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Licensee: GPU Nuclear Corporation
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Inspection At: Oyster Creek Nuclear Generating Station

Inspection Conducted: November 28 through December 16, 1988

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SAFETY SYSTEMS OUTAGE MODIFICATIONS INSPECTION
at Oyster Creek Nuclear Generating Station
(Inspection Report 50-219/88-203)

1.0 INTRODUCTION

The safety systems outage modifications inspection (SSOMI) was performed (1) to examine the adequacy of the licensee's management and control of modifications performed during a major plant outage and (2) to identify strengths and weaknesses in licensee modification programs and their implementation. The SSOMI team examined selected modifications and maintenance work activities that were performed during a recent outage at the Oyster Creek Nuclear Generating Station (OCNGS).

This inspection was conducted in two phases. During the first phase, the inspection team verified that the detailed design, engineering support, and procurement activities were adequate to support the safety-related modifications performed during this outage. The first phase was performed from November 17 through December 4, 1988, and documented in inspection report 50-219/88-202. During the second phase, the inspection team reviewed the installation and testing of modifications performed during the outage and verified that repaired or modified components and systems had been properly installed and had been tested to ensure that they were capable of performing their intended functions. The second phase was performed from November 28 through December 16, 1988, and is documented in this inspection report 50-219/88-203.

2.0 INSTALLATION AND TESTING INSPECTION

2.1 Electrical and Instrumentation and Control Modifications

2.1.1 Scope

The inspection team reviewed the safety-related electrical and instrumentation and control (I&C) plant modifications performed during the 12R outage, including the associated procedures, job orders, instructions, and drawings. The team also verified that the equipment modifications conformed to design requirements and to the commitments of the Updated Safety Analysis Report (USAR). The licensee uniquely identified the modification packages by assigning budget activity (BA) numbers, which are referenced in this inspection report.

2.1.2 Reactor Protection System Relay Power Supply Replacement (BA 402887)

This modification changed the power source for a reactor protection system (RPS) relay circuit from the vital alternating current power panel No. 1 (VACP-1) to continuous instrument panel No. 1 (CIP-1). The modification eliminated spurious actuations of the containment isolation system and the standby gas treatment system (SBGT) due to inadvertent transfers of VACP-1 from the normal power source to the alternate power source. The inspection team identified one strength and two deficiencies during the review of this modification.

The licensee developed a comprehensive summary of the systems that were affected by the installation of the modification. The summary identified the applicable systems and equipment, including the specific devices affected and the elementary electrical drawings for the devices, and described the effects of loss of power for the equipment and devices. The summary also identified if

a technical specification (TS) limitation applied and recommended evaluation of the effects of repowering the equipment and any temporary measures needed for reenergizing the circuit. The inspection team considered the summary to be a strength.

The first deficiency involved the licensee's safety evaluation of the modification. The licensee incorrectly determined that the electrical separation design criteria had been satisfied for the new circuitry. The B division motor control center (MCC) provided the normal power source for both VACP-1 and CIP-1 and the B division 125 VDC system provided the alternate power source for CIP-1; however, an A division MCC provided the alternate power for VACP-1. This arrangement resulted in powering the two panels by different divisions whenever VACP-1 transferred to alternate power. Since the new circuit between VACP-1 and CIP-1 was routed through VACP-1, the modification allowed a cable powered from the B division in a panel with cables powered from the A division, whenever VACP-1 received alternate power.

Although Specification SP-9000-41-005 for installing cables and raceways required redundant Class 1E circuits in panels to be separated by 6 inches or fire retarding barriers, the modification made no provision to separate or protect the new circuit in VACP-1. The safety evaluation concluded that the installation specification did not require separation of the circuits because of the short duration of the transfer of power. The licensee maintained that this conclusion was consistent with the original design criteria of the plant. The inspection team was concerned because the licensee had not documented the basis for this determination and had not indicated that the circuit required a fire barrier. As corrective action for this concern, the licensee implemented Field Change Request (FCR) C-71020 to provide a fire wrap for the affected circuit.

The second deficiency involved discrepancies with respect to conduit support drawings. The support configuration for Drawing 3431-C0231, Revision 0, showed three anchor bolts; however, the bill of material required four anchor bolts. As corrective action, the licensee's construction organization issued Field Change Notice (FCN) C-71486 which changed the drawing's bill of material to correctly indicate that the support required three anchor bolts.

