UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
SAM NUNN ATLANTA FEDERAL CENTER
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ATLANTA, GEORGIA 30303-8931

April 12, 2004

Duke Energy Corporation
ATTN: Mr. G. R. Peterson
Vice President
McGuire Nuclear Station
12700 Hagers Ferry Road
Huntersville, NC 28078-8985

SUBJECT: MCGUIRE NUCLEAR STATION - NRC INTEGRATED INSPECTION REPORT 0500369/2003005 AND 05000370/20040003

Dear Mr. Peterson:

On March 13, 2004, the US Nuclear Regulatory Commission (NRC) completed an inspection at your McGuire Nuclear Station. The enclosed report documents the inspection findings, which were discussed on March 18, 22, and 31, 2004, with you and members of your staff.

The inspection examined activities conducted under your licenses as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your licenses. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

This report documents four NRC-identified findings of very low safety significance (Green). The findings were determined to be violations of NRC requirements. However, because of their very low safety significance and because they were entered into your corrective action program, the NRC is treating these findings as non-cited violations (NCV) consistent with Section VI.A of the NRC Enforcement Policy. In addition, the NRC identified a Severity Level IV violation of 10 CFR50.71(e) for a failure to update the Updated Final Safety Analysis Report. It was determined that this violation should also be non-cited in accordance with Section VI.A of the NRC's Enforcement Policy. Furthermore, one licensee-identified violation which was determined to be of very low safety significance (Green) is listed in Section 4OA7 of this report. If you deny these non-cited violations, you should provide a response with the basis for your denial, within 30 days of the date of this inspection report, to the United States Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555-0001, with copies to the Regional Administrator, Region II; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the NRC Resident Inspector at the McGuire facility.

The material in Attachment 2 contains Safeguards Information as defined by 10 CFR 73.21 and its disclosure to unauthorized individuals is prohibited by Section 147 of the Atomic Energy Act of 1954, as amended. Therefore, the material will not be placed in the Public Document Room. In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, the Enclosure and Attachment 1 will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Robert C. Haag, Chief
Reactor Projects Branch 1
Division of Reactor Projects

Docket Nos. 50-369, 50-370
License Nos. NPF-9, NPF-17

Enclosure: NRC Integrated Inspection Report 05000369/2004003, 05000370/2004003 w/Attachments: (1) Supplemental Information; and (2) [SAFEGUARDS INFORMATION]

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U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos:	50-369, 50-370
License Nos:	NPF-9, NPF-17
Report Nos:	05000369/2004003, 05000370/2004003
Licensee:	Duke Energy Corporation
Facility:	McGuire Nuclear Station, Units 1 and 2
Location:	12700 Hagers Ferry Road Huntersville, NC 28078
Dates:	December 14, 2003 - March 13, 2004
Inspectors:	J. Brady, Senior Resident Inspector S. Walker, Resident Inspector P. Fillion, Reactor Inspector (Section 4OA5.3) K. Maxey, Reactor Inspector (Section 4OA5.3) R. Schin, Senior Reactor Inspector (Section 4OA5.4) S. Shaeffer, Senior Project Engineer (Attachment 2)
Approved by:	Robert C. Haag, Chief Reactor Projects Branch 1 Division of Reactor Projects

Enclosure

ATTACHMENT 2 CONTAINS SAFEGUARDS INFORMATION

SUMMARY OF FINDINGS

IR05000369/2004-003, IR05000370/2004-003; 12/14/2003 - 3/13/2004; McGuire Nuclear Station, Units 1 and 2; Fire Protection and Other.

The report covered a three month period of inspection by resident inspectors and announced inspections by two reactor inspectors, one senior reactor inspector and one senior project engineer. Four Green and one Severity Level IV non-cited violations (NCV) were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using IMC 0609, “Significance Determination Process” (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, “Reactor Oversight Process,” Revision 3, dated July 2000.

A. Inspector-Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

- Green. The inspectors identified a non-cited violation of the operating license condition for fire protection (2.C.4 for Unit 1, 2.C.7 for Unit 2) for failure to have pre-fire (strategy) plans for the interior and exterior doghouse fire areas as part of the fire fighting procedures. The dog houses contain safety-related main steam piping and main steam isolation valves, steam generator power operated relief valves, main steam safety valves, main feed piping and isolation valves, and auxiliary feedwater piping and isolation valves.

  This finding was considered to be more than minor because the manual fire suppression defense-in-depth feature was moderately impacted, which affected the mitigating systems cornerstone objective of protection from external factors including fire. This finding was considered to be of very low safety significance because the dog houses are physically independent (separated by distance and enclosed in 3-hour fire barriers) and either the interior or exterior doghouse can independently provide the necessary safe shutdown functions. (Section 1R05.b.(1))

- Severity Level IV. The inspectors identified a non-cited violation for failure to update the Updated Final Safety Analysis Report (UFSAR) as required by 10 CFR 50.71(e) for inclusion of all aspects of the fire protection program, including the standby shutdown facility (SSF) and fire protection safe shutdown methodology.

  This issue is greater than minor because the failure to include descriptive information on fire protection defense-in-depth features in the UFSAR could have an impact on future design or operational changes to the safe shutdown methodology or SSF. However, it is of very low safety significance because use of the un-updated UFSAR did not result in unacceptable changes to the facility or procedures. (Section 1R05.b.(2))

- Green. The inspectors identified a non-cited violation of the operating license condition for fire protection (2.C.4 for Unit 1, 2.C.7 for Unit 2) for failure to have a 3-hour-rated fire barrier that enclosed the SSF power system equipment as described in the McGuire Safety Evaluation Report Supplement 6.

  This finding was considered to be more than minor because it is a degradation of the fire protection defense-in-depth feature to protect structures, systems, and components important to safety in order to minimize the affect of fire, which affects the mitigating systems cornerstone objective of protection from external factors including fire. This finding was considered to be of very low safety significance because B safe shutdown train equipment can independently provide the necessary safe shutdown functions and is physically independent of the SSF. (Section 1R05.b.(3))

- Green. The inspectors identified a non-cited violation of Unit 2 license condition 2.C.(7), in that, the licensee failed to properly analyze the impact of a fire on Unit 2 auxiliary feedwater system valve 2CA0007A for potential fires in the control room and Fire Area 4. Immediate corrective action by the licensee was to revise fire response procedures to incorporate a time critical local operator manual action to de-energize the valve to preclude spurious closure.

  This finding is greater than minor because it is associated with the protection against external factors attribute and degraded the Mitigating Systems Cornerstone of Reactor Safety objective. This performance deficiency potentially degraded the defense-in-depth for fire protection. However, the finding was determined to be of very low safety significance because review and analysis could not identify credible or likely fire scenarios in the chosen fire areas that would lead to loss or degradation of the secondary heat removal function as a result of spurious closure of 2CA007A, auxiliary feedwater turbine pump suction valve. (Section 4AO5.3)

- Green. The inspectors identified a non-cited violation (NCV) of Unit 1 operating license condition 2.C.4 for the licensee's failure to provide a dedicated shutdown capability [the Standby Shutdown Facility (SSF)] that was independent of cables that were located in Fire Areas 2 and 14.

  This finding was of greater than minor significance because it affected the objectives of the mitigating systems cornerstone, in that, it affected the availability and reliability of the SSF to maintain the plant in hot shutdown following a fire in Fire Areas 2 or 14. This finding was of very low significance because the large sizes of Fire Areas 2 and 14 would prevent a credible fire from causing a challenging hot gas layer that could affect all cables in the fire areas; the ignition frequencies for credible fires that could damage the cables that would affect the SSF were sufficiently low; and sufficient fire mitigation and safe shutdown equipment would be available to reduce the risk to very low significance. (Section 4OA5.4)

B. Licensee-Identified Violations

A violation of very low safety significance, which was identified by the licensee has been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. This violation and corrective actions are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status:

Unit 1 began the inspection period at approximately 100 percent rated thermal power (RTP) and shut down for refueling outage 16 on March 6, 2004. Unit 2 operated at approximately 100 percent RTP during the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R04 Equipment Alignment

a. Inspection Scope

Partial System Walkdowns

During this inspection period, the inspectors performed the following four partial system walkdowns, while the indicated structures, systems, and components (SSCs) were out of service for maintenance and testing:

- 2B diesel generator with 2A diesel generator out of service on December 16, 2003
- 1A auxiliary feedwater (CA) system with 1B CA system unavailable on January 7, 2004
- 1B safety injection (NI) system with 1A NI system unavailable on February 5, 2004
- 1B diesel generator with 1A diesel generator out of service on February 17, 2004

To evaluate the operability of the selected trains or systems under these conditions, the inspectors verified correct valve and power alignments by comparing observed positions of valves, switches, and electrical power breakers to the procedures and drawings listed in Attachment 1 to this report.

b. Findings

No findings of significance were identified.

