The team questioned the effect of the loss of the air supply to this valve. PCV-13-23 was installed in the 2-inch cooling water supply line to the RCIC pump lube oil cooler to regulate the flow of the cooling water supply from the RCIC pump discharge. A relief valve, SR-13-26, was installed between PCV-13-23 and the lube oil cooler for overpressure protection.

In response to the team's questions, the licensee's engineering personnel investigated this condition and determined that PCV-13-23 would fail in the fully open position upon a loss of air. The licensee performed a hydraulic analysis of the affected portion of the RCIC system during the inspection. The analysis determined that fully opening the pressure control valve would have resulted in a flow of approximately 170 gpm through the valve, as opposed to the design flow of 16 gpm. The analysis also determined that the lube oil cooler, which has a design pressure of 150 pounds per square inch gauge (psig), would have been exposed to a maximum pressure of approximately 1100 psig. Both relief valve SR-13-26 and relief valve SR-13-27, installed on the RCIC pump barometric condenser, would have opened to pass the expected flowrate. The licensee's investigation determined that this condition has existed since the original operation of the RCIC system.

The licensee documented this issue in condition report CR-VTY-2004-2535 and performed an operability determination, which the team reviewed. The operability determination stated that a loss of air was considered unlikely during any of the events where the RCIC system was credited. It also concluded that, if the air supply was lost, the lube oil cooler and associated piping components would not rupture when exposed to the expected pressures. This was based, in part, on vendor testing which showed that there was significant margin above

1100 psig before these components would rupture. With regard to the potential loss of RCIC system capacity, the determination concluded that the RCIC pump would have sufficient capacity to provide the required flow to the reactor vessel even with the expected flow diversion. The licensee also initiated condition report CR-VTY-2004-2536 because the RCIC design basis document identified PCV-13-23 as a self-contained pressure control valve.

The licensee performed a limited extent-of-condition review during the inspection to verify that a similar condition did not exist for other air-operated components. No additional concerns were identified by the licensee during this review. The team also performed an independent sampled-based review and did not identify any additional issues. The licensee stated that a full extent-of-condition review would be performed as part of the resolution of CR-VTY-2004-2535. At the time of the inspection, the licensee was developing a plan to correct this design deficiency.

The team also noted that the piping between the pressure control valve and lube oil cooler did not contain a restricting orifice as described in the UFSAR. UFSAR Figure 4.7-3 indicated that a flow-restricting orifice was installed downstream of valve PCV-13-23. No such orifice exists in the system. The licensee initiated condition report CR-VTY-2004-2537 to document this concern.

Analysis. The team determined this issue was a performance deficiency since the licensee had not instituted measures to ensure that the RCIC system was installed consistent with its design and licensing basis. This issue was more than minor because it was associated with the Mitigating Systems Cornerstone attribute of Equipment Performance and affected the objective of ensuring the reliability of the RCIC system. The issue screened as very low safety significance in Phase I of the SDP, because it was a design deficiency that was not found to result in a loss of function. This deficiency would not have resulted in the RCIC system becoming inoperable due to a loss of air to the lube oil cooler pressure control valve.

A contributing cause of this finding is related to the cross cutting area of Problem Identification and Resolution. The licensee had previously reviewed the failure positions of air-operated equipment and issued a report, "Compressed Air Systems," dated July 16, 1989. During this review, the licensee did not identify that the pressure control valve was not independent of the instrument air system. In addition, the licensee did not fully assess all aspects of the issue associated with the pressure control valve being supplied by instrument air rather than being self contained in its initial operability determination associated with CR-VTY-2004-2535. The licensee had to complete two additional supplemental operability determinations to resolve the team's concerns.

Enforcement. 10 CFR Part 50 Appendix B, Criterion III, "Design Control," requires, in part, that design control measures be established and implemented to assure that applicable regulatory requirements and the design basis for structures, systems, and components are correctly translated into specifications, drawings, procedures, and instructions. Contrary to the above, the licensee did not implement measures to ensure that the design basis for the cooling water supply to the lube oil cooler of RCIC was correctly translated into the specifications, drawings, procedures, or instructions. Specifically, the installed pressure control valve in the lube oil cooler water supply line was not independent of air systems, and the installed piping between the pressure control valve and lube oil cooler did not contain a restricting orifice. Because this violation is of very low safety significance and has been entered into the licensee's corrective action program (CR-VTY-2004-2535), this violation is being treated as a non-cited violation consistent with Section VI.A of the NRC Enforcement Policy. **(NCV 05000271/2004008-05 Cooling Water Supply Portion of RCIC Not Installed per Design Basis)**

(2) Failure To Correct Non-Conforming RCIC Pressure Control Valve

Introduction. The team identified a Green non-cited violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," because the licensee failed to correct a longstanding non-conformance associated with PCV-13-23, the control valve that supplies cooling water to the RCIC lube oil cooler.

Description. During review of Operating Procedure (OP) 2121, "Reactor Core Isolation Cooling System," and OP 4121, "Reactor Core Isolation Cooling System Surveillance," the team identified that these procedures contained steps to manually operate PCV-13-23 during RCIC operation. The team questioned the reason for these steps, given that the RCIC system is designed to function automatically as described in UFSAR Section 4.7.4.

The team determined that during initial start-up testing, problems were identified with the automatic operation of this valve. These problems affected its ability to properly regulate the supply of cooling flow to the lube oil cooler. During the inspection, the licensee could not provide the team with an open condition report identifying this problem. Additionally, the licensee did not have an analysis to show that setting PCV-13-23 as described in the procedure would ensure an adequate flow of cooling water to the lube oil cooler. Rather, the licensee used the fact that RCIC bearing temperatures have been acceptable during surveillance testing to justify that lube oil cooling was sufficient. However, the team noted that the conditions that exist during surveillance testing may be different from those existing under design conditions (for example, use of a higher temperature suppression pool as a suction source and operation with maximum expected RCIC room temperature). These conditions would result in higher bearing temperatures when RCIC is operating under design conditions.

The team reviewed alarm response procedures for the RCIC bearing temperature alarms and determined that they were adequate to prevent damage to major RCIC components if the cooling flow was inadequate. However, the manual operation of PCV-13-23 represents a longstanding operator work-around that creates an additional operator burden and could challenge equipment reliability if called upon to operate during an event.

Analysis. The team determined that the licensee's failure to correct a longstanding non-conformance with PCV-13-23 was a performance deficiency. Specifically, operation of this valve in a mode other than automatic may have challenged system operation if needed for an actual event. This issue was more than minor because it was associated with the Mitigating Systems attribute of Equipment Performance and affected the cornerstone objective of ensuring the reliability of the RCIC system. The issue screened as very low safety significance (Green) in Phase I of the SDP, because it was a design deficiency that was not found to result in a loss of function. While PCV-13-23 did not function automatically as designed, the licensee had implemented manual actions as a compensatory measure for the operation of this valve.

Enforcement. 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requires that measures be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and non-conformances are promptly identified and corrected. Contrary to the above, the licensee failed to correct a longstanding non-conformance associated with PCV-13-23, the control valve that supplies cooling water to the RCIC lube oil cooler. Because this issue is of very low safety significance and has been entered into the licensee's corrective action program (CR-VY-2004-2535), this issue is being treated as a non-cited violation, consistent with Section VI.A of the NRC Enforcement Policy.
(NCV 05000271/2004008-06 Failure To Correct Non-Conforming RCIC Pressure Control Valve)

(3) Potential Preconditioning of RCIC MOVs

The team identified a minor finding related to Vermont Yankee's method of testing RCIC system MOVs. The team determined that a procedural requirement to conduct the quarterly RCIC system pump operability test prior to system MOV surveillance testing resulted in the operation of several RCIC system valves immediately before their required stroke-time testing. This practice could have affected the results of the stroke-time testing by preconditioning the valves and this potential impact was not evaluated by the licensee. This issue was evaluated using Inspection Manual Chapter 0612 and determined to be minor because it applied to a limited number of valves, most of the valves would not have affected system operability, a review of these valves' performance history indicated that there was significant margin to stroke-time limits, and no operability issues were noted during past testing.

2.1.3 Residual Heat Removal System (RHR)

a. Inspection Scope

During the inspection, the team reviewed selected components of the RHR system to ensure the system and components would be capable of performing their required design functions, for both current conditions and those conditions that would exist under the proposed EPU. In its power uprate submittal to the NRC, the licensee stated that it would need to take credit for the containment overpressure that would exist under postulated accident conditions in order to ensure adequate net positive suction head (NPSH) was available to the RHR pumps. The team did not assess the appropriateness of allowing credit for containment overpressure. The team did, however, perform specific reviews of the licensee's calculations to ensure that the RHR pumps would have adequate NPSH assuming such credit is given. The team's review included pressure losses associated with the RHR suction strainers, potential bubble ingestion and the potential for torus vortexing.

b. Findings

No findings of significance were identified.

2.1.4 Safety Relief Valves and Code Safety Valves

a. Inspection Scope

Due to the increased steam flow that would result from the licensee's proposed EPU, the team conducted a detailed review of General Electric (GE) Topical Report T0900, which evaluated the adequacy of the safety relief valves (SRVs) for EPU conditions. The team reviewed the GE analysis and licensee modification package associated with the installation of a third American Society of Mechanical Engineers (ASME) Code safety valve with increased relief capacity for EPU conditions. The team also reviewed the out-of-service and calibration history for the existing SRVs. Lastly, the team reviewed the back-up nitrogen bottle system, which was added to ensure an adequate supply of nitrogen to the SRVs.

b. Findings

No findings of significance were identified.

2.1.5 Reactor Feedwater and Condensate Components

a. Inspection Scope

Due to the increased feedwater flow that would be required under the licensee's proposed EPU, the team assessed the adequacy of modifications to the reactor feedwater system. Because of the increased feedwater flow requirements, the licensee would need to run all three reactor feedwater pumps under EPU conditions, reducing the capability to mitigate feedwater transients. Included within the team's review was a recent seal replacement on a feedwater pump and modifications to the reactor feedwater pump low-suction pressure trip and reactor recirculation system runback. The team also reviewed flow control valve FCV-102-4 and its associated controls, since failure of this valve to open could disable low flow capability for the condensate pumps, resulting in a loss of feedwater flow during low-flow demands.

The team reviewed aspects of the licensee's Flow Assisted Corrosion (FAC) Program and reviewed the adequacy of the thermal sleeves located at connections between the RCIC and feedwater systems and the reactor vessel. The team conducted a walkdown of the main feedwater and condensate pumps and adjacent piping with Vermont Yankee engineering personnel. Lastly, the team inspected the feed and condensate panels in the main control room. The reviews were conducted to identify any alignment discrepancies or visible signs of deficient material conditions.

b. Findings

No findings of significance were identified.

2.1.6 Reactor Building-to-Torus Vacuum Breaker System

a. Inspection Scope

The team reviewed the components associated with the reactor building-to-torus vacuum breaker system. This system includes two redundant air-operated vacuum breaker valves, each in series with a check valve. This system functions to relieve pressure from the reactor building to the torus to protect the structural integrity of the torus. Additionally, the system must remain leak-tight from the torus to the reactor building to maintain primary containment isolation. In reviewing these components, the team assessed condition reports, operating procedures, test results, maintenance and modification history, drawings and applicable sections of the UFSAR and TS. The team's review included verification that these components would be capable of performing their required design functions for both current licensing basis conditions and the proposed EPU conditions.

The team also completed a walkdown of the reactor building-to-torus vacuum breakers and their air-operators, check valves and associated piping. Additionally, the team reviewed operator burden and work-around lists to identify any deficiencies that could affect operation of these components.

b. Findings

No findings of significance were identified.

2.1.7 Review of Transient Analysis Inputs

a. Inspection Scope

During the inspection, the team reviewed selected plant parameters used by the licensee as inputs into its transient analyses. Included in this review were analyses performed solely to support the proposed EPU. In conjunction with this review, the team conducted plant equipment walkdowns, reviewed plant procedures and calculations, and discussed calculations and parameters with plant design engineers.

b. Findings

Introduction. The team identified a finding of very low safety significance involving a non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," because the licensee had neither established the correct condensate storage tank (CST) temperature limit for use in the plant transient analyses nor translated this CST temperature into plant procedures.

Description. During the inspection, the team noted that although the CST temperature was monitored on operator logs, the licensee had not established a maximum temperature limit for the CST. A CST temperature limit of 90 degrees Fahrenheit (°F) was used as an input to several plant transient analyses, including Transient Analysis VYC-1825, "Analysis of Suppression Pool Temperature for Relief Valve Discharge Transients," Revision 0. The CST temperature used for this analysis was based on the maximum ambient summer temperature of approximately 90°F and did not take into account the recirculated hotwell water that has on occasion raised the CST temperature to approximately 120°F.

In addition, the team noted that in December 2002, the licensee had also identified that there was no maximum CST temperature limit and that CST temperature had previously exceeded the temperature assumed in the high pressure coolant injection (HPCI) and RCIC design basis documents for calculating pump NPSH. The licensee documented this condition in CR-VTY-2002-2942. At that time, the licensee performed a limited evaluation and determined that the non-conservative CST temperature had little to no effect on the transient analyses. The team reviewed this evaluation and determined that transient analysis VYC-1825, which assessed the adequacy of the NPSH of the pumps supplied from the CST or the suppression pool, would be affected by the increased CST temperature.

In response to the team's concerns, the licensee reviewed the transient analyses and identified that the relief valve discharge transient was the most limiting. The licensee determined that using the higher CST temperature of 120°F led to an increase in suppression pool temperature, which reduced the net positive suction head margin for the most limiting component, the core spray pumps, from 0.5 feet to 0.0 feet. The team reviewed the input parameters to the NPSH calculation for the core spray pumps and determined that because of conservatism in other aspects of the calculation, the core spray pumps would still have adequate NPSH to remain operable.

The team determined that in the licensee's EPU submittal to the NRC, the licensee had not taken into account the higher CST temperature for all transient scenarios. As a result of this issue, the licensee began an extent-of-condition review of all calculations, drawings, and inputs to transient analyses where a non-conservative maximum CST temperature was used, both for current plant conditions (CR-VTY-2004-2600) and for analyses associated with the planned EPU (CR-VTY-2004-2799). The licensee also instituted a tentative maximum temperature limit of 120°F for the CST.

Analysis. The team determined this issue was a performance deficiency since the licensee had not used the correct CST temperature in the plant transient analysis and had not translated the CST temperature limit into the station procedures. Specifically, using the correct CST temperature in the relief valve discharge transient analysis resulted in a higher suppression pool temperature and lowered the available net positive suction head to the core spray pumps. This issue was more than minor because it was associated with the Mitigating Systems Cornerstone attribute of Equipment Performance and affected the cornerstone objective of ensuring the reliability of the core spray system. The issue screened as very low safety significance (Green) in Phase I of the SDP, because it was a design deficiency that was not found to result in a loss of function. Although available NPSH margin was lowered, adequate NPSH for the core spray pumps remained due to the conservatism that existed in other aspects of the licensee's NPSH analysis.

A contributing cause of this finding is also related to the cross-cutting area of Problem Identification and Resolution. The licensee identified this issue in December 2002, but concluded that the non-conservative CST temperature had little to no effect on the transient analyses.

Enforcement. 10 CFR Part 50 Appendix B, Criterion III, "Design Control," requires, in part, that design control measures be established and implemented to assure that applicable regulatory requirements and the design basis for structures, systems, and components are correctly translated into specifications, drawings, procedures, and instructions. Contrary to the above, the licensee had neither established the correct condensate storage tank (CST) temperature limit for use in the plant transient analyses nor translated the CST temperature limit into plant procedures. Because this finding is of very low safety significance and has been entered into the licensee's corrective action program (CR-VTY-2004-2600, CR-VTY-2004-2793, and CR-VTY-2004-2799), this finding is being treated as a non-cited violation consistent with Section VI.A of the NRC Enforcement Policy. **(NCV 05000271/2004008-07 Failure to Implement Adequate Design Control for Condensate Storage Tank Temperature)**

2.2 Review of Operator Actions

a. Inspection Scope

During the inspection, the team reviewed risk-significant, time-critical operator actions that had little margin between the time required and time available to complete the action. The team determined the review scope and performed the detailed review of critical operator actions using risk information contained in the licensee's PRA, Operator Task Validation Studies, Emergency Operating Procedures (EOPs), Power Uprate Safety Analysis Report (PUSAR), Appendix R Analyses, Off-Normal and Operating Procedures, and the licensee's CR database. The team performed a detailed review of the following time-critical and low-margin operator actions:

- Monitoring of the Vernon tie line to ensure availability as a station blackout source.
- *Manual initiation of the RCIC system using alternate shutdown panels.*
- Initiation of the standby liquid control (SLC) system with the main condenser failed.
- Manual initiation or control of feedwater and condensate flow under normal and transient conditions, in single element or three element control.
- Manual initiation of RCIC system from the control room.

For all the above operator action scenarios, the team verified that operating procedures were consistent with operator actions for a given event or accident condition and that the operators had been adequately trained and evaluated for each action. The team also reviewed the fidelity between EOPs, pump NPSH calculations and containment spray operation to ensure proper EOP implementation. Control room instrumentation and alarms were also reviewed by the team to verify their functionality and to verify alarm response procedures were accurate to reflect the current plant configuration. Additionally, the team performed a walkdown of accessible field portions of the reviewed systems to assess material condition and to verify that field actions could be performed by the operators as described in plant procedures.

The team also reviewed each operator action to assess the impact the proposed EPU could have on further reducing the margin available for task completion and to verify that the associated EPU plant modifications would be reviewed by the licensee for their effect on the operators' ability to complete the critical actions within the required time parameters.

b. Findings

Introduction. The team identified a Green non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," because the licensee did not adequately coordinate between the operations department and the engineering organization procedure revisions that increased the length of time required to place the reactor core isolation cooling system in service from the alternate shutdown panels. As a consequence, the licensee did not revise its Vermont Yankee Safe Shutdown Capability Analysis (SSCA).

Description. The Vermont Yankee SSCA relies on the reactor core isolation cooling (RCIC) system to be placed in service from the alternate shutdown panels prior to reactor water level reaching the top of active fuel following a loss of feedwater flow. In December 1999, the Vermont Yankee SSCA documented that, for the present day 100 percent power level, it would take 25.3 minutes for reactor water level to reach the top of active fuel following a loss of feedwater and that it would take approximately 15 minutes to place the RCIC system in service from the alternate shutdown panels. The Vermont Yankee SSCA concluded adequate margin (approximately 10 minutes) existed to ensure that the RCIC is placed in service prior to reactor water level reaching the top of active fuel.

In June 2001 the Operations Department conducted an additional review of the time it would take to place RCIC in service from the alternate shutdown panels. The Operations Department determined that, using the version of the procedure in effect in June 2001, it would take 19.3 minutes to place RCIC in service from the alternate shutdown panels .

During the inspection, using the version of the procedure in effect during the inspection period, the team performed a field walkdown with licensed operators to validate that RCIC could be placed into service from the alternate shutdown panels within 19.3 minutes. The team noted that since June 2001, the licensee had added steps in the procedure to comply with Electrical Safety Standards. Based on the team's validation, the total time to place RCIC in service from the alternate shutdown panels was determined to be approximately 21 minutes. The team concluded that this time was still within the 25.3 minute limit stated in the Vermont Yankee SSCA.

Additionally, the team found that the licensee had not revised the December 1999 Vermont Yankee SSCA to reflect the June 2001 time estimate or present day version of the procedure to place RCIC in service from the alternate shutdown panels. The team also determined that the licensee's engineering organization was unaware that the time to complete the task had increased from approximately 15 to 21 minutes and had effectively reduced the time margin available for event mitigation from about 10 minutes to 4 minutes at the current full power level. As a consequence, the engineering organization had not revised the Vermont Yankee SSCA.

The team reviewed the impact the licensee's proposed EPU would have on this issue. Based on an EPU power level, the licensee calculated it would take 21.3 minutes for reactor water level to reach the top of active fuel following a loss of feedwater. Therefore, the team concluded that for the proposed EPU, the ability to place the RCIC in service from the alternate shutdown panels (21 minutes) prior to reactor water level reaching the top of active fuel (21.3 minutes) is questionable. Additionally, the team found that the December 1999 value of the time to place RCIC in service from the alternate shutdown panel was used in licensee Technical Evaluation (TE) 2003-065, "Appendix R PUSAR Input." The TE was then used as an input to the Vermont Yankee Power Uprate Safety Analysis Report (PUSAR) and submitted to the NRC as part of the power uprate application. The licensee initiated CR-VTY-2004-2552 and 2004-2614 in response to these issues.

Analysis. The team considered this finding to be a performance deficiency since the licensee did not coordinate between the operations department and engineering department regarding procedure revisions which increased the time required to place the RCIC in service from the alternate shutdown panels. This issue was more than minor because it was associated with the Mitigating Systems Cornerstone attribute of Human Performance and affected the cornerstone objective of ensuring the availability of the RCIC system. Furthermore, this finding resulted in the use of the December 1999 value of time to place RCIC in service from the alternate shutdown panel in documents submitted to the NRC as part of the Vermont Yankee PUSAR. The issue screened as very low safety significance (Green) in Phase I of the SDP because it was a design deficiency that was not found to result in a loss of function. At the present 100 percent power level, RCIC could be placed in service from the alternate shutdown panels prior to reactor level reaching the top of active fuel.

Enforcement. 10 Part CFR 50, Appendix B, Criterion III, "Design Control," requires, in part, that revision of documents shall be coordinated among participating organizations. Contrary to above, between June 2001 to September 2004, the licensee did not adequately coordinate between the operations department and the engineering organization regarding procedure revisions that increased the length of time required to place the reactor core isolation cooling system in service from the alternate shutdown panels. Because this finding is of very low safety significance and has been entered into the licensee's corrective action program, it is being treated as a non-cited violation, consistent with Section VI.A of the NRC Enforcement Policy. (NCV 05000271/2004008-08

Failure to Coordinate Information Related to Safe Shutdown Capability Analysis Report)

2.3 Review of Operating Experience and Generic Issues

a. Inspection Scope

During the inspection, the team reviewed selected operating experience issues that had been identified at other facilities for their possible applicability to Vermont Yankee. Several issues that appeared to be applicable to Vermont Yankee were selected for a more in-depth review. Additional consideration was given to those issues that might be impacted by the licensee's planned EPU. The issues that received a detailed review by the team included:

- An NRC inspection finding at the Point Beach Nuclear Power Station, documented in IR 50-266/2004-004, concerning the use of a non-conservative CST temperature in accident and transient analyses.

