UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-8064

May 16, 2000

EA-00-077

Randal K. Edington, Vice President - Operations
River Bend Station
Entergy Operations, Inc.
P.O. Box 220
St. Francisville, Louisiana 70775

SUBJECT: NRC INSPECTION REPORT NO. 50-458/00-02

Dear Mr. Edington:

This refers to the inspection conducted on January 18 to March 3, 2000, at your River Bend Station facility. The purpose of the inspection was to review your corrective action program using the guidance provided in NRC inspection Procedure 40500, dated May 3, 1999. An initial exit meeting was held with you and your staff on February 4, 2000. A second exit meeting was conducted telephonically with your staff on April 6, 2000. The enclosed report presents the results of this inspection.

During this inspection, we noted that site personnel and management clearly understood the importance of the corrective action program. However, we also noted instances in which problems were not appropriately placed into the corrective action program or problems were not adequately analyzed and corrected. Examples of problems identified by the NRC included: instances of failing to write condition reports; instances of failing to review operable but degraded conditions; instances of failing to perform operability evaluations or failing to perform technically adequate operability evaluations; and a failure to report an inoperable emergency diesel generator. We remain concerned that these implementation problems could, in the future, result in a failure to identify and resolve potentially more significant problems, particularly latent equipment problems.

This report also documents issues involving the Division III emergency diesel generator. We are particularly concerned about continuing problems affecting emergency diesel generators, including the ability of your staff to recognize, assess (e.g., perform technically adequate operability evaluations), and correct these problems. We note that the issues documented in this report represent a third occurrence within the past 2 years of conditions affecting emergency diesel generator operability, which resulted in violations of the applicable emergency diesel generator technical specifications (refer to EA 98-478 and EA 99-158). While issues affecting emergency diesel generator reliability and availability were discussed during a management meeting conducted in the Region IV Office on December 9, 1999, the emergency diesel generator issues documented in this report were not discussed at that meeting. Accordingly, within 30 days of the date of this letter, we request a response to this letter that outlines your current and future activities to address and correct emergency diesel generator operability, reliability, and availability issues (including applicable support and subsystems that have the potential to affect emergency diesel generator operability).

Based on the results of this inspection, the NRC has determined that three Severity Level IV violations of NRC requirements occurred. These violations are being treated as Non-Cited Violations, consistent with Section VII.B.1.a of the Enforcement Policy. These Non-Cited Violations are described in the subject inspection report. If you contest these violations or their severity level, 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 DC 20555-0001, with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission, Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC resident inspector at the River Bend Station facility.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be placed in the NRC Public Document Room (PDR).

Should you have any questions concerning this inspection, we will be pleased to discuss them with you.

Sincerely,

/***RA***/

Arthur T. Howell, III, Director
Division of Reactor Safety

Docket No.: 50-458
License No.: NPF-47

Enclosure:
NRC Inspection Report No.
50-458/00-02

cc w/enclosure:
Executive Vice President and
Chief Operating Officer
Entergy Operations, Inc.
P.O. Box 31995
Jackson, Mississippi 39286-1995

Vice President
Operations Support
Entergy Operations, Inc.
P.O. Box 31995
Jackson, Mississippi 39286-1995

General Manager
Plant Operations
River Bend Station
Entergy Operations, Inc.
P.O. Box 220
St. Francisville, Louisiana 70775

Director - Nuclear Safety
River Bend Station
Entergy Operations, Inc.
P.O. Box 220
St. Francisville, Louisiana 70775

Wise, Carter, Child & Caraway
P.O. Box 651
Jackson, Mississippi 39205

Mark J. Wetterhahn, Esq.
Winston & Strawn
1401 L Street, N.W.
Washington, DC 20005-3502

Manager - Licensing
River Bend Station
Entergy Operations, Inc.
P.O. Box 220
St. Francisville, Louisiana 70775

The Honorable Richard P. Ieyoub
Attorney General
Department of Justice
State of Louisiana
P.O. Box 94005
Baton Rouge, Louisiana 70804-9005

H. Anne Plettinger
3456 Villa Rose Drive
Baton Rouge, Louisiana 70806

President
West Feliciana Parish Police Jury
P.O. Box 1921
St. Francisville, Louisiana 70775

Ronald Wascom, Administrator
and State Liaison Officer
Department of Environmental Quality
P.O. Box 82135
Baton Rouge, Louisiana 70884-2135

Distribution to DCD (IE01)
Electronic distribution from ADAMS by RIV:
Regional Administrator **(EWM)**
DRP Director **(KEB)**
DRS Drector **(ATH)**
Senior Resident Inspector **(TWP)**
Branch Chief, DRP/B **(WDJ)**
Senior Project Engineer, DRP/B **(RAK1)**
Branch Chief, DRP/TSS **(LAY)**
RITS Coordinator **(NBH)**
D. Lange **(DJL)**
NRR Event Tracking System **(IPAS)**
Document Control Desk **(DOCDESK)**
RBS Site Secretary **(PJS)**
RBorchardt, OE (**RWB1**)
OE:EAFile (**OEMail**)
GSanborn - EAFile (**GFS**)
MVasquez (**GMV**)

Hard copy distribution:
RIV File Room

DOCUMENT NAME: R:_RB\rb002rp-tfs.wpd
To receive copy of document, indicate in box: "C" = Copy without enclosures **"E"** = Copy with enclosures **"N"** = No copy

OE:OB		RI:EMB		SOE:OB		SRI:PBB		C:OB	
TFStetka/lmb*		PAGoldberg*		MEMurphy*		TPruett*		JLPellet*	
04/24/00 /***RA***/		04/24/00 ***E***/***RA***/		04/24/00 ***E***/***RA***/		04/24/00 ***E***/***RA***/		04/24/00 ***E***/***RA***/	
SRA		ACES		C:PBB		D:DRS			
WBJones*		GFSanborn		WDJohnson*		ATHowell			
05/09/00 /***RA***/		05/11/00 /***RA***/		04/25/00 /***RA***/w/**C**		05/16/00 /***RA***/			

*previously concurred OFFICIAL RECORD COPY

ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket No.:	50-458
License No.:	NPF-47
Report No.:	50-458/00-02
Licensee:	Entergy Operations, Inc.
Facility:	River Bend Station
Location:	5485 U.S. Highway 61 St. Francisville, Louisiana
Dates:	January 18, 2000 to March 3, 2000
Inspectors:	Thomas Stetka, Senior Operations Engineer, Operations Branch Paula Goldberg, Reactor Inspector, Engineering and Maintenance Branch Mike Murphy, Senior Operations Engineer, Operations Branch Troy Pruett, Senior Resident Inspector, Projects Branch B
Accompanying Personnel:	Donald Prevatte, Consultant
Approved By:	John L. Pellet, Chief, Operations Branch Division of Reactor Safety

ATTACHMENT: Supplemental Information

EXECUTIVE SUMMARY

River Bend Station
NRC Inspection Report No. 50-458/00-02

An inspection team performed a routine core inspection of the corrective action program implementation at the River Bend Nuclear Station. An inoffice inspection was conducted from January 10 to 14, 2000, which was followed by an onsite inspection that was conducted during the weeks of January 18 to 21, 2000, and January 31 through February 4, 2000. Further inoffice inspection was conducted from February 29 to March 3, 2000. The inspection was conducted in accordance with the guidance provided by NRC Inspection Procedure 40500.

Operations

- The corrective action program was adequately implemented overall with multiple exceptions noted. Site personnel and management clearly understood the importance of this program. However, the team found examples of procedure adherence problems (Sections O7.1b(3) and(5), Section E7.1b and Section R7.1b). The team also identified a continuing lack of understanding with regard to the performance of operability determinations (Section O7.1b(5)) and additional problems regarding the operability and reliability of the emergency diesel generators (Section O7.1b(7)).

- There were six examples of a failure to follow procedures. These constitute a Severity Level IV violation of Criterion V of Appendix B to 10 CFR Part 50. This violation is being treated as a Non-Cited Violation consistent with Section VII.B.1.a of the NRC Enforcement Policy and have been entered into the licensee's corrective action program. These examples included the following:

  * Condition reports were not generated for two adverse findings identified by the management observation program as required by Corporate Policy PL-150. As a result, these findings were not entered into the corrective action program (Section O7.1b(3)).

  * The facility review group failed to review and approve two operable, but degraded conditions, prior to plant startup from a refueling outage as required by Procedure RBNP-030 (Section O7.1b(5)).

  * An operability evaluation was not performed as required by Procedure RBNP-078 for an operable, but degraded condition of Main Steam Leakage Control Valve LSV PCV-42A (Section O7.1b(5)).

  * An operability evaluation was not performed as required by Procedure RBNP-078 for an operable, but degraded condition, involving the early failure of hydrogen sample valves (Section O7.1b(5)).

  * The calculations for the control building chilled water condenser pumps did not have all relevant information and did not receive the same review and approval as did the original calculations, as required by Procedure EDP-AA-20 (Section E7.1b).

* A plant modification to add a radiation detector to the offgas pretreat system piping was not made in accordance with Modification Procedure RBNP-010 (Section R7.1b).

- There were two examples of a failure to meet the requirements of Technical Specification 3.8.1 for the electrical power system ac sources. These constitute a Severity Level IV violation of Technical Specification 3.8.1. This violation is being treated as a Non-Cited Violation consistent with Section VII.B.1.a of the NRC Enforcement Policy and have been entered into the licensee's corrective action program. These examples include the following:

  * The limiting conditions for operation of Technical Specification 3.8.1 were not met between March 16 and April 1, 1999. Both the Division I and III emergency diesel generators were inoperable and neither emergency diesel generator was restored to an operable status within 24 hours, nor was a plant shutdown to Mode 3 conducted within 12 hours (Section O7.1b(7)).

  * The surveillance requirements of Technical Specification 3.8.1 were not met between March 24 and 31, 1999. The licensee failed to perform the required surveillances for the offsite circuits (within 1 hour and every 8 hours thereafter) and test the operable emergency diesel generators within 24 hours (Section O7.1b(7)).

- A condition that caused the Division III emergency diesel generator to be inoperable when isolated from standby service water Division I water supply, which was prohibited by the technical specifications, was not reported within 30 days, as required by 10 CFR 50.73(a)(2)(i)(B). This was a Severity Level IV violation of 10 CFR 50.73(a)(2)(i)(B). This violation is being treated as a Non-Cited Violation consistent with Section VII.B.1.a of the NRC Enforcement Policy and has been entered into the licensee's corrective action program (Section O7.1b(7)).

Report Details

Summary of Plant Status

On January 19, 2000, reactor power was reduced to 30 percent in response to a main condenser tube rupture. The plant was returned to 100 percent reactor power on January 22, 2000. On January 24, 2000, reactor power was reduced to 75 percent to perform a final rod pattern adjustment and then returned to 100 percent power where it remained for the rest of the inspection period. On March 3, 2000, the plant shutdown to start Refueling Outage 9.