1R05 Fire Protection

a. Inspection Scope

For the nine areas identified below, the inspectors reviewed the licensee's control of transient combustible material and ignition sources, fire detection and suppression capabilities, fire barriers, and any related compensatory measures, to verify that those items were consistent with Updated Final Safety Analysis Report (UFSAR) Section 9.5.1, Fire Protection System. The inspectors walked down accessible portions of each area, as well as reviewed results from related surveillance tests, to verify that conditions in these areas were consistent with descriptions of the areas in the UFSAR. Documents reviewed during this inspection are listed in Attachment 1 to this report. The areas inspected included:

- Unit 1 and 2 internal dog houses - (fire areas 28 and 29)
- Unit 1 and 2 external dog houses - (fire areas 30 and 31)
- Unit 1 component cooling water (KC) pumps, Unit 2 residual heat removal (RHR) heat exchangers, and Units 1 and 2 volume control tank (VCT) - (fire area 14)
- standby shutdown facility (SSF) - (fire areas 110, 111,112, and 113)

The inspectors reviewed the Problem Investigation Process reports (PIPs) listed in Attachment 1 associated with local fire detection panel design and maintenance problems to verify that the licensee identified and implemented appropriate corrective actions. (The inspection findings are discussed below and in section 4OA7 of the report.)

b. Findings

(1) Fire Strategy Plans for the Internal and External Doghouses

Introduction: A Green non-cited violation (NCV) was identified for failure to have pre-fire (strategy) plans for the interior and exterior doghouse fire areas as part of the fire fighting procedures. The dog houses contain safety-related main steam piping and main steam isolation valves (MSIVs), steam generator (S/G) power operated relief valves (PORVs), main steam safety valves, main feedwater piping and main feedwater isolation valves (MFIVs), and auxiliary feedwater piping and isolation valves.

Description: The inspectors discovered on December 18, 2003, that the licensee did not have pre-fire plans for the interior and exterior doghouses (fire areas 28 and 30 for Unit 1, and fire areas 29 and 31 for Unit 2, respectively) as part of the fire fighting procedures. The doghouse fire areas do not have detection or automatic suppression and are vented to atmosphere at the top. Consequently, detection of a fire in a doghouse would be by visual observation of smoke from inside the doghouse, or from observation of smoke coming from the vent outside the building, or an unusual or unexpected indication from one of the safety-related functions that provide an alarm in the control room (i.e., MSIV or MFIV going shut, S/G PORV going open, S/G PORV block valve going shut, or CA valves going shut).

Analysis: The failure to have pre-fire (strategy) plans is addressed in Inspection Manual Chapter (IMC) 0609 Appendix F, Attachment 2, as a moderate impact (degradation) of the defense-in-depth feature to rapidly detect and suppress those fires that do occur. Not having pre-fire plans/ strategies would reduce the effectiveness and responsiveness of the fire brigade, because preplanned strategies, locations of fire fighting equipment, and locations of combustibles in the area would not be available to the brigade; leaving them with only their knowledge about the fire area based on training and experience. The impact is on the manual suppression fire fighting portion of the feature as shown in Appendix F, Figure 4-1. This performance deficiency affects the mitigating systems cornerstone objective of protection from external factors, including fire. Consequently, this deficiency is greater than minor. There are no installed fire detection or automatic suppression features in the subject fire areas. However, because the dog houses are physically independent (separated by distance and enclosed in 3 hour fire barriers) and either the interior or exterior doghouse can independently provide the necessary safe shutdown functions, the loss of the functions from one doghouse due to fire would not prohibit the safe shutdown functions located in the other doghouse from providing for the safe shutdown of the Unit. Consequently, the deficiency is considered to be of very low safety significance based on the screening criteria from Appendix F, Figure 4-5, protection scheme 1.

Enforcement: McGuire operating license condition 2.C.4, for Unit 1, and 2.C.7, for Unit 2, states that the licensee shall maintain in effect and fully implement all provisions of the approved fire protection program as described in the Final Safety Analysis Report, as updated, for the facility and as approved in the NRC Staff's McGuire Safety Evaluation Report (NUREG-0422) and its supplements. McGuire UFSAR Section 9.5.1 states that the fire protection program is contained in document MCS-1465.00-0008, Design Basis Specification for Fire Protection. The Fire Protection Plan states, in Appendix B.5, Fire Fighting Procedures, that fire fighting procedures should identify the strategies established for fighting fires in all safety-related areas and areas presenting a hazard to safety-related equipment. Contrary to the above, prior to December 18, 2004, the licensee did not have pre-fire (strategy) plans for the Unit 1 interior and exterior doghouses (fire areas 28 and 30) and the Unit 2 interior and exterior doghouses (fire areas 29 and 31) which contain safety-related equipment. The failure to have pre-fire plans for the doghouses as required by the fire protection program is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy and is identified as: NCV 05000369,370/2004003-01, Failure to have pre-fire plans for the Unit 1 and 2 interior and exterior doghouses. This issue is in the licensee's corrective action program as PIP M-03-06071.

(2) UFSAR Not Updated For Safe Shutdown and Standby Shutdown Facility

Introduction: A Severity Level IV non-cited violation was identified for failure to update the UFSAR as required by 10 CFR 50.71(e) for inclusion of all aspects of the fire protection program, including the SSF and fire protection safe shutdown methodology.

Description: The inspectors discovered on February 17, 2004, that the licensee's UFSAR did not contain current information relative to the SSF and safe shutdown for fires. The licensee's UFSAR Section 9.5.1, identified that the fire protection program is contained in design basis document (DBD) MCS-1465.00-0008, Design Basis Specification for Fire Protection. The inspectors found that the pre-fire plan for the SSF identified that four fire areas existed within the facility. Neither the UFSAR nor DBD contained any information on the SSF in relation to fire areas or fire protection defense-in-depth features. The NRC's McGuire Safety Evaluation Report (NUREG-0422) Supplement (SSER) 6, Appendix C, Standby Shutdown System, stated in Section C.3.10, in part, that the SSF support systems provide lighting, fire protection, and fire detection; and stated in Section C.3.9, that the SSF power system located in the SSF was enclosed within 3-hour-rated barriers.

The inspectors found, in general, an absence of information in UFSAR sections and the DBD in relation to fire protection for the SSF. The inspectors reviewed the licensee's license amendment requests for license amendment 98 for Unit 1, and amendment 80 for Unit 2 (issued on June 6, 1989), which placed the current license condition wording in the McGuire Operating License (2.C.4 for Unit 1 and 2.C.7 for Unit 2) and removed the fire protection Technical Specifications (TS) to the selected licensee commitment (SLC) manual. The amendment request contained information and documents pertaining to the fire protection program that was not contained in the UFSAR. It also contained draft updated UFSAR pages and indicated that additional information would be added pertaining to a list of references. Those references were submittals that provided the basis for SSER 6. Those references, including descriptions, were never added to the UFSAR.

Analysis: The inspectors found that the information and analysis submitted to the NRC related to safe shutdown and the SSF were not placed in the UFSAR as required by 10 CFR 50.71(e). The inspectors based this finding on the fact that the NRC SERs had considerable information on the SSF and safe shutdown that the licensee's UFSAR did not have. In addition, the license amendment request listed a number of documents that contained fire protection information that were not incorporated into the UFSAR. This issue is greater than minor because the failure to have descriptive information on fire protection defense-in-depth features could have an impact on future design or operational changes to the SSF or safe-shutdown methodology. However, it is of very low safety significance because use of the un-updated UFSAR did not result in unacceptable changes to the facility or procedures.

Enforcement: 10 CFR 50.71(e) requires that licensees shall update periodically the UFSAR originally submitted as part of the application for the operating license, to assure that the information included in the report contains the latest information developed. This submittal shall contain all the changes necessary to reflect information and analysis submitted to the Commission by the licensee or prepared by the licensee pursuant to Commission requirements since the submittal of the original UFSAR, or as appropriate the last update of the UFSAR. Contrary to this requirement, prior to February 17, 2004, the licensee had not included significant portions of their fire protection program in the UFSAR, including the safe shutdown analysis and the SSF, discussed in SSER 6. The failure to update the UFSAR for fire protection safe shutdown as required by 10 CFR 50.71(e) is characterized as a Severity Level IV violation and is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy and is identified as: NCV 05000-369,370/2004003-02, Failure to update the UFSAR for fire protection safe shutdown. This issue is in the licensee's corrective action program as PIPs M-04-776 and M-04-847

(3) Standby Shutdown Facility Power Supply Fire Barrier

Introduction: A Green NCV of the operating license condition for fire protection was identified for failure to have a 3-hour-rated fire barrier that enclosed the SSF power system equipment as described in the McGuire SSER 6.

Description: NUREG-0422, Safety Evaluation Report related to operation of McGuire Nuclear Station Units 1 and 2, Supplement 6, section C.3.9 states that, "The SSF power system equipment is located within the SSF and in the A division switchgear room. Both of these areas are enclosed within 3-hour-rated barriers." The inspectors discovered on February 23, 2004, that the licensee did not have a rated 3-hour barrier around the SSF power system equipment. The licensee was unable to produce any fire ratings for the SSF walls to show that they were 3-hour-rated fire barriers. The SSF was not described in the licensee's fire protection program documents pertaining to the fire hazards analysis. The fire hazards analysis is part of the approved fire protection program, provides the fire area/zone descriptions, and describes the hazards and fire protection features for each area/zone.