Although the final electrical connection in CIP-1 and cable splicing in VACP-1 were incomplete, the inspection team concluded that good quality craftsmanship was used to install the new cabling between VACP-1 and CIP-1 and the new conduits and supports. Nevertheless, the inspection team identified a minor discrepancy with the attachment of conduit CGPA1159 to support 641-002. The conduit installation exceeded the minimum distance from the end of the unistrut arm required by Drawing 3431-C0232, Revision 0. Although the licensee had completed a partial walkthrough inspection of the conduit installation, the final quality control (QC) acceptance hold point for the modification was not performed. QC Plant Inspection Report 6121-2-88-29925 documented and accepted the installation of conduit CGPA1159 from VACP-1 to CIP-1 and noted no discrepancies. As corrective action, the licensee subsequently issued FCN C-58624 to evaluate and accept the conduit installation. The inspection team concluded that no further NRC followup is required because there were no outstanding concerns with this modification.

2.1.3 Containment Particulate Monitor Modification (BA 402815)

This modification relocated the containment particulate monitor (CPM) containment isolation valves and the control circuits for the CPM and oxygen analyzer containment isolation valves. The inspection team reviewed the modification documents, inspected a portion of the electrical installation, and witnessed an insulation resistance test on the new cable. The inspection team identified one minor wiring discrepancy involving cable 21-2086. This cable was rerouted and terminated in newly installed panel ER-666-143; however, one conductor of the cable was terminated on the opposite side of the terminal block as shown on Drawing 3431-E0735, Revision 1.

Although further licensee action is necessary to update the applicable wiring diagrams, the inspection team concluded that no further NRC followup is required because this deficiency did not affect the operation of the equipment.

2.1.4 Limitorque Limit Switch Modification (BA 323512)

This modification relocated the open indication contacts and adjusted limit switch rotors for various Limitorque actuators. The licensee took these actions in response to Significant Operating Experience Report (SOER) 86-2, issued by the Institute of Nuclear Power Operations (INPO). The SOER identified several concerns regarding the use of limit switches for valve position indication purposes. Specifically, valve actuators that use a two-rotor limit switch assembly have the potential to provide inaccurate indication of the valve's closed position. The SOER indicated that valve failures were caused, in part, by setting the torque switch bypass contacts to reinstate the torque switch in the valve control circuit before the valve disc had unseated. To resolve this problem, the torque switch was reinstated at a point later in the valve opening cycle. However, this resulted in the indication light for the open position going out earlier in the closing cycle, which indicated that the valve was closed while it was still partially open.

In response to the SOER, the licensee modified the close-to-open torque switch bypass setting to provide assurance that the valves would overcome any differential pressure. However, because the valves used a two-rotor switch assembly, the licensee recognized that resultant inaccuracies in valve position indication could adversely impact operational and surveillance requirements. Therefore, the licensee used relay contact points on separate rotors to allow independent settings for valve position indication and torque switch bypass. The licensee had scheduled the modification of approximately 40 valve actuators during the 12R outage cycle, which left 10 valve actuators to be modified at the time of the inspection. The inspection team selected five completed valve modifications for physical examination and reviewed Specification OCMM-323512-001, "Limitorque Motor Operated Valves Limit Switch Modification." This document provided the general installation requirements for the modification and detailed subsequent maintenance and test activities. The licensee had completed the appropriate safety evaluations.

Although the requirements of the installation specification and associated work order appeared thorough and logically ordered, the inspection team identified two significant concerns involving the acceptance criteria for valve stroke times and hardware electrical installation deficiencies. These are discussed below.

Stroke Time Acceptance Criteria

Section 1.4 of the installation specification (OCMM-323512-001) required testing the modified valves using the motor-operated valve analysis and test system (MOVATS). The MOVATS data sheets recorded the valve stroke times in the open and close directions and used acceptance criteria based on the inservice test (IST) program. The inspection team noted that the IST program acceptance criteria differed from the design assumptions provided in the USAR. In some cases, the IST program specified stroke times significantly less conservative than the values specified in the USAR. The specific stroke times for each of the valves discussed are listed in a table provided as Appendix D to this report. This table is summarized below.

- USAR Table 6.2-12 specified a maximum closing stroke time of less than 60 seconds for containment isolation valves; however, IST Procedure 607.4.003, "Containment Spray and Emergency Service Water Pump Operability and Inservice Test," identified values significantly more conservative.

- USAR Section 6.2 specified a maximum opening stroke time of less than 30 seconds for some containment spray system valves; however, IST Procedure 607.4.003 identified stroke times of 90 seconds.

- USAR Section 6.3 specified a maximum opening stroke time of less than 20 seconds for 4 isolation valves in the core spray system; however, IST Procedure 610.4.003, "Core Spray Valve Operability and Inservice Test," identified stroke times of 22 seconds. In addition, the historical test data indicated that the actual stroke times for containment spray valves V-20-15 and V-20-40 exceeded the USAR limits by a considerable margin.