I. Operations

O7 Quality Assurance in Operations

O7.1 Corrective Action Program

a. Inspection Scope (40500)

This inspection consisted of a review of the licensee's programs that were intended to identify and correct problems discovered at the facility. The review focused on the following seven specific areas: (1) the identification and reporting threshold for adverse conditions, (2) the setting of problem resolution priorities that were commensurate with operability and safety determinations, (3) program monitoring used by the licensee to assure continued program effectiveness, (4) program measurement or trending of adverse conditions, (5) the understanding of the program by all levels of station personnel, (6) the ability to identify and resolve repeat problems, and (7) resolution of Non-Cited Violations.

In addition to these seven areas, the corrective action program implementation for the standby service water system was selected for a focused review. This system was selected based on the system risk importance ranking, a review of the licensee documented system status, and past NRC review activity. Details on this focused review are documented in Section E7 of this report.

b. Observations and Findings

The licensee's corrective action program was primarily implemented by Procedures Corporate Policy PL-150, “Condition Reporting”; and RBNP-30, "Initiation and Processing of Condition Reports."

(1) **Threshold of Reporting**

The team interviewed approximately 20 personnel from a cross section of maintenance, operations, engineering, training, and emergency preparedness departments and reviewed approximately 80 condition reports to determine the threshold level for entering issues into the corrective action process. The interview responses indicated that licensee personnel were identifying issues

and resolving concerns within the scope of the corrective action program. As a result of the condition report review, the team did not identify any threshold problems. However, during the conduct of this inspection, the team identified two examples where events occurred and required condition reports were not issued. These examples are discussed in Section O7.1b(3) of this report.

(2) **Priority of Resolution**

The licensee's priority setting for condition reports was delineated in Procedures PL-150 and RBNP-030. These procedures did not specifically set a 'priority' on condition reports, but rather defined the three classifications and seven categories that the licensee used to place the condition reports in the order of most important to least important. The three levels of classification were 'significant', 'non-significant,' and 'below scope' or 'duplicate condition report.' The licensee then categorized condition reports with three levels of significance, three levels of non-significance, and the below scope level. The initial review and priority setting was made by the shift superintendent.

Out of approximately 80 condition reports reviewed, the team found the condition report and corrective action priority setting to be appropriate.

(3) **Effectiveness of Program**

The team interviewed approximately 20 personnel and determined that the individuals believed that the corrective action program was effectively addressing identified issues. The individuals interviewed were not aware of any conditions, which had not been adequately resolved by the licensee. However, the team identified one area where the program did not address identified issues.

The team reviewed comments in the licensee's management observation program to determine if licensee personnel were entering issues into the corrective action program. The management observation program had three purposes, which included, in part, promoting observation of worker performance, assuring that the interaction with workers and worker performance was in accordance with management expectations, and to allow tracking of low level (below condition report) human performance issues.

The team reviewed program comments for the periods of January 1 through April 1, 1999, and October 1 through December 31, 1999. The team selected 24 negative observations and requested that the licensee provide the applicable corrective action document. The licensee provided a corrective action document for 22 of the 24 observations. The team noted that two of the observations should have had a condition report initiated and did not. Specifically:

- Management Observation OBS-99-0333, initiated March 15, 1999, identified that an area adjacent to the spent fuel cooling backwash tank was contaminated. The main control room was notified of the issue; however, a condition report was not initiated to correct the deficiency. The team determined that the spread of radioactive material that contaminated adjacent, normally non-contaminated areas, to be a condition that was adverse to quality. Following questioning by the team, the licensee concurred and initiated Condition Report 2000-0153 on January 26, 2000.

- Management Observation OBS-99-1138, initiated November 14, 1999, identified that a ladder required to be prestaged by Emergency Operating Procedure, Enclosure 17, “Venting Control Rod Drive Overposition Volumes," was missing from the designated storage area. The ladder was subsequently located and rechained in the designated location. No condition report was initiated to document the adverse condition. The team determined that the failure to have a ladder prestaged as required by an emergency operating procedure was a condition that was adverse to quality. Following notification by the team, the licensee concurred and initiated Condition Report 2000-0150 on January 26, 2000.

Section 5.4 of Corporate Policy PL-150, “Condition Reporting,” specified that all personnel are responsible for identifying, reporting, and documenting adverse conditions by initiating a condition report.

Criterion V of Appendix B to 10 CFR Part 50 requires, in part, that activities affecting quality shall be prescribed by procedures and be accomplished in accordance with procedures. The failure to initiate a condition report for these two adverse conditions, as required by Corporate Policy PL-150 was the first example of a violation of Criterion V of Appendix B to 10 CFR Part 50. This Severity Level IV violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy (50-458/0002-01). This item was entered in the licensee’s corrective action program as Condition Reports 2000-0150 and 2000-0153.

(4) **Program Measurement**

The team reviewed the licensee’s methods for determining the status of the corrective action program. The team noted that the licensee’s executive trending covered adverse trends, repetitive equipment failures, and a corrective action program overview. The team also noted that the licensee was trending corrective action issues**.** The team reviewed two Quality Assurance Six-Month Effectiveness Review Audit Reports dated February 18 and September 11, 1999, respectively, one quality assurance surveillance report dated September 9, 1999, and one self-assessment report dated October 11 to 15, 1999. As the result of these reviews, the team concluded that the licensee’s quality assurance activities and management self-assessments provided an acceptable measure of the

program. For example, the report dated September 9, 1999, resulted in the Vice President, Operations, requesting a presentation on the following three long-standing problems:

- In 1997, a plant shutdown was required due to excessive recirculation pump seal leakage. Following this plant shutdown, the licensee continued to have seal degradation problems, but no further plant shutdowns were required due to excessive seal leakage. The licensee had continued to work with the seal vendor to resolve an apparent seal design problem. While this issue was not yet resolved, the team noted that the issue was entered into the licensee's corrective action program and was being actively pursued for resolution.

- On two occasions the emergency diesel generators were momentarily overloaded (in 1997 for the Division I diesel and in 1999 for the Division II diesel) during post-maintenance testing. The issue was finally resolved by changing the testing technique and resetting the mechanical load limiter. The momentary overloading did not affect emergency diesel generator operability.

- The licensee identified that room unit cooler fan hubs were not being replaced at the end of their qualified life. This replacement failure did not result in any room cooler unit failures. This issue was resolved by establishing a scheduled replacement frequency for the fan hubs.

During interviews with station personnel, the team determined that some managers and supervisors were aware of the performance indicators used by their respective departments. However, the team also found that the majority of personnel interviewed, which included a diverse cross section of plant personnel, were not familiar with departmental performance indicators, success criteria, or the location of the performance indicators. In addition, the team found one specific area involving main control room deficiencies, operator work arounds, and annunciator deficiencies, as described below, where measurement of program trends was less effective.

The team determined that, as of January 17, 2000, 24 maintenance action items for equipment in the main control room were not included in either the main control room deficiency, operator work around, or annunciator deficiency lists. After the team notified the licensee of these incomplete lists, the licensee added three maintenance action items to the main control room deficiency list and four maintenance action items to the annunciator deficiency list. An example of one of the seven maintenance action items not listed involved a blue light on Service Water Cooling Valve SWP MOV-13 that would not illuminate when the valve was in bypass (Maintenance Action Item 330912). The team determined that the remaining 17 maintenance action items did not meet the criteria for listing in any of these three lists.

To further explore this area, the team requested a listing of all maintenance action items that involved activities in the main control room. The team selected 37 of these additional 117 maintenance action items to determine if the activity was tracked on the main control room deficiency list, operator work around list, or annunciator deficiency list. Following review of these 37 maintenance action items by the licensee and interactions with the team, the licensee added five additional maintenance action items to the annunciator deficiency list and five additional maintenance action items to the main control room deficiency list. For example, the licensee added Maintenance Action Item 329848 because the vibration monitor trouble annunciator was not functioning properly. The team noted that the remaining 27 maintenance action items did not meet the listing criteria.

The eight additional maintenance action items that were added to the main control room deficiency list from the team's review raised the main control room deficiency number from 11 to 19 and changed the performance indicator from “GREEN” to “WHITE.” In addition, the nine additional maintenance action items that were added to the annunciator deficiency list, raised the total from 17 to 26 and changed the performance indicator from “YELLOW” to “RED.” Operations management used the performance indicators as a measure of the success of the facility to reduce main control room and annunciator deficiencies. The team determined that the discrepancies in the identification of main control room and annunciator deficiencies impacted the numerical values associated with the performance indicators and resulted in inaccurate data for decision making. The licensee initiated Condition Report 2000-0143 to review the classification of maintenance action items as annunciator or main control room deficiencies.

The team noted that the plant level performance indicators for operator work arounds and annunciator deficiencies did not provide results for May or June 1999, due to outage activities. Four goal levels were provided for each performance indicator. Specifically, the annunciator deficiency performance indicator goal levels consisted of: “GREEN” - less than or equal to 10, “WHITE” - less than or equal to 15, “YELLOW” - less than or equal to 19, and “RED” - greater than 19. During the period of November 1998 through November 1999, the annunciator deficiency performance indicator was “RED” for 8 months, “YELLOW” for 3 months, and not applicable (data not collected) for 2 months. The operator work around performance indicator goals were: “GREEN” - less than or equal to 10, “WHITE” - less than or equal to 12, “YELLOW” - less than or equal to 14, and “RED” - greater than 14. During the period of July 1998 through July 1999, the operator work around indicator was “RED” for 10 months, “YELLOW” for 1, and not applicable (no data collected) for 2 months.

The team questioned licensee personnel involved with the development of the monthly annunciator deficiency and operator work around performance indicators to determine if the conditions were an adverse trend, what actions were specified to be taken when goals were exceeded, and how the data was used by the facility. The licensee could not describe how the goals were established or if any actions were required when goals were exceeded. On

several occasions, the licensee stated that the use of performance indicators was new to the facility and the information was not utilized. The team noted that the collection of data for performance indicators had existed since 1997 and determined that the information was under-utilized and not understood by licensee personnel.

Following discussions with the team, the licensee determined that a potential adverse trend existed for operator work arounds and annunciator deficiencies. As the result of the team's findings, the licensee subsequently initiated Condition Reports 2000-0185 to review the potential trend in annunciator deficiencies, and 2000-0186 to review the potential trend in operator work arounds.

(5) **Program Understanding**

The team interviewed approximately 20 personnel concerning the corrective action program processes. The individuals were very knowledgeable of the various methods available to raise concerns within the corrective action program. However, as the result of condition report reviews, the team identified a number of items that demonstrated a lack of understanding of Procedure RBNP-78, "Operability Determinations."

Identification of Degraded but Operable Conditions

During a comparison of selected condition reports involving degraded, but operable conditions, the team determined that the tracking list used by the licensee was not inclusive. Specifically, the issues tracked by the licensee's list included 18 condition reports (3 from 1996, 3 from 1997, 11 from 1998, and 1 from 1999). An additional list provided to the team by the licensee's corrective action group of operable, but degraded conditions, included 27 condition reports, all from 1999. Because of the discrepancy, the licensee conducted an additional query of the condition report database and identified 38 condition reports, which needed additional review to determine if they were applicable to Procedure RBNP-078. Because of the discrepancies in the lists, the licensee initiated Condition Report 2000-0030 on January 7, 2000, to determine the causes for the inconsistencies in the tracking processes.