- Licensee Event Report (LER) 2003-003-00, issued on September 29, 2003, from the Byron Station where the licensee had exceeded its licensed maximum power level due to inaccuracies in feedwater ultrasonic flow measurements caused by signal noise contamination.

- An NRC inspection finding from the Peach Bottom Station, documented in IR 50-277/2002-011, concerning inadequate Emergency Operating Procedures to return the suction of the High Pressure Coolant Injection (HPCI) system from the suppression pool to the CST in order to ensure self-cooled HPCI lube oil temperatures remained within analyzed limits.

- Information Notice 2001-13, "Inadequate Standby Liquid Control Relief Valve Margin," issued on August 10, 2001, concerning a problem identified at the Susquehanna Station involving inadequate SLC system relief valve margin after a power uprate increased the relief valve setpoint pressure, thereby increasing SLC discharge pressure. This was complicated by using a non-conservative maximum reactor vessel pressure in accident analysis.

- NRC Generic Letter (GL) 96-05, "Periodic Verification of Design-Basis Capability of Safety-Related Power-Operated Valves," pertaining to the periodic testing of motor-operated valves. With regard to this GL, the team reviewed the NRC safety evaluation report that documented the NRC staff's understanding of the licensee's commitments and plans for establishing a periodic verification program. The team also reviewed procedures, test and maintenance records, corrective action documents, and correspondence relative to four RCIC system MOVs.

b.1 Findings

Introduction. The team identified a Green non-cited violation of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control," because the licensee conducted periodic testing of MOVs using test instrumentation that had not been validated to be adequate for its intended function. Additionally, the test procedures did not incorporate requirements and acceptance limits contained in applicable design documents.

Description. In its SER dated December 14, 2000, the NRC provided its basis for accepting Vermont Yankee's response to NRC GL 96-05, "Periodic Verification of Design-Basis Capability of Safety-Related Power-Operated Valves." The SER documented the licensee's intentions to use motor current data acquired from the MCCs as a way of detecting actuator and valve degradation. The SER also documented Vermont Yankee's intention to verify this testing methodology by comparing the data with direct torque and thrust measurements at the valve over extended intervals. In addition, the SER stated the licensee would have to determine MCC test instrumentation accuracies and sensitivities to MOV degradation, as well as evaluate changes in MCC data and MOV thrust and torque performance.

During the inspection, the team concluded that Vermont Yankee had not validated the adequacy of the MCC diagnostic test instrumentation with respect to its ability to provide detect actuator torque and stem thrust degradation that would indicate actuator or valve degradation. A cooperative effort with Crane-MOVATS to perform the required validation was terminated in March 2004, when the parties determined that a statistically meaningful and valid correlation of MCC to direct diagnostic test data that would allow setting switches could not be completed. As a result of the team's concerns, the licensee entered this issue into the corrective action program on CR-VTY-2004-2802.

The team also identified that separate procedures (OP 5217 and OP 5287) had been established to obtain and evaluate MCC diagnostic test data; however, neither of these procedures included specific acceptance criteria tied to stem thrust or available design margin. The SER stated that an acceptance procedure for MCC testing was under development to specify parameters to be monitored for trending, including specific acceptance criteria. The team observed that the lack of acceptance criteria could lead to the inconsistent evaluation of the data between different reviewers. Also, the documentation of problem identification and resolution of issues identified through test data review was missing or unclear. An inspector-identified example of entering improper test data into the MOV test package was entered into the corrective action program on CR-VTY-2004-2623.

The team also identified that no administrative or procedural prohibition had been implemented against using MCC testing to set MOV switches, and that the procedures specifically allowed establishing a baseline with MCC testing

(OP 5287). The MOV program had been revised in 2002 to eliminate any periodicity requirements for "at-the-valve" diagnostic testing that can measure torque and thrust to known accuracies. The team identified and the licensee confirmed that the MCC test equipment had been used in at least one instance to set MOV switches on one of the four RCIC valves reviewed. Also, the team identified several cases where diagnostic testing following replacement of the valve packing was limited to MCC testing. The team noted that packing replacement affects stem friction and consequently changes in stem thrust. Since the MCC testing instrumentation had not been validated, the team concluded that the change in stem friction from initial set-up was indeterminate for these valves.

Analysis. The performance deficiency was the failure to validate motor-operated valve test instrumentation to ensure its adequacy and to establish test procedures with adequate acceptance criteria tied to stem thrust or available design margin. Specifically, there was no analysis demonstrating that testing conducted at the MCC ensured the development of proper operating thrust at the valve to ensure the MOV would perform satisfactorily under design basis conditions. This issue was more than minor because it was associated with the Mitigating Systems Cornerstone attribute of Equipment Performance and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems and components that respond to initiating events. Specifically, the unvalidated test method had the potential to affect the reliability of safety-related motor-operated valves. The issue screened as very low safety significance (Green) in Phase I of the SDP, because it was a qualification deficiency that was not found to result in a loss of function. The team did not identify any examples of degraded or inoperable valves during the inspection and noted that the design basis calculations for the MOVs reviewed had available thrust margin of greater than 60 percent.

The inspectors also identified that a contributing cause of the finding was related to the human performance cross-cutting area, in that, the licensee did not manage NRC commitments and conditions documented in the SER for the GL 96-05 MOV periodic verification program.

Enforcement. 10 CFR Part 50, Appendix B, Criterion XI, "Test Control," requires that a test program be established to ensure that all testing required to demonstrate that systems and components will perform satisfactorily in service is performed in accordance with written test procedures which incorporate the requirements and acceptance limits contained in applicable design documents. The test procedures shall include provisions for ensuring that adequate test instrumentation is available and used. Contrary to the above, Vermont Yankee had conducted MOV diagnostic tests using procedures that did not include acceptance limits which were correlated to and based on applicable (stem thrust and torque) design documents. Additionally, MOV diagnostic testing had been conducted solely from the motor control centers using test instrumentation that had not been validated to ensure its adequacy. Because this finding is of very low safety significance and has been into Vermont Yankee's corrective action program (CR-VTY-2004-2802 and CR-VTY-2004-2644), it is being treated as a non-cited violation, consistent with Section VI.A of the NRC's Enforcement Policy. **(NCV 05000271/2004008-09 Failure To Establish Adequate MOV Periodic Test Program)**

b.2 Observations

The team also had other observations regarding the licensee's NOV program. The team concluded these observations did not impact valve operability due to existing value capability margins.

The team identified that Vermont Yankee had not maintained current the risk ranking of MOVs. At the time that the SER was issued, the licensee's risk ranking of the MOVs was considered acceptable. During a review of program documents during this inspection, the team noted that low- and medium-risk MOVs were specified for test at every other refueling outage, whereas, high-risk MOVs were specified for testing every refueling outage. For the RCIC system MOVs reviewed, the team noted that several valves had the same risk achievement worth (RAW), but they were assigned different risk rankings in the MOV program documents and consequently were not tested at the same periodicity. Discussions with Vermont Yankee's risk analyst indicated that the licensee's PRA had been updated in 2000 and May 2004; however, the updated PRA data were not reflected back into the MOV risk ranking. This issue was entered into the corrective action program on CR-VTY-2004-2798.

The team also concluded that Vermont Yankee's trending methods to identify degradation from design basis conditions were informal. The SER documented the existence of established procedures to review and trend MOV failure and diagnostic test data every two years. Primary MOV parameters identified for trending were various thrust values, stem friction coefficient, load sensitive behavior and dynamic margin. The SER noted that Vermont Yankee would perform quantitative and qualitative assessments looking for overall changes in MOV performance, including the use of diagnostic trace overlays and analysis. The team found that the procedure referenced in the SER (DP 0210) had been canceled. The trending of alternating current MOVs was moved to the procedure for evaluating MCC test data; however, a procedure for trending direct current MOVs had not been established. Currently, Vermont Yankee's trending program consists of reviewing the data from a diagnostic test to the results of the previous test, which may not identify degradation from the established baseline or identify slow but continual degradation. This issue was entered into the corrective action program on CR-VTY-2004-2644.

4OA6 Meetings, Including Exit

The team presented the issues identified during the inspection to Mr. Dreyfuss and other members of the licensee's staff at a team debrief on September 3, 2004.

On October 27, 2004, the inspection team leader provided the preliminary results of the inspection, including risk significance and enforcement, to Mr. Bronson, Mr. Dreyfuss, and other members of licensee's staff in a teleconference call.

The preliminary results of the inspection were also included in a letter to Vermont Yankee Nuclear Power Station dated November 5, 2004, which was originally issued in preparation for a planned public exit meeting.

A final closeout discussion on the inspection was held with Mr. Thayer, Mr. Bronson and other members of the licensee's staff via teleconference on November 23, 2004. The Vermont State Nuclear Engineer was invited to the closeout discussion, but was not available to attend.

ATTACHMENT A

Summary of Items Reviewed

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
115 kV - Breaker K1	Transformer T-4 feed to 115 kV bus: required to supply power from the 345 kV switchyard to the Startup Transformers.	No automatic actions required except fault clearing; safety busses would disconnect or be prevented from connecting to circuit after a fault.
115 kV - K.1 Logic Relay	RCIC logic relay K.1 fails to operate on demand. Rationale: Malfunction of RCIC turbine trip instrumentation could cause loss of RCIC System.	The inspectors found no specific operator action for this component and that a failure of the logic relay would result in control room alarms which would be responded to by the operators. The inspectors found that related control room alarms were functioning properly, and that the associated alarm response procedures were current.
125 V Battery B-1 and A-1	Station Battery: Supplies power to the station 125 VDC loads when the battery chargers are not available.	Detailed review completed.
24 Vdc - ES-24DC-2	Power Supply Converter: Supplies power to the 24 VDC ECCS Analog Trip System.	No low margin or other issues identified.
345 kV - Breaker 381-1	Northfield 345 kV line to 345 kV North Bus: required to provide power from the Northfield 381 to the 345 kV switchyard.	Detailed review completed.
4 Kv - Breaker 12	Bus 1 Feed Breaker from UAT: required to open on generator trip to enable access of one safety train to the offsite source through the SUT	No low margin issues identified.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
4 Kv - Breaker 13	Bus 1 Feed Breaker from SUT: required to close on generator trip to enable access of one safety train to the offsite source through the SUT .	Detailed review completed.
4 Kv - Breaker 22	Bus 2 Feed Breaker from UAT: required to open on generator trip to enable access of one safety train to the offsite source through the SUT.	The inspectors found that the only operator action for this component was breaker open/close operation. Additionally, the inspectors found that the related control room alarms were functioning properly and that the associated alarm response procedures were current. The inspectors found no issues with this component related to operator actions.
4 Kv - Breaker 23	Bus 2 Feed Breaker from SUT: required to close on generator trip to enable access of one safety train to the offsite source through the SUT.	Detailed review completed.
4 Kv - Breaker 3V	Vernon Supply Breaker to Bus 3: required to supply power from the Alternate AC Power source to one 4160V safety bus.	No specific issues identified with breaker. Other issues reviewed as part of overall Station Blackout Capability.
4 Kv - Breaker 3V4	Vernon Tie Breaker: required to supply power from the Alternate AC Power source to either 4160V safety bus.	Detailed review completed.
4 kV UV Relays	4160V Undervoltage Relays: required to provide adequate voltage to safety-related AC loads, reset setpoint must be optimized to prevent spurious loss of offsite power.	Detailed review completed.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
69 kV - Vernon Generator	Vernon Hydroelectric generator station: required to supply power from the Alternate AC Power source to either 4160V safety bus.	Detailed review completed.
69 kV to 4160 V Vernon Transformer	Vernon Tie Transformer: required to supply power from the Alternate AC Power source to either 4160V safety bus.	Detailed review completed.
125 VDC Distribution Panels	Supplies 125 VDC loads.	Detailed review completed.
Alignment of RHRSW to the RPV	Operator fails to align the RHRSW injection to RPV.	Aligning RHRSW injection to the RPV is one of the methods which can be used for RPV injection to prevent core damage in accordance with EOPs given an ATWS scenario. The validated time through simulator observation was 1 minute to complete the actions for alignment. Additionally, prior to using RHR SW for RPV injection, other systems such as condensate/feedwater , CRD, and RHR will be used to attempt to fill the RPV. The operators are regularly trained and evaluated in this event scenario further reducing the likelihood of the task not being completed within the required time.
Bus Transfer Scheme	Circuit breakers, synchronism check relays, timing relays, and voltage relays required to enable transfer of 4160V buses from the Unit Aux Transformer to the Startup Transformers.	Detailed review completed.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
Closure of Vernon Tie Breakers	Operator fails to close the Vernon tie breakers.	One of the primary AC power recovery actions in the event of a loss of normal power is to use the dedicated tie line from the Vernon hydro Station to power either 4260VAC Bus 3 or 4 (vital power). The action is performed by the operators in the main control room by manipulating switches for 2 DC powered breakers. Validation studies and operator observation in the simulator have shown that the task can be accomplished in less than 4 minutes. Adequate margin exists currently and for the CPPU to accomplish the action. Additionally, operator response to loss of power events is trained regularly in the simulator and classroom. While no issues identified with VY operator actions, a finding was identified with the licensee's overall station blackout response.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
Condensate Pump	Review condensate operation before and after the power uprate (including recirc pump runback modification). The Condensate and Feedwater system does not directly perform any safety-related function. Portions of the Feedwater system and check valves provide Reactor Coolant Pressure Boundary and Containment Isolation functions. The condensate pumps 1) supply water to the Feedwater pumps and 2) provide sufficient NPSH for operation of the FW pumps. The loss of a condensate pump could be a contributing factor to a transient initiation. The condensate pumps are directly impacted by the EPU due to the need to increase the flow volume by approximately 20%.	No low margin or other issues identified.
Containment Pressure	During a loss of coolant event or an ATWS the containment pressure will be elevated and the suppression pool level will increase.	Detailed review completed.
CST Transient Analysis Temperature Non-conservative	Transient analysis Condensate Storage Tank Temperature non-conservative compared to actual maximum operating temperatures. This issue stems from a similar event at Point Beach.	Detailed review completed.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
CST Level Instrumentation	Rationale: Important for maintaining required CST inventory for RCICS and controlling automatic transfer of RCICS suction to the suppression pool.	Detailed review completed.
CV-109	Failure of check valve CV-109 (valve between the N2 bottle and the SRV) to open. Failure of this check valve to open will prevent N2 supply to the Main Steam Safety Relief Valves.	Detailed review completed.
CV-19	RCIC check valve CV-19 (RCIC suction check valve from the CST) fails to open on demand. This valve must open to provide flow from CST to RCIC pump suction, and close to prevent flow from torus to CST during RCIC pump suction transfer.	A detailed review was not performed for this check valve because no performance problems were indicated from the maintenance history.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
CV-2-1A, 1B, 1C	RFP discharge check valves. They are risk significant because if they fail to close following an RFP trip they could make other RFPs inoperable. Prior to EPU two pumps are operational. After EPU three pumps will be operational. When two pumps are operational, one of the MOVs, 4A, 4B or 4C will be closed for the non-operational pump as such, this is not a current potential event. However, after EPU the third valve will not be closed thus this is a potential failure scenario.	A detailed review was not performed for these check valves because no performance problems were indicated from the maintenance history.
CV-22	RCIC check valve CV-22 (RCIC injection path discharge check valve) fails to open on demand. This valve must open for RCIC injection flow. The valve must also fully close when the pump is not in operation to prevent back-leakage and a possible waterhammer.	Detailed review completed.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
CV-2-27B	This valve is the feedwater isolation valve upstream of the RCIC injection path. The risk significant function of the component is to close to prevent RCIC from flowing back into the feedwater system. EPU uprate will increase the flow through this check valve by approximately 20%, however the function of the valve is not altered.	A detailed review was not performed for this check valve because no performance problems were indicated from the maintenance history.
CV-2-28B	Feedwater check valve CV-28B ('B' feedwater line check valve inside containment) fails to open on demand. This valve is located on drawing G-191167, H-5. Failure to open will prevent flow from either the RCIC or the Feedwater system. EPU uprate will increase the flow through this check valve by approximately 20%, however the function of the valve is not altered.	A detailed review was not performed for this check valve because no performance problems were indicated from the maintenance history.
CV-2-96A	Feedwater check valve V96A fails to open on demand. Failure of this valve will prevent flow from either the RCIC or the FW system. EPU uprate will increase the flow through this check valve by approximately 20%, however the function of the valve is not altered.	A detailed review was not performed for this check valve because no performance problems were indicated from the maintenance history.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
CV-40	RCIC check valve CV-40 (RCIC suction check valve from the suppression pool) fails to open on demand. This valve must open to provide a flow path from the torus to the RCIC pump suction.	A detailed review was not performed for this check valve because no performance problems were indicated from the maintenance history or walkdown.
CV-6/7	RCIC check valves CV- 6/7 (RCIC turbine exhaust check valves to torus) fails to open on demand.	Detailed review completed.
CV-72-109	Failure of check valve CV-109 (N2 bottle supply check valve to the plant N2 system) to close. The component is risk significant because if the check valve failed to close, the N2 bottle could bleed down to the plant N2 system.	Detailed review completed.
Digital Feedwater Control/Single Element Control	Following the modification that installed the digital feedwater control system, the licensee had problems with loss of inputs to the three-element controller (steam flow). This resulted in a reactor level transient. Since the event the plant had been operating in single-element control. Evaluate the modification and the acceptability of operating in single-element. Also determine if operation in single-element control would challenge the licensee's assumption that the plant would not scram following a single reactor feed pump trip, post-uprate.	Detailed review completed.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
DPIS-83/84	Spurious high steam flow signal. This steam flow instrument isolates RCIC steam in the event of a line rupture (indicated by high flow). Spurious isolation would result in the loss of RCIC flow.	These instruments are not included because there is significant margin in the setpoint to detect a steam line rupture, as well as margin between the normal operating point and the setpoint.
EOP/NPSH Fidelity	Verify fidelity between Emergency Operation Procedures and NPSH calculations and Containment Spray operation.	Detailed review completed.
FCV-2-4	FCV.4 (condensate pump minimum flow valve) fails to open on demand.	Detailed review completed.
FCV-2-4 Instrumentation	Failure of FCV.4 (condensate pump minimum flow valve) control instrumentation.	Detailed review completed.
Feed/Condensate Control	Operator fails to initiate and/or control feedwater/condensate.	Detailed review completed.
FT-58/FE-56	RCIC pump discharge flow instrument. This instrument is associated with the RCIC turbine control logic.	Detailed review completed.
GE SIL 351	GE SIL 351 - HPCI and RCIC Turbine Control System Calibration.	Vermont Yankee implemented SIL 351R.2 and provided the procedural changes recommended in the SIL for the HPCI system (OP 5337 Rev. 7). SIL 351 does not apply to RCIC since RCIC does not use a ramp generator (RGSC). This SIL is primarily procedural change recommendations and is not a high risk/low margin system.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
GE SIL 377	GE SIL 377 RCIC Startup Transient Improvement with Steam Bypass (June 24, 1982).	GE SIL 377 recommended a bypass for the steam supply line to the turbine for improved startup performance during a transient where RCIC is needed. This does not apply to Vermont Yankee since the SIL was a recommendation for plants who have issues with cold startup of the RCIC system. Upon talking to the system engineer, these issues have not existed for at least 20 years at VY.
GE SIL 467 (Bistable Vortexing)	GE SIL 467 and IEN 86-110 - Bistable vortexing is still a phenomenon that occurs periodically at VY.	The first occurrence of bistable vortexing at Vermont Yankee was following beginning of cycle 12 when recirculation system piping was replaced; however, this is a low risk event and thus does not meet the high risk / low margin criteria for this inspection. Vermont Yankee has had problems with bistable vortexing in the past and responded in depth to this SIL. The licensee responded to the SIL, added discussion on bistable vortexing at VY and action items for operators when bistable vortexing occurs. A review of Vermont Yankee's response to SIL 467, showed VY satisfied GE's recommended actions and placed guidance in OP 2110, Recirculation Procedure to aid the operators in identifying bistable vortexing.
GL 96-05, MOV Periodic Verification	GL 96-05 - Implementation of program for MOV Periodic Verification (As applicable to the selected sample of valves RCIC-MOV-15, 16, 131 and 132)	Detailed review completed.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
IN 2001-13 (SLC Relief Valve Margin)	Information Notice 2001-13 (8/10/01) - Inadequate Standby Liquid Control System Relief Valve Margin (Susquehanna, Units 1 and 2) Susquehanna's power uprate increased SRV setpoint pressure thus increasing SLC discharge pressure. However, the maximum SLC pump discharge pressure used a non-conservative maximum reactor vessel pressure in accident analysis.	Detailed review completed.
LER 3871995009 (LCO 3.0.3 Entry)	LER 1995-009-00 (7/3/95) - Condition Prohibited by the Plant's Technical Specifications (Susquehanna, Unit 1) - Non-conservative plant input into reactor core flow calculation.	Feedflow used in the analysis for power uprate is consistent with current feedflow indications.
LER 3251997005 (FW Indication Error)	LER 1997-005-01 (8/8/97) - Feedwater Flow Indication Discrepancy (Brunswick Steam Electric Plant, Unit 1).	Vermont Yankee does not have and is not required to have chemical tracer mass flow rate tests. This is more conservative then having the tracers since the chemical tracer mass flow rate tests are controversial and have had past issues. VY is waiting for industry or regulatory guidance on this issue before adding this test.
LER 2961998001 (LOCA Sensor Problem)	LER 1998-001-00 (4/1/1998) - Computer Modeling Indicates Sensors May Not Detect All Possible Break Locations (Browns Ferry, Unit 3).	Vermont Yankee does use the GOTHIC computer code to analyze high energy pipe breaks; however, this is a low risk issue and presented no significant safety issue at Browns Ferry.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
LER 2601999009 (Scram Due to EHC Leak)	LER 1999-009-00 (10/14/99) - Manual Reactor Scram Due to EHC Leak (Browns Ferry Nuclear Power Station, Unit 2).	The EHC leak was on a very specific 3/8 inch nominal outer diameter tubing connection which consisted of socket weld glands and standard nuts to connect the accumulator to a pressure transmitter. The leak was due to poor fabrication and poor work practices specific to Browns Ferry.
LER 2372001005 (1/7/02)	LER 2001-005-00 (1/7/02) - Unit 2 Scram Due to Increased First Stage Turbine Pressure (Dresden, Unit 2).	Vermont Yankee responded to GE SIL 423, in 1998, by implementing corrective actions.
LER 4612002002 (Inadequate PM on FW System)	LER 2002-002-00 (7/11/02) - Inadequate Preventive Maintenance Program for the Feedwater System Results in Lockup of a Turbine-Driven Reactor Feed Pump and Scram on High Reactor Pressure Vessel Water Level During Extended Power Uprate Testing (Clinton Power Station). Feedwater increased due to the power uprate; however, the feedwater limit switch did not increase to accommodate this increase in flow.	This operating experience does not apply since Vermont Yankee does not have turbine driven feedwater pumps, and this issue does not apply to other turbine driven pumps in the plant.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
LER 3412002005 (Non-Conservative Setpoint)	LER 2002-05 (1/16/03) - Discovery of Non-Conservative Setpoint for the Thermal-Hydraulic Stability Option III Oscillation Power Range Monitor (OPRM) Period Based Algorithm, Tmin (Fermi, Unit 2).	This OE does not apply to Vermont Yankee since power oscillations are monitored using approved BWROG Option 1D not Option III. Vermont Yankee does not have Oscillation Power Range Monitors, Period Based Detection Algorithms, and Tmin values. Option III is used for larger BWRs that have local power oscillations. Since Vermont Yankee has a small BWR core, only core-wide oscillations occur (not local oscillations). The inspector met with an individual from power uprate (and used to work in reactor engineering) and discussed, in detail, core monitoring using Option 1D for the new ARTS/MELLA core design and the power uprate core design.
LER 4542003003 (Maximum Power Exceeded)	LER 2003-003-00 (9/29/03) - Licensed Maximum Power Level Exceeded Due to Inaccuracies in Feedwater Ultrasonic Flow Measurements Caused by Signal Noise Contamination (Byron).	Detailed review completed.
LER 3411992009	LER-92-009-00 (11/20/92) - Safety Relief Valves Set Pressure Outside Technical Specifications (Fermi, Unit 2).	VY has had no issues with setpoint drift on the SRVs or RVs in containment. Setpoint drift considered in this LER was an indication of disc-to-seat sticking due to corrosion binding on the SRVs and RVs at Fermi thus making these valves fail their set pressures tests.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
LSHH-4A	Level switch LSHH 4A contacts fail/short. High Water Make up - Condenser level Control Switch Fails high - auto make malfunctions to the CST - Operator Action is required. No EPU impact.	Operator can take manual action to overcome this failure. The consequence of the failure of the switch is not significant because the operator can take manual control.
Manual Initiation of HPCI/RCIC	Operator fails to manually initiate HPCI and RCIC systems.	Detailed review completed.
Manual Operation of SRVs (Medium LOCA)	Operator fails to manually open the SRVs for a medium LOCA.	Emergency Operating Procedures (EOP) require operator action to manually open the SRVs to depressurize the reactor under medium break LOCA conditions. Validation studies and operator observations in the simulator have shown that given various factors that influence human performance (stress, training, equipment failures, etc.), the task to open the SRVs manually would be accomplished in less than 7 minutes which is lower than the 33 minutes (or 24 minutes for CPPU) needed to assure > 1/3 core coverage. Additionally, operator training frequently focuses on this event making it unlikely that the operator would fail to perform the task within the required time.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
Manual Operation of SRVs (Small LOCA/Transient)	Operator fails to manually open the SRVs for transient/small LOCA.	Emergency Operating Procedures (EOP) require operator action to manually open the SRVs to depressurize the reactor under transient and small break LOCA conditions. Validation studies and operator observations in the simulator have shown that given various factors that influence human performance (stress, training, equipment failures, etc.), the task to open the SRVs manually would be accomplished in less than 5 minutes which is much lower than the 66 minutes (or 48 minutes for CPPU) needed to assure > 1/3 core coverage. Additionally, operator training frequently focuses on this event making it unlikely that the operator would fail to perform the task within the required time.
Manual RCIC operation-Appendix R Safe Shutdown	Appendix R Safe Shutdown Analysis - Operator fails to manually initiate RCIC system using alternate shutdown panels (Generic Human Actions that are Risk Important), and GE document NEDC-330090P, Table 10-5 (Assessment of Key Operator Action).	Detailed review completed.
MOV-131	RCIC MOV 131 (RCIC turbine steam supply valve) fails to open on demand. This valve is required to open to provide steam to the RCIC turbine for operation.	Not included because valve has adequate design margin to open when required.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
MOV-132	RCIC MOV 132 (cooling water valve to the RCIC lube oil cooler) fails to open on demand. This valve is required to open to provide cooling water to the RCIC pump lube oil cooler. Failure to cool the lube oil could result in failure of the pump/turbine.	Not included because valve has adequate design margin to open when required.
MOV-15/16	RCIC MOV 15/16 (steam supply to RCIC turbine) fails closed during its mission time. These valves are required to close in the event of a line break in the RCIC turbine steam supply to isolate the HELB. These valves are also required to remain open when the RCIC pump is required to operate.	Detailed review completed.
MOV-18	RCIC MOV 18 (RCIC pump suction valve from the CST) transfers closed during its mission time. This valve is required to automatically close when the RCIC pump suction is transferred from the CST to the torus. This valve must remain open while the RCIC pump is operating from the CST.	Not included because valve has adequate design margin to close when required.
MOV-21/20	RCIC MOV 21 (inboard discharge valve to the reactor vessel) fails to open on demand. Also look at MOV-20 (the normally open outboard discharge isolation valve). These valves must automatically open to provide RCIC injection flow in response to an RCIC initiation signal.	Detailed review completed.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
MOV-27	This is the RCIC minimum flow valve. This valve is required to open at low RCIC flow to protect the pump.	Detailed review completed.
MOV-39	RCIC MOV 39 (RCIC suction valve from the suppression pool) fails to open on demand. This valve is required to open when the RCIC pump suction is transferred from the CST to the torus.	Detailed review completed.
MOV-41	RCIC MOV 41 (RCIC suction valve from the suppression pool) fails to open on demand. This valve is required to open when the RCIC pump suction is transferred from the CST to the torus.	Not included because valve has adequate design margin to open when required.
MOV-64-31	MOV 64-31 (manual makeup valve from the CST to hotwell) fails to open on demand.	Failure of this valve will prevent make-up from the hot-well to the CST. The loss of this valve would not be safety significant and there are no indications that there is low margin on for this valve
Offsite Transmission System	Offsite Transmission System: preferred source of power to the 4160V safety buses; must remain stable and available following the trip of the VY generator.	Detailed review completed.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
Operator Bypasses the MSIV Isolation Interlocks	Operator Bypasses MSIV Isolation Interlocks. The justification is the decrease in the Allowable Action Time for the operators at the EPU level (CPPU). It is based on input from the Human Performance technical staff, Appendix A of NUREG 1764 (Generic Human Actions that are Risk Important), and GE document NEDC-330090P, Table 10-5 (Assessment of Key Operator Action).	The allowable action time to bypass the MSIV low-low level isolation interlocks is based upon the time it would take to reach the RPV low-low level setpoint for an ATWS with no injection. Validation studies by the licensee have shown that the task would be accomplished for transient and LOCA events within the required time. The margin to accomplish the task is adequate, for current and CPPU conditions, given other operational factors and steps in the EOPs which must be taken into account (e.g., a high main steam line radiation isolation signal maintaining the valves closed). Operators train and are evaluated and tested on a regular basis for this scenario further reducing the likelihood that the task would not be completed in the time required.
Operator Inhibits ADS	Operator action to inhibit ADS. The justification is the decrease in the Allowable Action Time for the operators at the EPU level (CPPU). It is based on input from the Human Performance technical staff, Appendix A of NUREG 1764 (Generic Human Actions that are Risk Important), and GE document NEDC-330090P, Table 10-5 (Assessment of Key Operator Action).	The operator action to inhibit ADS is one of the first actions taken by the operators under certain transient conditions in the EOPs. The allowable action time is based on the time to reach the vessel level low-low set point for ATWS without injection plus two minutes for the ADS timer. Validation studies and operator observation in the control room have demonstrated that the action would be accomplished in less than 3 minutes. The margin to complete the task is not significantly changed under CPPU conditions. Additionally, operators are trained and tested regularly in this EOP action step.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
Passive Failure of Feedwater Piping	Review effect of increased feedwater flow on flow-accelerated corrosion rates following the power uprate.	Detailed review completed.
PB IR 2002-011 (HPCI Functional Issue)	Peach Bottom Finding for IR 50-277/2002-011 (8/5/02) - Finding Related to High Pressure Coolant Injection Function (may apply to RCIC system at VY).	Detailed review completed.
PCV-23	RCIC PCV 23 (RCIC air operated lube oil temperature control valve) fails to open on demand. This valve uses instrument air to control its setpoint and fails fully open on a loss of instrument air. This valve is required to provide cooling water, at the correct pressure, to the RCIC pump lube oil cooler when the RCIC pump is operating.	Detailed review completed.
PS-67	Spurious RCIC low suction pressure trip signal. This instrument will cause the RCIC pump to trip in the event of low pump suction pressure. Spurious trips will result in a loss of RCIC flow.	Not included because there is significant margin in the setpoint to prevent a spurious trip.
PSH-72A/B	Spurious RCIC turbine exhaust high pressure trip. This instrument will trip the RCIC pump in the event of high pressure in the exhaust steam line. Spurious trips will result in a loss of RCIC flow.	Not included because there is significant margin in the setpoint to prevent a spurious trip.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
PT-59/60	RCIC pump discharge pressure. This instrument is associated with the RCIC turbine control logic.	Not included because there is significant margin in the setpoint.
PT-68	Spurious low steam line pressure signal. This instrument will isolate steam flow to the RCIC turbine in the event of low steam supply pressure, indicating a steam line break. Spurious isolation would result in a loss of RCIC flow.	Not included because the pressure switch setpoint has significant margin to prevent a spurious pump trip.
PT-70	Spurious RCIC trip on high turbine exhaust pressure signal. Component ID is PT-70. Include exhaust rupture disks S3 and S4. This instrument will trip the RCIC pump in the event of high pressure in the exhaust steam line. Spurious trips will result in a loss of RCIC flow.	Not included because there is significant margin in the setpoint and operating pressure to prevent a spurious trip.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
Manual operation of MOV 64-31	Operator fails to manually open MOV 64-31 (used to manually transfer makeup from the CST to the condenser).	The operator action to manually open valve MOV 64-31, Hotwell Emergency Makeup Valve, is performed in the main control room. The action is required when turbine bypass is not available (during an MSIV closure event). In that case automatic makeup to the hotwell from the Condensate Storage Tank (CST) may not be sufficient to keep up with reactor vessel makeup requirements (feedwater pumps providing vessel level makeup). Validation studies and operator observations have estimated a 1 minute time to manipulate the valve from the control room. If the valve is required to be opened from the field the estimates are less than 15 minutes, however, other EOP mitigation strategies such as use of low pressure ECCS pumps, would assure core coverage if the valve could not be opened.
RB/Torus Vacuum Breakers	Reactor Building to Torus vacuum breakers. The vacuum breakers are required to open to prevent a vacuum in the containment. These also must remain closed to ensure containment integrity and to prevent loss of overpressure for ECCS NPSH.	Detailed review completed.
RCIC Pump P-47-1A and Turbine TU-2-1-A	RCIC pump P-47-1A fails to start on demand. This sample includes the turbine driven RCIC pump, the governor valve, and trip throttle valve.	Detailed review completed.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
Reactor Feed Pump	Failure of the feedwater pump will fail to deliver flow required for normal operation or to mitigate an accident. Prior to EPU 2 of three feedwater pumps are required to support the Feedwater system requirements. As such there is a 50% spare capability. For EPU three pumps are required to operated due to the increase requirements of feedwater flow.	Detailed review completed.
RHR Pump	Review RHR pump NPSH calculation, associated suction strainers, bubble ingestion, and torus vortexing issues.	Detailed review completed.
Safety Valve (New)	Addition of third main steam safety valve for power uprate. Failure of SSV to open and relieve pressure during transients or small/medium break LOCA.	Detailed review completed.
SLC Initiation with Condenser Failed	Operator fails to initiate SLC with the main condenser failed. The justification is the decrease in the Allowable Action Time for the operators at the EPU level (CPPU). It is based on input from the Human Performance technical staff, Appendix A of NUREG 1764 (Generic Human Actions that are Risk Important), and GE document NEDC-330090P, Table 10-5 (Assessment of Key Operator Action).	Detailed review completed.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
Spurious High Steam Line Space Temperature Trip	Spurious RCIC trip on high steam line space temperature (instrument TS 79 through 82). These instruments would result in isolation of the steam flow to the RCIC turbine in the event of a steam line break. A spurious trip would result in loss of RCIC flow.	Not included because there is significant margin between the setpoint and the operating temperature to prevent a spurious trip.
Spurious High Steam Tunnel Temperature Trip	Spurious RCIC trip on a high steam tunnel temperature trip signal. These instruments would result in isolation of the steam flow to the RCIC turbine in the event of a steam line break. A spurious trip would result in loss of RCIC flow.	Not included because there is significant margin between the setpoint and the operating temperature to prevent a spurious trip.
Spurious Reactor High Level Trip	Spurious high reactor water level signal (trip could affect both the RCIC pump or feed water pump). These instruments would result in tripping the RCIC turbine in the event of high RPV level. A spurious trip would result in loss of RCIC flow.	Excluded because HPCI and the RFP trip signals are provided by different instruments and the probability of a simultaneous failure of these instruments is extremely low.
SR-26	SR-26 (RCIC supply to lube oil cooler relief valve) fails open. This component is designed to protect the RCIC lube oil cooler and may be important on a loss of IA when the flow control valve fully opens (based on interview with RCIC System Manager).	Detailed review completed.
SRVs	Safety relief valves allow the reactor to be depressurized.	Detailed review completed.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
Vernon Tie Line	Operator monitoring of Vernon tie line to ensure availability as a station blackout source.	Detailed review completed.