The licensee indicated that the discrepancies in the acceptance criteria for the stroke times of the containment isolation valves resulted from the erroneous incorporation of information into the USAR during a 1985 update. In early 1986, a member of the licensee's staff identified the discrepancy in USAR Table 6.2-12 and informally forwarded it to the licensing department for resolution. However, the licensing department failed to correct the discrepancy because an effective mechanism did not exist to formally identify and resolve these types of discrepancies. This failure was significant because the erroneous information may have been incorrectly used as the basis for subsequent safety evaluations or design modifications. The licensee was not able to justify any deviation from the USAR stroke times for the valves in the containment spray and core spray systems valves.

As immediate corrective action, the licensee issued a deviation report (DVR) to evaluate the operability of the core spray and containment spray systems. In addition, the licensee committed to perform the following corrective actions concerning the erroneous stroke times for the containment isolation valves.

- Review all modifications and safety evaluations issued after the 1985 USAR update to ensure that the erroneous USAR information did not affect the conclusions of these evaluations.

- Implement programmatic controls to evaluate the effect of any future USAR errors on subsequent safety evaluations and plant modifications.

- Perform a review to ensure that the stroke times specified in existing IST procedures for containment isolation valves are conservative and revise the USAR to accurately reflect the correct IST values.

- Develop a formal method to ensure that future errors in the USAR are appropriately identified and corrected and that their effect on plant systems and programs is evaluated.

The inspection team concluded that these immediate corrective actions adequately resolved the identified concerns. Further NRC followup is required to ensure that the incorrect USAR information did not adversely affect the conclusions of subsequent safety evaluations. This issue will be followed as an unresolved item.

At the conclusion of the inspection and in a letter dated December 23, 1988, the inspection team requested an expeditious evaluation of the operability of the core spray and containment spray systems. In a letter dated January 12, 1989, the licensee confirmed that the stroke times for the core spray and containment spray valves exceeded the design assumptions of the USAR. However, a recent engineering evaluation demonstrated that the core spray valves were capable of passing more than the assumed flow rate to the reactor vessel and that the containment spray initiation could be delayed up to 10 minutes without significant effect on the containment temperature and pressure. Nevertheless, the inspection team concluded that the licensee's IST program failed to adequately demonstrate that the core spray and containment spray valves operated within the design basis established in the USAR. This failure is considered to be a violation of the surveillance requirements of the technical specifications for IST of valves. This item will be followed as an unresolved item pending further NRC evaluation.

Installation Deficiencies

The inspection team identified a significant number of installation deficiencies within three of the five valve actuators. These deficiencies included damaged control wires; overstressed, twisted, and cracked terminal lugs; excessive wire insulation cutbacks; and grease contamination on terminal blocks and torque and limit switch contacts. In response to the inspection team's observations, the licensee performed an additional examination of five valve actuators and found broken terminal lugs that could potentially affect the operability of the valve actuators. These deficiencies appeared to be the result of original plant construction rather than recent modification or maintenance activities. However, because of the nature and quantity of these deficiencies, the inspection team concluded that they should have been identified and resolved during the performance of the recent modifications. As corrective action for these hardware concerns, the licensee issued Work Request (WR) 054986 to reinspect all safety-related valves modified during the outage. Additionally, the licensee committed to develop a program to further examine all safety-related valve actuators for similar problems. This item will be followed as an open item pending completion of these corrective actions.

The inspection team noted an additional minor concern during review of the limit switch modification. Installation Specification OCMM-323512-001 required that the limit switch open indication light be adjusted to de-energize when the valve was between 97 percent and 99 percent closed. The modification

incorporated this requirement and established QC hold points for verification of the 97 to 99 percent limit. The completed test data sheets indicated that the licensee had deleted the QA hold points and adjusted 7 of the 10 valves to values of less than 97 percent. Quality Assurance Procedure 9830-QAP-7210.03, "QA Mod/Ops Section Inspection Program," required documentation of the justification of changes to hold points on a Hold/Witness Point Deviation/Modification Form. The licensee had not documented the basis for these deviations nor the deletion of the QA hold points. The licensee subsequently verified that the intent of the hold points were properly implemented and included a Hold/Witness Point Deviation/Modification Form in the work package. In addition, the licensee issued FCR C-072701, which evaluated and accepted the valves that did not meet the 97 percent acceptance criteria. On the basis of these corrective actions, the inspection team concluded that further NRC followup is not required.

2.1.5 Elimination of Lifted Leads and Jumpers in the Core Spray System Procedures (BA 323545)

This modification eliminated lifted leads and electrical jumpers in the core spray system. The licensee used these jumpers to simulate various plant conditions during instrument channel calibration of the core spray system. During the modification, test terminal blocks were installed and changes were initiated to appropriate test procedures so that the functions previously served by the eliminated jumpers and lifted leads would be appropriately addressed.