The licensee subsequently determined that of the 38 condition reports, which required additional review, 32 were categorized as applicable to Procedure RBNP-078; however, they did not involve operable, but degraded conditions. Of the remaining 6 condition reports, 4 that were initiated after Refueling Outage 8, were added to the tracking list of operable, but degraded issues. The remaining 2 condition reports, 1998-1053 and 1999-0911, represented operable, but degraded conditions that were known before the start of Refueling Outage 8. The team reviewed the 6 condition reports that involved operable, but degraded conditions. These condition reports included:

- Condition Report 1999-0911 regarding fluid leakage from an emergency diesel generator cylinder vent port during diesel barring.

- Condition Report 1999-1053 regarding increased wear on the annulus mixing fan expansion joints.

- Condition Report 1999-1510 regarding a problem switching from normal service water to standby service water.

- Condition Report 1999-1801 regarding closure operability of Valves SWP-MOV 506 A/B and SWP-MOV 74A/B without the ability to bypass the valve closing torque switch.

- Condition Report 1999-1914 regarding the potential to challenge the pressure integrity of the containment unit coolers.

- Condition Report 1999-1915 regarding the ability of the standby service water system to restore the drywell coolers to service following an accident.

Of these 6 condition reports, Condition Reports 1999-1510, 1999-1801, 1999-1914, and 1999-1915 were reviewed in detail. From this review, the team determined that none of these condition reports involved issues that affected plant safety. However, the team noted that Condition Report 1999-1915 represented a repetitive issue as discussed in Section O7.1b(6) of this report. In addition, the team noted that Condition Reports 1998-1053 and 1999-0911 were not reviewed and approved by the facility review committee prior to plant startup from the refueling outage.

Section 5.4.4 of Procedure RBNP-030, “Initiation and Processing of Condition Reports,” required, in part, that corrective action items identified as operable, but degraded, that are determined to exceed the next refueling outage must be reviewed and approved by the facility review committee prior to restart from that outage.

Criterion V of Appendix B to 10 CFR Part 50 requires, in part, that activities affecting quality shall be prescribed by procedures and be accomplished in accordance with procedures. The failure to ensure that operable, but degraded conditions, were approved by the facility review committee before plant startup from a refueling outage, as required by Procedure RBNP-030, was the second example of a violation of Criterion V of Appendix B to 10 CFR Part 50. This Severity Level IV violation is being treated a Non-Cited Violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy (50-458/0002-01). This item was entered in the licensee’s corrective action program as Condition Report 2000-0030.

The team noted that the licensee initiated several immediate corrective actions, which included the issuance of Standing Order 174, “Tracking of Open Generic Letter 91-18, 'Operable but Degraded,' Conditions in the Paperless Condition Report System,” approval of Condition Reports 1998-1053 and 1999-0911 by the facility review committee, commencement of a daily review of newly issued condition reports for operability issues, which needed to be tracked, and development of a condition report database query.

Leakage Control System Pressure Control Valve

During the review of annunciator deficiencies, the team determined that on December 13, 1998, operations personnel initiated Maintenance Action Item 320881, which described a deficiency with main steam positive leakage control system Pressure Control Valve LSV PCV-42A. The deficiency was that the low discharge pressure alarm came in due to the regulator valve not controlling properly. The team noted that the main steam positive leakage control system was a backup to the main steam isolation valves. The system was designed to pressurize the space between the inboard and outboard main steam isolation valves to prevent potential fission product leakage to the environment if the closed main steam isolation valves did not fully close and seal. If Valve LSV PVC-42A did not properly control air pressure, sufficient air pressure would not be provided between the inboard and outboard isolation valve spaces, thereby, reducing the effectiveness of this backup system. Maintenance Action Item 320881 specified that the regulator should be repaired or replaced. On January 14, 2000, the team questioned licensee personnel and determined that an operability determination had not been completed for Valve LSV PCV-42A.

Section 6.4.2 of Procedure RBNP-078, specified that if the structure, system, or component having a degraded or nonconforming condition involved an operability concern, then a shift technical advisor or senior reactor operator shall develop an operability determination.

Criterion V of Appendix B to 10 CFR Part 50 requires, in part, that activities affecting quality shall be prescribed by procedures and be accomplished in accordance with procedures. The failure to conduct an operability determination for the degraded condition of Valve LSV PCV-42A, as required by Procedure RBNP-078, was the third example of a violation of Criterion V of Appendix B to 10 CFR Part 50. This Severity Level IV violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy (50-458/0002-01). This item was entered in the licensee’s corrective action program as Condition Report 2000-0064.

Following the identification of this issue by the team, the licensee determined that Valve LSV PCV-42A was operable, but degraded. On January 18, 2000, the licensee repaired the valve.

Penetration Valve Leakage Control System and Emergency Diesel Generator Starting Air System

The penetration valve leakage control system is designed to provide a backup air supply to the automatic depressurization system safety relief valves. The system provides approximately 120 psig of air pressure via associated Air Storage Tanks LSV-TK6A and B. The technical specification minimum air pressure for this system is 101 psig.

The team reviewed Condition Report 1998-0498, dated April 25, 1998, which identified that the penetration valve leakage control system pressure relief valve on one of the two air receiver tanks opened and depressurized the tank to approximately 70 psig before the valve reseated. The team noted that since only one division of the automatic depressurization system is required to be operable to mitigate accident conditions, and the penetration valve leakage control system was a backup to the normal air supply to the safety relief valves, this blow down did not affect automatic depressurization system operability. The licensee determined that the pressure relief valves installed on the tank had a nonadjustable blow down setting and that the valves would reseat at 30 to 70 percent below the valve set pressure.

As part of the corrective actions for the condition report, the licensee reviewed all of the relief valves that did not incorporate a blow down adjustment. The licensee reviewed each valve to determine if the blow down pressure was below the minimum operating pressure and/or technical specification operating pressure for the system. As the result of this review, the licensee found that the emergency diesel generator starting air receiver pressure relief valves also did not have a blow down adjustment and that the valve reseat could occur at a pressure that was less than the minimum pressure required by the technical specifications. The team noted that since each emergency diesel generator has redundant air supply systems (forward and rear subsystems), the loss of one of these subsystems did not affect the operability of the emergency diesel generator. The team also noted that Condition Report 1998-0044, dated January 14, 1998, identified that during testing of the Division II diesel generator, the pressure relief valve on one of the starting air receiver tanks lifted and failed to reseat until the tank pressure was below the 160 psig pressure required by the technical specifications. The licensee determined that the nonadjustable blow down valves for the diesel generator starting air receivers and the steam penetration leakage control system were misapplied. The corrective action was to replace these valves with adjustable blow down valves. The team noted that while the original due date for replacement of these valves was March 31, 1999, the completion date was changed to the end of 2000 due to the lead time required to obtain the replacement valves.

Hydrogen Monitoring System

During a review of operator work arounds, the team determined that on April 3, 1999, the licensee initiated Condition Report 1999-0425, which described a condition where operation of sample valves for drywell and containment hydrogen monitoring over the entire 100 day post loss-of-coolant accident period was questionable. Specifically, the valve manufacturer stated that the sample valves would only perform 600 cycles before starting to degrade. However, the team noted that if the valves were left in the automatic mode of operation, the valves would cycle approximately 5,200 times in 100 days.

On November 9, 1999, the licensee revised Procedure SOP-0084, "Containment Atmosphere Monitoring System," to include procedural requirements to switch the hydrogen monitoring system from the automatic mode of operation to the manual mode of operation prior to reaching day 11 following a loss-of-coolant. Placing the sample valves in manual would preclude further degradation and maintain the ability to collect independent hydrogen samples from locations in the containment and drywell. The team noted that while these valves remained operable, they were degraded and that an operability determination for this degraded condition was not performed.

Section 6.4.2 of Procedure RBNP-078, specified that if the structure, system, or component having a degraded or nonconforming condition involves an operability concern, then a shift technical advisor or senior reactor operator shall develop an operability determination.

Criterion V of Appendix B to 10 CFR Part 50 requires, in part, that activities affecting quality shall be prescribed by procedures and be accomplished in accordance with procedures. The failure to conduct an operability determination for the degraded condition of the hydrogen sample valves as required by Procedure RBNP-078, was a fourth example of a violation of Criterion V of Appendix B to 10 CFR Part 50. This Severity Level IV violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy (50-458/0002-01). This violation was entered in the licensee's corrective action program as Condition Report 2000-0145.

The team also compared the radiation exposure of these hydrogen sample valves to the radiation exposure assumed in the accident analysis. Assumption 6 of Calculation 12210-PR(C)-547, "Normal and Accident Gamma and Beta Doses for Mechanical Equipment Qualification," which specified the design criteria for the containment monitoring system, indicated that the drywell atmosphere would not be sampled until 2 hours following a loss-of-coolant accident. Calculation 12210-PR(C)-547 also specified that the beta doses due to plate-out of halogens were not included because the containment monitoring system was assumed not to begin sampling drywell atmosphere until 2 hours following a loss-of-coolant, at which time 25 percent of the halogens were assumed to have completely plated-out on the drywell walls. However, the team determined that the post-accident hydrogen recorders automatically start

recording when a manual or automatic containment isolation signal is present. This means that the hydrogen sample valves would begin sampling as soon as the loss-of-coolant occurred, thus, negating the 2-hour delay assumed in the calculations.

Following the identification of this issue by the team, the licensee reperformed Calculation 12210-PR(C)-547. As the result of the licensee's effort, the team noted that a 2-hour delay was not required and that the halogen plate-out would not affect valve operability.

(6) **Repetitive Problems**

The team noted that repetitive problems were being identified and placed in the corrective action program. However, during review of condition reports and Non-Cited Violations (see Section O7.1b(7) of this report), the team identified five specific items that were repetitive. Although four of these items did not represent a regulatory concern, the fifth repetitive item, involving the operability of the emergency diesel generators, was a regulatory concern.

Motor-Operated Valve Operability

During the performance of this inspection, the team noted 11 condition reports where motor-operated valves failed to operate due to a variety of causes. The team reviewed these condition reports and determined that the valve problems did not impact any system's accident mitigation capability or safety function. However, the team considered these condition reports to be additional examples of repetitive problems.

Emergency Operating Procedure 0002, "Primary Containment Control"

The team reviewed Condition Report 1999-1915, which identified concerns with Step 3 of Emergency Operating Procedure 0002, "Emergency Operating Procedure - Primary Containment Control." This procedure directed operators to operate all available drywell cooling, including defeating isolation interlocks, when drywell temperature cannot be maintained below 145°F under loss-of-coolant accident conditions. Condition Report 1999-1915 also addressed the ability of the operators to reclose the drywell cooler isolation valves. The condition report stated that "Isolation valves are located in the containment building, and they are accessible." However, the team identified that the post loss-of-coolant accident radiation environment inside containment would prohibit operator access to these valves. While the condition report statement was incorrect, the team noted that the valves could be closed remotely from the control room, if required, and that single failure protection was maintained by the standby service water containment isolation valves. Therefore, no safety issue existed. The team noted that the condition report did not identify the potential for

leakage from the drywell to the environment by way of the standby service water system through the drywell isolation valves that provided the supply and return flowpath to the nonsafety-related drywell coolers. This factor was not addressed in Condition Report 1999-1915 because the licensee considered that it had been previously resolved by Condition Report 1996-1357.