ATTACHMENT B

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

D. Amidon	EFIN Engineer
M. Arnett	Systems Engineer - Electrical
K. Bronson	General Manager
F. Burger	Corrective Action
J. Callaghan	Design Engineering Manager
M. Castronova	Design EFIN Supervisor
J. Devincentis	Licensing Manager
J. Dreyfuss	Director of Engineering
E. Duda	Power Uprate Engineer
N. Fales	Systems Engineer - FW and Condensate
K. Farabaugh	Systems Engineering Supervisor
J. Fitzpatrick	Design Mechanical/Structural Engineering - FAC
M. Flynn	Design Engineer – Electrical
D. Girroir	Systems Engineering Supervisor
S. Goodwin	Design Mechanical/Structural Engineering Supervisor
A. Graves	Design Admin Assistant
C. Hansen	Design Engineer - Components
A. Haumann	Design Engineer – Electrical
B. Hobbs	Power Uprate – Engineering Supervisor
M. Janus	Design Engineer – Electrical
P. Johnson	Design Engineer - Electrical
J. Kritzer	Operations/Reactor Engineer
M. Lefrancois	Systems Engineering Supervisor
P. Longo	Design Engineer - Components
L. Lukens	Systems Engineering Supervisor
M. McKenney	Maintenance Support Engineering
J. Melvin	Systems Engineer – SLC
M. Metell	Entergy-Vermont Yankee Response Team Leader
B. Naeck	Systems Engineer - RCIC
C. Nichols	Power Uprate Engineering Manager
T. O'Connor	Design Engineer – Mechanical/Structural
M. Palionis	PRA Engineer
P. Perez	Design Engineer – Fluid Systems
P. Rainey	Design Engineer – Fluid Systems
A. Robertshaw	Design Engineer – Fluid Systems
J. Rogers	Design Fluid Systems Engineering Supervisor
R. Rusin	Design Engineering Supervisor - Components
B. Slifer	Power Uprate Engineer
J. Stasolla	Systems Engineer – Electrical
J. Taylor	Corrective Action

J. Thayer	Site Vice President
G. Thomas	Power Uprate – Contractor Interface
J. Twarog	Operations Shift Engineering Supervisor
R. Vibert	Design Electrical Engineering Supervisor
C. Wamser	Operations Manager
R. Wanczyk	Director of Nuclear Safety
G. Wierzbowski	Systems Engineering Manager
A. Wonderlick	Systems Engineer – Electrical

Other

W. Farnsworth	Training Coordinator - REMVEC / National Grid
D. Goodwin	Operations Supervisor US-GEN
W. Houston	Manager of Transmission - REMVEC / National Grid
W. Sherman	Vermont State Nuclear Engineer

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000271/2004008-04	URI	Ungrounded 480 VAC Electrical System. (Section 4OA5.2.1.1.b.3)

Opened and Closed

05000271/2004008-01	NCV	Availability of Power from the Vernon Station. (Section 4AO5.2.1.1.(b).1)
05000271/2004008-02	NCV	Procedures for Assessing Off-site Power Operability. (Section 4AO5.2.1.1.(b).2)
05000271/2004008-03	NCV	Degraded Relay Setpoint Calculations. (Section 4AO5.2.1.1.(b).3)
05000271/2004008-05	NCV	Cooling Water Supply Portion of RCIC Not Installed per Design Basis. (Section 4AO5.2.1.2.(b).1)
05000271/2004008-06	NCV	Failure to Correct Non-Conforming RCIC Pressure Control Valve. (Section 4A05.2.1.2(b).2)
05000271/2004008-07	NCV	Failure to Implement Adequate Design Control for Condensate Storage Tank Temperature. (Section 4AO5.2.1.7.(b))

05000271/2004008-08	NCV	Failure to Revise Safe Shutdown Capability Analysis Report. (Section 4AO5.2.2.(b))
05000271/2004008-09	NCV	Failure to Establish Adequate MOV Periodic Test Program. (Section 4AO5.2.3.(b))

LIST OF DOCUMENTS REVIEWED

Procedures and Tests

Emergency Operating Procedures

EOP-1 - RPV Control, Rev. 2
EOP-2 - ATWS, Rev. 4
EOP-3 - Primary Containment Control, Rev. 3
EOP-5 - RPV-ED, Rev. 3

Operating Procedures

OP-0023, Installation and Testing of Cable and Conduit, Rev. 8
OP-2113, Main and Auxiliary Steam, Rev. 20
OP-2114, Operation of the Standby Liquid Control System, Rev. 22
OP-2115, Primary Containment, Rev. 44
OP-2116, Secondary Containment Integrity Control, Rev. 19
OP-2119, Nitrogen Supply System, Rev. 13
OP-2121, Reactor Core Isolation Cooling System (RCIC), Rev. 29
OP-2124, Residual Heat Removal System, Rev. 52
OP-2140, 345 KV Electrical System, Rev. 25
OP-2141, 115KV Switchyard, Rev. 17
OP-2142, 4KV Electrical System, Rev. 21
OP-2145, Normal 125 VDC Operation, Rev. 24
OP-2149, Normal 24 VDC Operation, Rev. 7
OP-2170, Condensate System, Rev. 23
OP-2172, Feedwater System, Rev. 23
OP-3126, Shutdown Using Alternative Methods, Rev. 16
OP-4255, Calibration of 4kV Bus Degraded Grid Undervoltage Relays, Rev. 11
OP 5217, MOV Motor Control Center (MC2) Testing, Rev. 2
OP 5287, Evaluation of MOV Motor Control Center (MC2) Testing, Rev. 2
OP 5219, Diagnostic Testing of Motor Operated Valves, Rev. 12
OP 5220, Limitorque Operator PM, Rev. 25

Operational Transient

OT-3113, Reactor Low Level, Rev. 13
OT-3114, Reactor High Level, Rev. 13
OT-3115, Rx Low Pressure, Rev. 8

OT-3116, Rx High Pressure, Rev. 8
OT-3121, Inadvertent Opening of a Relief Valve, Rev. 13
OT-3122, Loss of Normal Power, Rev. 20

Other

ENN-OP-104, Operability and Determination Procedure, Rev. 2
ENN-DC-325, Component Performance Monitoring, Rev. 0
ENN-DC-151, PSA Maintenance and Update, Rev. 0
AP 6038, Component Level Review of Vermont Yankee Motor-Operated Valves (MOVs), Rev.1
AP 6039, Electrical Design Basis Review of Vermont Yankee Motor-Operated Valves (MOVs), Original Issue
AP 6037, System and Functional Design Basis Review of Vermont Yankee Motor-Operated Valves (MOVs), Original Issue
AP 6040, Vermont Yankee Motor-Operated Valve Electrical Configuration, Original Issue
AP 6041, Vermont Yankee Engineering Evaluations of MOV Diagnostic Testing and Feedback of Results into MOV Component Calculations, Rev. 1
PP 7004, Vermont Yankee Nuclear Power Station Motor Operated Valve Program, Rev. 1
PP 7005, Periodic Verification of Motor Operated Valves, Original Issue
CRP 9-8, Main Control Room Overhead Alarm Panel, Vernon BKR 3V4 Trip/Bus Voltage Low
ON 3155, Loss of Auto Transformer, Rev. 9

Calculations and Studies

Vendor Calculations

RCIC hydraulic calculations (VYE-1064 and VYE-1423)
Structural Integrity Inc. Report SIR-04-020 Rev C, File VY-10Q-401, Updated Stress and Fatigue Analysis for the Vermont Yankee Feedwater Nozzles, March 2004
Structural Integrity Inc. File VY10Q-302 Loads and Transient Definitions, Rev. 0
Structural Integrity Inc. Calculation Package VY-10Q-303, Uprated Feedwater Nozzle Stress and Fatigue Analysis, Rev. 0
Structural Integrity Inc. Calculation VY-10Q-301 Feedwater Nozzle Finite Element Model and Heat Transfer Coefficients, Rev. 0
Vendor Calculation DC-A34600-03, RHR and CS Suction Strainer Bubble Ingestion, Rev. 0

Vermont Yankee Calculations

VYC-415, Appendix R RCIC, HPCI, and ECCS Room Cooling, Rev. 0
VYC-462C, RCIC Steam Line Area High Temperature Setpoint, Rev. 0, and CCN 01
VYC-706, Condensate Storage Tank Level (RCIC) Monitoring, Rev. 1, CCN 01 and 02
VYC-709, RCIC System Flow Control and Indication Loop Accuracy, Rev. 1
VYC-715, Degraded Bus Voltage Monitoring loop Accuracy, Rev. 1
VYC-808, Core Spray and RHR Pump Net Positive Suction Head Margin Following a LOCA with Fibrous Debris on the Intake Strainers, Rev. 0, and CCN 4, 5 and 6 and its supporting references
VYC-830, Voltage Drop Calculations for VY Distribution Panels DC-1 and DC-2, Rev. 9

and CCN No. 5.