Installation Specification OCMM-323545-002, "Elimination of Lifted Leads and Jumpers for Core Spray System II Instrument Channel Calibration," provided a general overview of the modification and detailed specific requirements for performance of associated work activities. System interfaces and limitations were clearly described, and applicable safety evaluations provided the appropriate operational, design, and regulatory considerations. The inspection team examined affected components in panels ER18-A and ER18-B. These panels contained logic circuitry for the core spray system channel 1 and were the focus of this modification. The licensee installed the required test plugs and test terminals and completed the wiring as required by the work order. Although functional testing of the modification had not been completed at the time of this inspection, the installation specifications required functional and surveillance testing before operation of the core spray system. The inspection team did not identify any deficiencies in this modification.

2.1.6 Main Steam Line Radiation Monitor Replacement (BA 408761)

This modification replaced main steam line radiation monitors RN06A, RN06B, RN06C, and RN06D. The new monitors directly replaced the existing radiation monitors and used the same electrical connectors and panel mounting hardware. The licensee calibrated the replacement monitors before installation. The inspection team identified one minor deficiency concerning the revision of the work documentation and one significant deficiency concerning control of the work process. Because the second deficiency affected the work control procedures used for all the modifications and maintenance activities performed at OCNGS, the inspection team considered the deficiency safety significant.

Inadequate Revisions of a Job Order

The licensee revised the terminal block termination points and transmitter numbers of Job Order 00011007 by handwritten changes in step 4.2.1. Administrative Procedure A000-ADM-1220-11, "Revision Process," defined "pen and ink" changes as temporary changes and provided the requirements for review and approval of both temporary changes and permanent revisions to procedures. The procedure provided a less detailed level of review for temporary changes than it did for permanent changes. Although the licensee did not perform the changes in accordance with the applicable administrative instructions for revisions, the changes did not affect the performance of the modification. The inspection team did not find any further examples of this discrepancy and considered it to be an isolated example. No further NRC followup is required.

Inadequate Procedures for Job Orders

The inspection team initially identified several discrepancies in the documentation of the work control process for this modification. However, further review identified that the discrepancies existed in all the work procedures used at OCNGS. On the basis of its comprehensive evaluation of work management system procedures used for the maintenance, construction, and installation activities at OCNGS, the inspection team concluded that the licensee failed to implement the work control procedures in accordance with Administrative Procedure A000-ADM-1220.8, "M & C Job Order." This procedure described the requirements for preparation, review, approval, and revision of job orders on safety-related equipment and systems.

The licensee revised the work control process in 1987 by implementing the Generation Maintenance System 2 (GMS-2) computer system. The licensee originally used this system as a maintenance tracking aid; however, during March and April 1987, the licensee expanded the implementation of the GMS-2 system to include work conducted in accordance with Administrative Procedure A000-ADM-1220.13, "Short Form." This procedure described an abbreviated job order process for work that did not require complex planning or multiple job orders. The GMS-2 computer system provided a computer-generated format for the development and issuance of these short form job orders and accurately incorporated the administrative requirements of A000-ADM-1220.13.
In early 1988, the licensee expanded the implementation of the GMS-2 system to include all job order preparation and processing, including those job orders performed in accordance with A000-ADM-1220.8, "M & C Job Order." This procedure provided the requirements for all maintenance and modifications that required complex planning, multiple job orders, or detailed installation instructions. However, the GMS-2 system did not include the same level of engineering review and management approval for job orders required by A000-ADM-1220.8 and the licensee did not revise A000-ADM-1220.8 to reflect this new method of controlling the work process.

In QA Audit S-OC-86-14 the licensee's staff had identified problems with implementation of the GMS-2 system and the timeliness of revisions to procedures; however, the audit did not identify the lack of procedure revisions as a formal finding. The audit characterized the observation as a hindrance to implementing the GMS-2 system rather than a failure to follow the administrative procedures for the work control process.

Following detailed discussions with the inspection team concerning the deficiencies in the programmatic control of the work control process, the licensee initiated Quality Deficiency Report (QDR) 88-039 and revised Administrative Procedure A000-WMS-1220.8, "MCF Job Order," on December 23, 1988. The QDR documented that the work management system procedures, which governed maintenance, construction, and installation activities, provided inadequate instructions concerning the GMS-2 system and about how organizations affected by the maintenance activity interfaced. The licensee characterized the QDR as important to safety.

The revision to A000-WMS-1220.8 included references to the GMS-2 system and corrected the major concerns with regard to the level of review and approval of work processed in accordance with the computer system; however, the inspection team identified several additional deficiencies that required correction. These are discussed below.