Analysis: The failure to have a 3-hour fire barrier as approved in SSER 6 affects a fire protection defense-in-depth feature to protect structures, systems, and components important to safety to minimize the effects of fire. The SSF is important to safety because it houses major portions of the standby shutdown system that is necessary for safe shutdown of the facility for fires in some areas. This performance deficiency affects the mitigating systems cornerstone objective of protection from external factors, including fire. Consequently, this deficiency is greater than minor. A fire in the SSF would not affect the A safe shutdown division (SSD) in the A switchgear room because of isolation breakers, with the exception of wide range steam generator level. A hot short of the wide range steam generator water level transmitter would cause a steam-driven auxiliary feedwater pump start, but would not cause a plant transient of any significance or a plant trip. The performance deficiency was evaluated as very low safety significance because the SSF is physically separated from other areas of the plant and because a fire in the SSF would not affect the ability of the licensee to safely shutdown the Units.

Enforcement: McGuire operating license condition 2.C.4, for Unit 1, and 2.C.7, for Unit 2, stated that the licensee shall maintain in effect and fully implement all provisions of the approved fire protection program as described in the Final Safety Analysis Report, as updated, for the facility and as approved in the NRC Staff's McGuire Safety Evaluation Report (NUREG-0422) and its supplements. SSER 6 section C.3.9 states that the SSF power system equipment is located within the SSF and in the A division switchgear room and that both of these areas are enclosed within 3-hour-rated barriers. Contrary to the above, prior to February 23, 2004, the licensee failed to fully implement the provisions of the approved fire protection program in that the SSF power system is not enclosed by a 3-hour rated fire barrier. The failure to fully implement the fire protection program approved in SSER 6 is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy and is identified as: NCV 05000369,370/2004003-03, Failure to have a rated 3-hour barrier around the SSF power system. This issue is in the licensee's corrective action program as PIP M-04-00776.

1R11 Licensed Operator Requalification

a. Inspection Scope

On January 29, the inspectors observed licensed-operators during requalification simulator training for shift A, to verify that operator performance was consistent with expected operator performance, as described in Exercise Guide OP-MC-SRT-29. This training tested the operators' ability to perform abnormal procedures dealing with a loss of component cooling water surge tank level during shutdown with reactor vessel level in the reduced inventory range (time to boil approximately 20 minutes) and the containment open. The inspectors focused on clarity and formality of communication, use of procedures, alarm response, control board manipulations, group dynamics, and supervisory oversight. The inspectors observed the post-exercise critique, to verify that the licensee identified deficiencies and discrepancies that occurred during the simulator training.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness

a. Inspection Scope

The inspectors reviewed the two degraded SSC/function performance problems or conditions listed below, to verify the licensee's appropriate handling of these performance problems or conditions in accordance with 10CFR50, Appendix B, Criterion XVI, Corrective Action, and 10CFR50.65, Maintenance Rule.

- 24kV main generator circuit breaker air compressor pilot valve & supply regulator failures
- Foxboro E-13 transmitters for the SSF

The inspectors focused on the following:

- Appropriate work practices,
- Identifying and addressing common cause failures
- Scoping in accordance with 10 CFR 50.65(b)
- Characterizing reliability issues (performance)
- Charging unavailability time (performance)
- Trending key parameters (condition monitoring)
- 10 CFR 50,65(a)(1) or (a)(2) classification and reclassification, and
- Appropriateness of performance criteria for SSCs/functions classified (a)(2) and/or appropriateness and adequacy of goals and corrective actions for SSCs/functions classified (a)(1)

The inspectors reviewed the PIPs associated with this area as listed in Attachment 1, to verify that the licensee identified and implemented appropriate corrective actions.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Evaluation

a. Inspection Scope

The inspectors reviewed the licensee's risk assessments and the risk management actions used to manage risk for the plant configurations associated with the six activities listed below. The inspectors assessed whether the licensee performed adequate risk assessments, and implemented appropriate risk management actions when required by 10CFR50.65(a)(4). For emergent work, the inspectors also verified that any increase in risk was promptly assessed, and that appropriate risk management actions were promptly implemented.

- Work activities on Unit 1 for the week of January 19, 2004, involving scheduled work on power range channel 43, 1A containment air return/hydrogen skimmer

(VX) RAF Damper, and emergent work on 1WG-180 and 1EKVA breaker. An Orange grid condition prevented work on any T1 or T2 activities; thus, power range channel 43 work was postponed. Isolation of 1A VX RAF Damper power supply 1EKVA breaker 15 caused the loss of various control room indications and an unplanned entry into TS.

- Scheduled work activities for Unit 2 for the week of January 26, 2004, which included testing on the solid state protection system (SSPS), “B” Diesel Generator, and “B” CA system. A Yellow grid condition established certain criteria for scheduling risk significant evolutions.

- Work activities on Unit 1 and 2 for the week of February 1 involving scheduled work on Unit 1B safety injection system, Unit 1 containment purge, Unit 2 containment air return system, and Unit 2B CA pump, as well as emergent work on the “E” instrument air compressor (common to both Units) and vital battery D equalizing charge (common to both Units).

- Work activities on Units 1 and 2 for the week of February 15, 2004, involving concurrent scheduled work for Unit 1 on train A motor-driven (MD) CA pump and 1A diesel generator, as well as emergent work on the KC thermal barrier heat exchanger throttle valve to the 2A reactor coolant pump with the “E” instrument air compressor out of service.

- Scheduled work activities on Units 1 and 2 for the week of March 1, 2004, including T-ref/T-avg coastdown on Unit 1; emergent work on Unit 1 chemical volume control (NV) check valves NV-141 and NV-163 following a failed leak rate test; and emergent work conducted on Unit 2 to replace a pressurizer pressure 7300 card, which resulted in an ORAM risk assessment color change from green to yellow.

The inspectors reviewed the PIPs associated with this area as listed in Attachment 1, to verify that the licensee identified and implemented appropriate corrective actions.

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Nonroutine Plant Evolutions

a. Inspection Scope

During the non-routine evolutions identified below , the inspectors observed plant instruments and operator performance to verify that the operators performed in accordance with the associated procedures and training.

- Degassing and straightening of a bent fuel rod in the Unit 2 spent fuel pool in accordance with work order 98629428 and procedure PT/0/A/4550/043, Controlling Procedure for Degassing and Straightening Bent Fuel Rod.

- Unit 2 decrease/increase in power for quarterly inspection of turbine governor, throttle, intercept, and reheat valves per PT/2/A/4250/004A, Turbine Valve Movement Test.

- Unit 1 controlled power reduction and reactor trip at start of the refueling outage per OP/1/A/6100/003, Controlling Procedure for Unit Operation.

The inspectors reviewed the PIPs associated with this area as listed in Attachment 1, to verify that the licensee identified and implemented appropriate corrective actions.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the six operability determinations the licensee had generated that warranted selection on the basis of risk insights. The inspectors assessed the accuracy of the evaluations, the use and control of any necessary compensatory measures, and compliance with the TS. The inspectors verified that the operability determinations were made as specified by procedure Nuclear System Directive (NSD) 203, Operability. The inspectors compared the arguments made in the determinations to the requirements from the TS, the UFSAR, and associated design-basis documents to verify that operability was properly justified and the subject component or system remained available, such that no unrecognized increase in risk occurred. The selected samples are addressed in the PIPs listed below:

- M-03-06088, Failed to perform PT on NPS 1-inch and smaller class B welds.
- M-04-0001, Operability concerns due to gas buildup in the KC systems.
- M-02-02829, Potential single failure could result in only 1 MD CA pump available when “A” service water (RN) is aligned to the standby nuclear service water pond (SNSWP)
- M-04-00145, Qualifications of liquid waste (WL) pipe supports (both units) did not include seismic loads
- M-03-690, Leakage into Unit 2 emergency core cooling system (ECCS) sump (revised 2/13/2004)
- M-04-0163, AC failures on fire detection data gathering panels (DGPs)

The inspectors reviewed associated PIP M-03-05432, Inadequate administrative controls to ensure correct TS Condition entered when “A” RN is aligned to the SNSWP, to verify that the licensee identified and implemented appropriate corrective actions.

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds

a. Inspection Scope

The inspectors reviewed the cumulative effects of the operator workarounds listed in Attachment 1 to this report, to verify that those effects would not increase an initiating event frequency, affect multiple mitigating systems, or affect the ability of operators to respond in a correct and timely manner to plant transients and accidents. The inspectors also reviewed the licensee's workaround aggregate assessment, dated December 10, 2003, performed as required by procedure NSD-506, Operator Workarounds.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications

a. Inspection Scope

The inspectors reviewed the modification described in McGuire Modification MGMM13620, Modification to Diesel Engine Shutdown Cylinder Rod End, to verify that:

- this modification did not degrade the design bases, licensing bases, and performance capabilities of risk significant SSCs;
- implementing this modification did not place the plant in an unsafe condition; and
- the design, implementation, and testing of this modification satisfied the requirements of 10CFR50, Appendix B.