The team's review of Condition Report 1996-1357, identified that the licensee's resolution of this concern was incomplete. The 10 CFR 50.59 safety evaluation for this condition report stated that the failure of the drywell cooler due to the loss-of-coolant accident and an assumed failure of the standby service water piping inside containment would provide only a 0.4 ft^2 drywell-to-containment bypass leakage flowpath. Since this was less than the 1.0 ft^2 allowed by the technical specifications, the licensee concluded that this was acceptable. The evaluation failed to recognize that the leakage was not between the drywell and the containment, but rather between the drywell and the environment (via the nonsafety-related drywell coolers and the open isolation valves). Therefore, this evaluation was incomplete in that it did not address fully the condition report's concern.

The condition report stated that a maximum cooler leak would be 45 gpm and that this leakage could be detected as a standby service water supply-versus-return flow mismatch on Instrument SWP-FR60A/B, that had an instrument inaccuracy of 400 gpm. Emergency Operating Procedure 0005, "Defeating Drywell Cooling Isolation Interlocks," required that if a leak was indicated by this instrument, the drywell cooler isolation valves were to be reclosed.

The team determined that since the instrument’s absolute accuracy was about 400 gpm, it would be unable to quantify the 45 gpm leak from the standby service water system. The team also determined that since the sensitivity of this instrument to flow changes was approximately 20 gpm, it should be adequate to detect the 45 gpm change from a leak in the standby service water system. However, the team also noted that this was true only if Instrument SWP-FR60A/B was used correctly, i.e., comparing the indicated leakage before and after opening the standby service water system isolation valves and noting the supply-versus-return flow change. This change would be the actual cooler leakage. Since Emergency Operating Procedure 0005 required the operators to reclose the isolation valves if Instrument SWP-FR60A/B indicated a leakage situation, there was the potential that the operators would shut the standby service water isolation valves even if no leakage was present due to the inaccurate reading from Instrument SWP-FR60A/B. Although discussions with licensee personnel indicated that this comparison would likely be done without procedural guidance due to training and experience, the team determined that additional procedure guidance would enhance the intent of Emergency Operating Procedure 0005. The licensee agreed with the team’s observations and initiated a procedure change to Emergency Operating Procedure 0005 to provide this additional guidance.

As a result of the team's identification of this finding, the licensee issued Condition Report 2000-0131. In this condition report, the license determined that for a large failure of the standby service water piping or components inside the drywell, the failure would be detected due to the guidance provided in Emergency Operating Procedure 0005. This guidance required the operator to compare the supply and return flows of the standby service water system, and if any leak were indicated, to re-isolate the drywell coolers. In addition, during the time until the operators determined that a re-isolation was necessary, the licensee determined by review of Calculation G13.18.4.4*043, that there would be no release to the environment because the standby service water system pressure on both the supply side and the return side of the break was greater than the drywell pressure. For small leaks that might not be detectable in accordance with Emergency Operating Procedure 0005, the licensee determined by review of Calculation G13.18.4.0*048, that the pressure inside the drywell cooler components and piping would be greater than the drywell atmosphere. Any leakage would, therefore, be from the standby service water system into the drywell rather than from the drywell into the standby service water system. Therefore, there would be no release from the drywell to the environment.

Although the emergency operating procedure concerns were not safety significant, the condition reports represented repeated opportunities to determine that engineering reviews were not complete. The team considered these condition reports to be an example of a repetitive problem.

Main Steam Safety Relief Valve Test Failures

The team reviewed Condition Report 1998-1430, which described that 9 of the 16 main steam safety relief valves tested at Wyle Laboratories failed their as-found set pressure tests by exceeding the technical specification allowable tolerance of +0/-2%. These valves were removed during Refueling Outage 7. The team also reviewed Condition Report 1997-0781, which documented that 11 of the 16 main steam safety relief valves removed during Refueling Outage 6 failed their as-found set pressure tests. In addition, the team reviewed Condition Report 1995-0558, which documented that 6 of the 16 valves removed during refueling outage Refueling Outage 5 failed their as-found set pressure tests. The team noted that testing had not yet been performed on the 16 valves removed during the last refueling outage, Refueling Outage 8. Since Technical Specification 3.4.4.1 required that at least five main steam safety relief valves be operable during plant operation, the team noted that even with these test failures, the licensee had a sufficient number of operable main steam safety relief valves to meet license conditions. As a part of its corrective actions, the licensee submitted an interim technical specification amendment request to the NRC to change the as-found set pressure tolerance from +0/-2 to +0/-3. The team determined that while this problem did not affect license conditions, it was indicative of a repetitive problem that had not yet been corrected.

Service Water Relief Valve Test Failures

The team reviewed six condition reports (1999-1022,1999-0525,1999-0524, 1999-0933, 1999-0240, and 1999-0923) involving as-found set pressure failures of six safety-related relief valves in the service water system. The failures all occurred in 1999 within a few months of each other. Since there were numerous as-found set pressure failures in 1999, the team expanded their sample size and reviewed a summary of ASME Section XI inservice test relief valve set pressure test results since 1994. Out of the 106 relief valve tests, there were 52 valves that failed their as-found set pressure tests and 54 that passed. This 50 percent failure rate had a steady trend from 1994 through 1999, which indicated that the licensee's relief valve program was not correcting repetitive failures. The team noted that the licensee was initially addressing the failures on an individual basis instead of as a generic problem. On May 26, 1999, the licensee issued Condition Report 1999-0932, which addressed the generic concerns for the high failure rate. A root-cause analysis was performed, which determined that a lack of maintenance of the pressure relief valves and valve chattering due to system conditions contributed to the high failure rate. The team found that the immediate corrective actions were to generate a condition report for each valve that failed and either adjust, repair, or replace the valves that failed their test. While these corrective actions were not yet complete, the corrective action regarding valve replacement was to be accomplished under the preventive maintenance program. The team noted that the licensee had not yet established a completion date for the valve replacements. The team determined that this was an example of a repetitive issue that had not yet been corrected.

Emergency Diesel Generator Operability

Over the past 2 years, the team noted three occurrences where the licensee failed to maintain emergency diesel generator operability in accordance with the technical specifications. The team considered these occurrences to be examples of repetitive problems. Details of these occurrences are discussed in Section O7.1b(7) of this report.

(7) **Non-Cited Violation Followup**

Non-Cited Violation 50-458/9909-01

This Non-Cited Violation, concerning an inadequate operability determination involving the effect of increased auxiliary building temperatures on safety-related equipment due to degraded auxiliary building coolers, was entered in the corrective action program via Condition Report 1999-0875. The team noted that the corrective actions provided detailed training to engineering personnel, but did not include operations personnel involved in the operability determination process. Subsequent to discussions with the team, the licensee stated that additional training in the operability determination process was to be provided to operations personnel as part of the shift briefings in February 2000. The team

questioned the adequacy of this corrective action given the short duration of shift briefings, the impact on maintaining a professional atmosphere in the main control room, the need to provide separate training facilities for operations personnel, and the length of time the training on the NRC Generic Letter 91-18 process would take. Following these discussions, and since Condition Report 1999-0875 was already closed, the licensee added a corrective action to another condition report, Condition Report 1999-1475. This item provided for training for operations personnel during licensed operator requalification following Refueling Outage 9.

The team's review of this Non-Cited Violation also identified an issue involving the inoperability of the Division III emergency diesel generator. The Division III emergency diesel generator is cooled by either the Division I or II train of the standby service water system. While either of these divisions are capable of providing cooling water to the Division III emergency diesel generator, the safety evaluation in the Updated Safety Analysis Report assumed that both the Division I and II standby service water system supplies were available. On March 16, 1999, following an inservice test failure of Division I standby service water system Check Valve SWP-135, the Division I Standby Service Water Supply Valve SWP MOV-77A to the Division III emergency diesel generator was closed to isolate the leaking check valve. Valve SWP MOV-77A was reopened in April 1999, after repair of the check valve. The purpose of this check valve was to prevent a loss of standby service water system cooling to the Division III emergency diesel generator if a rupture in the Division I supply occurred. However, the closure of Valve SWP MOV-77A also isolated the Division I standby service water supply to the Division III emergency diesel generator. This isolation was contrary to the assumptions made in the Updated Safety Analysis Report.

In September 1999, during a routine NRC inspection (NRC Inspection Report 50-458/99-12), a partial review of the standby service water system was conducted. During the review, the inspectors determined that the licensee had failed to consider all aspects of closing the Division I Standby Service Water Supply Valve SWP MOV-77A in the technical evaluation. Specifically, the licensee had not addressed the following issues:

- With the Division I standby service water supply isolated, a failure of the Division II emergency diesel generator or the Division II standby service water system could render the Division III emergency diesel generator inoperable due to a loss of cooling water. Normally, the Division I standby service water supply would be in service; therefore, no interruption of cooling water flow would occur following a loss of the Division II standby service water system.

- With Valve SWP MOV-077A closed, the differential pressure across the valve seat would increase to approximately 110 psid due to a failure of the Division II standby service water system. However, Calculation G13.2.3*289, “Generic Letter 98-10 Design Basis Review for SWP MOV 506A/B & 077A/B," assumed a 4.0 psid differential pressure across Valve SWP MOV-077A.

- Plant procedures for a loss-of-service water directed personnel to close the Division II service water isolation valves (including Valve SWP MOV-077B) and then open the Division I service water isolation valves. With Valve SWP MOV-077A already closed, both divisions of standby service water supply and return valves to the Division III emergency diesel generator would be isolated before the Division I standby service water system valves could be reopened to restore flow. Calculation G13.2.3*289 assumed that since there were no requirements to close the supply and return valves for both divisions, the supply and return valves would always remain open.

- The evaluation did not consider the amount of time required for operators to recognize a failure of the Division II standby service water system and take action to open Valve SWP MOV-077A to restore cooling water flow to the Division III emergency diesel generator.

On September 22, 1999, the licensee concurred with the NRC’s conclusion that the technical evaluation for closing Valve SWP MOV-077A was inadequate and on an interim basis, issued Standing Order 169, “Operability of Division III Diesel Generator and Ventilation-Reactor Plant Unit Cooler 5,” to require that the Division III emergency diesel generator be declared inoperable if any of the associated standby service water supply or return valves were closed. As stated earlier, the licensee initiated Condition Report 1999-1475 to review the lack of system interactions in the technical evaluation and was the subject of Non-Cited Violation 50-458/9912-04.

The licensee documented two root causes for the inadequate operability determination in Condition Report 1999-1475. Root Cause 1 was that personnel misunderstood instructions for performing operability determinations. Root Cause 2 was that past practices or “mind set” by personnel resulted in the Division I and Division II standby service water supply and return lines to the Division III emergency diesel generator being viewed as redundant trains. The personnel involved did not realize that both trains were required for Division III emergency diesel generator operability. This misconception supported the contingency action of closing Valve SWP MOV-077A when Check Valve SWP-135 failed.