- The revision to A000-WMS-1220.8 failed to reference or include information from other procedures necessary for the initiation and issuance of a job order. For example, the revision did not reference Station Procedures 114, "Testing," and 124.2, "Control of Plant Engineering Directed Replacements and Modifications," and Administrative Procedures A000-ADM-7175.01, "Post Maintenance Testing," and A000-ADM-1220.11, "Revision Process."

- The revised procedure did not require a description of job order changes or a history of revisions to be part of the completed job order package.

- The GMS-2 system used 16 protected profiles for station personnel and managers that allowed controlled inquiry, review, revision, and approval of the information on the job orders. The revised procedure did not provide descriptions of the titles, duties, and responsibilities of profile holders, nor did it describe the relationship of profile holders to normal plant organizational positions.

- The procedure did not contain a description of the numbering system for job orders or sub-orders, nor did it contain requirements for control of official and field copies of job orders.

- The job order forms generated by GMS-2 and the forms to be used in case the computer fails were not consistent in format and content. For example, the manual job order checklist addressed post-maintenance and installation testing, but the computer generated job order checklist addressed post-maintenance testing and operational testing.

Although it represented an improvement, the revised administrative procedure contained inconsistencies and lacked guidance in several areas. The inspection team acknowledged that the licensee rapidly implemented corrective actions to revise the procedure when the deficiency was identified by the inspection team. Nevertheless, further licensee action is required to improve the administrative procedures for the work control process.

The inspection team concluded that the failure to identify the deficiencies with respect to the work management system procedures that governed maintenance, construction, and installation activities indicated a significant

deficiency in the effectiveness of management oversight. The failure to perform the maintenance and modification activities in accordance with documented instructions and procedures violated the requirements of Appendix B to 10 CFR 50 for instructions, procedures, and drawings. This item will be followed as an unresolved item pending further NRC review and evaluation.

2.1.7 RE03/RE15 Analog Conversion Modification (BA 402896)

This modification replaced pressure switches RE03A, RE03B, RE03C, and RE03D in the reactor protection system (RPS) and pressure switches RE15A, RE15B, RE15C, and RE15D in the engineered safety features (ESF) system. The licensee replaced the pressure switches with Rosemount transmitters and analog loop channels to decrease the number of spurious operations and false half scrams in the RPS. The inspection team reviewed the modification package and interviewed the personnel who installed the modification. The inspection team performed field inspections of the mounting, installation, and wiring for all eight transmitters on instrument racks RK01 and RK02 and noted two minor deficiencies.

The licensee terminated the instrument leads for transmitters RE015A, RE015C, and RE015D on the incorrect side of their respective terminal boards. The licensee issued FCR C-075011 to correct these deficiencies on Installation Drawing E0-758. In addition, the bend radius of the wiring for transmitter RE03A at terminal point 2 on terminal board TB-11 and one wire to transmitter RE015A exceeded the installation acceptance criteria of QA Inspection Procedure 6100-STD-7210.05, "Installation and Termination Inspection of Control, Instrumentation and Power Cable," and Station Procedure 700.5.031, "General Cable Installation, Testing, and Terminating Procedure." As corrective action, the licensee rerouted and inspected the wires and tested the insulation resistance. No further NRC followup is required.

2.1.8 Reactor Protection System Switch Upgrades (BA 402879)

This modification replaced three Barton pressure switches with a new style of pressure switch to evaluate the new switches and improve system operability and maintainability. The modification included installation of new Barton pressure switches, brackets, mounting plates, wall anchors, and wiring between the switches and existing junction boxes. The inspection team identified the following minor deficiencies in the modification installations and adjacent equipment.

- The licensee installed Teflon tape on both process line tubing connections at pressure switch RE-18D. Installation Specification SP-9000-44-001, "Instrument and Control Equipment Installation," specifically prohibited the use of Teflon tape on tubing installations. As corrective action, the licensee verified that this example was an isolated example.

- The licensee installed pressure switch RV-46D one inch outside the maximum tolerance allowed by note 5 of Installation Drawing C230. Because the installation drawing was not specific concerning the installation mounting tolerances and did not specify the location of the pressure switch on the mounting plate, nor the location of the mounting plate on the Unistrut supports, maintenance personnel arbitrarily mounted the support plate on the Unistrut to avoid interference with an adjacent valve. The resulting

location exceeded the tolerances allowed by the drawing. As corrective action, the licensee initiated Material Nonconformance Condition Report (MNCR) 880419 to investigate and resolve the problem.

- The licensee installed ASCO solenoid valve V-6-2917, located near pressure switch RE-22D, without a turned-down elbow on the bleed port as recommended by the vendor manual. A turned-down elbow prevents entry of foreign material that could affect valve operation.