The inspectors reviewed associated PIP M-03-05419, Work Order performed under Non-Field Work Minor Mod resulted in extended inoperability time for 2B Diesel Generator, to verify that the licensee identified and implemented appropriate corrective actions.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing

a. Inspection Scope

For the post-maintenance tests listed below, the inspectors witnessed the test and/or reviewed the test data, to verify that test results adequately demonstrated restoration of the affected safety function(s) described in the UFSAR and TS.

- PT/2/A/4350/002A, Diesel Generator 2A Operability Test (down day maintenance)
- PT/1/A/4350/002B, Diesel Generator 1B Operability Test (down day maintenance)
- OP/1/A/6200/001B, Chemical and Volume Control System Charging, Enclosure 4.2 (1A NV motor inspection and inspection of oil cooler and pump)
- PT/2/A/4350/002B, Diesel Generator 2B Operability Test (down day maintenance)
- PT/1/A/4206/003B, Valve Stroke Time in Closing Direction (replace actuator for 1NI-135B, B safety injection (NI) pump suction from fueling water storage tank (FWST))
- OP/1/A/6250/002, Auxiliary Feedwater System- 1A CA pump (breaker/valve maintenance)

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities

a. Inspection Scope

The inspectors evaluated licensee outage activities as described below, to verify that the licensees considered risk in developing outage schedules, adhered to administrative risk reduction methodologies they developed to control plant configuration, adhered to operating license and TS requirements that maintained defense-in-depth, and developed mitigation strategies for losses of the following key safety functions:

- Decay heat removal (DHR)
- Inventory control
- Power availability
- Reactivity control
- Containment

Prior to the outage, the inspectors reviewed the licensee's outage risk control plan to verify that the licensee had performed adequate risk assessments and had implemented appropriate risk management strategies when required by 10CFR50.65(a)(4).

The inspectors observed portions of the cooldown process to verify that TS cooldown restrictions were followed.

The inspectors observed the items or activities described below, to verify that the licensee maintained defense-in-depth commensurate with the outage risk control plan for key safety functions and applicable TS when taking equipment out of service.

- Clearance Activities
- Reactor Coolant System (RCS) Instrumentation
- Electrical Power

- Decay Heat Removal
- Spent Fuel Pool Cooling
- Inventory Control
- Reactivity Control
- Containment Closure

The inspectors reviewed the licensee's responses to emergent work and unexpected conditions to verify that resulting configuration changes were controlled in accordance with the outage risk control plan and that control room operators were kept cognizant of plant configuration.

The inspectors observed fuel handling operations (removal and sipping) and other ongoing activities, to verify that those operations and activities were being performed in accordance with TS and procedure PT/0/A/4150/037, Total Core Unloading. Also, the inspectors observed refueling activities to verify that the location of the fuel assemblies was tracked, including new fuel, from core offload through core reload.

Prior to mode changes and on a sampling basis, the inspectors reviewed system lineups and/or control board indications to verify that TSs, license conditions, and other requirements, commitments, and administrative procedure prerequisites for mode changes were met prior to changing modes or plant configurations. Also, the inspectors periodically reviewed RCS boundary leakage data, and observed the setting of containment integrity, to verify that the RCS and containment boundaries were in place and had integrity when necessary.

Periodically, the inspectors reviewed the items that had been entered into the licensee's corrective action program to verify that the licensee had identified problems related to outage activities at an appropriate threshold and had entered them into the corrective action program. For the significant problems documented in the corrective action program and listed in Attachment 1 to this report, the inspectors reviewed the results of the licensee's investigations to verify that the licensee had determined the root cause and implemented appropriate corrective actions, as required by 10CFR50, Appendix B, Criterion XVI, Corrective Action.

b. <u>Findings</u>

No findings of significance were identified.

1R22 <u>Surveillance Testing</u>

a. <u>Inspection Scope</u>

For the nine surveillance tests identified below, the inspectors witnessed testing and/or reviewed the test data to verify that the SSCs involved in these tests satisfied the requirements described in the TSs, the UFSAR, and applicable licensee procedures, as well as that the tests demonstrated that the SSCs were capable of performing their intended safety functions.

- PT/0/A/4601/008 A, SSPS Train A Periodic Test With NC System Pressure > 1955 PSIG
- PT/1/A/4350/036B, 1B Diesel Generator (D/G) 24-Hour Run
- PT/1/A/4252/001, Unit 1 Turbine Driven (TD) CA Pump Performance Test*
- PT/1/A/4401/014A, Train A KC/ND HX Valve Stroke Timing - Quarterly
- IP/0/A/3061/012, Charging Lead Acid Batteries
- PT/1/A/4350/036A, D/G 1A 24 Hour Run
- PT/0/A/4250/001, Main Steam Safety Valve Setpoint Test*
- PT/1/A/4206/015A, 1A Safety Injection Pump Head Curve Performance Test*
- PT/1/A/4206/015B, 1B Safety Injection Pump Head Curve Performance Test*

* This procedure included inservice testing requirements.

The inspectors reviewed the associated PIPs listed in Attachment 1 to the report to verify that the licensee identified and implemented appropriate corrective actions.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation

a. Inspection Scope

The inspectors observed an emergency preparedness drill conducted on February 11, 2004, to verify licensee self-assessment of classification, notification, and protective action recommendation development in accordance with 10CFR50, Appendix E.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification

a. Inspection Scope

For the performance indicators (PIs) listed below, the inspectors sampled licensee PI data for the period from January 2003 through December 2003. To verify the accuracy of the PI data reported for both units during that period, the inspectors compared the licensee's basis in reporting each data element to the PI definitions and guidance contained in NEI 99-02, Regulatory Assessment Indicator Guideline, Revision 2.

Initiating Events Cornerstone

- Unplanned Scrams
- Scrams with Loss of Heat Removal
- Unplanned Power Changes

The inspector reviewed a selection of licensee event reports, operator log entries, daily reports (including the daily PIP descriptions), monthly operating reports, and PI data sheets to verify that the licensee had adequately identified the number of scrams and unplanned power changes greater than 20 percent that occurred during the previous four quarters. The inspectors compared this number to the number reported for the PI during the current quarter. The inspectors also reviewed the accuracy of the number of critical hours reported. In addition, the inspectors interviewed licensee personnel associated with the PI data collection, evaluation, and distribution.

b. Findings

No findings of significance were identified.

4OA2 Problem Identification and Resolution

As required by Inspection Procedure 71152, "Identification and Resolution of Problems", and in order to help identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the licensee's corrective action program. This review was accomplished by reviewing hard copies of condition reports, attending daily screening meetings, and accessing the licensee's computerized database.

.1 Annual Sample Review

a. Inspection Scope

The inspectors selected PIP M-02-02829 for detailed review. This PIP was associated with a potential operability concern which was recognized for fundamental differences between procedures AP/A/5500/20, Loss of RN, and OP/A/6400/006, Nuclear Service Water, when aligning 'A' train of RN to the Standby Nuclear Service Water Pond (SNSWP). The inspectors reviewed this PIP to verify that the licensee identified the full extent of the issue, performed an appropriate evaluation, and specified and prioritized appropriate corrective actions. The inspectors evaluated the PIP against the requirements of the licensee's corrective action program as delineated in corporate procedure NSD 208, Problem Identification Process, and 10 CFR 50, Appendix B .

b. Observations and Findings

No findings of significance were identified.

.2 Cross-References to PI&R Findings

The inspectors identified a weakness in the identification of fire protection problems as indicated by the findings identified in sections 1R05, 4OA5.3, 4OA5.4, and 4OA7. The findings are associated with defense-in-depth of fire protection features, safe-shutdown, and completeness of the licensing basis in the UFSAR. The majority of items have existed for longer than a decade despite the licensee's performance of self-assessments and quality assurance audits of fire protection, and a 1999 UFSAR update project that reviewed UFSAR Section 9.5.1. The licensee independently came to the same conclusion and initiated PIP M-04-1140 on March 9, 2004.

4OA5 Other Activities

.1 (Closed) Temporary Instruction 2515/154: Spent Fuel Material Control and Accounting at Nuclear Power Plants, Phase I and Phase II, were completed during this inspection period. No discrepancies were identified during the inspection.

.2 Reactor Pressure Vessel Lower Head Penetration Nozzle Inspection

a. Inspection Scope

The inspectors observed activities associated with the inspection of the Unit 1 reactor vessel lower head penetrations in response to NRC Bulletin 2003-02. The guidelines for the inspection are provided in NRC temporary instruction (TI) procedure 2515/152, "Reactor Pressure Vessel (RPV) Lower Head Penetration Nozzle Inspection" (NRC Bulletin 2003-02). The inspectors reviewed the licensee's responses to the bulletin, dated September 18, 2003, and December 4, 2003, to verify that the commitments identified were being accomplished.

The inspection included review of nondestructive examination (NDE) procedures, assessment of NDE personnel training and qualification, and observation and assessment of Remote Visual (VT) examinations. Discussions were also held with contractor representatives and other licensee personnel. The inspectors reviewed results of the licensee's 100% Bare Metal Visual (BMV) and VT examination. The inspectors also performed a visual inspection of the lower head to verify items on the video tape prior to licensee cleaning of the lower head. The activities and documents listed below were examined to verify licensee compliance with regulatory requirements and gather information to help the NRC staff identify possible further regulatory positions and generic communications.