The root cause investigation documented in Condition Report 1999-1475 also addressed each of the NRC’s concerns (as documented in NRC Inspection Report 50-458/9912). Specifically:

- The failure to assess the impact on Division III emergency diesel generator operability: It took the licensee from March 16, 1999, until November 19, 1999, to determine that the Division III emergency diesel generator was inoperable when either the Division I or II standby service water supply to the Division III emergency diesel generator was isolated.

- The failure to assess the differential pressure across a closed Valve SWP MOV-077A: The licensee completed a preliminary evaluation of the condition and determined that Valve SWP MOV-077A had ample margin for valve opening even with the increase in the differential pressure from approximately 4 to 110 psid. The licensee developed a corrective action item to complete a formal evaluation by May 1, 2000.

- The failure to consider the normal operating configuration of Valve SWP MOV-077A: The licensee determined that a March 1999 evaluation incorrectly specified that sufficient guidance existed in Procedure AOP-016, "Loss of Standby Service Water." Specifically, Procedure AOP-016 assumed Valve SWP MOV-077A was normally open at the start of an event. The situation in which Valve SWP MOV-077A was closed at the start of an event was unanalyzed.

- The failure to consider the amount of time necessary for operations personnel to recognize a degraded condition involving Division II standby service water and to restore standby service water flow to the Division III emergency diesel generator by re-opening Valve SWP MOV-077A: The licensee determined that the Division III emergency diesel generator must accomplish the following sequence in 13 seconds: Start, accelerate to rated speed and voltage, and connect to its respective engineered safety features bus. The Division III bus had no load sequencing logic other than to start Standby Service Water Pump 2C and open the associated pump discharge valve 30 seconds after the Division III breaker closed. Therefore, standby service water flow must be established to the Division III emergency diesel generator less than 1 minute following closure of the Division III emergency diesel generator output circuit breaker. This sequence provided insufficient time for operator action to establish the flow path. Additionally, the licensee determined that any operator action would require a safety evaluation.

The team developed the following sequence of events for the isolation of Valve SWP MOV 077A:

March 16, 1999	Division III Emergency Diesel Generator Supply Check Valve SWP-135 failed inservice testing and was declared inoperable. The licensee entered technical specification limiting condition for operation 5.5.6 to address the inservice testing failure. As a contingency action, Valve SWP MOV-077A was closed to isolate Division I standby service water from Division II standby service water and the Division III emergency diesel generator.
March 24, 1999	The Division I emergency diesel generator failed during testing due to inadequate maintenance on the emergency diesel generator fuel pump coupling. The licensee subsequently determined that the Division I emergency diesel generator was inoperable between February 24 and March 25, 1999. This issue was discussed in NRC Inspection Reports 50-458/9903 and 50-458/9907 (Refer also to EA 98-478 and EA 99-158).
March 25, 1999	Repairs were completed and the Division I emergency diesel generator was restored to operable.
March 31, 1999	Maintenance was completed on Check Valve Standby Service Water-135.
April 1, 1999	Valve SWP MOV-077A was reopened and Technical Specification 5.5.6 was exited at 5:21 a.m.
September 1999	NRC inspectors performed a partial review of the standby service water system. The review identified, in part, an inadequate operability determination for the closure of Valve SWP MOV-077A.
November 19, 1999	Engineering personnel determined that the Division III emergency diesel generator was inoperable when Valve SWP MOV-077A was closed due to a loss-of-redundancy for the standby service water supply to the Division III emergency diesel generator.
December 9, 1999	The NRC met with the licensee to discuss its corrective actions for the failed fuel pump coupling on the Division I emergency diesel generator. While these discussions addressed the material condition of the emergency diesel generators, it did not include the inoperability of the Division III emergency diesel generator while the Division I emergency diesel generator was inoperable.

January 12, 2000	During a review of corrective actions for Non-Cited Violation 50-458/9912-04, the team determined that the licensee had not reported the discovery of a condition prohibited by the technical specifications to the NRC.
January 18, 2000	The licensee initiated Condition Report 2000-0090 for not reporting the inoperability of the Division III emergency diesel generator.
February 23, 2000	The licensee issued Licensee Event Report 50-458/00-002 to report the closing of Valve SWP MOV-77A.

Following identification of this issue by the team, a risk analysis of this degraded emergency diesel generator capability was performed by both the licensee and the NRC. These analyses concluded that the conditional core damage probabilities calculated for the periods the Division I emergency diesel generator was inoperable concurrent with the standby service water cross-tie valve being closed, did not result in a risk significant condition; however, from the increase in risk, the above configurations approached the cut off value of E-6 used to assess a condition as moderately risk significant.

The team noted that the licensee missed prior opportunities to identify the simultaneous inoperability of the Division I and III emergency diesel generators. The team considered the licensee's investigation to be inadequate because it failed to identify the effect of a combined Division I and III failure on the emergency power systems.

Technical Specification 3.8.1, "AC Sources Operating," required, in part, that three emergency diesel generators be operable in Modes 1, 2, and 3. The technical specification further specified that with two required emergency diesel generators inoperable, restore one required emergency diesel generator to an operable status within 2 hours (or 24 hours if the Division III emergency diesel generator is one of the inoperable emergency diesel generators). If this required action was not met, then be in Mode 3 within 12 hours and be in Mode 4 within 36 hours. The team determined that between March 16 and 24, 1999, both the Division I and III emergency diesel generators were inoperable and that the licensee did not restore an emergency diesel generator to an operable status within 24 hours, place the facility in Mode 3 within 12 hours, or place the facility in Mode 4 within 36 hours. This is the first example of a violation of Technical Specification 3.8.1. This Severity Level IV violation of Technical Specification 3.8.1 is being treated as a Non-Cited Violation consistent with Section VII.B.1.a of the NRC Enforcement Policy (50-458/0002-02).

Technical Specification 3.8.1 also specified that with one required emergency diesel generator inoperable, perform Surveillance Requirement 3.8.1.1 for the operable required offsite circuits within 1 hour and once per 8 hours, thereafter. In addition, it specified to determine that the operable emergency diesel generators are not inoperable due to common cause failure within 24 hours or

perform Surveillance Requirement 3.8.1.2 for the operable emergency diesel generator within 24 hours. It also required the restoration of the required emergency diesel generator to an operable status within 72 hours. The team determined that between March 24 and 31, 1999, the Division III emergency diesel generator was inoperable and the licensee did not perform the required surveillances, restore the Division III emergency diesel generator to an operable status within 72 hours, place the facility in Mode 3 within 12 hours, or place the facility in Mode 4 within 36 hours. The team determined that the failure to implement the required actions and completion times associated with the inoperability of the Division III emergency diesel generator was a second example of a violation of Technical Specification 3.8.1. This Severity Level IV violation of Technical Specification 3.8.1 is being treated as a Non-Cited Violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy (50-458/0002-02). This item was entered in the licensees corrective action program as Condition Report 1999-1475.

Licensees are required by 10 CFR Part 50.73(a)(2)(i)(B) to submit a licensee event report within 30 days after the discovery of any operation or condition prohibited by the plant's technical specifications. During the review of Condition Report 1999-1475, the team determined that engineering personnel had reached a conclusion on November 19, 1999, that the Division III emergency diesel generator was inoperable when either the Division I or II standby service water supply or return valves to the Division III emergency diesel generator were closed. On January 12, 2000, the team identified that even though engineering personnel determined that the Division III emergency diesel generator was inoperable, the licensee did not make the required notification to the NRC. The licensee stated that the reportability of the issue was unknown at the time that Condition Report 1999-1475 was initiated and that due to a personnel error, a corrective action item had not been initiated in Condition Report 1999-1475 to perform the reportability evaluation following the completion of the engineering review. The failure to submit a licensee event report within 30 days after the discovery of a condition prohibited by technical specifications was a violation. This Severity Level IV violation of 10 CFR Part 50.73(a)(2)(i)(B) is being treated as a Non-Cited Violation consistent with Section VII.B.1.a of the NRC Enforcement Policy (50-458/0002-03). This item was entered in the licensee's corrective action program as Condition Report 2000-0090.

Non-Cited Violation 50-458/9909-02

This Non-Cited Violation was placed in the corrective action program via Condition Report 1999-1135. The Non-Cited Violation involved a failure to perform a 10 CFR 50.59 safety evaluation for a degraded, but operable condition, for three safety-related room coolers. The Non-Cited Violation was issued in July of 1999 and had still not been fully resolved because the licensee was performing 10 CFR 50.59 safety evaluations as individual corrective actions

were completed. The team noted that the licensee has developed an auxiliary building unit coolers margin recovery plan to correct the room cooler problems. The licensee's projected completion date for this plan was April 4, 2000. The team determined that the licensee was making progress toward resolving the issue.

Non-Cited Violation 50-458/9909-03

This Non-Cited Violation was placed in the corrective action program via Condition Report 1999-0885. The Non-Cited Violation involved the licensee's failure to take prompt actions to restore the designed insulation configuration of the high pressure core spray piping. The insulation was installed on the piping in the high pressure core spray pump room approximately 3 years after the problem was discovered. The team found that the Non-Cited Violation was entered into the corrective action program and resolved in an adequate manner.

c. Conclusions

The team found four examples of a failure to follow procedures involving condition reports and operability evaluations. Two additional examples of a failure to follow procedures are described in Sections E7.1b and R7.1b. These examples constitute a Severity Level IV violation of Criterion V of Appendix B to 10 CFR Part 50. This violation is being treated as a Non-Cited Violation consistent with Section VII.B.1.a of the NRC Enforcement Policy. These four examples involving condition reports and operability evaluations included the following:

- Condition reports were not generated for two adverse findings identified by the management observation program as required by Corporate Policy PL-150. As a result, these findings were not entered into the corrective action program (Section O7.1b(3)).

- The facility review group failed to review and approve two operable, but degraded conditions prior to plant startup from a refueling outage as required by Procedure RBNP-030 (Section O7.1b(5)).

- An operability evaluation was not performed as required by Procedure RBNP-078 for an operable, but degraded condition of Main Steam Leakage Control Valve LSV PCV-42A (Section O7.1b(5)).

- An operability evaluation was not performed as required by Procedure RBNP-078 for an operable, but degraded condition, involving the early failure of hydrogen sample valves (Section O7.1b(5)).

There were two examples of a failure to meet the requirements of Technical Specification 3.8.1 for the electrical power system ac sources. These constitute a Severity Level IV violation of Technical Specification 3.8.1. This violation is being treated as a Non-Cited Violation consistent with Section VII.B.1.a of the NRC Enforcement Policy. These examples included the following:

- The limiting conditions for operation of Technical Specification 3.8.1 were not met between March 16 and April 1, 1999. Both the Division I and III emergency diesel generators were inoperable and neither emergency diesel generator was restored to an operable status within 24 hours nor was a plant shutdown to Mode 3 conducted within 12 hours.

- The surveillance requirements of Technical Specification 3.8.1 were not met between March 24 and 31, 1999. The licensee failed to perform the required surveillances for the offsite circuits (within 1 hour and every 8 hours, thereafter) and test the operable emergency diesel generators within 24 hours.