VYC-1005, Crack Growth Calculation for the Vermont Yankee FW Nozzles, Rev. 2
VYC-1053, Motor Operated Valve (MOV) Voltage Analysis, Rev. 8 and CCN 02
VYC-1088, Vermont Yankee 4160/480 Volt Short Circuit/ Voltage Study, Rev. 3
VYC-1293, System Level Review of Reactor Core Isolation Cooling MOVs for GL 89-10, Rev. 3
VYC-1347, Main Steam Tunnel Heatup Calculation, Rev. 0
VYC-1349, 125V Direct Current DC Voltage Drop Study, Rev. 2 and CCN 05
VYC-1512, Station Blackout Voltage Drop and Short Circuit Study, Rev. 2
VYC-1700, 4.16kV Bus Protective Relay Settings Verification, Rev. 1
VYC-1726, Reactor Core Isolation Cooling Pump Test Acceptance Values, Rev. 1 and CCN 01
VYC-1816, RCIC Pump Net Positive Suction Head (NPSH), Rev. 0 and CCN 01
VYC-1825, Analysis of Suppression Pool Temperature for Relief Valve Discharge Transients, Rev. 0 and CCN 1
VYC-1844, HPCI and RCIC Vortex Height, Rev. 1
VYC-1857, Fast and Residual Voltage Bus Transfer Analysis, Rev. I
VYC-1920, RHR and CS Suction Strainer Vortex/Minimum Submergence, Rev. 0 (DE&S Calculation DC-A34600-02 Rev. 0)
VYC-1924, Vermont Yankee ECCS Suction Strainer Head Loss Performance Assessment, RHR and CS Debris Head Loss Calculations, Rev. 0 (DE&S Calc DC-A32600-006 Rev. 0)
VYC-1950, Hydrodynamic Mass and Acceleration Drag Volume of Vermont Yankee ECCS Strainers, Rev. 0
VYC-1959, Analysis of Tests for Investigation (of) the Effects of Coatings Debris on ECCS Strainer Performance for Vermont Yankee, Rev. 1 (DE&S Report ITS/VY-98-01, Rev.1)
VYC-2153, 125 VDC Battery A-1 Electrical System Calculation, Rev. 0 and CCN 03
VYC-2154, 125 VDC Battery B-1 Electrical System Calculation, Rev. 0
VYC-2314, Minimum Containment Overpressure for Non-Loca Events, Rev. 0 and CCN 01 and 02
VYPC 98-010, Component Level Review of Reactor Core Isolation Cooling (RCIC) MOVs for GL 89-10, Rev. 2

<u>Studies and Evaluations</u>

Franklin Institute Technical Report F-C2653-01 Design and Stress Analysis of the Vermont Yankee NPS Clean-up / Feedwater Recombination Tee
General Electric (GE) Topical Report T0900
GE-NE-0000-0009-9951-01 Rev 1, Task 0302 Reactor Vessel Integrity Stress Analysis (Excludes the radius of the forging)
GE-NEDC-330090P, Assessment of Key Operator Actions, Table 10-5
Strainer Head Loss Performance Assessment, RHR and CS Debris Head Loss, Rev 0.
VYNPS:EPU T0400: DBA-LOCA for Long Term NPSH Evaluation
Yankee Uprate System Impact Study, dated November 11, 2003

Condition Reports

CR-96-117	CR-00-1575	CR-02-1860	CR-04-448
CR-96-129	CR-00-1596	CR-02-2193	CR-04-815
CR-96-136	CR-01-880	CR-02-2194	CR-04-1234
CR-98-467	CR-01-889	CR-02-2716	CR-04-1484
CR-98-1171	CR-01-890	CR-02-2733	CR-04-1522
CR-98-2066	CR-01-1007	CR-02-2942	CR-04-2600
CR-99-175	CR-01-1232	CR-03-441	CR-04-2621
CR-99-618	CR-01-1340	CR-03-962	CR-04-2623
CR-00-94	CR-01-1834	CR-03-1491	CR-04-2644
CR-00-306	CR-01-2084	CR-03-1855	CR-04-2723
CR-00-468	CR-01-2186	CR-03-1910	CR-04-2798
CR-00-1509	CR-01-2214	CR-03-2810	CR-04-2799
CR-00-1567	CR-02-151	CR-04-433	CR-04-2802

Drawings

Drawing B-191301 Sh. 1150, Core Spray System "B" Aux. Relays Sh 1, Rev. 13
Drawing B-191301 Sh. 306, 4kV SWGR #3 Instr & Relaying, Rev. 16
Drawing B-191301 Sh. 317, 4kV SWGR Aux. Relay Ckt., Rev. 10
Drawing B-191301 Sh. 327, 4kV SWGR #3 Tie to 4kV SWGR #1 Bkr. #3T1, Rev. 8.
Drawing B-191301 Sh. 328A, 4Kv SWGR #3 Compt, 10 Diesel Generator DG1-1B Bkr & LNP Ckt., Rev. 11
Drawing G-191157 Sheet 2 Location L-9, Flow Diagram Condensate, Feedwater and Air Evacuation Systems, Rev. 5
Drawing G-191174, Sheet 2, Flow Diagram - Reactor Core Isolation Cooling, Rev. 23
Drawing B-191261, Sheet 26C, Impulse Piping to Rack RK-6, Rev. 6
Drawing G-191298 Sh.1, Main One Line Diagram, Rev. 32
Drawing G-191298 Sh.2, Main One Line Phasor Diagram, Rev. 8
DS801-2, Generator SN 180X383 Reactive Capability Curve, dated February 11, 2003
Drawing 6202-001, General Plan Pressure Suppression Containment Vessel C Residual Heat Removal System - Bubble Ingestion from Safety Relief Valve and LOCA, Rev. 3

Operability Determinations

CR-VTY-1999-00990; Damaged Threads, Originated: 8/17/1999, Closed: 10/6/1999
CR-VTY-2001-00966; Leak Rate Test Results Exceeded the Acceptance Criteria, Originated: 5/04/2001, Closed: 6/29/2001
CR-VTY-2002-02258; IST Leak Rate Test Results Exceed the Acceptance Criteria, Originated: 10/09/2002, Closed: 4/10/2004
CR-VTY-2004-01607; Breaker 381 Fails to Stay Closed (it trips free), Originated: 5/2/2004, Closed 5/18/2004
CR-VTY-2004-2596; The Design Basis for Degraded Grid UV Relay not Adequately Documented in Calculation, Originated: 8/16/2004, Closed: Still Open

Modifications and Work Orders

DBD Pending Change Numbers RCIC 2004-002 and HPCI 2004-003
EDCR 81-22 in accordance with NUREG-0737, Item II.K.3.22
EDCR 97-404, MOV Electrical and Pressure Locking Modifications, dated June 17, 1998
EDCR 94-406, MOV Improvements, dated July 13, 1995
Modification Package MM-2003-015, Reactor Feed Pump Suction Pressure Trip Changes for EPU
Modification Package MM-2003-016, Reactor Recirculation System Run Back For Feedwater and Condensate System Transients
Modification Package MM-2004-015, Improve SLC Relief Valve Tolerances to Meet New SLC System Operating Pressure Requirements
Vermont Yankee Design Change VYDC 2003-013, Addition of 3rd Main Steam Safety Valve, dated 7/9/2003
Vermont Yankee Design Change VYDC 2001-003, RCIC Turbine Exhaust Check Valve Replacement, dated 10/28/2004

Correspondence

Memorandum, E. Betti to S. Miller, Feedwater Leakage Monitoring Data Analysis, dated January 30, 1991
Memorandum, E. Betti to S. Miller, Monthly Feedwater Leakage Monitoring Data Report Analysis, dated December 6, 1993
Letter FVY 82-105, VY to NRC, Feedwater Spargers - Response to NRC's Request for Additional Information, dated September 21, 1982
Letter BVY 94-07, VY to NRC, Request for Relief from NUREG-0619 Inspection Requirements, dated February 11, 1994
Letter NVY 95-142, VY to NRC, Feedwater Nozzle Inspection Relief Request - Vermont Yankee Nuclear Power Station (TAC No. M92940), dated October 12, 1995
Calculation VYC1005, Revision 1, Crack Growth Calculation for the Vermont Yankee FW Nozzles, Attachment 1, GE-NE-523-A71-0594 with NRC SER dated March 10, 2000
Letter BVY 01-02, VY to NRC, Alternative Feedwater Nozzle Inspection, dated January 22, 2001
Letter, NRC to VY, Vermont Yankee Nuclear Power Station Safety - Evaluation of Licensee Response to Generic Letter 9605 (TAC NO. M97114), dated December 14, 2000
Letter BVY 96-143, VY to NRC, Vermont Yankee 60-day Response to Generic Letter 96-05, dated November 15, 1996
Letter BVY 97-36, VY to NRC, Vermont Yankee 180-day Response to Generic Letter 96-05, dated November 15, 1996
Summary of Changes in Leak Detection Data, Report Generated August 30, 2004
Summary of Changes in Leak Detection Data, Report Generated September 1, 2004
GE Letter VYNPS-AEP-346 Revisions 0, 1 and 2

Event Reports

Event Report 20030340, Root Cause Analysis, The Outboard Seal on RFP "C" Failed

Other Documents

Generic Letter (GL) 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance," dated June 28, 1989
Generic Letter (GL) 96-05, "Periodic Verification of Design-Basis Capability of Safety-Related Power Operated Valves," dated September 18, 1996
Information Notice (IN) 2001-13, "Inadequate Standby Liquid Control System Relief Valve Margin, dated August 10, 2001.
Operational Decision-Making Issue (ODMI) Action Plan 2003-1812
NRC SER, Degraded Grid Voltage Protection for Class 1E Power Systems, dated March 31, 1986
Regulatory Guide 1.82, "Water Sources for Long-Term Recirculation Cooling following a Loss-of-Coolant Accident," Revision 3, dated November 2003
Vermont Yankee Updated Final Safety Analysis Report (UFSAR), Revision 18
Vermont Yankee Individual Plant Examination (IPE) Document
Vermont Yankee Appendix R Safe Shutdown Capability Analysis (SSCA), dated December 23, 1999
Vermont Yankee Technical Specifications, through Amendment No. 219

LIST OF ACRONYMS

AC	Alternating Current
ASME	American Society of Mechanical Engineers
CR	Condition Report
CST	Condensate Storage Tank
EPU	Extended Power Uprate
EOP	Emergency Operating Procedure
FAC	Flow Assisted Corrosion
GE	General Electric
GL	Generic Letter
HPCI	High Pressure Coolant Injection
kV	Kilovolt
LER	Licensee Event Report
MCC	Motor Control Center
MOV	Motor-Operated Valve
NCV	Non-Cited Violation
NPSH	Net Positive Suction Head
NRC	US Nuclear Regulatory Commission
OD	Operability Determination
psig	Pounds Per Square Inch Gauge
PRA	Probabilistic Risk Assessment
PUSAR	Power Uprate Safety Analysis Report

RAW	Risk Achievement Worth
RCIC	Reactor Core Isolation Cooling
RHR	Residual Heat Removal
ROP	Reactor Oversight Process
SBO	Station Blackout
SDP	Significance Determination Process
SLC	Standby Liquid Control
SPAR	Simplified Plant Analysis Risk
SRV	Safety/Relief Valve
TE	Technical Evaluation
TS	Technical Specifications
UFSAR	Updated Final Safety Analysis Report
V	Volt
VY	Vermont Yankee
VY SSCA	Vermont Yankee Safe Shutdown Capability Analysis

UNITED STATES
NUCLEAR REGULATORY COMMISSION

In Re: Entergy Nuclear Vermont Yankee)
LLC and Entergy Nuclear) Docket No. 50-271
Operations, Inc.)
(Extended Power Uprate at VY)) ASLBP No. 04-832-02-OLA

AFFIDAVIT OF WILLIAM K. SHERMAN

1. My name is William K. Sherman. I am employed by the Vermont Public Service Department ("Department") in the position of State Nuclear Engineer. I have held this position since November, 1988. My duties include ongoing State regulatory oversight of the Vermont Yankee Nuclear Power Station ("Vermont Yankee"), as well as advising the Department and other State agencies on issues related to Vermont Yankee and nuclear power. I have attached my resume to this affidavit and attest that the information contained therein is true and correct.

2. Additionally I interface with NRC staff around issues regarding Vermont Yankee. This includes contact with the resident inspectors stationed at Vermont Yankee as well as a wide range of other NRC personnel.

3. During the period from August 9 through September 3, 2004, the NRC conducted a team inspection at Vermont Yankee in accordance with Temporary Instruction 2515/158, "Functional Review of Low Margin/Risk Significant Components and Human Actions" ("Inspection"). The team was comprised of eight inspectors. I participated in the inspection with the other inspectors as an observer.

4. The Department has been advised by NRC personnel in a letter dated February 16, 2005, that the "NRC plans to inspect Entergy's corrective actions for the engineering team's finding, including those actions taken to reduce the time required to place RCIS in service from the alternate shutdown panels to increase available margin, during a problem identification and resolution sample inspection during the week March 21, 2005." A copy of the NRC letter is attached.

Exhibit B
NRC Docket No. 50-271
ASLBP No. 04-832-02-OLA
DPS Opposition Motion to Dismiss Contention 6
March 7, 2005

5. The DPS cannot respond fully to Entergy's claim that it has accomplished the verification required by the NRC Inspection, until it can be privy to the portions of the NRC Staff Hearing File or through other means the review of the inspectors of the documents submitted by Entergy in support of its claim that it has accomplished the verification required by the Inspection.

6. The documents necessary for my review of the verification will not be available until after the "problem identification and resolution sample inspection" conducted during the week of March 21, 2005 is completed.

William K. Sherman
William K. Sherman
State Nuclear Engineer

Subscribed and sworn to before me this 4th day of March, 2005.

Audrey A. Lindgren
Audrey Lindgren
Notary Public
My commission expires on February 10, 2007

William K. Sherman

Mr. Sherman has a broad range of policy, public relations, economic and technical experience in the nuclear area over a thirty five-year career.

Professional Employment

1988 - Present	**Vermont Department of Public Service** State Nuclear Engineer
1973 -1985	**Stone & Webster Engineering Corporation** Senior Power Engineer
1971 - 1973	**EDS Nuclear, Inc.** Senior Engineer
1967 - 1971	**U.S. Naval Nuclear Power Program** Lieutenant

Experience

Vermont Department of Public Service

Cognizance of the daily status of operation of the Vermont Yankee Nuclear Plant.

Periodic inspections at the Vermont Yankee Nuclear Plant.

Liaison with the federal regulator of the Vermont Yankee Nuclear Plant.

Responsibility for monitoring and evaluating physical plant conditions during nuclear emergencies.

Maintains cognizance of issues and activities related to nuclear power in support of the Commissioner's position as NRC State Liaison Officer.

Expert witness testimony for the Department for issues associated with Vermont Yankee and nuclear power.

Serves as Vermont's Member on the Texas Low-level Radioactive Waste Disposal Compact Commission.

Serves as a member of the Nuclear Waste Strategy Coalition, a coalition of state public utility commission, attorney general and nuclear utility representatives, acting to effect a solution for the disposal of nuclear high-level radioactive waste.

Serves as a member and past-chairman of the Northeast High-Level Radioactive Waste Transportation Task Force.

Testifies before legislative committees on nuclear power issues.

Serves as principal staff for the Vermont State Nuclear Advisory Panel (VSNAP).

Experience - (continued)

Stone & Webster Engineering Corporation

Environmental Qualification Manager for a nuclear power plant under construction (May 1985 - Jan 1986). Supervised compliance with the requirements for environmental qualification of Class 1E electrical equipment.

Lead Power Engineer (Mar 1982 - May 1985) for a nuclear power plant under construction. Responsible for the overall technical and administrative direction of the power-related engineering and design activities associated with the 1200 MW pressurized water reactor in the construction phase. Direction of ongoing efforts such as preparation of System Descriptions and the Final Safety Analysis Report.

Principal Nuclear Engineer (Feb 1981 - Apr 1982) for a nuclear power plant under construction. Responsible for nuclear-related engineering and design activities during the construction phase. Supervised the activities of Engineers responsible for the NSSS contract, nuclear systems, nuclear-related buildings, and major specifications.

Power Engineer, assigned to the Nuclear Engineering Group (Feb 1980 - Feb 1981) for a nuclear power plant under construction. Coordinated all activities for the fuel building and fuel handling systems, and for the auxiliary building and component cooling water system. Responsible for safety-related specifications for pumps, heat exchangers, and cranes.

Lead Licensing Engineer (Mar 1973 - Jan 1980). Responsible for project activities toward obtaining construction permits for three nuclear projects. Supervised the preparation of the Safety Analysis Reports and Environmental Reports. Responsible for evaluation of plant design to ensure compliance with NRC licensing requirements. Responsible for liaison with federal and state regulatory agencies.

EDS Nuclear, Inc.

Licensing and engineering consulting work for a number of nuclear utiities.

U.S. Naval Nuclear Power Program

Instructor at U.S. Naval Nucelar Power School in the areas of Reactor Physics, Heat Transfer, and Physics.

Education

1963 - 1967	**The University of Michigan** Bachelor of Science (Mechanical Engineering)

Licenses

Registered Professional Engineer - California, Massachusetts, Connecticut

DO
WKS

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

February 16, 2005

Mr. David O'Brien, Commissioner
Department of Public Service
State of Vermont
112 State Street - Drawer 20
Montpelier, VT 05620-2601

SUBJECT: NRC INSPECTION OF CORRECTIVE ACTIONS AT VERMONT YANKEE NUCLEAR POWER STATION

Dear Mr. O'Brien:

This letter responds to your letter dated January 26, 2005, regarding NRC inspection of Entergy's corrective actions for items found in the Vermont Yankee Nuclear Power Station engineering team inspection. Specifically, you wanted to know whether the NRC had reviewed Entergy's corrective actions for the item related to the length of time required to place the reactor core isolation cooling (RCIC) system in service from the alternate shutdown panels.

During the August 2004 engineering inspection, the team assured that there were no current reactor safety issues regarding this item. Specifically, the engineering inspection team determined that under the current licensed power level, the RCIC system could be placed in service from the alternate shutdown panels (outside the control room) within the required time. However, the team identified that the Safe Shutdown Capability Analysis associated with the initiation of RCIC from the alternate shutdown panels during an Appendix R fire scenario had not been updated to account for the increase in the time needed for operators to complete required actions that resulted, in part, from new personnel safety requirements. The NRC plans to inspect Entergy's corrective actions for the engineering team's finding, including those actions taken to reduce the time required to place RCIC in service from the alternate shutdown panels to increase available margin, during a problem identification and resolution sample inspection during the week March 21, 2005. This schedule was coordinated with Bill Sherman of your staff.

The other items from the Vermont Yankee engineering team inspection will be reviewed in future NRC inspections as part of the NRC reactor oversight process.

If you have any questions regarding our planned inspection, please contact me or Mr. Larry Doerflein of my staff at (610) 337-5378.

Sincerely,

Wayne D. Lanning

Wayne D. Lanning, Director
Division of Reactor Safety

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

cc:
Sen. Patrick Leahy
Sen. James Jeffords
Rep. Bernard Sanders
Jay Thayer, Entergy

PREAPPROVED LPC FORM

PART 1 – Initiation ☐ Converted to Admin. Revision # **LPC No:** 13

A. Procedure No.: OP 3126	Current Revision #: 16	Title: Shutdown Using Alternate Methods

B. Owner Depart. Permission obtained: ☐ Yes ☒ N/A Initials of Person Contacted: Date:

C. Description of Change:

1. Deleted note prior procedure step 3.a. The note was confusing and subsequent procedure steps provide all necessary information.
2. Step 3.b was revised to correct a typo and to indicate that the chemistry tech is to use OP 3540 Appendix A to make the initial state and NRC emergency notifications. Previously the entire OP 3540 procedure was referenced so this change speeds performance by directing the individual directly to the procedure section to be used.

D. Reason for Change: ☐ Result of Design Change, Minor Mod, EDCR________
☐ Related CR No.______ - ______
☒ Other:________
☐ Errata (DCC USE ONLY)

E. Duration: ☒ Permanent ☐ One Time Only
F. Surveillance Database Change? ☐ Yes, change submitted ☒ No
G. Procedure Type: ☒ Technical ☐ Admin. (AP,PP)
H. AP 0091, Risk Assessment ☐ Yes ☒ No
I. Page(s) affected: 5

J. Originator (Print/Sign/Date/mail code/ext.) (Complete & attached AP 0096, App. C)
D.J. DeForge 700/5512
D.J. DeForge 8/19/04

PART 2 - Review/Approval (Refer to LPC Criteria of Appendix A)

A. Technical Verification Review ☐ N/A
(Print/Sign/Date)
KAREN MEGG 8/19/04
Karen Megg
(May perform Qualified Review) (N/A if errata change)

B. Cross-Discipline Review(s) ☐ N/A
(Print/Sign/Date)
D.J. DeForge for Roger Verderi per Discussion
D.J. DeForge 8/19/04

C. Qualified Review (Print/Sign/Date) ☐ N/A
D.J. DeForge
D.J. DeForge 8/19/04

D. ENN-LI-100/ENN-LI-101 reviews completed type:
☒ PAD/Screen ☐ Evaluation ☐ N/A
☐ 50.54(q) (EPIP only)

E. RPO Approval (Print/Sign/Date) ☐ N/A if an Errata
Edward L. Harms 8/19/04

F. IF 10CFR50.59 Evaluation: ☒ N/A
PORC Mtg. Date:

G. General Manager (Print/Sign/Date) (SPs only)

H. Training: (Required for Admin Procedures, N/A if an Errata) ☒ N/A

I. Effective Date: 08/19/04 DUK per telecon DJD 8/23/04

CDS Initials DuK Admin. Rev. ONLY: Procedure Change #______ Issue Date:______

VYAPF 0097.01
AP 0097 Rev. 4
Page 1 of 1
LPC #1

Exhibit C
NRC Docket No. 50-271
ASLBP No. 04-832-02-OLA
DPS Opposition Motion to Dismiss Contention 6
March 7, 2005

APPENDIX C
CROSS-DISCIPLINE REVIEW CHECKLIST

Required to be completed for new procedures, procedure revisions, and LPCs.