Specifically, the inspectors reviewed and observed:

-MP/0/A/7150/165 R1, Rx Vessel Bottom Head Bare Metal Inspection
-MP/0/A/7700/080 R7, Inspection, Evaluation and Cleanup of Boric Acid on Plant Materials.
-QAL-15 R20, Inservice Inspection (ISI) Visual Exam, VT-2, Pressure Test

-PIP M-03-04004, U2 Rx Vessel Bottom Head Bare Metal Inspection Results,
-PIP M-03-04096 Count Room Analysis of Smear Samples,
-Video results of VT-2 exam of U1 Rx Bottom Head Inspection

b. Findings

TI 2515/152 Reporting Requirements:

1.1 Was the examination performed by qualified and knowledgeable personnel?

The BMV examination of the reactor vessel (RV) lower head was conducted by certified visual inspectors to procedure QAL-15, Inservice Inspection (ISI) Visual Exam, VT-2, Pressure Test. The qualification documentation for the Level II VT-2 personnel performing the inspection was verified. The inspectors also reviewed the inspection standards, acceptance criteria, calibration requirements of the camera and lighting, and the resolution and sensitivity requirements for the inspection equipment. The inspectors found that the licencee's inspection personnel were very knowledgeable with the requirements in all of these areas. In addition, the licensee had used a mock up and experience from the Unit 2 inspection for pre-job training, including review of the South Texas leakage pictures.

1.2 Was the examination performed in accordance with demonstrated procedures?

The inspectors reviewed the applicable inspection procedures and verified they had been reviewed and approved through the licensee's procedure review process. The inspectors determined that the procedures were consistent with the licensee's bulletin response. The BMV examination was performed in accordance with licensee procedure MP/0/A/7150/165, Rx Vessel Bottom Head Bare Metal Inspection.

1.3 Was the examination able to identify, disposition, and resolve deficiencies?

The inspectors reviewed the procedures controlling the 100% Bare Metal VT-2 examination techniques and determined that they provided adequate guidance to ensure that they would be able to identify, disposition and resolve relevant deficiencies in the RV lower head penetration materials.

1.4 Was the examination capable of identifying pressure boundary leakage and/or RPV lower head corrosion as described in BL 2003-02?

Based upon review of the results for the BMV examination, procedures, qualifications, appropriate lighting, and sensitivity requirements, the inspectors determined that the licensee was capable of identifying and dispositioning pressure boundary leakage and boric acid corrosion, if present.

2.0 What was the condition of the reactor vessel lower head (debris, insulation, dirt, boron from other sources, physical layout, viewing obstructions)?

Prior to the RPV lower head inspection all the insulation was removed, and the reactor vessel bottom head was entirely accessible for the BMV inspection. Minor boron deposits and metal corrosion were identified on the bottom reactor vessel and incore guide tubes. In all cases there were visible leak tracks running down the side of the vessel that originated from previous cavity seal and sandbox cover seal leaks. Each of the 58 penetrations was videoed twice, one pass from each side. The combination of the two passes provided a complete 360 degree view of each penetration. The inspection results were documented in a PIP as required by procedure MP/0/A/7150/165, step 11.4.1 (M-04-1125, 1EOC16 U1 Reactor Vessel Bottom Head Bare Metal Inspection Results). The inspectors viewed the RPV lower head and reviewed the video of the bottom head inspection to verify the licensee's inspection results, and held discussions with the appropriate engineering and examination staff. No significant boron buildup at the annular areas around the BMV was found that would indicate leakage. The inspectors did not see any "popcorn" type boric acid crystals surrounding the penetrations. There was no wastage, corrosion or cracks that needed repair.

3.0 Could small boron deposits, as described in the bulletin, be identified and characterized?

With the available lighting on the remote visual equipment and the clarity of the picture, the inspectors were able to verify that the boric acid deposits present on the bottom head would not mask any indications of penetration leakage. Boron deposits, as described in the bulletin, could have been readily identified and characterized.

4.0 What materiel deficiencies (associated with the concerns identified in the bulletin) were identified that required repair?

There was no wastage, corrosion or cracks that needed repair. The licensee was planning to conduct an additional BMV examination upon completion of hydro-cleaning the reactor vessel bottom head. This will provide the licensee with appropriate baseline documentation for future inspections.

5.0 What, if any, impediments to effective examinations were identified.

There were no items that could impede effective examinations. The licensee was able to inspect 360 degrees around each of the 58 lower head penetration nozzles.

6.0 Did the licensee perform appropriate follow-up examinations for indications of boric acid leaks from pressure-retaining components above the RPV lower head?

The licensee was aware of cavity seal leaks from previous outages. The licensee planned to hydro-clean the bottom vessel head in order to establish a baseline visual inspection record for any future BMV examinations.

The licensee obtained residue samples at various locations on the reactor bottom vessel head, and performed an isotopic analysis. The results verified the source of the deposits to be from past cavity seal leaks greater than 18 months old.

.3 <u>(Closed) Unresolved Item (URI) 05000370/2003007-05:</u> Spurious Closure of Valve 2CA0007A Could Lead to Damage of the Turbine Driven Auxiliary Feedwater (TDAFW) Pump

<u>Introduction</u>: The inspectors identified a Green NCV of Units 2 license condition 2.C.(7), in that, the licensee failed to properly analyze the impact of a fire on Unit 2 auxiliary feedwater system valve 2CA0007A, auxiliary feedwater turbine pump suction valve, for potential fires in the control room and auxiliary building 733' elevation (fire area 4).

<u>Description</u>: As discussed in Inspection Report 05000370/2003007, this URI was opened pending determination of the safety significance of valve 2CA0007A not being analyzed in the licensee's Safe Shutdown Analysis (SSA). This motor operated valve is in the suction flow path from the 300,000 gallon auxiliary feedwater storage tank to the TDAFW pump. This valve could be important in terms of safe shutdown for scenarios involving fire areas that rely on the SSF for post-fire shutdown. The control room and Fire Area 4 were the areas chosen by the original team that relied on the SSF for post-fire shutdown, and considered when evaluating the risk associated with this finding.

The original concern was damage to the TDAFW pump if valve 2CA0007A spuriously closed while the TDAFW pump was running with suction flow through the valve. While reviewing this issue to determine the safety significance, the inspectors determined that the TDAFW pump receives automatic start signals from low-low steam generator level as well as loss of power to the 4160 volt essential busses. In the case of a "smaller" control room fire, during which operators remain in the control room, the inspectors were unable to postulate a credible fire which could cause spurious closure of 2C0007A and cause low-low steam generator level or loss of offsite power resulting in a TDAFW pump start.

For a "larger" control room fire, the inspectors concluded that it is possible to have valve 2CA0007A spuriously close concurrent with loss of offsite power. However, the inspectors concluded that it is likely that sufficient time to man the SSF would exist prior to the fire progressing to the point that both these conditions occurred. The inspectors noted that the procedure for operation of the SSF directs the operator to establish a flow path other than through valve 2CA0007A before starting the TDAFW pump. Therefore, the inspectors concluded that there was no likely control room fire scenario that could lead to damage of the TDAFW pump as a result of spurious closure of valve 2CA0007A. Similarly, for the case of a fire in Fire Area 4, the inspectors could not identify any credible fire scenarios which would cause automatic starting of the TDAFW pump.

<u>Analysis</u>: This finding is greater than minor because it is associated with the protection against external factors attribute and degraded the reactor safety mitigating system cornerstone objective. The performance deficiency potentially degraded the defense-in-

depth for fire protection. However, the finding was determined to be of very low safety significance because review and analysis did not identify credible or likely fire scenarios in the fire areas chosen for the inspection that would lead to loss or degradation of the secondary heat removal function as a result of spurious closure of valve 2CA007A.

Enforcement: McGuire Nuclear Station Unit 2 Operating License NPF-17, Condition 2.C.(7) states, in part, that the licensee shall maintain in effect and fully implement all provisions of the approved Fire Protection Program as described in the Updated Final Safety Analysis Report for the facility, as approved in the Safety Evaluation Report (NUREG-0422). The Fire Protection Program, Section C.2, and Supplemental Safety Evaluation Reports 5 and 6 require that the licensee comply with 10 CFR 50, Appendix R, Sections III.G and III.L. 10 CFR 50, Appendix R, Sections III.G and III.L require that the alternative or dedicated shutdown capability be independent of cables in the area under consideration. The dedicated shutdown capability that was relied on for a control room fire was the SSF.

Contrary to these requirements, on July 3, 2003, the NRC identified that valve 2CA0007A was not included in the SSA resulting in the SSF not being independent from Fire Area 24 or Fire Area 4, such that a fire in these areas could result in spurious closure of this valve. This condition existed for approximately 20 years. A contributing cause for failure to include valve 2CA0007A in the SSA was the fact that the valve has no safe shutdown function once the SSF is operational, and the failure to recognize a vulnerability to spurious closure prior to abandoning the control room for the SSF. The licensee took immediate corrective action by revising their fire response procedures to de-energize valve 2CA0007A within ten minutes of receiving a fire alarm. Because this finding was of very low safety significance and documented in the licensee's corrective action program as PIPs M-03-02084, M-03-02118, and M-03-02311, this violation is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy: NCV 05000370/2004003-04, Failure to Include Valve 2CA0007A in Fire Protection Safe Shutdown Analysis for Control Room Fire.