A condition that caused the Division III emergency diesel generator to be inoperable when isolated from standby service water Division I water supply and was prohibited by the technical specifications, was not reported within 30 days, as required by 10 CFR 50.73(a)(2)(i)(B). This was a Severity Level IV violation of 10 CFR 50.73(a)(2)(i)(B). This violation is being treated as a Non-Cited Violation consistent with Section VII.B.1.a of the NRC Enforcement Policy.

O7.2 Industry Operating Experience

a. Inspection Scope

This inspection evaluated the adequacy of the licensee's implementation of corrective actions for operational experience feedback. The evaluation encompassed the period of November 24, 1999, through January 10, 2000.

b. Observations and Findings

The licensee's Industry Events and Analysis group was assigned the responsibility to conduct reviews of events that occurred externally to their facility. The purpose of this review was to determine if any of these events had an impact on facility operations. The group's activities were documented in Procedure RBNP-062, "River Bend Industry Events and Analysis Program."

To accomplish this inspection, the team reviewed the corrective actions for 2 generic letters, 3 NRC information notices, and 13 Part 21 reports. The corrective actions for the generic letters, the 3 information notices, and 12 of the 13 Part 21 reports were found to be adequate and complete. With one exception, the team considered the Industry Events and Analysis program to be effective at identifying issues and entering them into the corrective action program.

The one exception involved a Part 21 report from the Thomas and Betts Company involving misapplication of Agastat E7000 relays. On January 28, 1999, an Entergy Operations, Inc., system document (MISC-9901261032) regarding the use of these relays at the Calvert Cliffs facility, was entered into the database by another Entergy Operations, Inc., facility, Arkansas Nuclear One. The Calvert Cliffs facility reported that the problem was not a misapplication of the relays, but instead was a problem caused by the use of old molds to manufacture the relays. Licensee representatives stated that

while they had not received the Part 21 report at that time, the Entergy Operations, Inc., notification prompted them to conduct a search of their component data base on February 16, 1999. This search did not identify any use of these relays at River Bend Station and the system document was closed. However, also on February 16, the Entergy Operations, Inc., Waterford 3 facility noted River Bend Station's negative response regarding the use of these relays. The Waterford 3 facility contacted River Bend Station to inform them that they believed that River Bend Station did have these relays. As the result of the Waterford 3 notification, the licensee, on March 8, 1999, issued a recommendation to procurement engineering to again determine applicability of these relays to River Bend Station. On June 24, 1999, procurement engineering also determined that they did not have these relays and action on this issue was closed again. On the day before, June 23, 1999, the licensee decided to conduct a third evaluation when they were notified that Operating Experience Report OE-10023 was issued. This report addressed this same relay problem. Based on the team's discussions with licensee personnel, the licensee determined that:

- Seventeen of these relays were installed in the plant, with 4 located in nonsafety-related systems and 13 located in the safety-related high pressure core spray system. All of these relays were properly installed and operable.

- This problem occurred because the searches made on AMERACE and AGASTAT (which provided the negative information) did not reflect the vendor acquisition name change.

- River Bend Station had actually received the Part 21 report on April 6, 1999, but the report was "misplaced" within its Industry Events and Analysis program.

- As a result of a conversation with the manufacturer, Thomas and Betts, the licensee determined that the problem was not caused by the use of old relay molds, but was actually the use of the relays at voltage conditions that were below those specified for the relay's application.

As the result of these findings, the licensee wrote Condition Report 2000-0110 on January 19, 2000. In addition, on January 20, 2000, the licensee completed its evaluation and concluded that the River Bend Station relays were properly installed in applications that had the appropriate voltage and, therefore, were operable.

The team considered this issue to be a good indication that the licensee's internal Entergy Operations, Inc., communication system was effective.

c. Conclusions

With the exception of the failure to address the misapplication of the Agastat relay Part 21 report, the team considered the licensee's industry operating experience program to be effective. The internal Entergy Operations, Inc., communication system was found to be useful toward identifying reports that could affect multiple plants.

II. Maintenance

M7 Quality Assurance in Maintenance

M7.1 Maintenance Rule

a. Inspection Scope (40500)

This inspection reviewed the licensees' monitoring of the structures, systems, and components that were within the scope of the maintenance rule. This monitoring was reviewed to determine if the corrective actions, goals, and monitoring of structures, systems, and components that were in 10 CFR 50.65(a)(1) were appropriate and adequate.

b. Observations and Findings

The team reviewed documentation concerning the administration of the maintenance rule, specifically, in the area of declaring systems, structures, and components as being in either Category (a)(1) or (a)(2) of the rule. This review confirmed that the licensee was adhering to its administrative procedures in this area and was assigning corrective actions, setting goals, and properly assessing the declaration of systems, structures, and components as Category (a)(1) or (a)(2).

c. Conclusions

The licensee's corrective actions, goal setting, and monitoring of the structures, systems, and components included in the maintenance rule were found to be appropriate.

III. Engineering

E7 Quality Assurance in Engineering Activities

E7.1 System Reviews

a. Inspection Scope (40500)

This inspection consisted of a review of the corrective action processes as they related to engineering activities for the standby service water system. The review included 40 condition reports, 7 engineering requests, 7 maintenance action items, 6 procedures, 8 drawings, and miscellaneous licensing documents for the standby service water system.

b. Observations and Findings

The team identified a concern with Condition Report 1998-1460. The condition report documented that the performance of all of the control building chilled water chiller condenser pumps was slightly less than their design basis performance requirement, that no margin had been allowed in the design between the design basis performance requirement and the new-pump capability as shown on the original vendor pump curves, and that the acceptance criteria contained in their Surveillance Test Procedures STP-256-6321, STP-256-6322, STP-265-6303, and STP-256-6304 were based on reference values from these curves.

Contained within this condition report were computer-based and hand calculations that had been used to determine that the pumps and associated equipment were operable, but degraded. These calculations were used to change the design basis performance requirements for these pumps and the surveillance test procedure acceptance criteria. However, the team noted that these calculations had not been performed and controlled in accordance with licensee Calculation Procedure, EDP-AA-20, "Engineering Calculations."

Procedure EDP-AA-20 allowed calculations to be included in condition reports and other documents, if three conditions were met: (1) the calculations were in retrievable permanent plant records, (2) all relevant calculation information required for review and approval was included, and (3) the documents in which the calculations were included were subjected to the same level of review and approval as would be required by the calculation procedure. The team noted that not all relevant calculation information was included and that the calculations were not subjected to the same level of review and approval, as was required by the calculation procedure. The team's review also revealed that for the computer-based calculation, the purpose, methodology, assumptions and their bases, inputs and their sources, and other details were not identified and documented, as required by Procedure EDP-AA-20.

Criterion V of Appendix B to 10 CFR Part 50, requires, in part, that activities affecting quality shall be prescribed by procedures and be accomplished in accordance with procedures. The failure to perform engineering calculations for the safety-related control building chilled water chiller condenser pumps in accordance with Procedure EDP-AA-20 was considered to be a fifth example of a violation of Criterion V of Appendix B to 10 CFR Part 50. This Severity Level IV violation is being treated as a Non-Cited Violation consistent with Section VII.B.1.a of the NRC Enforcement Policy (50-458/0002-01). This violation was entered into the licensee's corrective action program as Condition Report 2000-0220.

c. Conclusions

The calculations for the control building chilled water condenser pumps did not have all relevant information and did not receive the same review and approval as did the original calculations as required by Procedure EDP-AA-20. This Severity Level IV violation of Criterion V of Appendix B to 10 CFR Part 50 is being treated as a Non-Cited Violation.

IV. Plant Support

R7 Quality Assurance in Radiation Protection and Chemistry Controls

R7.1 Review of Radiation Protection Logs

a. Inspection Scope (40500)

This inspection scope involved a review of radiation protection logs for the period of September 24 through December 18, 1999. The review was conducted to determine if issues identified in the log entries were entered into the corrective action process.

b. Observations and Findings

The team determined that radiation protection personnel used the condition reporting system to identify issues for resolution. The team reviewed radiation protection logs and requested that the licensee provide a supporting corrective action document for approximately 30 deficiencies identified in the log. The licensee was able to provide a corresponding corrective action document for each example of a deficiency described in the radiation protection logs. For example, the radiation protection log entry at 4:15 p.m, on October 26, 1999, specified that radiation protection personnel had identified packing leakage on Inboard Main Steam Isolation Drain Valve DTM-V-4552. Radiation protection personnel provided Maintenance Action Item 326491, which was initiated to address the packing leakage.

During the review of radiation protection logs, the team identified several entries regarding the dose rate reading from the flux tilt radiation monitor. The team subsequently determined that in late 1998, a portable radiation survey meter had been attached with a plastic strap to the offgas pretreat piping to provide early warning information of a fuel element failure and to provide an indication of offgas pretreat radiation levels. On January 12, 2000, the team questioned if the radiation detector installation was a modification installed in accordance with plant procedures. Following discussions with the team, the licensee stated that the detector had not been installed in accordance with plant procedures. The licensee subsequently removed the radiation detector and reinstalled the instrument in accordance with its modification Procedure, RBNP-010, "Configuration Management."

Section 6.3.1 of Procedure RBNP 010 specified that physical configuration changes shall be identified, documented, controlled, and evaluated by all affected organizations. Criterion V of Appendix B to 10 CFR Part 50 requires, in part, that activities affecting quality shall be prescribed by procedures and be accomplished in accordance with procedures. The failure to identify, document, control, and evaluate the installation of the radiation detector on the offgas pretreat piping, as required by Procedure RBNP-010, was the sixth example of a violation of Criterion V of Appendix B to 10 CFR Part 50. This Severity Level IV violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy (50-458/0002-01). This item was entered in the licensee's corrective action program as Condition Report 2000-0111.

c. Conclusions

The team determined that deficiencies identified in radiation protection logs were appropriately entered into the licensee's corrective action process.

A plant modification to add a radiation detector to the offgas pretreat system piping was not made in accordance with modification Procedure RBNP-010. This Severity Level IV violation of Criterion V of Appendix B to 10 CFR Part 50 is being treated as a Non-Cited Violation.

P7 Quality Assurance in Emergency Preparedness Activities

P7.1 Review of Emergency Preparedness Critiques

a. Inspection Scope (40500)

This inspection involved the review of 7 emergency preparedness critiques, 10 open emergency preparedness condition reports, and the emergency preparedness action tracking system for issues identified during drills/exercises conducted in 1999.

b. Observations and Findings

The team determined that weaknesses and deficiencies identified during emergency preparedness drills and exercises were entered into the emergency preparedness action tracking system and that condition reports were initiated for non-drill related issues. The team reviewed open and closed items identified by the licensee in 1999 and placed into the emergency preparedness action tracking system. This review identified five areas that involved communications, work orders, field team communications, status boards, and emergency response information system data.

The team questioned emergency preparedness personnel to determine what actions were taken to close the drill or exercise associated issues listed in the emergency preparedness action tracking system. Based on this discussion and review of the items in the tracking system, the team determined the following:

- Emergency Preparedness Action Tracking System Item 1319 initiated on April 30, 1999, involved inadequate communications. The licensee closed the item after revising the table top lesson plan. The team noted that the licensee entered 21 additional entries in the emergency preparedness action tracking system following closure of Item 1319 that also involved poor communications, but had not taken action on these items.