Not required for procedure revisions designated as Editorial

Procedure Number/Revision OP 3126 / R16 LPC#: 13 DWR
Reviewer/Date (Print) D.J. DeForge / 8-19-04

GENERAL REVIEW GUIDELINES/SPECIAL REVIEW REQUIREMENTS
• The Cross-Discipline Review Guidelines below constitute minimum review requirements; other reviews may apply. • Determination of reviews should focus on *changes* made to a procedure and the potential impact of those changes on the affected group. Changes that are minimally or nonimpacting do not need review by the potentially affected group. If change impact is unclear, the procedure should be routed to the potentially affected group for review. • New or revised Administrative or Program Procedures that significantly impact other departments, shall be reviewed by the appropriate Superintendent or Senior Manager. The Supervisor, Office Services-DCC maintains a list of these Administrative and Program Procedures. • ALL noneditorial changes to Special Process procedures (WP, NE, heat treating, etc.), including Vendor Procedures that address Special Processes, shall be reviewed by: a Welding Engineer (welding procedures) or a NDE Level III certified in the method addressed by the procedure (nondestructive examination procedures), AND the Quality Assurance Manager, AND submitted to the Authorized Nuclear Inservice Inspector (ANII) prior to use. • A "YES" indicates that a Cross Discipline Review shall be done by the indicated Department. Document the review on VYAPF 0096.01, VYAPF 0097.01, or VYAPF 0097.02, as applicable.

	APPLICABLE	
	YES	NO
Chemistry: • Potentially affects condensate, feedwater, or reactor water chemistry, or chemistry instruments. • Procedures that implement the requirements of the VY Environmental Program. (see PP 7603, Appendix A) • Produces/affects effluents or effluent monitoring (VY/QA 01-015). • Affects NPDES limits or method of compliance.		√
Maintenance (Mech, Elec, I&C): • Requires Maintenance personnel to perform activities, such as performance of maintenance procedures, installation of M&TE, lifting and landing of leads and connectors.		√
Operations: • Changed requirements for entry into a Limiting Condition for Operation (LCO) or significantly changes duration of LCO. • Requires Operations alignment/restoration of systems or components. • Specifies surveillance or post maintenance testing by Operations.		√
EOP/SAG Coordinator: • Procedures that have the potential to affect the EOPs/SAGs.		√

APPENDIX C (Continued)

	APPLICABLE YES	APPLICABLE NO
Quality Assurance: • Compliance with QA Program requirements cannot be readily determined by the Qualified Reviewer.		√
Radiation Protection: • Involves work in contaminated areas and high radiation areas. • Involves work that breaches contaminated systems or components. • Changes in radwaste or hazardous waste generation.		√
Emergency Plan Coordinator: • Emergency Plan Implementing Procedures. • Obtain and attach a 10CFR50.54(q) Evaluation. • Affects Emergency Plan personnel, facilities or equipment.		√
Software Quality Assurance Administrator • Procedures that define how software is developed.		√
Reactor Engineering: • Could affect core reactivity, thermal power, reactor heat balance, or fuel integrity. • Involves refueling operations.		√
Systems/Project/Design Engineering: • Maintenance Rule in-scope systems unavailability time. • Involves infrequently performed test or evolution. • Changed requirements for entry into a Limiting Condition for Operation (LCO) or significantly changes duration of LCO. • Significant changes in system test or operation methodology.		√
Appendix J Coordinator: • Changes that affect App. J leakrates or containment boundaries, or boundary valve manipulation.		√
Appendix R Coordinator: • Appendix R implementing procedures.	√	
Environmental Qualification (EQ) Coordinator: • Change in EQ test methodology or component lifetime. • Potentially affects area EQ component environment.		√
Fire Protection Coordinator (FPC): • Fire Protection procedures. • Affects fire loading • Affects fire barrier integrity. • Affects fire protection systems or component functionality.		√
IST Program Coordinator: • Inservice Testing Program implementing procedures. • All surveillance procedures. • Relief Valves, Check Valves, MOV and AOV Program Procedures (SURV2002-025_03).		√
ISI Program Coordinator: • Inservice Inspection Program implementing procedures.		√

APPENDIX C (Continued)

	APPLICABLE YES	APPLICABLE NO
Setpoint Coordinator: • Changes that impact setpoints, as-found/as-left tolerances, M&TE or testing methodology.		√
Nuclear & PRA • Potentially affects IPEEE or ORAM Sentinel Risk Models. • Potentially affects plant SSCs reliability. • Potentially affects Nuclear or Radiological Safety Analysis.		√
Security: • Procedures that implement the requirements of the VY Physical Security and Training and Qualification Plans. • Changes that have a potential for reduction of the VY Physical Security and Training and Qualification Plan commitments. • Obtain and attach a 10CFR50.54(P) Evaluation.		√
MOV Program Coordinator: • Potentially affects system parameters for which MOV operation has been evaluated.		√
AOV Program Coordinator: • Potentially affects system parameters for which AOV operation has been evaluated.		√

ATTACHMENT 9.1 PROCESS APPLICABILITY DETERMINATION

1 of 7

Part I ☐ IP1 ☐ IP2 ☐ IP3 ☐ JAF ☐ PNPS ☒ VY Nuclear Power Plant Activity No: op 3126 LPC#: 13 Preparer (Print/Sign): D.J. DeForge D.J. DeForge
Activity Description: Procedure change Date: 8/19/04

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 Protection
☐ Yes ☒ No	Radiation Protection/ALARA program	Rad Protection	Rad Protection	Rad Protection	Rad Protection	Rad Protection	Rad Protection
☐ 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)	N/A	N/A	N/A	MCM-4.3/4.4	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.

ATTACHMENT 9.1 PAGE 2 OF 7

Part II. LBD/Program Questions (Department or Program Owner)	
	Technical Specifications or Facility Operating License (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?
	Tech Spec Bases, Technical Requirements Manual (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?
	Security Plan (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?
	QA Program (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?

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?

ATTACHMENT 9.1

Part II - LBD/Program Questions (Department or Program Owned)

	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?

Part II: LBD/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?

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?
	Commitments (Licensing Manager)
☐Yes ☒ No	Does the proposed activity modify or delete any commitments?

ATTACHMENT 9.1 PAGE 7 OF 7

	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?

ATTACHMENT 9.1 **50.59 SCREEN CONTROL FORM**

Sheet 1 of 2

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

Activity ID/No. OP 3126 R16 LPC#: 13 Activity: ☐ Design Change; ☒ Procedure; ☐ Test; ☐ Experiment; ☐ Other

Description:
1. Deleted note prior procedure step 3.a. The note was confusing and subsequent procedure steps provide all necessary information.
2. Step 3.b was revised to correct a typo and to indicate that the chemistry tech is to use OP 3540 Appendix A to make the initial state and NRC emergency notifications. Previously the entire OP 3540 procedure was referenced so this change speeds performance by directing the individual directly to the procedure section to be used.

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: UFSAR 1.6.2.17, 4.4.5, 7.4.3.3.2, 7.4.4, 8.4.5, 8.6, 8.8.3, 10.11.3, SSCA 2.6

Part III Justification (Attach additional pages as necessary):

This change is essentially editorial in nature. A poorly worded note is removed from the procedure. Step 3.b is made more specific to direct the performing individual to the appropriate procedure section and prevent wasting time searching through a large procedure for the appropriate section. This activity is performed in parallel with operator activities so no time line benefit or penalty is incurred by this activity.

Part IV 50.59 Evaluation is *NOT* required:

PREPARER: D.J. DeForge SIGNATURE: D.J. DeForge DATE: 8/19/04

REVIEWER: Karen Mero SIGNATURE: [illegible] DATE: 8/19/04

\# of pages attached: 0

VERMONT YANKEE NUCLEAR POWER STATION

OPERATING PROCEDURE

OP 3126

REVISION 16

SHUTDOWN USING ALTERNATE SHUTDOWN METHODS

USE CLASSIFICATION: **CONTINUOUS**

LPC No.	Effective Date	Affected Pages
1	08/23/00	App. C Pg 3 & 4 of 9
2	10/06/00	App. E Pg 7 of 8
3	04/18/01	App. D Pgs 6,7 & 8 of 8
4	05/03/01	App. D Pgs 7 & 8 of 8; App. E Pg 8 of 8
5	06/12/01	5 of 5; App. B Pg 2 of 8
6	12/20/01	App. C Pg 6 of 9
7	04/30/02	App. A Pgs 1 - 7 of 7
8	07/25/02	3 & 5 of 5
9	10/11/02	App. A Pg 1 of 7
10	11/26/02	App. F Pg 1 of 1
11	09/11/03	App. E Pg 5 of 8
12	08/13/04	App D Pg 6 of 8
13	08/19/04	5 of 5

Implementation Statement: N/A

Issue Date: 03/21/00

Dept. Mgr.	[signature]	Proc. No.	OP 3126
PORC	N/A	Rev. No.	16
Plant Mgr.	N/A	Issue Date	03/21/00
		Review Date	09/02/02

SHUTDOWN USING ALTERNATE SHUTDOWN METHODS

PURPOSE

The purpose of this procedure is to outline those actions necessary to safely shutdown the plant in the event that the Control Room must be evacuated, or there is a fire in the cable vault or other plant area affecting the operation of equipment needed for a safe shutdown.

The use classification of this procedure is Continuous Use.

DISCUSSION

The Shift Supervisor is authorized to implement this procedure if it is determined the reactor must be shut down from outside the Control Room. This determination is based upon actual or possible events that have occurred or could occur. Events such as a fire in the Cable Vault or the Control Room, that affect equipment control, toxic gas intrusion that affects Control Room habitability, or threat of a bomb in the Control Room, could require entry into this procedure. Since implementation of this procedure ultimately will result in a Site Area Emergency it should be declared concurrently with implementation.

If a sufficient amount of time exists in an emergency, actions should be taken by Control Room personnel to mitigate the emergency prior to abandoning the Control Room by proceeding as far as possible in achieving a cold shutdown using OP 0105.

The three basic objectives of this procedure are the following:

a. Scram and isolate the reactor.

b. Use RCIC and SRV's or LPCI and SRV-71A and/or 71B to control reactor level and pressure after the initial transient.

c. Use the RHR system to cool the torus and, when possible, for shutdown cooling.

Should the Control Room or cable vault be inaccessible for an extended period of time, this procedure provides direction for a complete plant cooldown. Switches, local control panels, and alternate power sources have been provided to permit the reactor to be shut down without reliance on the Control Room or the cable vault. The resources available to accomplish a reactor shutdown by alternate means include the RCIC system (with its alternate shutdown panels), the A RHR system (with its alternate shutdown panel), the Vernon Tie and "A" Diesel Generator, and the support equipment for these systems. The Vernon Tie is the preferred power source. The Appendices to this procedure contain supplements which provide instructions for non-routine events.

The alternate shutdown panels for RCIC are located on the 252' level of the reactor building (by RCIC door) and on the 213' level in the RCIC corner room. The RHR alternate shutdown panel is located on the 280' level of the reactor building. The Vernon Tie is controlled from the Switchgear Rooms during alternate shutdown. The "A" Diesel Generator is controlled from the "A" Diesel Generator Room. The location of other components used for alternate shutdown are identified in the appendices.

The alternate shutdown system is designed with the intent that either the RCIC alternate shutdown subsystem is used to control reactor water level with the aid of the SRVs for reactor pressure control, or the reactor depressurized using the SRV's and the RHR system used to control reactor level. The RHR alternate shutdown system can be utilized for torus cooling, shutdown cooling and for reactor level control. The Vernon Tie is used to provide power to Bus 4 after the bus has been isolated from outside power sources.

This procedure is designed to be implemented with a minimum shift complement to safely shutdown the plant from outside the Control Room. However, during such an event all possible courses of the event can not be described in a procedure. Shift personnel are expected to use this procedure to the extent possible to reach a safe shutdown condition. Those actions that, in the opinion of the Shift Supervisor, are not needed do not have to be accomplished. Personnel assignments and procedural steps may be combined at the discretion of the Shift Supervisor.

ATTACHMENTS

1.	Appendix A	Amplifying Information - Operator #1
2.	Appendix B	Amplifying Information - Operator #2
3.	Appendix C	Amplifying Information - Operator #3
4.	Appendix D	Amplifying Information - Operator #4
5.	Appendix E	Amplifying Information - Miscellaneous
6.	Appendix F	Instructions for RHR-18 Alternate Power Connection

REFERENCES

1. Technical Specifications

   a. None

2. Administrative Limits

   a. None

3. Other

   a. NRC Letter to D.A. Reid, VYNPS Appendix R Exemptions, dated 8/12/97
   b. EPC_9502, Assess Memo RLS to DCP, "Review of Service Water System As It Pertains To Appendix R", dated 12/20/94
   c. Memo, P.A.R to S.R.M, VYS 21/94, "Service Water System Water Hammer", dated 2/18/94
   d. Memo, P.A.R to J.D., VYS 83/97, "Proposed Response For Resolving NRC RAI On RHR/CS Pump Minimum Flow", dated 8/6/97

e. PFI 9409102, Revise Procedures To Reflect The Need To Monitor Diesel Generator Fuel Usage As The Site Does Not Have Enough Fuel Oil On Site To Run The Diesels For Seven Days At 2750KW
f. NVY94084_03, "RE: BVY 94-90, Encl. A; Thermal Hydraulic Stability - Develop Procedures to Provide Operators Guidance"
g. VYC0706R01_04, Revise Appendix C to Transfer RCIC Suction at $\geq$7% CST Level
h. VYC-1507, Appendix R Safe Shutdown Analysis for Vermont Yankee Nuclear Power Station
i. VYC-1522 Rev. 0, "Drywell Spray Initiation Limits for Containment Temperature Control for Appendix R Alternate Shutdown"
j. ER 99-0548, OP 3126 Procedure Different than App. R Analysis
k. DWG G-191376, Sound Powered Telephone Drawing
l. OP 0105, Reactor Operations
m. OP 0109, Plant Restoration
n. OP 2126, Diesel Generators
o. OT 3122, Loss of Normal Power
LPC 8 p. OP 3540, Control Room Actions During an Emergency
q. OP 3504, Emergency Communications

PRECAUTIONS

1. Placing the RCIC, RHR, 4KV/480V Switchgear, or the DG transfer switches in EMER removes control function from the Control Room and defeats most automatic functions and system interlocks.

2. The Vernon Tie should be placed in service or the "A" Diesel Generator should be started as soon as possible to provide LPCI capability in the event an SRV opens.

3. RHR pump operation in the minimum flow mode should be minimized. (Memo VYS 83/97)

4. The ability to communicate is necessary for the performance of this procedure. It is possible that no one communications method will be successful in all situations. Listed below in order of preference are the methods available to the shutdown crew:

   a. Radios
   b. Sound-powered phones
   c. Gai-Tronics
   d. Runners

5. Exercise caution prior to entry into an unoccupied area since conditions associated with the emergency may dictate that protective equipment should be used.

6. Exercise caution and use protective equipment when replacing fuses or operating knife switches.

7. A Cardox system actuation due to a fire in the Cable Vault will result in an evacuation of the Administration Building lower level per OP 3020. Operators may safely transit from the Control Room to the Switchgear Rooms to implement this procedure. Operators exiting the Switchgear Rooms during the performance of this procedure shall exit through either the double doors to the Turbine Building or East (outside) door of the East Switchgear Room until such time that the habitability of the Administration Building has been determined to be acceptable for re-entry.

PROCEDURE

1. Assignment of Responsibilities

   a. Fire Emergency not declared:

      1) Operator #1 SCRO

      2) Operator #2 CRO

      3) Operator #3 ACRO

      4) Operator #4 as assigned

   b. Fire Emergency declared:

      1) Operator #1 SS

      2) Operator #2 SCRO

      3) Operator #3 CRO

      4) Operator #4 ACRO

2. Automatic Actions

   a. In the event of a fire in the cable vault, the cardox system in that room should initiate.

   b. Depending on the casualty, the sections of the plant affected and the manner in which the casualty progresses, various automatic actions may or may not occur as intended or they may occur inadvertently.

ILPC 13

3. Initial Actions

a. Using the Gai-Tronics paging mode, declare a Site Area Emergency due to evacuation of the Control Room and shutdown by alternate shutdown methods.

ILPC 13

b. Request the Chemistry Technician to implement the initial State and NRC notification requirements of the E-Plan from the TSC per OP 3540, Appendix A, States and NRC Notification For a Control Room Evacuation Event.

c. Perform the following before leaving the Control Room:

1) Manually scram the reactor

2) Trip the "A" and "B" Recirc Pumps.

3) Close all the MSIV's.

4) Place ADS bypass switch to "BYPASS".

5) Place the "A" RHR Pump control switch in Pull-to-Lock

6) Place the HPCI Aux Oil Pump control switch in Pull-to lock

7) Place the Reactor Feed Pump control switches in Pull-to-Lock

ILPC5

8) Take the portable radios and keyrings when the Control Room is abandoned.

4. Subsequent Actions

a. Perform the appropriate actions on the alternate shutdown methods appendices.

b. Monitor Fuel Oil Storage Tank level and make arrangements for fuel oil deliveries as necessary. (PFI9409102)

FINAL CONDITIONS

1. Reactor level 175-185 inches.

2. Reactor temperature 100-212°F.

APPENDIX A

AMPLIFYING INFORMATION FOR OPERATOR #1

1. Perform the following at 4KV Bus 1:

   a. Remove the "CLOSE" fuses for and open/check open the following breakers:

      1) REACTOR FEED WATER PUMP P-1-1A

      2) REACTOR RECIRC MG SET MG-1-1A DRIVE

      3) REACTOR FEED WATER PUMP P-1-1B

2. Perform the following at 4KV Bus 2:

   a. Remove the "CLOSE" fuses for and open/check open the following breakers:

      1) REACTOR RECIRC MG SET MG-1-1B DRIVE

      2) REACTOR FEED WATER PUMP P-1-1C

3. Assist Operator #4 in restoring power to 4KV Bus 4 and 480V Bus 9 per Appendix D.

CAUTION

IF THE CARDOX SYSTEM FOR THE CABLE VAULT HAS ACTUATED, EXIT THE SWITCHGEAR ROOMS THROUGH EITHER THE DOUBLE DOORS INTO THE TURBINE BUILDING, OR OUT THE EAST (OUTSIDE) DOOR OF THE EAST SWITCHGEAR ROOM UNTIL SUCH TIME THAT THE HABITABILITY OF THE ADMINISTRATION BUILDING HAS BEEN DETERMINED TO BE ACCEPTABLE FOR RE-ENTRY.

----

4. Perform the following at ECCS 24VDC DISTRIBUTION PANEL B:

   LPC7 a. Contact Operator #2 and determine that all Appendix R transfer switches at CP-82-2 have been transferred to the EMERGENCY position.

   LPC9 LPC7 b. Open the circuit breaker from ECCS POWER SUPPLY ES-24DC-2 (CKT 7) at 24VDC.

   LPC9 LPC7 c. Close the APPENDIX R POWER SUPPLY ES-24DC-3 (CKT 6) at 24VDC

5. Establish a Command and Control Center at the RHR ALTERNATE CONTROL SYSTEM CP-82-2.

6. Contact Operator #3 for operation status of RCIC, and for initial Reactor and Containment parameters.

7. Direct Operator #2 to place "A" RHR in Torus Cooling per Appendix B

8. Once Plant conditions are stable, direct Operator #3 to commence a plant cooldown at a rate of 80 to 100°F/Hr using SRV-71A or SRV-71B per Appendix C.

9. If nitrogen was lost to the Containment Air System, direct Operator #4 restore nitrogen per Appendix A of OT 3122.

10. When reactor pressure reaches 650-700 psig as read on PT-2-3-56A(M) on CP-25-6B, direct Operator #4 in the Switchgear Room to open/verify open all Condensate Pump breakers.

11. When Reactor Pressure is reduced to less than 100 psig as read on PT-2-3-56A(M) ON CP-25-6B, direct Operator #2 to establish shutdown cooling per Appendix B.

12. Monitor Reactor Water Level on LT-2-3-73A(M) on CP-25-6B.

13. If vessel level is at or below TAF, perform the following:

    a. Verify with Operator #2 that "A" RHR is operating in the Torus Cooling Mode.

    b. Direct Operator #3 to open SRV-71A and SRV-71B.

    c. When Reactor Pressure decreases below 280 psig as read on PT-2-3-56A(M) on CP-25-6B, direct Operator #2 to, perform the following:

        1) Open/check open RHR V10-25A INBOARD INJECTION VALVE..

        2) Open RHR V10-27A OUTBOARD INJECTION VALVE.

        3) Close RHR V10-34A SUPP. CHAMBER SPRAY BYPASS VALVE.

        4) Restore Reactor water level to 130" to 170" as indicated by LT-2-3-73A(M) on CP-25-6B.

        5) Open RHR V10-34A SUPP. CHAMBER SPRAY BYPASS VALVE.

        6) Close RHR V10-27A OUTBOARD INJECTION VALVE.

    d. Maintain vessel level 130" to 170" by operating RHR-34A and RHR-27A to inject to the vessel.

    e. Direct Operator #2 to establish shutdown cooling per Appendix B.

14. If elevated Torus pressure affects RCIC operation, then:

a. Direct Operator #2 to start the "A" RHR system in the Torus Cooling Mode.

b. Direct Operator #3 to open SRV-71A and SRV-71B.

c. When reactor pressure decreases below 280 psig as read on PT-2-3-56A(M) on CP-25-6B, direct Operator #2 to perform the following:

1) Open/check open RHR V10-25A INBOARD INJECTION VALVE.

2) Open RHR V10-27A OUTBOARD INJECTION VALVE.

3) Close RHR V10-34A SUPP. CHAMBER SPRAY BYPASS VALVE.

4) Restore Reactor water level to 130" to 170" as indicated by LT-2-3-73A(M) on CP-25-6B.

5) Open RHR V10-34A SUPP. CHAMBER SPRAY BYPASS VALVE.

6) Close RHR V10-27A OUTBOARD INJECTION VALVE.

d. Maintain vessel level 130" to 170" by operating RHR-34A and RHR-27A to inject to the vessel.

e. Direct Operator #2 to establish shutdown cooling per Appendix B.

15. If Drywell air space temperature exceeds 325°F as read on TI-16-19-42A (CP-82-1), then:

a. Direct Operator #2 to start the "A" RHR system in the Torus Cooling Mode.

b. Direct Operator #3 open SRV-71A and SRV-71B.

c. When reactor pressure decreases to less than 280 psig as read on PT-2-3-56A(M) on CP-25-6B, direct Operator #2 to perform the following:

1) Open/check open RHR V10-25A INBOARD INJECTION VALVE.

2) Open RHR V10-27A OUTBOARD INJECTION VALVE.

3) Close RHR V10-34A SUPP. CHAMBER SPRAY BYPASS VALVE.

4) Restore Reactor water level to 130" to 170" as indicated by LT-2-3-73A(M) on CP-25-6B.