.4 (Closed) URI 05000369,370/2000009-01: Potential for Loss of Auxiliary Feedwater Flow for a Fire in Fire Areas 2 and 14

a. Inspection Scope

This inspection and significance determination review was on URI 05000369, 370/2000009-01, which identified a lack of electrical independence of the SSF from fires in fire areas 2 and 14.

The inspectors conducted onsite and in-office review of the significance of potential credible fires that could affect the control cables for the TDAFW pump suction motor-operated valve (MOV) 1CA0007AC in fire areas 2 and 14. To accomplish this review, the inspectors located the cables of concern on drawings and walked them down in the fire areas; inspected the fire areas and potential ignition sources of concern; reviewed design information for equipment potentially affected by the fires of concern; evaluated the safety significance of the identified finding with consideration for plant design and operating characteristics; and discussed the plant design, procedures, and staffing with licensee operators and engineers.

b. <u>Findings</u>

<u>Introduction</u>: The inspectors identified a Green NCV of McGuire Unit 1 operating license condition 2.C.4 for failure to provide a dedicated shutdown capability for fire areas 2 and 14 that was independent of cables in fire areas 2 and 14.

<u>Description</u>: As described in URI 05000369,370/2000009-01, NRC inspectors identified that control cables for MOV 1CA0007AC, the suction valve for the TDAFW pump, were routed through fire areas 2 and 14 and were not protected from fire damage in those areas. [The URI is documented in Inspection Report 05000369,370/2000009, which is in ADAMS with Accession Number ML003778709.] Fire damage to those cables could result in spurious closure of 1CA0007AC, loss of auxiliary feedwater, and consequent failure of the dedicated shutdown capability (the SSF) that was relied upon for safe shutdown from fires in those areas. While the TDAFW pump had automatic backup suction sources from the nuclear service water (RN) system, the licensee’s SSA assumed that those sources could be affected by large (Appendix R) fires in fire areas 2 and 14. The licensee’s safe shutdown analysis (SSA) relied upon the TDAFW pump, with suction from the condensate auxiliary feedwater storage tank through MOV 1CA0007AC, to shut down the plant following an Appendix R fire in fire areas 2 and 14.

Fire area 2 was the Unit 1 motor-driven auxiliary feedwater (MDAFW) pump room in the auxiliary building, was approximately 3,200 sq. ft. in size, contained both trains of Unit 1 MDAFW pumps, and had full area automatic sprinklers. Fire area 14 was the Unit 1 and Unit 2 large common area in the auxiliary building, was approximately 40,000 sq. ft. in size, contained both trains of Unit 1 component cooling water (KC) pumps, and had automatic sprinklers over the KC pumps.

This issue had initially been identified as an example of an associated circuit and the URI was left open pending generic resolution of associated circuit issues. However, the control cables for MOV 1CA0007AC, which is in the required flowpath for a safe shutdown system, are circuits required for safe shutdown from Appendix R fires; hence they are not associated circuits and resolution of this issue is not tied to the generic resolution of associated circuit issues.

The inspector reviewed operating procedures that were in place at the time this issue was identified in November 2000. AP/1/A/5500/24, Loss of Plant Control Due to Fire, Rev. 16, was the procedure implemented to activate the SSF during a large (Appendix R) fire in fire areas 2 or 14. The procedure was to be used if a fire had caused a loss of control of both trains of systems required to safely shut down the plant. AP/1/A/5500/24 directed control room operators to trip the reactor; dispatch operators to activate the SSF and switch control power for necessary equipment (including 1CA0007AC) to the SSF; and start the TDAFW pump from the control room (before the dispatched operators had accomplished their tasks). If 1CA0007AC had spuriously closed before the operators started the TDAFW pump from the control room, and if the alternate RN suction sources to the TDAFW pump had been failed by the fire, then the TDAFW pump could be started with no suction source. Starting the TDAFW pump with no suction source would damage the pump and result in it being unavailable to support the SSF after the SSF was activated.

Analysis: The finding of a lack of independence of the SSF from cables in fire areas 2 and 14 was a performance deficiency because it was contrary to the requirements of McGuire Unit 1 operating license condition 2.C.4. This finding was of greater than minor significance because it affected the objectives of the Mitigating Systems Cornerstone of Reactor Safety in that it affected the availability and reliability of systems that mitigate initiating events to prevent undesirable consequences. The finding affected the availability and reliability of the SSF to maintain the plant in hot shutdown following a fire in fire areas 2 or 14.

Significance Determination Process (SDP) assumptions for a fire analysis in fire area 2 included:

- No ventilation (fire causes fire damper in ventilation exhaust to close);

- Nearest significant installed fire initiator is a MDAFW pump, which is about 3 feet above the floor and 10 feet horizontally away from the cable, has a largest lubricating oil reservoir of 48 ounces and a 500 HP motor [generating a heat release rate (HRR) of up to 650 KW];

- Transients that credibly could be below the cable could generate an HRR of 200 KW; and

- Cables all contained IEEE-383 qualified insulation inside a steel armor jacket that was coated on the outside with PVC.

These assumptions led to the conclusion that the most challenging credible fires near the cable of concern would not damage the cable and would not initiate a plant transient.

SDP assumptions for a fire analysis in fire area 14 included:

- No ventilation (fire causes fire damper in ventilation exhaust to close);

- Nearest significant installed fire initiators are a KC pump, which is about 15 feet horizontally away from the cable, has a largest lubricating oil reservoir of 32 ounces and a 200 HP motor [generating an HRR of up to 650 KW];

- An electrical terminal box is about 3 feet away horizontally from the cable [generating an HRR of up to 200 KW];

- Transients that credibly could be near the cable could generate an HRR of 200 KW; and

- Cables all contained IEEE-383 qualified insulation inside a steel armor jacket that was coated on the outside with PVC.

These assumptions led to the conclusion that only the nearby electrical box or nearby transient fires could credibly damage the cable of concern. Ignition frequency from the licensee's ignition source data sheet (ISDS) for the electrical box was 1/54 x 1.46 E-3 and for transients/welding/cutting was 3.06 E-3. SDP assumptions for mitigating equipment included:

- Mitigating equipment affected by fire damage to cables (each involving spurious actuations) includes one volume control tank (VCT) outlet MOV (cable in vertical A train trays) which in turn fails the running high pressure injection (HPI) pump; the A train of RN (cable in vertical A train trays) which causes a loss of RN (assuming the A pump was running and both RN headers were cross connected); and one pressurizer power operated relief valve (PORV) (cable in vertical A train trays) which fails open.

- The loss of RN affects both trains of MDAFW, HPI, safety injection (SI), KC, and emergency diesel generators (EDGs). Assume that operators recover RN by starting the other pump and then recover MDAFW, SI, KC, and EDGs. Also, assume that operators recover HPI by opening a refueling water storage tank (RWST) outlet MOV and starting the other HPI pump.

These assumptions led to the conclusion that the most dominant core damage sequences are the plant transient (TRANS) and stuck open relief valve (SORV) sequences containing EIHP or HPR. Also, the significance of the finding was not greater than very low significance because the large sizes of Fire Areas 2 and 14 would prevent a credible fire from causing a challenging hot gas layer that could affect all cables in the fire areas; the ignition frequencies for credible fires that could damage the cables for 1CA0007AC were sufficiently low; and sufficient fire mitigation and safe shutdown equipment would be unaffected by the fires and would be available to reduce the risk to very low significance.

<u>Enforcement</u>: McGuire Unit 1 license condition 2.C.4 states that the licensee shall maintain in effect and fully implement all provisions of the approved Fire Protection Program as described in the Final Safety Analysis Report, as updated, for the facility as approved in the NRC Staff's McGuire Safety Evaluation Report (NUREG-0422) and its supplements. The Fire Protection Program, Section C.2 and Supplemental Safety Evaluation Reports 5 and 6 require that the licensee comply with 10 CFR 50, Appendix R, Sections III.G and III.L. 10 CFR 50, Appendix R, Sections III.G and III.L require that the alternative or dedicated shutdown capability be independent of cables in the area under consideration. The dedicated shutdown capability that was relied on for large fires in fire areas 2 and 14 was the SSF.

Contrary to the above requirements, the dedicated shutdown capability (the SSF) was not independent of cables for valve 1CA0007AC which were in fire areas 2 and 14. This violation was identified in November 2000 during an NRC inspection and the condition had existed for more than 30 days. The safety consequence was a reduction in the availability and reliability of the SSF to mitigate a large (Appendix R) fire in fire areas 2 or 14. Because this failure to comply with McGuire Unit 1 operating license condition 2.C.4 was of very low safety significance and has been entered into the licensee's corrective action program as Problem Investigation Process (PIP) No. M-00-04480, this violation is being treated as a NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy: NCV 05000369/2004003-05, Standby Shutdown Facility was Not Independent of Cables in Fire Areas 2 and 14.