- The inspection team identified several deficiencies that indicated poor housekeeping practices. The inspection team found loose relay terminal screws in the bottom of auxiliary relay panel ER-642-113/115 and excessive dust and unused wire tags and spare Brady markers in the bottom of panel TB-21-1922. The licensee took immediate action to correct these deficiencies.

- The inspection team found that pressure switches RV-46D, RV-46B, and 1P15, and valve V-20-100 lacked support clamps. In addition, the installation of one of two mounting studs for drywell high pressure isolation pressure switch PS-RE04D spalled the surrounding concrete, preventing full anchor engagement with the concrete wall. The cracked concrete and missing clamps on the pressure switches invalidated the seismic mounting of the piping assembly. The deficiencies were not directly related to the modification under evaluation; however, these examples indicated that the maintenance personnel failed to identify pre-existing installation deficiencies.

No further licensee action is necessary for these specific deficiencies. However, the inspection team concluded that increased management attention is warranted to ensure that existing installation criteria are implemented and that existing programmatic controls for the identification of pre-existing, deficient material conditions are effectively implemented by station personnel.

2.1.9 HFA Relay Replacement (BA 323397)

This modification upgraded 78 HFA relays to satisfy previous commitments. The modification required removal of the entire system or subsystem from service to perform this work. The licensee released the system for the replacement of the relays after the operations department removed electrical power and removed the system from service. The inspection team identified no deficiencies during the review of this modification.

The licensee implemented appropriate work control measures and properly tagged and released the system. The licensee correctly incorporated the relay parameters specified in Station Procedure 732.2.006, "Relay Replacement," in accordance with the manufacturer's recommendations. In addition, the licensee used the proper technique to measure relay pickup voltage and correctly compensated the acceptance criteria for temperature. The relay data sheets contained in the work package correctly documented the results of shop testing and satisfied the requirements of Station Procedure 732.2.006.

The inspection team observed the installation of two HFA relays. The licensee correctly documented the wiring configuration before removing the existing relay and properly tagged the existing relay. In addition, the licensee

installed the relays in accordance with instructions, properly tested the replacement relay, and properly performed independent verification of the wiring terminations. The inspection team noted that a quality control inspector actively verified work activities.

The team discussed the planned relay post-maintenance testing with the job planner. The job planner explained the elementary electrical drawings and the system surveillance procedure steps required to make the final verification of the relay installation. Relay testing consisted of a combination of relay cycling, relay contact verification, and system testing that verified proper relay operation after actuation. On the basis of the tests performed during relay installation and the actions that would be verified during surveillance testing, the inspection team concluded that the licensee performed adequate testing to ensure that the relays and the system performed satisfactorily.

2.1.10 Reactor Protection System Solid State Trip System Installation (BA 328180)

This modification installed a solid-state trip system in plant circuit breakers. The inspection team reviewed Job Order 47452 and the associated documentation and witnessed the installation of a portion of this modification for one circuit breaker. The licensee had not updated the breaker electrical drawings to show that the trip coils were replaced by new current transformers. The licensee acknowledged that the drawings required revision and indicated that an FCR would be initiated once the equipment was turned over to the plant operations department. Since the modification was still in progress, the inspection team could not verify that this item had been completed.

The inspection team identified a minor documentation deficiency. The installation procedure contained hold points to ensure verification of the installation criteria. The licensee incorrectly changed several mandatory quality assurance hold points to optional witness points and did not provide a justification for the change as required by Quality Assurance Procedure 9830-QAP-7210.03, "QA Mod/Ops Section Inspection Program." The procedure required documented justification of changes to hold points on a Hold/Witness Point Deviation/Modification Form. The licensee subsequently verified that the intent of the hold points were properly implemented and included a Hold/Witness Point Deviation/Modification Form in the work package.

Because a similar example of this deficiency was identified during the review of the Limitorque switch modification, as discussed in Section 2.1.4 of this report, the inspection team concluded that further licensee action is necessary to ensure that the existing programmatic controls for QA hold and witness points are effectively implemented.

2.1.11 Conclusions

On the basis of the electrical modifications inspected, the inspection team concluded that the licensee performed the installation of the modifications with high quality workmanship. In addition, the licensee personnel responsible for the modifications appeared knowledgeable of the design and installation requirements. The overall quality of the installation of the electrical and instrumentation and control modifications was considered a strength.