5) Open RHR V10-34A SUPP. CHAMBER SPRAY BYPASS VALVE.

6) Close RHR V10-27A OUTBOARD INJECTION VALVE.

d. Maintain vessel level 130" to 170" by operating RHR-34A and RHR-27A to inject to the vessel.

e. Direct Operator #2 to establish shutdown cooling per Appendix B.

16. Once the plant is in a stable condition, direct available personnel to perform the following:

a. Close SW-261, SW supply to SFPC, 303' level north of RBCCW HXs.

b. Isolate instrument air to Drywell ventilation valves:

1) Close IA-24E (Rx Bldg 303' level east of RBCCW HXs).

2) Close IA-24F (Rx Bldg 303' level east of RBCCW HXs).

c. Open IA V72-126, IA accumulator #11 drain, Rx Bldg 303' level near RBCCW pumps.

d. Close VG-8A, CAD vent from the Drywell, Rx Bldg 303' level near RBCCW pumps.

e. Close CU V12-73A, "A" RCU Pump suction valve, "A" CU Pump Room 280' level.

f. Close CU V12-73B, "B" RCU Pump suction valve, "B" CU Pump Room 280' level.

g. Close VNP V-16-19-63, N2 makeup to Drywell/Torus, Rx Bldg 252' level Makeup Trim Heater.

h. Close RHR-192B, "B" RHR HX service water outlet, SE Corner Room 232' level.

i. Isolate instrument air to the Torus ventilation valves:

1) Close IA-66C (Torus Catwalk north).

2) Close IA-66D (Torus Catwalk north).

j. Open IA-127, IA accumulator #12 drain, Torus Catwalk north.

k. Close VG-8B, CAD vent from the Torus, Torus Catwalk north.

l. Isolate instrument air to containment ventilation valves:

1) Close IA-66A (Torus Catwalk south).

2) Close IA-66B (Torus Catwalk south).

m. Open IA-128, IA accumulator #13 drain, Torus Catwalk south.

n. Close/check closed RHR V10-183, RHRSW-RHR Emergency Fill, NE Corner Room 232' level.

o. Close/check closed RHR V10-184, RHRSW-RHR Emergency Fill, NE Corner Room 232' level.

p. Open the ACB for HPCI MINIMUM FLOW VALVE 23-25 (MCC-DC-1B).

q. Manually close/check closed HPCI V23-25 HPCI Minimum Flow Valve, HPCI Corner Room 213' level.

17. When additional personnel are available, restore Fuel Pool Cooling by performing the following:

a. Obtain permission from the Shift Supervisor to perform the wiring change.

b. Have Maintenance personnel perform the following:

Authorized By/Date

1) At 480V MCC-9B compartment 1M, open the ACB for SFPC PUMP P-19-2A.

Performed by Verified by

2) Disconnect cable C11223CSII in P-19-2A breaker cubicle (see CWD 1223).

Performed by Verified by

3) Install jumper between terminals 3 and 5 on the terminal block.

Performed by Verified by

4) If necessary, replace 3 amp control circuit fuse if necessary.

c. Open/check open SW ISOL TO SFPCS SW-261, Rx Bldg 303' level north of RBCCW HXs.

d. Open SFPC Hx 2A SW Outlet SW-257A, (Maintenance assistance may be required to operate this valve).

e. At 480V MCC-9B, close the SFPC PUMP P-19-2A ACB.

NOTE

The restoration of Drywell ventilation will be dependent upon plant conditions. It is expected that the TSC will support this and other plant restoration activities as required.

18. Perform the following and maintain the conditions established until normal shutdown cooling is available and a Drywell ventilation flow path has been restored.

a. Direct Operator #2 to start the "A" RHR system in the Torus Cooling Mode.

b. Direct Operator #3 to open SRV-71A and SRV-71B.

c. Maintain vessel level 130" to 170" by operating RHR-34A and RHR-27A to inject into the vessel as follows:

1) Open/check open RHR V10-25A INBOARD INJECTION VALVE.

2) Open RHR V10-27A OUTBOARD INJECTION VALVE.

3) Close RHR V10-34A SUPP. CHAMBER SPRAY BYPASS VALVE.

4) Restore Reactor water level to 130" - 170" as indicated by LT-2-3-73A(M) on CP-25-6B.

5) Open RHR V10-34A SUPP. CHAMBER SPRAY BYPASS VALVE.

6) Close RHR V10-27A OUTBOARD INJECTION VALVE.

NOTE

A rapid decrease in pressure and temperature is anticipated when Drywell sprays are initiated. Expect the Reactor Building to Torus vacuum breakers to open under these conditions.

d. If Drywell temperature exceeds 260°F as read on TI-16-19-42A, perform the following:

1) Direct Operator #2 to place the "A" RHR system in the Torus Cooling Mode.

2) Manually open RHR V10-26A

3) Manually open RHR V10-31A.

4) When Drywell temperature is reduced below 200°F as read on TI-16-19-42A,

   a) Manually close RHR V10-26A

   b) Manually close RHR V10-31A.

5) Repeat Steps d.1) though d.4) above as necessary until shutdown cooling is established and Drywell temperature remains less than 260°F.

APPENDIX B

AMPLIFYING INFORMATION FOR OPERATOR #2

1. Isolate and depressurize the outboard MSIV air header by performing the following:

   a. Close air supply valves (on mezzanine above TIP Room):

   - IA-28A
   - IA-28B

   b. Open air header vent valves (on mezzanine above TIP Room):

   - IA-28D
   - IA-28E

2. If required, close CRD CHARGING WATER HEADER SUPPLY CRD-56 to limit Reactor Vessel level increase.

3. On IAC panel A, open ckt. #4 to isolate Reactor Water Cleanup Drain regulator CU-55 (Rx Bldg 252' behind elevator).

4. At CP-82-2, RHR ALTERNATE SHUTDOWN SYSTEM, position the four RHR ALTERNATE SHUTDOWN TRANSFER switches to EMER <u>in the following sequence.</u>

   a. SS1315A

   b. SS1315B

   c. SS1315C

   d. SS1315D

   e. If power is not available on the panel or to some valves, replace the fuses as described in Appendix E.

5. If the Recirc MG foam system has initiated, close RECIRC MG FOAM DELUGE ISOL FP V76-312 (at the recirc MG foam system).

6. Open the following ACBs:

   a. V10-66 RHR DISCHARGE TO RADWASTE ISOL. VALVE (MCC-8B)

   b. EMERG. INTERTIE VALVE V10-183 (MCC-8B)

   c. MAIN STEAM DRAIN INBOARD VALVE V2-74, (MCC-8B)

   d. CLEANUP RECIRC PUMP P49-1A (MCC-7A)

e. MAIN STEAM LINE DRAIN VALVE V2-77 (MCC-DC-2A)

f. CONT. SPRAY OUTBOARD INJECT VALVE V10-26A (MCC-9B)

g. EMERG. INTERTIE VALVE V10-184, (MCC-9B)

h. CLEANUP RECIRC PUMP P49-1B (MCC-6A)

7. Close/check closed:

a. RHR-66 (NE torus catwalk).

b. RHR V10-26A, (Rx Bldg 252' level by North HCUs).

8. Place MCC-89A on the Maintenance Tie <u>in the following sequence</u>:

a. Open FEED FROM UPS 1-A breaker (MCC-89A).

b. Close FEED FROM MCC-9B breaker (MCC-89A).

9. Notify Shift Supervisor of completion to this point.

10. Operate RHR in the required mode per Shift Supervisor direction.

<u>CAUTION</u>

OPENING RHR-89A BEYOND 40 SECS. MAY RESULT IN EXCESSIVE SERVICE WATER FLOW THROUGH THE RHR HEAT EXCHANGER.

11. Torus Cooling Mode/LPCI Mode

LPC 5 a. Close/check closed RHR-192B, RHR Hx "B" SW outlet, (SE Corner Room 232' level).

b. Establish the following valve line-up on CP-82-2:

1) Close/verify closed the following:

- RECIRC V2-43A RECIRC PUMP A SUCTION VALVE (ER990548)
- RHR V10-27A OUTBOARD INJECTION VALVE
- RHR V10-15A RECIRC SUPPLY TO PUMP SUCTION VALVE
- SERVICE WATER V70-20 TURB. BLDG. CLG. WTR. VALVE

2) Open/verify open the following:

- RHR V10-39A SUPP. CHAMBER SPRAY UPSTREAM VALVE
- RHR V10-65A HT. EXCHANGE BYPASS VALVE
- RHR V10-34A SUPP. CHAMBER SPRAY BYPASS VALVE
- RHR V10-89A SERVICE WATER DISCHARGE VALVE (Throttle open for 30 to 40 seconds)
- RHR V10-13A TORUS TO PUMP SUCTION VALVE

NOTE

If Buses 4 and 9 are energized from "A" Diesel Generator or the Vernon Tie, torus cooling may commence using the RHR alternate shutdown panel.

c. Request Operator #4 start the following pumps from the Switchgear Room:

1) STATION SERVICE WATER PUMP P-7-1A (4KV Bus 4).

2) STATION SERVICE WATER PUMP P-7-1C (4KV Bus 4).

3) RHR SERVICE WATER PUMP P-8-1A or P-8-1C (4KV Bus 4).

4) RH REMOVAL PUMP P-10-1A (4KV Bus 4).

d. Adjust RHR V10-89A SERVICE WATER DISCHARGE VALVE to maintain >20 psid across the RHR heat exchanger as read on PI-10-91C.

NOTE

Torus temperature is monitored at CP-82-1 RCIC ALTERNATE SHUTDOWN SYSTEM.

e. Throttle RHR V10-65A HT. EXCHANGE BYPASS VALVE as necessary to control torus cooling.

f. When directed by the Shift Supervisor, inject to the reactor vessel:

1) Open/check open RHR V10-25A INBOARD INJECTION VALVE.

2) Open RHR V10-27A OUTBOARD INJECTION VALVE.

3) Close RHR V10-34A SUPP. CHAMBER SPRAY BYPASS VALVE.

g. Restore vessel level to 130" to 170" as indicated by LT-2-3-73A(M) on CP-25-6B.

h. Re-establish torus cooling as follows:

1) Open RHR V10-34A SUPP. CHAMBER SPRAY BYPASS VALVE.

2) Close RHR V10-27A OUTBOARD INJECTION VALVE.

i. Maintain vessel level 130" - 170" or establish torus cooling as follows:

1) Use RHR V10-27A OUTBOARD INJECTION VALVE for injection.

2) Use RHR V10-34A SUPP. CHAMBER SPRAY BYPASS VALVE for torus cooling.

j. When directed by the Shift Supervisor to establish shutdown cooling:

1) Raise reactor water level using the LPCI mode until level reaches 180" to 190" as read on LT-2-3-73A(M) on CP-25-6B.

2) Close/check closed RHR V10-34A SUPP. CHAMBER SPRAY BYPASS VALVE.

3) Close/check closed RHR V10-27A OUTBOARD INJECTION VALVE.

4) Request Operator #4 in Switchgear Room to Secure RH REMOVAL PUMP P-10-1A.

5) Proceed to Step 12 for Shutdown Cooling mode.

12. Shutdown Cooling Mode

NOTES

- If necessary, RHR-18 may be energized by cable connection from MCC-9B to MCC-8B per Appendix F. The required cable for this connection is located in a junction box above MCC-8B on the 280' level. A ladder will be required to reach this junction box. This task should only be performed by qualified maintenance personnel.
- If normal shutdown cooling is not available within 72 hours, it will be necessary to establish a shutdown cooling flowpath using LPCI mode through the "A" SRV.

---

a. Establish shutdown cooling by performing one of the following:

1) If RHR-18 is operable or power can be restored to RHR-18, proceed to step 12.b.

2) If power cannot be restored to RHR-18 within 72 hours, proceed to step 12.s.

b. Open the following ACB's:

1) RHR PUMPS P10-1A & 1C MIN FL BYPASS VA V10-16A (MCC-9B)

2) RECIRC SUPPLY TO PUMP P10-1C SUCT VA V10-15C (MCC-9B)

3) RECIRC. SUPPLY TO PUMP P10-1B SUCT VALVE V10-15B (MCC-8B)

4) RECIRC. SUPPLY TO PUMP P10-1D SUCT VALVE V10-15D (MCC-8B)

c. Close/check closed the following valves:

1) RHR V10-16A (NE Corner Room 213' level)

2) RHR V10-15C (NE Corner Room 213' level)

3) RHR V10-15B (SE Corner Room 213' level)

4) RHR V10-15D (SE Corner Room 213' level)

d. If RBCCW is not operating, line up alternate cooling to "A" RHR Pump by performing the following:

1) Close RCW V70-32A RBCCW CLG TO RADWASTE AND A/C RHR PUMPS (Torus area east, 213' level).

2) Open SW V70-32B ALT CLG TO RADWASTE AND A/C RHR PUMPS (Torus area east, 213' level).

3) Close/check closed RCW V70-28 RCW-28A BYPASS (Torus catwalk east).

4) Close RCW V70-28A RHR/CRD PUMP COOLERS AND RADWASTE RETURN (Torus catwalk east).

5) Open SW V70-29 RBCCW ALT CLG SW RETURN TO COOLING TOWER (Torus catwalk east).

6) Open RCW-29A (Torus catwalk east).

7) Throttle open 2 turns SW V70-36B SW LOOP B CROSS CONN TO ALT COOLING (Torus catwalk east).

e. Verify reactor pressure is less than 100 psig as read on PT-2-3-56A(M) on CP-25-6B.

f. If necessary, have Maintenance personnel install cable connection from junction box to MCC-8B at RHR-18 valve compartment per Appendix F.

g. Using a #50 key, unlock and reposition RHR REACTOR S/D COOLING ISOLATION VALVES OPEN PERMISSIVE RHR-17 RHR-18 (CS1308)to "OPEN PERM".. (Radwaste Corridor)

h. Open the ACB for RHR REACTOR SHUTDOWN COOLING ISOL VALVE V10-17 (MCC-DC-2A).

i. In the Drywell Ante-room, bleed the pressure off the bonnet on RHR-17:

1) Remove the pipe cap and open RHR-17A1.

2) Allow pressure to bleed off.

3) Shut RHR-17A1 and install the pipe cap.

j. Manually open RHR-17.

k. Establish the following valve lineup on CP-82-2:

1) Close/verify closed the following:

- RECIRC V2-43A RECIRC PUMP A SUCTION VALVE (ER990548)
- RHR V10-27A OUTBOARD INJECTION VALVE
- SERVICE WATER V70-20 TURB. BLDG. CLG. WTR. VALVE
- RHR V10-39A SUPP. CHAMBER SPRAY UPSTREAM VALVE
- RHR V10-13A TORUS TO PUMP SUCTION VALVE
- RHR V10-34A SUPP. CHAMBER SPRAY BYPASS VALVE

2) Open/verify open the following:

- RHR V10-65A HT. EXCHANGE BYPASS VALVE
- RHR V10-89A SERVICE WATER DISCHARGE VALVE (Throttle open for 30 to 40 seconds)
- RHR V10-25A INBOARD INJECTION VALVE
- RHR V10-18 REACTOR SHTDN. COOLING INBOARD ISOL VALVE
- RHR V10-15A RECIRC SUPPLY TO PUMP SUCTION VALVE

l. Open the ACB for SUPPRESS CHAMB SPRAY UPSTR. ISOL. VALVE V10-39A (MCC-9B).

m. Request Operator #4 start the following pumps in the SWGR Room:

1) STATION SERVICE WATER PUMP P-7-1A (4KV Bus 4).

2) STATION SERVICE WATER PUMP P-7-1C (4KV Bus 4).

3) RHR SERVICE WATER Pump P-8-1A or P-8-1C (4KV Bus 4).

n. When ready, request Operator #4 to start RH REMOVAL PUMP P-10-1A (4KV Bus 4).

o. Slowly fully open RHR V10-27A OUTBOARD INJECTION VALVE.

NOTE

Local reactor water temperature indication is not available. TSC assistance can help determine cooldown rate.

---

p. Throttle RHR V10-65A HT. EXCHANGE BYPASS VALVE as necessary to control the cooldown rate.

1) If RHR V10-65A HT. EXCHANGE BYPASS VALVE is fully open and additional control of the cooldown rate is desired, unlock and throttle HX INLET VALVE RHR V10-23A as necessary (NE Corner Room. 213' level).

q. Once cold shutdown is achieved, maintain reactor coolant temperature between 100 - 212°F.

r. If it is necessary to provide makeup water to the vessel during cooldown, request assistance from the TSC to determine the sources and flowpaths available.

s. If power to RHR-18 is not available and shutdown cooling is required then perform the following:

1) Request Operator #3 at RCIC place the control switch for SRV-71A to OPEN.

2) Establish the following valve line-up on CP-82-2:

a) Close/verify closed the following:

- RECIRC V2-43A RECIRC PUMP A SUCTION VALVE (ER990548)
- RHR V10-27A OUTBOARD INJECTION VALVE
- SERVICE WATER V70-20 TURB. BLDG. CLG. WTR. VALVE
- RHR V10-39A SUPP. CHAMBER SPRAY UPSTREAM VALVE
- RHR V10-34A SUPP. CHAMBER SPRAY BYPASS VALVE
- RHR V10-15A RECIRC SUPPLY TO PUMP SUCTION VALVE

b) Open/verify open the following:

- RHR V10-65A HT. EXCHANGE BYPASS VALVE
- RHR V10-89A SERVICE WATER DISCHARGE VALVE (Throttle open for 30 to 40 seconds)
- RHR V10-25A INBOARD INJECTION VALVE
- RHR V10-13A TORUS TO PUMP SUCTION VALVE

3) Request Operator #4 start the following pumps from the Switchgear Room:

a) STATION SERVICE WATER PUMP P-7-1A (4KV Bus 4).

b) STATION SERVICE WATER PUMP P-7-1C (4KV Bus 4).

c) RHR SERVICE WATER PUMP P-8-1A or P-8-1C (4KV Bus 4).

d) RH REMOVAL PUMP P-10-1A (4KV Bus 4).

4) Once injection has commenced, use Figure 1 of Appendix C to determine the cooldown rate by monitoring the pressure drop versus time..

5) Throttle RHR V10-27A OUTBOARD INJECTION VALVE as necessary to establish the following conditions:

a) Reactor Pressure 100 - 230 psig using PT-2-3-56A(M) (CP-25-6B).

b) If Reactor pressure does not stabilize below 230 psig, request Operator #3 place the control switch for SRV-71B to OPEN.

NOTE

Local reactor water temperature indication is not available. TSC assistance can help determine cooldown rate.

---

6) Throttle RHR V10-65A HT. EXCHANGE BYPASS VALVE as necessary to control the cooldown rate at $<100°$F/hour.

a) If RHR V10-65A HT. EXCHANGE BYPASS VALVE is fully open and additional control of the cooldown rate is desired, unlock and throttle HX INLET VALVE RHR V10-23A as necessary (NE Corner Rm. 213' level).

7) Once Cold Shutdown is achieved, maintain Reactor coolant temperature 100-212°F.

APPENDIX C

AMPLIFYING INFORMATION FOR OPERATOR #3

1. If directed by the Shift Supervisor, scram the reactor by performing the following:

   a. Isolate the air supply to the scram air filters:

      1) Close CRD AIR FILTER S-3-27 INLET CRD-A1.

      2) Close CRD AIR FILTER S-3-27A INLET CRD-A4.

   b. Open/check open CRD AIR FILTER S-3-27 OUTLET CRD-A2.

   c. Open/check open CRD AIR FILTER S-3-27A OUTLET CRD-A3.

   d. Depressurize the scram air header as follows (scrams the reactor only):

      1) Open CRD AIR FILTER S-3-27 DRAIN CRD-A12.

      2) Open CRD AIR FILTER S-3-27A DRAIN CRD-A13.

<u>NOTE</u>

When MTS-13-1 or MTS-13-2 is positioned to EMERGENCY, the normal power supply breaker opens before the emergency power supply breaker closes.

---

2. At MTS-13-2 (Rx Bldg 252' by RCIC door), perform the following:

   a. Transfer 125V DC MANUAL RCIC TRANSFER SWITCH MTS-13-2 to "EMERGENCY" by turning counter-clockwise.

   b. Place RCIC V13-15 STEAM SUPPLY LINE ISOL VA SHUTDOWN TRANSFER (SS1188) to "EMER" (CP-82-3).

   c. Place RCIC V13-16 STEAM SUPPLY LINE ISOL VA SHUTDOWN TRANSFER (SS1189) to "EMER" (CP-82-3).

<u>NOTE</u>

At this time, power may not be available to RCIC-15. If RCIC-15 position can not be determined, continue with this procedure and verify RCIC-15 position once AC power is restored.

---

   d. Open/check open RCIC V13-15 STEAM SUPPLY LINE ISOL VALVE.

e. Open/check open RCIC V13-16 STEAM SUPPLY LINE ISOL VALVE.

3. In the HPCI Room, perform the following:

   a. Open the ACB for HPCI AUX OIL PUMP P85-1A (MCC-DC-1B).

4. At the RCIC Corner Room (Rx Bldg. 213' level) on ALTERNATE SHUTDOWN STATION ADS SAFETY RELIEF VALVES panel B1300SII perform the following:

   a. Check/place SAFETY RELIEF VALVE RV2-71A control switch to CLOSE.

   b. Check/place SAFETY RELIEF VALVE RV2-71B control switch to CLOSE.

5. At the APPENDIX R SRV ALT SHUTDOWN PANEL (RCIC Corner Room 232' level), place ADS TRANSFER, SS-752, switch to EMER.

6. At the RCIC Corner Room (Rx Bldg. 213' level) perform the following:

   a. Transfer 125V DC MANUAL RCIC TRANSFER SWITCH MTS-13-1 to "EMERGENCY" by turning counter-clockwise.

   b. At CP-82-1 RCIC ALTERNATE SHUTDOWN SYSTEM, place the three RCIC ALTERNATE SHUTDOWN TRANSFER switches to EMER <u>in the following sequence:</u>

      1) SS1178A

      2) SS1178B

      3) SS1178C

   c. In panel B1300SII, transfer the SRV control power knifeswitch to EMER.

7. If the power is not available on the panel, or to some valves, replace the fuses as described in Appendix E.

CAUTION

EXCEPT FOR MECHANICAL OVERSPEED, ALL TRIPS, ISOLATIONS, AND AUTO INITIATIONS ARE BYPASSED WHEN THE TRANSFER SWITCHES ON CP-82-3 AND CP-82-1 ARE IN THE EMERGENCY POSITIONS.