4OA6 Meetings, Including Exit

On March 18, and 22, 2004, the inspectors presented the inspection results to Mr. G. Peterson and other members of his staff who acknowledged the findings. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

4OA7 Licensee-Identified Violations

The following violation of very low significance was identified by the licensee and is a violation of NRC requirements which meets the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600 for being dispositioned as a NCV.

- Operating license condition for fire protection (C.4 for Unit 1, C.7 for Unit 2) required that the fire protection program described in the UFSAR be implemented and maintained. UFSAR Chapter 16, Selected Licensee Commitments Section 16.9.6 Fire Detection Instrumentation, required that when the fire detection function is inoperable, hourly fire watches are to be established. Contrary to the above, on January 12, 2004, the licensee failed to implement hourly fire watches when the fire detection function was inoperable in fire areas 14, 21, and 25, which are common to both units. This was identified in the licensee's corrective action program as PIP M-04-146. Although this resulted in a high degradation to the fire detection defense-in-depth element for those areas, the finding is of very low safety significance because the licensee has use of an alternate train of equipment (safe shutdown system), completely independent of the fire areas of concern.

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

Bailey, D., Fire Protection Engineer
Black, D., Security Manager
Bradshaw, S., Superintendent, Plant Operations
Bramblett J., Chemistry Manager
Brown, S., Manager, Engineering
Bryant, J., Regulatory Compliance Engineer
Crane, K., Technical Specialist
Evans, K., Manager, Mechanical and Civil Engineering (MCE)
Hackney, S., Operations Support
Harrall, T., Station Manager, McGuire Nuclear Station
Henneke, D., Corporate PRA Engineer
Johansen, R., Appendix R Safe Shutdown Analysis Engineer
Kammer, J., Manager, Safety Assurance
Loucks L., Radiation Protection Manager
Lukowski, J., Appendix R Electrical Support Engineer
Oldham, J., Fire Protection Engineer
Parker, R., Superintendent, Maintenance
Peterson, G.., Site Vice President, McGuire Nuclear Station
Thomas, J., Manager, Regulatory Compliance
Thomas, K., Manager, RES Engineering
Travis, B., Superintendent, Work Control

NRC personnel

R. Haag, Chief, Reactor Projects Branch 1
L. Olshan, Project Manager, NRR

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Closed

05000370/2003007-05	URI	Spurious Closure of Valve 2CA0007A Could Lead to Damage of the Turbine Driven Auxiliary Feedwater (TDAFW) Pump (Section 4OA5.3)

05000369,370/2000009-01	URI	Potential for Loss of Auxiliary Feedwater Flow for a Fire in Fire Areas 2 and 14 (Section 4OA5.4)

Opened and Closed

05000369,370/2004003-01	NCV	Failure to have pre-fire plans for the Unit 1 and 2 interior and exterior doghouses (Section 1R05.b.(1))
05000369,370/2004003-02	NCV	Failure to update the UFSAR for fire protection safe shutdown (Section 1R05.b.(2))
05000369,370/2004003-03	NCV	Failure to have a rated 3-hour barrier around the SSF power system (Section 1R05.b.(3))
05000370/2004003-04	NCV	Failure to Include Valve 2CA0007A in the Fire Protection Safe Shutdown Analysis for Control Room Fire (Section 4OA5.3)
05000369/2004003-05	NCV	Standby Shutdown Facility was Not Independent of Cables in Fire Areas 2 and 14 (Section 4OA5.4)

Previous Items Closed

2515/154	TI	Spent Fuel Material Control and Accounting at Nuclear Power Plants, Phase I and Phase II (Section 4OA5.1)
2515/152	TI	Reactor Pressure Vessel Lower Head Penetration Nozzle Inspection (NRC Bulletin 2003-02) - Unit 1 (Section 4OA5.2)

LIST OF DOCUMENTS REVIEWED

<u>Section1R04: Equipment Alignment</u>

Partial System Walkdown

2B Diesel Generator
Procedure OP/2/A/6350/002-079, Diesel Generator, Revision 79
DBD MCS-1609.LD-00-001-01, Design Basis Specification for the LD System
DBD MCS-1609.KD-00-001-09, Design Basis Specification for the KD System
DBD MCS-1609.FD-00-001-05, Design Basis Specification for the FD System
DBD MCS-1609.VG-00-001-012, Design Basis Specification for the VG System
Drawing MCFD-1609.01.00, Flow Diagram of Diesel Engine Cooling Water System, Rev. 2
Drawing MCFD-1609.02.01, Flow Diagram of Diesel Generator Lube Oil System, Rev. 4
Drawing MCFD-1609.03.01, Flow Diagram of Diesel Generator Fuel Oil System, Rev. 5

1A CA system
Procedure OP/1/6250/002, Auxiliary Feedwater System, Revision 89
DBD MCS-1592.CA-00-001-017, Design Basis Specification for the CA System
Drawing MCFD-1592-01.01 Flow Diagram of Auxiliary Feedwater, Rev. 3

1B NI system
Procedure OP/1/A/6200/006-049, Safety Injection System, Revision 49
DBD MCS-1562.NI-00-001-08, Design Basis Specification for the NI System
Drawing MCFD-1562-03.00, Flow Diagram of Safety Injection System, Rev.6

1B Diesel Generator
Procedure OP/1/A/6350/002, Diesel Generator, Revision 79
DBD MCS-1609.LD-06-001-01, Design Basis Specification for the LD System
DBD MCS-1609.KD-00-001-09, Design Basis Specification for the KD System
DBD MCS-1609.FD-00-001-05, Design Basis Specification for the FD System
DBD MCS-1609.VG-00-001-012, Design Basis Specification for the VG System

<u>Section 1R05: Fire Protection</u>

UFSAR section 9.5.1, Fire Protection

Procedures
DBD MCS-1465.00-00-022, Design Basis Specification for the Appendix R Safe Shutdown Analysis
DBD MCS-1465.00-00-008, Design Basis Specification for Fire Protection
Fire strategy RB4.1.1, Standby Shutdown Facility

PIPs reviewed for identification and resolution of problems

M-04-00098, Fire Zones trouble alarm not alarming and resetting at EFA computer when disconnected
M-04-00117, Operators failed to log an inoperable fire detector as required by SLC. Operability requirements not fully considered
M-04-00146, Incomplete functional test performed during EFA troubleshooting
M-04-00240, During troubleshooting of EFA issues, determined 6 additional DGPs should have been logged inoperable
M-04-00291, Fire watch missed during fire surveillance of Unit 2 CA pump room
M-04-00428, An emerging trend has been identified with EFA Fire Detection System
M-04-00528, Evaluate inoperability and missed surveillances associated with DGP 20
M-04-00592, Ground indication on fire detection model W940C Common Module is constantly giving off dim glow
M-04-00600, Containment temperatures required for fire watch in containment not obtained in time to meet hourly fire watch
M-04-00931, EFA Monthly surveillance PT/0/A/4600/15 did not have an adequate method for performing surveillance for several DGPs

PIPs generated for this inspection

M-04-163, Fire Detection DGPs have local AC failure indication
M-04-762, Discrepancy between installed fire protection equipment and fire strategy RB4.1.1
M-04-776, RB4.1.1 makes reference to fire areas in the SSF that are not listed in FP DBD
—04-847, evaluate UFSAR content for fire protection program requirements/licensing basis satisfies 10CFR 50.71
M-04-857, SLC16.9.1 bases indicate that fire suppression protects safety-related equipment; however, it also protects equipment important to safety such as SSF
M-04-1109, No Fire Plan Strategy for Annulus
M-04-1114, Fire Plan Strategies Revision Project
M-04-1118, Reactor Building fire area nomenclature mismatch between DBDs
M-04-1140, Fire Protection Program quality improvement initiative

Section 1R12: Maintenance Effectiveness

Maintenance Rule: SSC Summary Sheets - CF System, Revision 7
EDM 210, Engineering Responsibilities to the Maintenance Rule, Revision 16
MCM 1303.00-0031, Pneumatic Regulation of 3 Pole Circuit with Compressor

PIPs reviewed for identification and resolution of problems

M-02-06064, Unit Load Reduction to 50% to repair problem on Main Generator Circuit Breaker 2A
M-03-03900, Generator Circuit Breakers require “A(1)” status due to Repetitive MPFF
M-03-02420, 2A Generator Breaker Control air pressure began decreasing
M-02-04299, Unplanned Entry into TSs
—04-00002, U2 Stand by Makeup Pump low gauge stuck

Section 1R13: Maintenance Risk Assessments and Emergent Work Evaluation

Procedures
NSD 415, Operational Risk Management (Modes 1-3) per 10CFR50.65 (a.4)
NSD 417 Nuclear Facilities/Generation Status Communication

PIPs reviewed for identification and resolution of problems
M-04-00322, 1EKVA breaker 15 was opened for a tagout, this caused a loss of various indications in the control room
M-04-0977, Received annunciator alarms and noticed all backup pressurizer heaters on and pressure control rising; PCS power supply failure.