- Emergency Preparedness Action Tracking System Item 1323 initiated on April 30, 1999, involved deficiencies in the work order process. The licensee closed the item after discussing the issues with the technical support center maintenance coordinator. The team noted that the licensee entered five additional entries in the emergency preparedness action tracking system following closure of Item 1323 that involved deficiencies in the work order process, but had not taken action on these items.

- Emergency Preparedness Action Tracking System Item 3, initiated on September 12, 1999, involved poor field team communications. The licensee closed the item after conducting table top training. The team noted that the licensee entered three additional entries in the emergency preparedness action tracking system following closure of Item 3 that involved field team communications, but had not taken action on these items.

- Emergency Preparedness Action Tracking System Item 78, initiated on October 25, 1999, involved poor updates of facility status boards. The licensee closed the item after conducting training. The team noted that the licensee entered two additional entries in the emergency preparedness action tracking system following closure of Item 78 that involved status board updates, but had not taken action on these items.

- Emergency Preparedness Action Tracking System Item 1335, initiated on May 4, 1999, involved deficiencies with emergency response information system computer points. The licensee closed the item after correcting the emergency response information system computer points in question. The team noted that the licensee entered five additional entries in the emergency preparedness action tracking system following closure of Item 1335 that involved the emergency response information system, but had not taken action on these items.

The team determined that while the licensee documented ongoing emergency preparedness issues that were identified during drills or exercises, it had not taken action on these issues.

The team reviewed nine emergency preparedness condition reports initiated in 1999 and identified the following discrepancies during the review of Condition Reports 1999-1179, and 1999-1402:

- Condition Report 1999-1179 involved an issue where the site telephone exchange failed to connect to the computer program that automatically dialed the individuals assigned to the emergency response organization. As a result, the automatic dialing computer program reverted to the alternate method of contacting emergency response organization members by paging and telephoning each individual. The licensee noted that emergency response organization individuals were contacted within 30 minutes. However, the investigation conducted by licensee personnel was not complete in that it did not determine if the 30-minute responder requirements were met.

- Condition Report 1999-1402 involved an issue where no preventive maintenance program was in place to schedule, perform, or document maintenance on the emergency operating facility battery banks, inverters, uninterruptible power supplies, and emergency lighting. The team determined that the root cause conducted by licensee personnel did not identify the generic implications involving other components in the emergency operating facility. For example, the licensee did not assess the impact of a lack of preventive maintenance on

door seal integrity and on the additional facilities used by the emergency response organization (e.g., the environmental laboratory). While the team noted that there was no requirement to have an emergency preparedness preventive maintenance program, this finding was considered to be another example where the licensee's emergency preparedness organization's corrective actions were narrowly focused.

c. Conclusions

The team determined that the licensee had not implemented complete corrective actions for five performance areas identified during drills and exercises. These areas involved communications, work orders, field team communications, status boards, and emergency response information system data.

The team determined that the corrective actions taken with regard to emergency preparedness issues identified in two out of nine condition reports were narrowly focused.

V. Management Meetings

X1 Exit Meeting Summary

The team leader presented the inspection results to members of licensee management at the conclusion of the onsite inspection on February 4, 2000. In addition, a second exit meeting was conducted telephonically with members of licensee management on April 6, 2000. The licensee's representatives acknowledged the findings presented.

The team leader asked the licensee staff and management whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

ATTACHMENT

SUPPLEMENTAL INFORMATION

PARTIAL LIST OF PERSONS CONTACTED

Licensee

B. Trudell, Corrective Action and Assessment Manager
M. Bakarich, Manager, Emergency Preparedness
M. Jones, Emergency Preparedness Planner
D. Castleberry, Corrective Action and Assessment Specialist
C. Bush, Superintendent Operations
J. Pipkin, Senior Reactor Operator
A. Spencer, Operations Technical Assistant
R. Brian, Design Engineer
T. Hoffman, Design Engineer
G. Javaherian, Design Engineer
J. Malara, Design Engineer
D. Williamson, Senior Licensing Specialist
D. Lorfing, Supervisor, Licensing
B. Bare, Technical Specialist
D. Dormady, Manager, Support
J. McGhee, Manager, Operations
J. Clark, Shift Superintendent
D. Castleberry, Technical Specialist
D. Pace, Director, Engineering
D. Mims, General Manager
R. King, Director, Licensing
T. Hildebrandt, Manager, Maintenance
J. Schlesinger, Design Engineer
R. Jackson, System Engineer
D. Hebert, QC Specialist
B. Olinde, Supervisor, Maintenance and I&C
S. Tisdale, Emergency Preparedness Specialist
K. Borneman, System Engineer
R. Crawford, Operations Work Control
W. McDougal, Systems Engineer
M. Pendergraft, Radiation Protection Technician
T. Bolke, Technical Specialist
D. Felps, Reactor Operator
D. Northrup, Shift Technical Advisor
K. Bolli, Planner, Corrective Maintenance
B. Kelly, Technical Training Supervisor
D. Lacombe, Electrician

NRC

J. Pellet, Chief, Operations Branch

INSPECTION PROCEDURE USED

40500 Effectiveness of Licensee Process to Identify, Resolve, and Prevent Problems

ITEMS OPENED AND CLOSED

Opened and Closed

50-458/002-01	NCV	Six examples of a failure to follow plant procedures as required by Appendix B, Criterion V of 10 CFR Part 50.
50-458/002-02	NCV	Failure to meet operability and surveillance requirements of Technical Specification 3.8.1 for the Division III diesel.
50-458/002-03	NCV	Failure to report a condition prohibited by the technical specifications within 30 days, as required by 10 CFR 50.73.

PARTIAL LIST OF DOCUMENTS REVIEWED

PROCEDURES

SOP-0059, “Containment HVAC System,” Revision 18

STP 000-004, “Daily Cold Shutdown Logs,” Revision 15A

STP 000-005, “Daily Refueling Logs,” Revision 18

STP-000-6606, “Section IX Safety and Relief Valve Testing,” Revision 8

STP-202-6606, “ADS/SRV Accumulator Check Valve Leak Rate Operability Test,” Revision 3A

EQAR-081, “Crosby Safety Relief Valve Pilot Solenoid Valves Model IMF-3A,” Revision 0

RBNP-030, “Initiation and Processing of Condition Reports,” Revision 14

RBNP-069, “Significant Event Evaluation,” Revision 1

RBNP-078, “Operability Determinations,” Revision 5

ENG-3-006, “Modification Design Control Plan Definitions, Residual Processes and Guidance,” Revision 16

RBNP-100, “Modification Process Roles and Responsibilities,” Revision 0

ENG-3-037, “Engineering Request Process,” Revision 4

ENG-3-033, “Modification Design Control Plan,” Revision 4

ADM-0023, “Conduct of Maintenance,” Revision 15

“RBS On-Line Maintenance Guidelines,” Revision 5

ADM-0028, “Corrective Maintenance,” Revision 17

RBNP-062, “River Bend Industry Events and Analysis Programs,” Revision 6

“Corrective Action Process Binder,” dated October 1999

Corporate Policy PL-150, “Condition Reporting,” Revision 0

RBNP-010, “Configuration Management,” Revision 9

Standing Order 169, “Operability of Division III Diesel Generator and Ventilation Reactor Plant*Unit Cooler 5,” Revision 0

Standing Order 174, Tracking of Open Generic Letter 91-18, “Operable But Degraded,” Conditions in the Paperless Condition Report System

AOP-0016, “Loss of Standby Service Water,” Revision 12

EOP-0002, “Emergency Operating Procedure - Primary Containment Control,” Revision 12

RBNP-022, “Root Cause Analysis Program,” Revision 5

Entergy Root Cause Analysis Desk Guide, Revision 3

EDP-AA-20, “Engineering Calculations,” Revision 13

DRAWINGS

PID-09-10A, “System 118 Service Water - Normal,” Revision 27

PID-09-10B, “System 118 Service Water - Normal,” Revision 39

PID-09-10C, “System 118 Service Water Normal,” Revision 23

PID-09-10D, “System 118 Service Water - Normal,” Revision 30

PID-09-10E, “System 256 Service Water - Standby,” Revision 18

PID-09-10F, “System 118 Service Water Normal,” Revision 26

PID-09-10G, “SWP Corrosion Coupon and Monitoring Rack System 118, "C" Tunnel El. 67'- 6",” Revision 1

ENGINEERING REQUESTS (ER)

97-0828, Subject: “Installation Of Temporary RTDs On RHR Heat Exchangers B and D,” Revision 0

97-0127, Subject: “Sealing For Penetrations Over the Standby Service Water Cooling Tower Basin,” Revision 0

99-0435, Subject: “Documentation Of Field Walkdown of Service Water System,” Revision 0

99-0084, Subject: “Evaluation Of Replacement CTs' New Potting Compound,” Revision 0

99-0881, Subject: “Safety Function Determination in the Open Direction for Service Water Check Valves SWP-V153, SWP-V154, SWP-V155 and SWP-V156,” Revision 0

99-0613, Subject: “Assessment of the Effects of Higher Relief Pressures on Piping Systems,” Revision 0

99-0301, Subject: “Permanent Removal and Disposal of the Fuel Storage Pool Work Table,” Revision 0

CONDITION REPORTS INVOLVING REPORT FINDINGS

2000-0030 Inconsistency in Degraded But Operable Tracking List, January 7, 2000

2000-0064 LSV-C3A Low Discharge Pressure Alarm, January 14, 2000

2000-0090 Failure to Report Condition Prohibited by Technical Specifications, January 18, 2000

2000-0111 Installation of Radiation Detector on Off-Gas Piping, January 19, 2000

2000-0143 Maintenance Action Items not Properly Classified, January 25, 2000

2000-0150 Emergency Operating Procedure Enclosure 17 Ladder Missing, January 26, 2000

2000-0153 Contamination in Spent Fuel Cooling Backwash Tank Room, January 26, 2000

2000-0185 Potential Adverse Trend for Annunciator Deficiencies, January 31, 200

2000-0186 Potential Adverse Trend for Operator Work Arounds, January 31, 2000

2000-0208	Additional Accident Exposure to Containment Monitoring System, February 03, 2000
1999-0425	Hydrogen Analyzer Sample Valves, April 3, 1999
1999-0875	Inadequate Operability Determination of Unit Coolers, May 13, 1999
1999-1179	Failure of Telephone Exchange to Connect to Dialogics, July 14, 1999
1999-1402	Maintenance of Emergency Operating Facility Equipment, September 1, 1999
1999-1475	Inadequate Operability Evaluation for Isolating Service Water, September 15, 1999
1999-1748	Sirens Cut-off During Test, November 3, 1999
1999-1863	Security Plan Change Without Revision to Emergency Plan, November 19, 1999
1999-1135	Nonconformance with Design Requirements For the Room Coolers Exists, July 1, 1999
1998-0794	Area Temperatures For Rooms Cooled by Room Coolers Not In Conformance with Design Requirements, June 24, 1998
1999-1080	HVR-UC6 Room Cooler Failed Its Performance Test, June 22, 1999
1999-0560	Potentially Adverse Trend Discovered During Residual Heat Removal Heat Exchanger Performance Test, April 13, 1999
1998-0498	Penetration Valve Leakage Control Program Pressure Relief Lifted, April 25, 1998
1998-0044	Pressure Relief Valve On the DG [Diesel Generator] Starting Air Receiver Lifted, January 14, 1998
1999-0932	Generic Issues Concerning Relief Valve Failures, May 29, 1999
1999-1522	Weaknesses Identified In Preventative Maintenance Program, September 22, 1999
1999-0446	Service Water Relief Valve Failed Test, April 5, 1999
1995-0463	Liquid Control Relief Valve Failed Test, May 3, 1995
1999-0745	Relief Valve Failed As-Found Set Pressure Test, April 26, 1999
1999-1022	Service Water Relief Valve Failed Test, June 11, 1999