8. On CP-82-1, RCIC ALTERNATE SHUTDOWN SYSTEM operate RCIC as follows:

a. Close/check closed the following valves:

LPC 1

- RCIC V13-30 TEST BYPASS TO COND. STG. TANK
- RCIC V13-131 STEAM TO TURBINE
- RCIC V13-27 MINIMUM FLOW BYPASS TO SUPP. CHAMBER
- RCIC V13-41 PUMP SUCTION FROM SUPP. CHAMBER
- RCIC V13-39 PUMP SUCTION FROM SUPP. CHAMBER

b. Open/check open the following valves:

- RCIC V13-132 TURBINE COOLING WATER SUPPLY
- RCIC V13-18 PUMP SUCTION FROM COND. STG. TANK
- RCIC V13-20 PUMP DISCHARGE VALVE
- RCIC V13-21 PUMP DISCHARGE VALVE
- RCIC TURBINE TRIP THROTTLE VALVE

c. Start the RCIC GLAND SEAL VACUUM PUMP.

NOTE

While in Alt Shutdown Mode, the RCIC condensate pump is required to be manually started and stopped to prevent damage to the pump or exhauster. The sight glass on the condensate receiver may be used to determine when to operate the RCIC condensate pump.

d. Operate the RCIC GLAND SEAL VAC. TANK CONDENSATE PUMP as necessary to maintain vacuum tank level within the sightglass.

e. Set the RCIC TURBINE SPEED potentiometer to zero by turning counter-clockwise.

APPENDIX C (Continued)

CAUTION

OPENING RCIC-27 WILL CREATE A DRAIN PATH BETWEEN THE CST AND THE TORUS. MONITOR CST AND TORUS LEVEL WHENEVER RCIC-27 IS OPEN.

---

f. Open RCIC V13-27 MINIMUM FLOW BYPASS TO SUPP. CHAMBER.

   1) Monitor CST level on CONDENSATE STORAGE TANK LEVEL LI-107-12A.

   2) Monitor Torus level on TORUS WATER LEVEL LI-16-19-10A.

CAUTION

TO AVOID OVERSPEEDING THE TURBINE, ALWAYS OPEN THE DESIRED FLOW PATH BEFORE CLOSING THE UNDESIRED FLOW PATH.

CAUTION

TO PREVENT RCIC TURBINE TRIP ON LOW OIL PRESSURE, DO NOT REDUCE TURBINE SPEED BELOW 2000 RPM. TO LIMIT TURBINE VIBRATION, MAINTAIN TURBINE SPEED AT ≤4500 RPM.

---

g. Start the RCIC turbine by opening RCIC V13-131 STEAM TO TURBINE and increasing the RCIC potentiometer so turbine accelerates to greater than 2000 rpm immediately.

LPC 1 h. Adjust the RCIC potentiometer to obtain 400 gpm at ≤4500 rpm as indicated on local instrument dpis/FI-13-61.

i. When RCIC flow increases above 80 gpm, close RCIC V13-27 MINIMUM FLOW BYPASS TO SUPP. CHAMBER.

j. Maintain RCIC turbine speed ≤4500 rpm.

9. Adjust RCIC flow with the potentiometer as necessary to maintain Reactor Water level 137" and 167" as read on RPV WATER LEVEL LI-2-3-72C.

   a. If level is offscale, obtain a level reading from Operator #2 using LT-2-3-73A.

CAUTION

IN THIS MODE OF OPERATION, THE AUTOMATIC SUCTION PATH TRANSFER ON LOW CST LEVEL WILL NOT OCCUR.

10. Monitor CST level; when CST level decreases to 8% (LI-107-12A), shift suction path to the Torus as follows: (VYC0706R01_04)

    a. Open RCIC V13-41 PUMP SUCTION FROM SUPP. CHAMBER

    b. Open RCIC V13-39 PUMP SUCTION FROM SUPP. CHAMBER

    c. Close RCIC V13-18 PUMP SUCTION FROM COND. STG. TANK

11. Notify the Shift Supervisor of each 5 inch change in reactor level.

CAUTION

ELEVATED TORUS PRESSURE COULD ADVERSELY AFFECT RCIC OPERATION

12. Select position 1 or 2 for the Torus water temperature indicator and monitor Torus temperature changes.

13. Monitor Drywell air space temperature on APPENDIX R DRYWELL TEMPERATURE TI-16-19-42A.

    a. Notify the Shift Supervisor if this temperature exceeds 325 °F.

14. Monitor Barometric Condenser Vacuum Tank vacuum.

    a. If PI-13-46 indicates 0 or a positive pressure, notify the Shift Supervisor.

15. When supporting manpower is available, and the use of the RCIC full flow test line is desired to aid in Reactor level control, proceed as follows:

    a. If RCIC suction is being supplied from the Torus, exit this step and continue at Step 16.

    b. On panel CP-82-1, RCIC ALTERNATE SHUTDOWN SYSTEM:

        1) Verify open RCIC V13-18 PUMP SUCTION FROM COND. STG. TANK.

        2) Verify closed RCIC V13-41 PUMP SUCTION FROM SUPP. CHAMBER.

        3) Verify closed RCIC V13-39 PUMP SUCTION FROM SUPP. CHAMBER.

c. In the HPCI Room, open the ACB for HPCI TEST LINE TO CST VALVE V23-24.

d. At CP-82-1, hold the control switch for RCIC V13-30 TEST BYPASS TO COND. STG. TANK to "CLOSE" for 15 seconds.

e. In the HPCI Room, manually open HPCI V23-24 HPCI FULL FLOW TEST LINE CST INLET.

f. At CP-82-1, throttle RCIC V13-30 TEST BYPASS TO COND. STG. TANK as desired.

g. Use a combination of turbine speed and RCIC V13-30 TEST BYPASS TO COND. STG. TANK valve position to control Reactor level.

h. If RCIC suction must be aligned to the Torus, immediately close RCIC V13-30 TEST BYPASS TO COND. STG. TANK.

16. When directed by the Shift Supervisor, commence a cooldown by performing the following:

a. Determine the reactor water temperature for the existing reactor pressure using the saturation curve (figure 1 of Appendix C).

1) Record the pressure and temperature on Appendix C "Reactor Cooldown Log".

b. Subtract 90 degrees from the present saturation temperature and determine the corresponding reactor pressure.

1) Record this value on the "Reactor Cooldown Log".

LPC 6

c. Open SAFETY RELIEF VALVE RV2-71A or RV2-71B to reduce reactor pressure to that calculated in Step 16.b.

d. Log the time when the desired pressure is reached.

e. Operate the SRV as necessary to maintain pressure within +100/-0 psig of the desired pressure.

LPC 6

f. After one hour repeat Steps 16.a. through 16.e.

g. Repeat Steps 16.a. through 16.f. until reactor pressure reaches 100 psig.

17. If normal RCIC Room ventilation is not available, perform the following:

a. Inform Security that RCIC Room doors will be blocked open.

b. Obtain door wedges from the Appendix R tool box in the RCIC Room.

c. Block open the doors on the 213', 232', and 252' level.

18. When directed by the Shift Supervisor, secure RCIC as follows:

a. Close RCIC V13-131 STEAM TO TURBINE.

b. When the shaft has completely stopped:

1) Stop RCIC SEAL GLAND VACUUM PUMP

2) Stop RCIC GLAND SEAL VAC. TANK CONDENSATE PUMP.

c. Close/check closed the following:

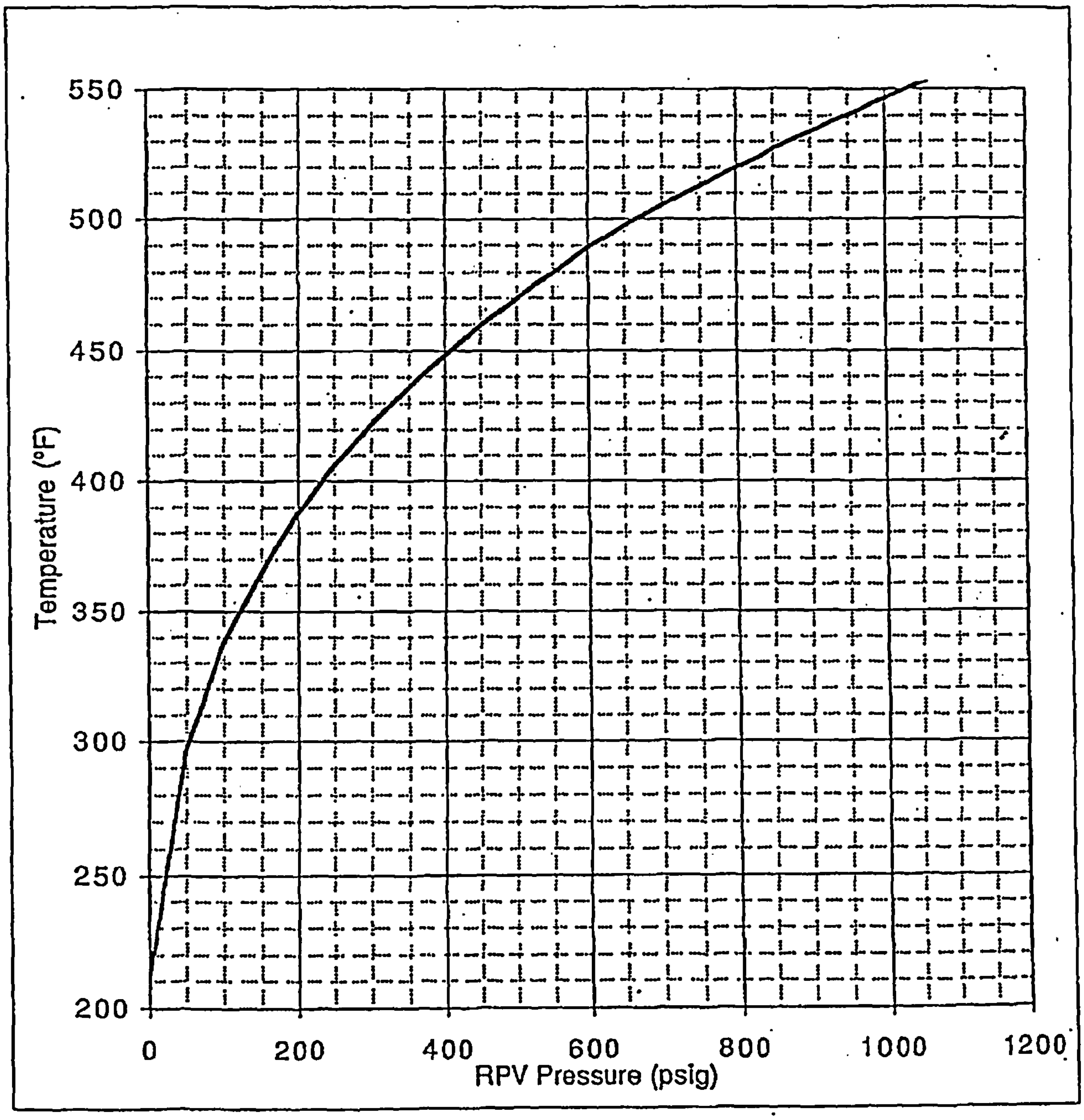
- RCIC V13-132 TURBINE COOLING WATER SUPPLY
- RCIC V13-21 PUMP DISCHARGE VALVE
- RCIC V13-30 TEST BYPASS TO COND. STG. TANK
- RCIC V13-27 MINIMUM FLOW BYPASS TO SUPP. CHAMBER

d. Set RCIC TURBINE SPEED potentiometer to zero by turning counter-clockwise.

Appendix C (Continued)

Figure 1

RPV SATURATION CURVE



APPENDIX C (Continued)

REACTOR (RX) COOLDOWN LOG

TIME	PRESENT RX PRESS	PRESENT SAT TEMP	(SAT TEMP) - (90°F)	TARGET RX PRESS

APPENDIX D

AMPLIFYING INFORMATION FOR OPERATOR #4

CAUTION

IF THE CARDOX SYSTEM FOR THE CABLE VAULT HAS ACTUATED, EXIT THE SWITCHGEAR ROOMS THROUGH EITHER THE DOUBLE DOORS INTO THE TURBINE BUILDING, OR OUT THE EAST (OUTSIDE) DOOR OF THE EAST SWITCHGEAR ROOM UNTIL SUCH TIME THAT THE HABITABILITY OF THE ADMINISTRATION BUILDING IS DETERMINED ACCEPTABLE FOR RE-ENTRY.

1. In the Switchgear Room, perform the following:

   a. Remove the normal "CLOSE" fuses for breaker 3V. (TIE TO 4KV BUS NO. 4 on Bus 3).

   b. Open/check open breaker 3V. (TIE TO 4KV BUS NO. 4 on Bus 3).

   c. Remove the normal "CLOSE" fuses for breaker 3V4. (4KV LINE FROM VERNON STATION on Bus 3).

   d. Open/check open breaker 3V4. (4KV LINE FROM VERNON STATION on Bus 3).

   e. Remove the normal "CLOSE" fuses for breaker 4V. (TIE FROM 4KV BUS NO. 3 on Bus 4).

   f. Open/check open breaker 4V. (TIE FROM 4KV BUS NO. 3 on Bus 4).

   NOTE

   Removing the "CLOSE" fuses from "A" DG breaker disables Bus 4 Load Shed and Under Voltage Protection.

   g. Remove the normal "CLOSE" fuses for DIESEL GENERATOR DG-1-1A breaker (4KV Bus 4).

   h. Open/check open DIESEL GENERATOR DG-1-1A breaker (4KV Bus 4).

2. Remove the normal "CLOSE" fuses and open/check open all breakers on 4KV Bus 4.

3. Isolate the current transformers for the following 4KV Bus 4 breakers by performing the following:

   a. Remove the "Test Knifeswitch Enclosure" covers located on the inside middle of the breaker cubicle door.

b. Open WHITE knifeswitch (second from right) for the following breakers:

1) STATION SERVICE WATER PUMP P-7-1C

2) STATION SERVICE TRANSF T-9-1A (49)

3) RH REMOVAL PUMP P-10-1A

4) RHR SERVICE WATER PUMP P-8-1C

5) STATION SERVICE WATER PUMP P-7-1A

6) RHR SERVICE WATER PUMP P-8-1A

4. Open/check open TIE FROM 480 BUS 8 (9T8) breaker on 480V Bus 9.

NOTE

Fire damage may cause control circuit fuses to blow prior to operating transfer switches. Moving the Alternate Shutdown Switches to "EMER" place reserve sets of fuses into service. If control power to some components, is still not available, fuse replacement per Appendix E may be required.

5. Don rubber gloves and, if necessary use a step stool and place the ALTERNATE/NORMAL control power knife switch for 480V Bus 9 (located inside the upper left-hand compartment of Bus 9) to ALTERNATE.

6. Don rubber gloves and, if necessary use a step stool and place the ALTERNATE/NORMAL control power knife switch for 4KV Bus 4 (located inside the box behind Bus 4) to ALTERNATE.

7. At 480V Bus 9, place ALTERNATE SHUTDOWN TRANSFER (SS343) switch to "EMER".

8. At 4KV Bus 4, place the following 8 ALTERNATE SHUTDOWN TRANSFER switches to "EMER".

- P7-1C ALTERNATE SHUTDOWN TRANSFER (SS427)
- T-9-1A ALTERNATE SHUTDOWN TRANSFER (SS330)
- P-10-1A ALTERNATE SHUTDOWN TRANSFER (SS1301)
- P-10-1B ALTERNATE SHUTDOWN TRANSFER (SS1303)
- P8-1C ALTERNATE SHUTDOWN TRANSFER (SS1307)
- DIESEL GEN 1-1A ALTERNATE SHUTDOWN TRANSFER (SS331)
- P7-1A & BKR 4V ALTERNATE SHUTDOWN TRANSFER (SS425)
- P8-1A ALTERNATE SHUTDOWN TRANSFER (SS1305)

9. At 4KV Bus 3, place BKR 3V4 ALTERNATE SHUTDOWN TRANSFER (SS325) to "EMER".

10. Close breaker 3V4 by placing the EMERGENCY BREAKER CONTROL switch to "CLOSE".

11. When directed by the Shift Supervisor, close breaker 4V on Bus 4 by placing the EMERGENCY BREAKER CONTROL switch to "CLOSE".

    a. Check for normal voltage indication (3900-4500 volts) on 4KV Bus 4.

NOTE

Normal breaker interlocks are still in effect. To close Breaker 99, Breaker 9T8 must be open and Breaker 49 must be closed.

---

1) If voltage is in the required range, perform the following.

   a) Close the STATION SERVICE TRANSF T-9-1A (49) breaker by placing the EMERGENCY BREAKER CONTROL switch to "CLOSE" (4KV Bus 4).

   b) Close the MAIN (99) Breaker by placing the EMERGENCY BREAKER 99 CTRL pushbutton to "CLOSE" for ~5 seconds (480V Bus 9)

   c) Continue with step 13.

2) If voltage is NOT within the required range continue with Step 12.

12. If the Vernon Tie is unavailable:

    a. Open/check open 4KV LINE FROM VERNON STATION (3V4).

    b. Open/check open TIE FROM 4KV BUS NO. 3 (4V)

    c. Establish the following conditions at the DG-1-1A GENERATOR PANEL:

NOTE

When switch 611A is in EMERG, the local lights which indicate which DG voltage regulator is in control will not be lit.

---

1) DIESEL GEN ALTERNATE SHUTDOWN TRANSFER SS611A in "EMERG".

2) DIESEL GEN ALTERNATE SHUTDOWN TRANSFER SS611B in "EMERG".

3) SS 611 MAN/AUTO CNTRL SW FOR ALT SHUTDOWN in AUTO.

NOTE

Fire damage may cause control circuit fuses may blow prior to operating, transfer switches. Moving the Alternate Shutdown Switches to "EMER" place reserve sets of fuses into service. If control power to some components is still not available, fuse replacement per Appendix E, may be required.

d. Request Operator #1 to perform the following:

1) If available, close STATION SERVICE WATER PUMP P-7-1C breaker 4KV Bus 4).

2) If "C" Service Water Pump is not available, close STATION SERVICE WATER PUMP P-7-1A breaker.

3) Close the STATION SERVICE TRANSF T-9-1A (49) breaker (4KV Bus 4).

4) Close the MAIN (99) breaker (480V Bus 9). Hold in pushbutton for ~5 seconds.

e. Request Operator #1 install/check installed the "TRIP" and "CLOSE" fuses for DIESEL GENERATOR DG-1-1A breaker (4KV Bus 4).

f. Verify the following occur:

- "A" Diesel Generator starts.
- "A" Diesel Generator accelerates to operating speed.
- "A" Diesel Generator frequency increases to approximately 60 Hz.
- "A" Diesel Generator voltage increases to approximately 4160 volts.

g. If the Diesel starts but the output breaker fails to close, at DG-1-1A GENERATOR PANEL:

1) Place synchronizing switch to the ON position.

2) Close the DG-1-1A breaker.

h. Verify that DIESEL GEN ROOM EXHAUST FAN TEF-2 operates as required.

i. Adjust generator voltage as necessary to maintain between 4000 to 4200 volts.

j. If DG-1-1A fails to auto start, manually start DG-1-1A as follows:

1) Check DG-1-1A GENERATOR PANEL for start failure annunciators.

2) Report the status of annunciators to the Shift Supervisor.

3) At the DG-1-1A INSTRUMENT PANEL place the REMOTE/AT ENGINE control switch to "AT ENGINE" position to remove auto start capabilities.

4) Assist in resolving the cause for the failure to start.

5) Reset any lockouts.

6) Depress the SHUTDOWN RELAY RESET pushbutton to reset the shutdown relay (DG-1-1A INSTRUMENT PANEL).

7) Wait approximately 100 seconds for the Shutdown Relay to time out.

8) At the DG-1-1A INSTRUMENT PANEL, auto start the diesel by placing REMOTE/AT ENGINE control switch to "REMOTE" position.

9) If the diesel does not roll, open AS-2A air start solenoid as follows:

    a) Rotate manual operator stem clockwise 180°.

    b) Leave manual override engaged for at least 15 seconds OR until the diesel starts.

    c) Rotate manual operator stem counterclockwise 180°.

10) Report the status of the diesel to the Shift Supervisor.

11) Verify auto closure of the DG-1-1A output breaker.

12) If the Diesel starts but the output breaker fails to close, at DG-1-1A GENERATOR PANEL:

    a) Place synchronizing switch to the ON position.

    b) Close DG-1-1A breaker.

13) Verify that DIESEL GEN ROOM EXHAUST FAN TEF-2 operates as required.

14) Adjust generator voltage as necessary to maintain between 4000 to 4200 volts.

k. Monitor the diesel engine and generator temperatures periodically as conditions warrant.

CAUTION

IF DLO-10A IS LEFT OPEN DURING OPERATION, NORMAL VIBRATIONS CAN CAUSE EXCESSIVE MAKE UP.

l. Open DLO-10A only as necessary to make up oil to the engine sump.

m. Monitor the diesel day tank level and refill as necessary.

n. If additional Service Water Pumps are required, request Operator #1 start STATION SERVICE WATER PUMP P-7-1A(C) (4KV Bus 4).

o. Continue with Step 13.

LPC 12

13. Reset "B" Air Compressor LSR using the pushbutton on MCC-9C.

14. At panel HVSGP A, place control switches for RRU-5 and RRU-7 to "Run".

15. Open/check open RH REMOVAL PUMP P-10-1C breaker (4KV Bus 3).

16. Open/check open RH REMOVAL PUMP P-10-1D breaker (4KV Bus 3).

17. Check open and rack out TIE FROM 480V BUS 8 (9T8) breaker (480V Bus 9).

18. Remove the Motor Cooling Water fuses for RHR SERVICE WATER PUMPS P-8-1A (4KV Bus 4).

19. Remove the Motor Cooling Water fuses for RHR SERVICE WATER PUMPS P-8-1C (4KV Bus 4).

LPC 3

20. Standby to close other breakers at the direction of the Shift Supervisor

I LPC 4

THIS PAGE DELETED PER LPC 4

LPC 4

21. When directed by the Shift Supervisor, shutdown the "A" diesel generator per OP 2126 (if applicable).

22. Refer to OP 0109 to restore equipment when appropriate.

APPENDIX E

AMPLIFYING INFORMATION - MISCELLANEOUS

INDEX

A. Sound-Powered Phone Locations

NOTES

1) Sound-powered phone lines are in parallel but the phones on each line are in series. The lines are listed separately. If a phone on a line isn't getting through, a lower number phone may get through, higher numbers will not work.

2) Sound-powered phones within a building are generally able to communicate with each other.