Section 1R14: Personnel Performance During Nonroutine Plant Evolutions

M-03-03014, Oconee SEIT Report and PIP O-03-02068, McGuire Applicability
M-03-00482, Unplanned Power Increase During Turbine Valve Movement Test
M-03-01212, Limits of Turbine impulse pressure were exceeded
M-03-02128, Reheat Stop Valve Failed to Reopen

Section 1R15: Operability Evaluations

Work Order: 98368128/05 for PIP M-03-6088

Section 1R16: Operator Work-Arounds

Workarounds reviewed for cumulative affect by OWA number

98-03, EFA zones
99-12, Excess leakage of 1RL-18 causes improper LT oil temperature
01-01, S/G level control at power levels
01-04, When starting/stopping main fire pumps, the Fire Protection Annunciator and the Fire detection Annunciator alarm
02-03, Repeated occurrences of high dissolved O_2 in RMWSTs.
03-01, Frequency changes to grid cause reactor power to exceed 100%
03-02, 1NV-124 in manual control due to erratic control in Auto
03-03,1CA-42B may have a problem reopening against D/P and sill not be cycled to control CA flow to 1D S/G during a loss of V1 or vital bus events.
03-04,Ongoing problems with both the U-1 and U-2 FWST level heat tracing systems have resulted in numerous malfunctions, alarms and eventually resulting in all 3 U-1 FWST level channels freezing and failing high
03-06,Control Room Operators must take turbine to manual to perform governor valve movement portion of PT/1(2)/A/4250/004A (Turbine Valve Movement Test), to prevent other governor valves from swinging drastically (20%)
03-09,1NV-6 letdown relief valve leaks by when temperature changes occur over a short period of time. To prevent this from happening, the monthly surveillance PT has been changing to require the operator to increase letdown as they increase charging
03-10,Operators are required to locally verify VA system operation during EP procedure implementation

03-11,DEH control panel reference display may not count when entered. Operators are required to use DEH computer screen to verify correct values
03-12,When starting ND pumps in various procedures (both unit, both trains), operators are required to isolate NS pump suction instruments to prevent over ranging the process instruments
03-13,During inclement weather, 1AD-13, C environmental system trouble alarms more than it should.
03-15,A and B train KC heat exchangers are required to be super flushed due to season fouling
03-16, A and B train KC heat exchangers are required to have high velocity flushes performed
03-17, A and B VC/YC chiller requires high velocity flushes
03-18, RV suction strainers require back-washing due to intake of alewives
03-19,Unit 2 OAC does not show correct indication when vital inverters 2EV1B and 2EV1D swapped to alternate
03-20,YC auto makeup is isolated and required manual valve operation to makeup to the system. In addition, the YC reliefs periodically lift requiring operators to clean up the spill
03-21,KC surge tank levels frequently need to be equalized, run enclosure 4.14 of OP/2/A/6400/005
03-22,U2 FWST yard line low temp annunciator has been coming in on a regular basis since December 2002. Also the OAC PT (M2A0591) has been alarming for FWST yard line low temp

<u>Section 1R20: Refueling and Outage Activities</u> (Unit 1)

<u>Procedures</u>
AP/1/A/5500/007, Loss of Electrical Power, Rev. 22
AP/1/A/5500/021, Loss of KC or KC System Leakage, Rev. 8
AP/1/A/5500/038, Emergency Boration, Rev. 7
AP/1/A/5500/012, Loss of Letdown, Charging, or Seal Injection, Rev. 19
AP/1/A/5500/014, Rod Control Malfunction, Rev. 8
AP/1/A/5500/009, Loss of ND or ND System Leakage, Rev. 16
AP/1/A/5500/020, Loss of RN, Rev. 16
AP/1/A/5500/035, ECCS Actuation During Plant Shutdown, Rev. 15
MP/1/A/7150/042A, Removal of Reactor Vessel Head
NSD 403, Shutdown Risk Management (Modes 4,5,6 and No Mode per 10CFR50.65(a)(4)
OP/1/A/6100/003, Controlling Procedure For Unit Operation
OP/1/A/6100/SD-2, Cooldown to 400 F, R21
OP/1/A/6100/SD-4, Cooldown to 240 F, R24
OP/1/A/6100/SD-4, Cooldown to 100 F, R19
PT/1/A/4600/031, Periodic Test Performance Verification for Mode Changes
OP/1/A/6100/SD-11, Mode 5 Checklist
OP/1/A/6100/SD-21, Mode 6 Checklist
PT/1/A/4200/006B, Boron Injection Valve Lineup Verification

<u>PIPs reviewed identification and resolution of problems</u>
M-04-1222, Containment Spray sump isolation valve jumper improperly installed during test
M-04-1090, Containment evacuation alarm due to source range channel N32 exceeded hi-flux at shutdown setpoint

M-04-1099, U1 primary system has a 1 GPM leak based on VCT makeup rate in Mode 5

1R22 Surveillance Testing

PIPs reviewed identification and resolution of problems
M-04-00260, MNS review of current CNS NV system gas intrusion event
M-04-00074, 1B D/G room temperature fell below SLC temperature of 55 degrees

Section 4OA5.3: Other

Drawings

MCEE-0247-20.00, Unit 2, Elementary Diagram, Auxiliary Feedwater System AWFPT Suction Valve 2CA0007A, Rev. 0
Cable schedule and routing for valve 2CA0007A
MC-2901-01.01, Unit 2, Computer Cable Routing Auxiliary Building Plan Below EL 733 ft., Rev. 44

Design Basis Document

MCS-1592.CA-00.001, Design Basis Specification for CA System [auxiliary feedwater], Rev. 17

Procedures

AP/2/A/5500/024, Loss of Plant Control Due to Fire or Sabotage, Rev.20

Miscellaneous

Work Order 98607974-01, to perform Periodic Test PT-1/A/4150/017A, Pressurizer Heater Capacity Measurement, on 9/18/03 Unit 1
Work Order 98613869-01, to perform Periodic Test PT-2/A/4150/017A, Pressurizer Heater Capacity Measurement, on 10/24/03 Unit 2

Section 4OA5.4: Other

Procedures
AP/1/A/5500/24, Loss of Plant Control Due to Fire, Rev. 16
EP/1/A/5000/ES-0.1, Reactor Trip Response, Rev. 12

Drawings

MCFD-1592-01.01, Unit 1 Auxiliary Feedwater System, Rev. 14

Analyses and Calculations

NEI 00-01 Pilot Plant Evaluation Report for the McGuire and Duane Arnold Plants, Rev. 0
Fire Compartment Ignition Source Data Sheet (ISDS) for McGuire Fire Area 2, Rev. 0
Fire Compartment Ignition Source Data Sheet (ISDS) for McGuire Fire Area 14, Rev. 0

LIST OF ACRONYMS

AP	-	Abnormal Procedure
BMV	-	Bare Metal Visual
CA	-	Auxiliary Feedwater
CF	-	Feedwater
CFR	-	Code of Federal Regulations
DBD	-	Design Basis Document
DGP	-	Data Gathering Panel
DHR	-	Decay Heat Removal
ECCS	-	Emergency Core Cooling System
EFA	-	Fire Protection
EOC	-	End-Of-Cycle
EP	-	Emergency Procedure
ESF	-	Engineered Safeguards Feature
FSAR	-	Final Safety Analysis Review
FWST	-	Fueling Water Storage Tank
GPM	-	Gallons Per Minute
HX	-	Heat Exchanger
IMC	-	Inspection Manual Chapter
IR	-	Inspection Report
ISI	-	In Service Inspection
KC	-	Component Cooling Water
MFIV	-	Main Feedwater Isolation Valve
MNS	-	McGuire Nuclear Station
MSIV	-	Main Steam Isolation Valve
NCV	-	Non-Cited Violation
ND	-	Residual Heat Removal
NDE	-	Non-Destructive Examination
NEI	-	Nuclear Energy Institute
NI	-	Safety Injection
NS	-	Containment Spray
NSD	-	Nuclear Site Directive
NV	-	Chemical and Volume Control
OAC	-	Operator Aid Computer
ORAM	-	Operator Risk Assessment Module
PI	-	Performance Indicator
PIP	-	Problem Investigation Process Report
PORV	-	Power Operated Relief Valve
PSIG	-	Per Square Inch Gauge
PT	-	Periodic Test
RCS	-	Reactor Coolant System
RHR	-	Residual Heat Removal
RN	-	Nuclear Service Water
RPV	-	Reactor Pressure Vessel
RTP	-	Rated Thermal Power

RX	-	Reactor
SDP	-	Significance Determination Process
S/G	-	Steam Generator
SLC	-	Selected Licensee Commitments
SNSWP	-	Standby Nuclear Service Water Pond
SSC	-	Structures, Systems, Components
SSA	-	Safe Shutdown Analysis
SSD	-	Safe Shutdown
SSER	-	Safety Evaluation Report Supplement
SSF	-	Standby Shutdown Facility
SSPS	-	Solid State Protection System
TDCA	-	Turbine Driven Auxiliary Feedwater
TI	-	Temporary Instruction
TS	-	Technical Specifications
UFSAR	-	Updated Final Safety Analysis Report
UT	-	Ultrasonic Testing
VCT	-	Volume Control Tank
VG	-	Diesel Generator Starting Air
VT	-	Incore Instrument Room
VX	-	Containment Air Return
WA	-	Work Around
WL	-	Liquid Waste
YC	-	Ventilation Chiller