In spite of the quality of the workmanship, the inspection team identified several minor hardware discrepancies that occurred during the installation of the modifications. These involved excessive installation tolerances, documentation deficiencies, and several minor wiring discrepancies. The inspection team also identified several hardware discrepancies that were unrelated to the modification activities. These discrepancies were located in the immediate area of the modifications and had not been identified or corrected. The failure to identify these obvious deficient conditions indicated the need for increased efforts to identify pre-existing deficient conditions and a more comprehensive post-modification inspection.

With regard to concerns identified during the review of the Limitorque limit switch modification, the inspection team concluded that the licensee failed to implement an effective method to maintain the USAR up-to-date. As a result, the conclusions of safety evaluations based upon this erroneous information may be incorrect. Further NRC and licensee action is necessary to evaluate the significance of this deficiency. The inspection team also concluded that the licensee's IST program had not satisfactorily demonstrated that the valves of the core spray and containment spray systems satisfied the USAR design basis. In fact, previous test data demonstrated that the stroke times of two core spray system isolation valves have exceeded the design basis limits since 1985. The licensee subsequently determined that this deficiency would not have resulted in less than the flow required by the safety analysis. Nevertheless, the failure to accurately incorporate the correct stroke times in the IST procedures prevented the identification of the deviation and degraded the effectiveness of the technical specification surveillance requirements.

The inspection team identified several examples in which existing programmatic controls and administrative procedures were not followed. The licensee failed to identify pre-existing, deficient material conditions, failed to document the justification of changes to QA hold and witness points, and incorrectly performed temporary revisions to job orders. In addition, the licensee failed to perform the maintenance and modification activities in accordance with documented instructions and procedures. In fact, the licensee's present job authorization system (i.e., the GMS-2 computer system) had not been incorporated into the administrative procedures. These procedural adherence deficiencies indicated that increased attention is necessary to ensure that existing programmatic controls and administrative requirements are effectively implemented.

2.2 Mechanical Modifications and Maintenance

2.2.1 Scope

The inspection team reviewed various modification packages that were complete, in progress, or pending completion and verified their conformance to licensee procedures, the licensing basis as described in the USAR and national codes and standards. The inspection team reviewed the detailed work authorization installation procedures and job order packages associated with the modifications to ensure that appropriate instructions were made available to the personnel responsible for performing the modification. The inspection team also interviewed several of the licensee's engineering and maintenance personnel to discuss various aspects of the modifications reviewed.

2.2.2 Emergency Diesel Generator No. 1 Maintenance and Improvements (BA 323476)

This modification replaced the fuel oil pumps and motors, control relays, wire harness stack assemblies and refurbished the emergency diesel generator (EDG) No. 1 power packs. The inspection team evaluated the licensee's modification and maintenance activities related to EDG No. 1 by reviewing modification packages and discussing the work with responsible station engineering, quality control (QC) and management personnel.

The inspection team found that the licensee had incorrectly performed complex maintenance on EDG-1 using a vendor generated procedure. This procedure had been substantively changed by the station engineer and had not received the required plant engineering reviews or administrative approvals before the work was performed. The EDG maintenance in Job Order 12108 consisted of completely tearing down and rebuilding the power pack (i.e., the piston, piston rings, and connecting rods), the intake cylinder head, intake and exhaust valves, and bearings. The work was performed in accordance with a 23-page vendor-generated procedure that was included as part of the job order package. This procedure, referred to in the job order as a memorandum, had numerous substantive handwritten changes made by the station engineer. These changes included deleting cleanliness control steps and changing lubricant types and fastener torque values. This procedure was not reviewed, issued, revised, or controlled in accordance with Station Procedures 107, "Procedure Control," or 107.3, "Use and Control of Technical Manuals." In addition, there was no evidence that the vendor's technical staff had reviewed or authorized these changes.

The inspection team identified that the licensee used handwritten, unreviewed, and unapproved instructions and data sheets to measure coil and contact resistances of EDG-1 relays in Job Order 13544 to determine the condition of the relays and determine whether they needed replacement. The licensee's safety evaluation for this work was invalidated because the actual field work had been performed using an unapproved and unreviewed procedure, contrary to the assumption made in the safety evaluation that the work would be performed with procedures that had been through the safety review process. Additionally, the contact resistance acceptance criteria were not specified in the job order or the handwritten instructions. In fact, the inspection team was not able to determine what basis or justifications were used by the station engineer to determine acceptability criteria for the contact resistance because such information was not documented in the job order package. The licensee indicated that the decision to replace the contacts was made solely on the judgment of the site engineer involved in the work. Finally, the inspection team found that the licensee had erroneously marked the QC sign-off for the acceptable completion of this task "N/A" although QC review and concurrence were required by the QA Procedure 8930-QAP-7210.03, "QA Mod/Ops Section Inspection Program."