3) Sound-powered phones in the reactor building are not ensured of being able to communicate with phones in the turbine building.

4) Any sound-powered phone not in the turbine building or reactor building is not ensured of being able to communicate with any other phone.

5) Reference drawing is G-191376.

Rx Bldg:

345 Level

1. Crane

318 Level

1. Inst Rack 25-19 (on wall by hose station across from SLC)
2. Inst Rack 13 (on wall by RWCU Oper desk, at corner)
3. Inst Rack 12B (RWCU under gray box at top of inst rack)
4. Inst Rack 12A (RWCU under gray box at top of inst rack)

303 Level

1. Inst Rack 25-65 (between RWCU door and sample sink)
2. Inst Rack RK-10 (beside ECCS 24 VDC Dist. Panel B)

280 Level

1. MCC-6A (on RWCU pump wall across from MCC-6A)
2. Inst Rack 25-6 (on N side of column across from rack)
3. MCC-DC-2A (on wall across from MCC between 25-6 and 25-2)
4. Inst Rack 25-5 (on west side of column across from rack)
5. MCC-8B (on wall at E end of MCC)

252 Level

1. Inst Rack 24-14 (on same column as CP-82-3)
2. Inst Rack 25-52 (on FW Nozzle Temp Recorder Box ≈3 ft off floor)
3. Cab 25-4 (by lighting panel LP-1M underneath lightbulb box)
4. MCC-89A (on E side of column across from MCC)
5. Inst Rack 25-51 (on wall between rack and S SDV)
6. Inst Rack 25-22 (on column across from HPCI stairs)

Lower Levels

HPCI Room	1.	Inst Rack 25-50 (between MCC-DC-1B and Rack 25-50)
SE RHR	1.	Inst Rack 25-7 (232') (on wall by Hx)
	2.	Inst Rack 25-60 (213') (on wall by Gai-Tronics)
NE RHR	1.	Inst Rack 25-23 (232') (on wall by rack side away from Hx)
	2.	Inst Rack 25-1 (213') (by Gai-Tronics)
RCIC	1.	Inst Rack 25-56 (232') (by Gai-Tronics)
	2.	MCC-DC-2B (213') (on wall by MCC-DC-2B)

Turbine Building:

272 Level

1. MCC-10A (HVAC TSF 2A/B room on wall by MCC)
2. MCC-7D (HVAC TSF 1A/B room on wall by MCC)
3. Crane

248 Level

1. Rack RK1, RK2, RK16 (under gray dist boxes on feed pump rack) (Top of racks, lube oil room isle)
2. SWGR Bus 6 (on N wall behind sample sink)

248 Level (Continued)

3. MCC-DC-2D (inside L.O. room door on right side)
4. SWGR 7 (on wall behind SWGR 7 by laundry)
5. HTG BLR DIST PANEL (on S wall behind rad monitor)
6. MCC-9C (A DG room between batt chgr and MCC)
7. MCC-8C (B DG room by MCC-8C)

Lower Levels

1. SWGR 10 (232') (N side of structural column)
2. Inst Rack 9 (232') (wall behind cond vacuum rack)
3. RK-3 (220') (Feed pump room by TRU-1)
4. RK-5 (220') (Feed pump room by TRU-4)
5. MCC-7C (220') (on column by TBCCW Hx B)
6. FP-201 (220') (Bowser room by TB deluge valve)

Switchgear Room

1. North Wall next to MCC-9A

B. Local Operation of Motor Operated Valves

1. Defeat the switchgear door interlock and open the breaker door. If a screwdriver is not available, the ACB may be tripped (thus satisfying the interlock), the switchgear door opened, and the ACB reclosed.

2. Locate the desired relay:

NOTE

RCIC and HPCI Hoffman boxes near TIPS have "72X/O" (open) - "72X/C" (close). There are no colors.

---

a. Opening relay - red

b. Closing relay - green

3. With a pencil, flashlight, or other suitably insulated device, momentarily depress the desired contactor to initiate valve motion. Full stroking valves have a seal in feature that keeps the contactor depressed. This allows the valve to travel to the intended position without further operator action. Throttle valves do not have this feature and the contactor must be held in until the valve has traveled to the desired position. The throttle valves are RCIC-30, RHR-27A, RHR-34A and RHR-65A.

C. Instructions for Control Power Fuse Replacement

NOTE

Replacement fuses are located in all alternate shutdown locations. The fuses and the tools required for fuse replacement are located in red tool boxes staged in these areas.

---

1. To replace an MCC control power fuse:

   a. Determine the compartment location for the affected equipment and the fuse size from the attached list.

   b. Position the MCC control switch for the affected equipment to the OFF position.

   c. Open the compartment door and replace the control power fuse.

   d. Close the compartment door and position the MCC control switch to the ON position.

2. To replace a 4 KV SWGR control power fuse:

   a. Open the compartment door for the affected equipment and remove the fuse holder for the affected control circuit. The fuse holders are labeled to identify the close and trip circuit fuses.

   LPC 11

   b. Replace the fuses in the fuse holder. For all 4 KV breakers except 3V4, install 15 amp fuses for the close circuits and 35 amp fuses for the trip circuits. For Breaker 3V4, install 15 amp fuses for both the close and trip circuits.

   c. Place the fuse holder back into the compartment. Ensure the ON is located in the upper left corner when installing the fuse holder.

   d. Close the compartment door and check the breaker position indicating lights to verify restoration of breaker control power.

3. For replacement of the RCIC speed controller control power fuses, replace the two 1 amp fuses (#5 and 6) mounted in CP-82-1.

4. For replacement of the RHR control power fuses, replace the two FRN-4 fuses located on the left side of the shutdown panel.

5. To replace 480 V Swgr 9 Station Transformer BKR 99 control power fuses: (EPC_9502)

   a. Open/check open BKR 99.

   b. Position the Bus 9 control power knife switch to the open position.

   c. Open BKR 99 compartment door and locate the two sets of control power fuses in the upper right side.

   d. Replace the two 6 amp fuses in the upper fuse holders.

   e. Replace the two 30 amp fuses in the lower fuse holders.

   f. Close BKR 99 compartment door.

   g. Position the Swgr 9 control power knife switch to the Alternate Feed From DC-2AS position.

   h. Check BKR 99 position lights, then close/check closed BKR 99.

6. To replace "A" Diesel Generator Control fuses:

   a. Verify/place the "A" Diesel Engine Panel Remote/At Engine Control switch to the "AT ENGINE" position.

      1) Verify "At Engine" indicator light energizes or replace the 15A fuses in fuse holder "X and Y" inside the local control cabinet.

      2) If "At Engine" indicator light is still not energized, replace 35A fuses in fuse holder "FU-1 and FU-2" inside the Engine Control Panel.

   b. Check local diesel alarm panel status for indication of start failures or trips.

   c. Verify/reset the generator lockout relay and verify white light lit. If the white light is not lit, replace 30A control power fuses in fuse holder "Q" inside the local control cabinet.

   d. If the auto voltage regulator cannot be adjusted, replace the 15A fuses in fuse holder "T" inside the local control cabinet.

APPENDIX E (Continued)

REPLACEMENT FUSES

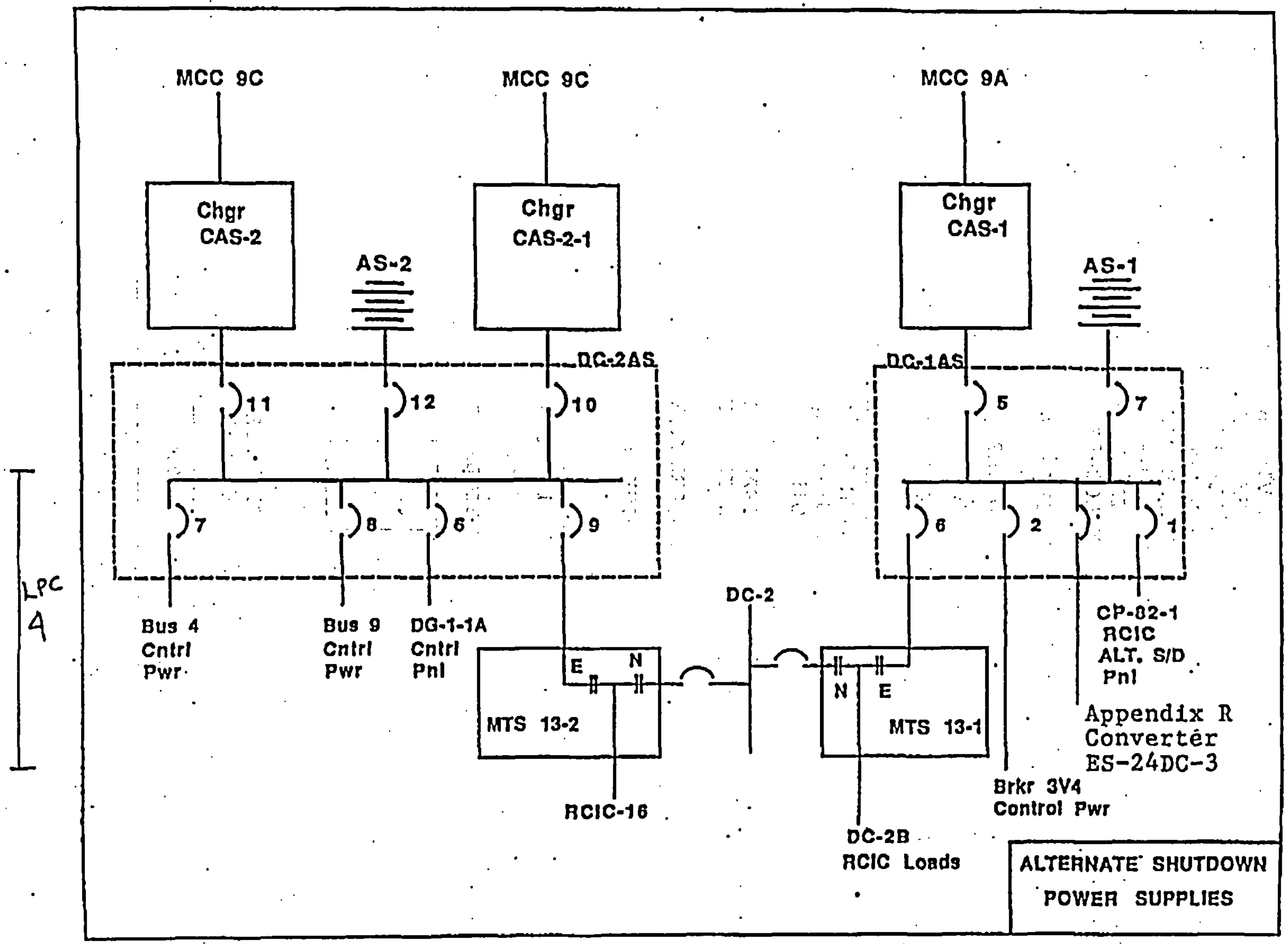
Component	Location		Fuse Size - Amps
RCIC-1	MCC DC-2B	LPC	1
RCIC-15	MCC 9B	2	1
RCIC-16	Local Starter		3
RCIC-18	MCC DC-2B		3
RCIC-20	MCC DC-2B		3
RCIC-21	MCC DC-2B		3
RCIC-27	MCC DC-2B		1
RCIC-30 (Throttle)	MCC DC-2B		3
RCIC-39	MCC DC-2B		1
RCIC-41	MCC DC-2B		1
RCIC-131	MCC DC-2B		1
RCIC-132	MCC DC-2B		1
RCIC Vacuum Pump	MCC DC-2B		1
RCIC Condensate Pump	MCC DC-2B		3
RHR-13A	MCC 9B		1
RHR-15A	MCC 9B		1
RHR-18	MCC 8B		1
RHR-25A	MCC 89A		2
RHR-27A (Throttle)	MCC 89A		3
RHR-34A (Throttle)	MCC 9B		1
RHR-39A	MCC 9B		1
RHR-65A (Throttle)	MCC 9B		1
RHR-89A	MCC 9B		1
RV-43A	MCC 89A		2
RRU-5	MCC 9B		1
RRU-7	MCC 9B		1
P92-1A	MCC 9C		1
SW-20	MCC 9D		1
TEF-2	MCC 9C		1

D. Local Operation of 4KV Bus 4 Breaker

1. Place the alternate shutdown transfer switch to the emergency position and then place the emergency breaker control switch to the desired position.

2. Verify that the breaker changes position by observing the local position lights and the mechanical indicator.

3. Report breaker status to the Shift Supervisor.


MCC 9C
MCC 9C
MCC 9A
Chgr CAS-2
AS-2
Chgr CAS-2-1
Chgr CAS-1
AS-1
DC-2AS
DC-1AS
11
12
10
5
7
7
8
6
9
6
2
1
Bus 4 Cntrl Pwr
Bus 9 Cntrl Pwr
DG-1-1A Cntrl Pnl
DC-2
CP-82-1 RCIC ALT. S/D Pnl
E
N
N
E
MTS 13-2
MTS 13-1
Appendix R Converter ES-24DC-3
Brkr 3V4 Control Pwr
RCIC-16
DC-2B RCIC Loads
ALTERNATE SHUTDOWN POWER SUPPLIES
LPC 4

APPENDIX F

INSTRUCTIONS FOR RHR-18 ALTERNATE POWER CONNECTION

SHUTDOWN COOLING ISOLATION VALVE V10-18 IS NORMALLY POWERED FROM MCC 8B WHICH RECEIVES POWER FROM DIESEL GENERATOR B (S1 SYSTEM). SINCE ONLY DIESEL GENERATOR A IS OPERABLE FOR ALTERNATE SHUTDOWN (BY DESIGN) PROVISIONS HAVE BEEN PROVIDED TO SUPPLY POWER TO V10-18 FROM MCC-9B IN THE EVENT OF A FIRE WHICH RESULTS IN LOSS OF POWER TO MCC-8B. A CABLE HAS BEEN INSTALLED FROM A SPARE BREAKER IN MCC-9B TO A BOX ABOVE MCC-8B. SUFFICIENT CABLE LENGTH IS LEFT IN THE BOX TO REACH THE CUBICLE FOR V10-18 IN MCC-8B.

THE INSTRUCTIONS FOR CONNECTING THIS CABLE ARE AS FOLLOWS.

ILPC10 1. ENSURE THE STANDBY FEED BREAKER FOR V10-18 IN MCC-9B (CUBICLE 11KL) IS OPEN.

2. OPEN THE BREAKER FOR V10-18 ON MCC-8B (CUBICLE 7F).

3. CONNECT THE CABLE FROM THE JUNCTION BOX ABOVE MCC-8B TO THE LOAD SIDE OF THE BREAKER FOR V10-18 AS SHOWN BELOW. DO NOT DISCONNECT THE EXISTING WIRING ON THESE TERMINALS. (CABLE MUST BE CONNECTED ON BOTH ENDS)

4. ENSURE THE APPENDIX R TRANSFER SWITCHES ON THE RHR ALTERNATE S/D PANEL ARE IN THE EMERGENCY POSITION.

ILPC10 5. CLOSE THE STANDBY FEED BREAKER ON MCC-9B (CUBICLE 11KL).

V10-18 CAN NOW BE OPERATED FROM THE RHR ALTERNATE S/D PANEL.

V10-18
BREAKER
MCC-8B
CUBICLE 7F

LOAD SIDE
(BOTTOM OF BREAKER)

BLACK	WHITE	RED

Vermont Yankee Training Change Request 04-0155

Title/Keyword: BIENNIAL EXAM HIGH MISS QUESTIONS

Originated by: CHRISTOPHER J. TABONE   Date: 05/21/04
Department: TRAINING

Originating Document:

Description:
The following 3 questions had high miss rates during the 2003 Biennial written exam. All three questions have to do with Alternate SHutdown. Cover these when Alternate Shutdow is taught in phase 24.2 (june-aug 2004)
854 - RHR valve interlocks that remain in force
903 - same as above
#1323 - actions taken when drywell temperature is > 260F

Commitment item (Y/N)? No

****

Priority: B

Number of sheets attached: 0

Cognizant Supervisor: MICHAEL E. GOSEKAMP   Date: 06/01/04

Programs affected: OPS

Review completion due date: 12/31/04

****

Reviewers	Assigned	Complete
1. CHRISTOPHER J. TABONE	06/01/04	11/29/04
2. DENNIS J. DEER	10/12/04	11/05/04

****

Feedback: Date:

Completed: Y MICHAEL E. GOSEKAMP   Date: 11/30/04

Closed: Y MICHAEL A. ROMEO   Date: 12/03/04

****

Exhibit D
NRC Docket No. 50-271
ASLBP No. 04-832-02-OLA
DPS Opposition Motion to Dismiss Contention 6
March 7, 2005

Comments

11/05/04 DJD Added to LOR-24-405-2 Alternate S/D training done at plant

Vermont Yankee Training Change Request 04-0160

Title/Keyword: ANNUAL EXAM JPM WEAKNESS

Originated by: CHRISTOPHER J. TABONE Date: 05/21/04
Department: TRAINING

Originating Document:

Description:
2 individuals failed their JPMs on the initial actions of 3126. review these failures and weak areas when Alternate Shutdown is taught (phase 24.2)
JPM number 29502

Commitment item (Y/N)? No

****

Priority: B

Number of sheets attached: 0

Cognizant Supervisor: MICHAEL E. GOSEKAMP Date: 06/01/04

Programs affected: OPS

Review completion due date: 12/31/04

****

	Reviewers	Assigned	Complete
1.	CHRISTOPHER J. TABONE	06/01/04	11/29/04
2.	DENNIS J. DEER	10/12/04	11/05/04

****

Feedback: Date:

Completed: Y MICHAEL E. GOSEKAMP Date: 11/30/04

Closed: Y MICHAEL A. ROMEO Date: 12/03/04

****

Exhibit E
NRC Docket No. 50-271
ASLBP No. 04-832-02-OLA
DPS Opposition Motion to Dismiss Contention 6
March 7, 2005

Comments

11/05/04 DJD Added to LOR-24-405-2 Alternate S/D trainig done at plant

UNITED STATES
NUCLEAR REGULATORY COMMISSION

In Re: Entergy Nuclear Vermont Yankee LLC and Entergy Nuclear Operations, Inc. (Extended Power Uprate)	))))	**Docket No. 50-271** **ASLBP No. 04-832-02-OLA**

VERMONT DEPARTMENT OF PUBLIC SERVICE RESPONSE TO ENTERGY'S STATEMENT OF MATERIAL FACTS ON WHICH NO GENUINE DISPUTE EXISTS

1. On October 18, 2004, the Vermont Department of Public Service ("DPS") submitted its request for leave to file a new contention ("DPS Contention 6"). Vermont Department of Public Service Request for Leave to File a New Contention (Oct. 18, 2004).

RESPONSE: Admit

2. In DPS Contention 6, DPS asserted a failure by Entergy to verify the assumption, used for purposes of the safe shutdown capability analysis (SSCA) in a 10 CFR Part 50 Appendix R event, that the reactor core isolation ("RCIC") system can be brought into service in sufficient time to permit the operator to perform the required actions before core uncovery. Id. at 1.

RESPONSE: Deny. In Contention 6 DPS asserted the failure of Entergy to conduct a particular verification of the assumptions it uses regarding SSCA in an Appendix R event, not merely the failure of Entergy to engage in any activity which they label a verification.

3. The scope of DPS Contention 6 is a challenge to Entergy's failure to perform the verification and submit the verification results to NRC. Memorandum and Order (Admitting Intervenor's New Contention) (Jan. 11, 2005) at 7.

RESPONSE: Deny. First, this is not a fact, but an interpretation of a document and the document speaks for itself. In addition, Contention 6 is also based upon the absence of NRC acceptance of the information submitted to it by Entergy a fact which Entergy concedes is material to this summary disposition motion. See ¶ 9, *infra*.

4. Entergy developed revised procedure governing the operator actions required to bring the RCIC system into service within approximately fifteen minutes in a 10 CFR Part 50 Appendix R event. September 30, 2004 VY Operating Procedure OP 3126 (Rev. 17), "Shutdown Using Alternate Shutdown Methods" (Exhibit 2).

RESPONSE: Admit to the extent the statement does not purport to claim that the revised procedures are in fact adequate to achieve the required result in case of an Appendix R event.

5. Entergy developed a training program guide to instruct the plant operators on the revised procedures. VY License Operator Requal Training Program Instructor Guide, LOR-24-405-2, Rev. 0, October, 2004 (Exhibit 3).

RESPONSE: Admit

6. All six crews of VY licensed operators received training on the revised procedures between October 18 and November 24, 2004. Daily Attendance Records for Classroom Review of 10 CFR 50 App. R and OP 3126 and Plant Walkthrough of the Time Critical Steps of OP 3126 (six sets of records, crews "A" through "F," dated October 18 through November 24, 2004) (Exhibit 4).

RESPONSE: Admit

7. After training, each crew conducted a timed walkthrough of the actions needed to bring the RCIC system into service to demonstrate that the crew was able to carry out the revised procedures within the time allowed. Narrative descriptions of timed walkthroughs of actions required by OP 3126 (six narratives, crews "A" through "F," dated October 20, 2004 through November 22, 2004) (Exhibit 5).

RESPONSE: Denied. Because the timed walkthrough occurred as a part of the training program and not independent in time from it, the walkthrough does not necessarily demonstrate that the crew is able to carry out the revised procedures in the time allowed in a realistic scenario.

8. The walkthroughs confirmed the ability of each of the six crews to start injection using the RCIC system within approximately fifteen minutes. Id; Memorandum from John Twarog to Chris Wamser, dated December 7, 2004, re Response to BVY 04-107 "Additional Information Related to the 10 CFR 50 Appendix R Timeline" (Exhibit 6).

RESPONSE: Denied. See 7.

9. Entergy completed the verification program by the December 1, 2004 deadline it had committed to the NRC. Letter from Jay Thayer, Site Vice President, to U.S.N.R.C., "Vermont Yankee Nuclear Power Station Technical Specification Proposed Change No. 263 – Supplement No. 22 Extended Power Uprate – 10 CFR 50 Appendix R Timeline Verification" BVY 04-131 (Dec. 8, 2004) at 1 (Exhibit 7).

RESPONSE: Denied. Since there is no final NRC action on the DPS submittal, there is no basis to assert that the program that was completed by December 1, 2004 was the verification program which NRC requires.

10. On December 8, 2004, Entergy notified NRC by letter of the completion and the results of the verification. Id.

RESPONSE: Admit

11. The December 8, 2004, Entergy letter to the NRC is available on ADAMS at Accession Number ML043510227.

RESPONSE: Admit