1999-0525	Service Water Relief Valve Failed Test, April 11, 1999
1999-0524	Service Water Relief Valve Failed Test, April 11, 1999
1999-0933	Service Water Relief Valve Failed Test, May 26, 1999
1999-0240	Service Water Relief Valve Failed Test, March 1, 1999
1999-0923	Residual Heat Removal Relief Valve Failed Test, May 25, 1999
1998-1430	9 of 16 Safety Valves Failed Set Pressure Test, November 14, 1998
1995-0558	6 of 16 Safety Valves Failed Set Pressure Test, April 17, 1995
1997-0781	11 of 16 Safety Valves Failed Set Pressure Test, May 23, 1997
1997-1385	Check Valves Failed Surveillance Test, September 13, 1997
1997-1788	7 of the 16 SVV/ADS Check Valves Failed Leakage Test, October 8, 1997
1999-0771	Check Valve Failed the Leakage Test, April 28, 1999
1998-1004	Discrepancies Between USAR and TS For Undervoltage Bus Settings, August 6, 1998
1999-0056	Average Suppression Pool Temperature Not Calculated Using All Functional Indicators, January 16, 1999
1999-0630	E22-S004 Feeder Breaker Tripped During Division III ECCS Test, April 18, 1999
1999-1557	Manual Valves Not Locked per USAR Requirements, September 30, 1999
1999-1646	Equipment Labels Without Accuracy Controls, October 18, 1999
1999-1653	ER 97-0170 Did Not Address Changes Required to STP-508-4523, October 18, 1999
1999-1672	Control Building Operator Accessing Unauthorized Web Page, October 21, 1999
1999-1667	Failure to Perform Operability Determination On Failed Radwaste Ventilation System, October 20, 1999
1998-1554	Pipe Clearance Violation, December 8, 1998
1999-0318	Check Valve SWP-V135 Found Open, March 16, 1999
1998-1570	SWP-MOV74A Motor Current Greater Than Acceptance Criteria, December 12, 1998

1998-1436	SWP-MOV74A Failed to Show Full Closed Indication, November 5, 1998
1999-0611	MOVs Were Hand Operated After Electrical Closure, April 16, 1999
1999-0840	SWP-MOV96B Could Not Be Opened Remotely, May 5, 1999
1999-0815	SWP-MOV96B Failed to Open During Standby Service Water Testing, May 2, 1999
1999-0699	SWP-MOV96A Failed To Open Electrically From the Control Room, April 22, 1999
1999-1915	Concerns With Standby Service Water System Related To Restoring Drywell Coolers To Service in an Accident per EOP-002, December 1, 1999
1999-1914	Potential To Challenge the Pressure Integrity Of Containment Unit Coolers, December 1, 1999
1999-0696	CA 2, Evaluation of Division I Standby Service Water Initiation, April 22, 1999
1999-1801	CA 1, Evaluation Of Operability Closed of SWP-MOVs 506A/B and 74A/B Without Closing Torque Switch Bypass, November 10, 1999
1999-1510	CA 1, Revise Calculation To Address Design Change Of Normal Service Water From Open Loop To Closed Loop System, September 21, 1999
1998-1569	Troubleshoot Elevated Dissolved Oxygen Levels In SWP System, December 10, 1998
1998-1501	SWP Pumps SWP-P2A-D Surveillance Test Acceptance Criteria Have No Allowance For Pump Degradation, November 19, 1998
1998-1460	SWP Pumps SWP-P3A-D Surveillance Test Acceptance Criteria Have No Allowance For Pump Degradation, November 11, 1998
1996-1695	SWC-MOV8E-C Motor Current Exceeded Acceptance Criteria, September 25, 1996
1997-1772	SWP-MOV96B Failed To Fully Open On First Attempt, October 7, 1997
1998-1503	SWP-MOV96B Did Not Reopen After Being Closed, November 19, 1999
1997-1603	CCP-MOV158 Failed To Fully Open, September 25, 1997
1998-0883	FPW-MOV122 Failed To Open On Demand During Testing, July 14, 1998
1999-0263	SWP-AOV599 Has No Accumulator Pressure Drop Test, March 4, 1999

1999-0817 SWP-V327 Failed Closed Position Testing, May 2, 1999

1999-1475 Condition Report 99-0318 Disposition Did Not Provide Sufficient Investigation Details or Cause Determination, September 15, 1999

1999-1581 Multiple Trips On SVV Compressors, October 6, 1999

1999-1489 Discrepancy Between USAR Section 9.2.5.3 For Standby Service Water and ARP*870-55, September 16, 1999

1998-0947 HVY-FN2A Tripped On Low Flow After Start, July 25, 1998

1997-0873 Breaker Handle Will Not Close Breaker EHS-MSS2F-8B, June 30, 1997

1996-1357 Evaluation of EOP-002 Direction To Defeat Isolation Of Drywell Coolers When Drywell Temperature Reaches 145°F, July 16, 1996

2000-0131 Evaluation of EOP-002 With Respect To the Potential For Drywell Leakage To the Environment, January 21, 2000

2000-0220 Documentation of NRC Inspection Finding Regarding Failure To Follow Calculation Procedure, February 4, 2000

2000-0227 Documentation of NRC Inspection Finding Regarding Failure To Account For Instrument Uncertainty In Safety-Related Pump Testing Acceptance Criteria, February 4, 2000

SELF-ASSESSMENTS AND QUALITY ASSURANCE AUDITS

"Data Review/Self-Assessment Of Corrective Action Program," dated October 11-13, 1999.

QA Audit, 99-01-I-CANC, dated February 18, 1999

QA Audit, 99-07-I-CANC, dated September 1, 1999

QA Surveillance Report, 908002, dated September 9, 1999

MAINTENANCE ACTION ITEMS

325680, Repair Valve SWP-MOV506A Seat Leakage, May 26, 1999

325015, Determine Cause Of SWP-MOV96B Failure To Open, May 2, 1999

325640, Control Building Chilled Water Recirculation Pump A Leaking Oil

323737, SWP-V135 HPCS Diesel Generator Supply Header Check Valve Stuck Open

325003, SWP-V3023 Auxiliary Building Unit Coolers Loop B Vent Valve Plugged

325281, SWP-V3023 Auxiliary Building Unit Coolers Loop B Vent Valve Still Plugged, May 8, 1999

324655, SWP-V467 Will Not Operate "Even With a Large Persuader", April 17, 1999

NRC INFORMATION NOTICES (IN)

99-13: Insights From NRC Inspections of Low - and Medium-Voltage Circuit Breaker Maintenance Program, dated April 29, 1999

99-14: Unanticipated Reactor Water Draindown at Quad Cities Unit 2, Arkansas Nuclear One Unit 2, and Fitzpatrick, dated May 5, 1999

99-21: Recent Plant Events Caused by Human Performance Errors, dated June 25, 1999

CONDITION REPORTS AND ENGINEERING REQUESTS REVIEWED THAT DID NOT INVOLVE INSPECTION FINDINGS

1998-0161	1996-0048	1999-1317	1998-0397
1998-0192	1997-1385	1999-1515	1998-1001
1999-1047	1997-1788	1999-1574	1999-1583
1999-1325	1997-2064	1999-0348	ER-1998-0059
1999-1541	1998-0036	1999-1943	ER-1998-0059
1999-1639	1998-0042	1999-1830	CN 1
1999-1757	1998-0049	1999-0735	ER-1998-0059
1999-1976	1998-0704	1999-0021	CN 2
1999-1987	1998-0854	1999-1092	ER-1998-0438
1992-0821	1998-1213	1999-1728	ER-1998-0438
1993-0038	1998-1524	1999-0735	CN 1
1994-0421	1999-1203	1999-1790	

NRC GENERIC LETTERS

99-02: Laboratory Testing of Nuclear-Grade Activated Charcoal, dated June 3, 1999 and Errata dated August 23, 1999

98-04: Potential For Degradation of the Emergency Core Cooling System and the Containment Spray System After a Loss-of-Coolant Accident Because Of Construction and Protective Coating Deficiencies and Foreign Material In Containment, dated July 14, 1998

PART 21 REPORTS

- Potential Need for Capacitor Replacement In Rosemount Specific Trip/Calibrator Systems, June 18, 1999
- Soldering Deficiencies In Woodward EGM Controllers, October 7, 1999
- Potential Failure of Foxboro N-2A0-L2C-R or 2A0-L2C-R Contact Output Isolator Cards, October 15, 1999

- Westronics Model 120OBC Recorders, November 16, 1999
- Faulty Resistance Temperature Detectors, February 25, 1999
- Velan Valve Weight Discrepancies, October 27, 1998
- Rosemount Trip/Slave Units, Model 710DU0TT, December 10, 1998
- Agastat E7000 Series Timing Relay, January 26, 1999
- ABB K-Line Breaker Defect After Repair, August 6, 1999
- Deficiency in Commercial Grade Dedication Process Used by Circuit Breaker Refurbishment Supplier Trentec, April 30, 1999
- Enterprise DSRV-4 Emergency Diesel Generator Connecting Rod Prestressed Fastners, April 12, 1999
- Damaged Safety Grade Electrical Cabling Found in Supply, August 31, 1999
- Synchrostart Model ESSB-4AT Speed Switch Defect, January 26, 1999

MISCELLANEOUS DOCUMENTS

Calculation 12210 PR(C) 547, "Normal and Accident Gamma and Beta Doses for Mechanical Equipment Qualification," Revision 1

Calculation DE-NE-003, "Mechanical Equipment Environmental Qualification," Revision 1

Calculation G13.18.15.3-03, "Determination of maximum service life of nonmetallic materials," Revision 0

January 17, 2000 Annunciator Deficiency Report

January 17, 2000 Main Control Room Deficiency Report

January 17, 2000 Operator Work Around Report

Emergency Preparedness Action Tracking System Database for 1999

Emergency Preparedness Drill Critiques for 1999

Executive Trending Report dated November 5, 1998

Executive Trending Report dated February 9, 1999

Executive Trending Report dated August 30, 1999

Executive Trending Report dated November 29, 1999

Guidance for Supervisors and Managers for Monitoring and Coaching of Workers

Management Observation Comments Between January 1 and April 1, 1999

Management Observation Comments Between October 1 and December 31, 1999

Radiation Protection Logs Between September 24 and December 18, 1999

Maintenance Rule Meeting Minutes:

02-05-1998	07-30-1998	02-16-1999	10-06-1999
03-05-1998	12-02-1998	08-10-1999	
05-12-1998			