The inspection team found that the licensee had made physical changes to EDG-1 system hardware after final QC acceptance had been performed without review or reinspection by QC personnel. The licensee had performed modifications to EDG-1 to upgrade the fuel transfer system, including replacement of transfer pumps and motors, rerouting piping and adding of a key-lock test switch. The licensee used a wiring data sheet and various job order hold points to ensure that everything was properly installed. The QC department had performed its inspections and signed to this effect on November 21, 27, and 28 for this

modification. However, the licensee performed additional modifications to the wiring without using the required wiring data sheets and without QC reinspection of the additional modifications. There were substantive handwritten changes made to Job Order 12107 that were beyond the intent of pen and ink changes. The changes included such items as revised wire gauges, termination numbers, switch positions and test termination requirements. The inspection team noted that these changes did not meet the requirements of Station Procedure 124.3, "Work Control and Record Closeout Process for Specific 12R Outage Work," or the requirements of Station Procedure A000-ADM-1220.11, "Revision Process."

The inspection team found that the licensee had performed extensive post-maintenance testing (PMT) on EDG-1 using a handwritten, unreviewed, and unapproved test. Although Job Order 12108 specified the PMT as performance of an existing EDG load test surveillance, the responsible station engineer determined that the specified PMT was inadequate and prepared a six-page handwritten procedure to start up and load the diesels for a 24-hour period. The group shift supervisor (GSS) authorized this test to be performed although this procedure was not referenced in the job order, had not received technical and QA/QC hold point review, had not received a safety evaluation, and was not approved as required by the licensee's administrative procedures. The inspection team noted that the test procedure that was used was not consistent with any of the numerous station procedures such as Station Procedures 107, "Procedure Control;" 114, "Testing;" 124.3, "Work Control and Record Closeout Process for Specific 12R Outage Work;" A000-ADM-7175.01, "Post Maintenance Testing;" and A000-WMS-1291.01, "Procedure for Nuclear Safety and Environmental Impact Review and Approval of Documents." The inspection team was particularly concerned because many station personnel who were involved in or had knowledge of the test took no corrective action to prevent the test from taking place. Additionally, the inspection team found that the PMT specified in Job Order 12107 was inadequate because Paragraphs 5.1 and 5.2 did not define a pump operability acceptance criterion (e.g., greater than 100 gpm). Furthermore, the job order did not require or provide space for any signatures certifying performance, review, or acceptance of the tests. The inspection team also noted that there was no indication on the completed job order form that a leak check had been performed as required by Section 5.3 of Administrative Procedure A000-ADM-7175.01, "Post Maintenance Testing."

At the close of the inspection, the licensee was conducting a complete review of all documentation and work activities related to EDG maintenance and modification during this outage. In a letter dated December 23, 1988, the licensee was requested to expeditiously evaluate the complex maintenance and testing performed on emergency diesel generator No. 1 to evaluate the reliability of the machine. In a letter dated January 12, 1989, the licensee indicated that all unapproved work and testing performed on EDG No. 1 was incorporated into a revised work package which was reviewed in accordance with approved procedures and found to be technically accurate. Although the review was performed after the work was completed, the review ensured that no work had been performed that would adversely affect operability or reliability of EDG No. 1. The failure to review and approve the complex maintenance and testing performed on EDG No. 1 prior to performance is considered to be a violation of the 10 CFR 50 Appendix B requirements for procedures control and as such will be followed as an unresolved item.

2.2.3 Limitorque Operator Replacement (BA 408737)

This modification replaced the Limitorque valve operators for valves V-1-99, V-2-2, V-2-82 as corrective action for maintenance problems identified during the 11R outage. In addition, the Limitorque operator for valve V-3-25 was replaced as final corrective action for valve operators that had been lubricated with incompatible greases. The use of incompatible greases can result in either a hardening or softening of the grease that may lead to failure of the valve operators. The licensee initially identified the mixed-grease problem during a review of lubrication records of all installed motor-operated valves in 1983, and concluded that 61 valve operators had been injected with incompatible greases. The licensee had corrected 45 of the valve operators by overhaul or replacement. Although 16 valve operators remained to be corrected upon entering the 12R outage, only one valve operator (V-3-25) was scheduled for corrective actions.

In response to the inspection team's questions concerning the history of the mixed-grease problems, the licensee found 17 additional valve operators that were affected by mixed-grease and that had not been previously identified, thus increasing the total number of problem valve operators to 32. The 17 additional operators were contaminated because the licensee did not realize that there was a grease transmission path between the valve operator handle and the transmission gears. The inspection team noted that of the 32 valve operators affected by mixed-grease, 2 were classified as "Nuclear Safety-Related" (NSR), and "Environmentally Qualified" (EQ), 7 were classified as "Regulatory Required" (RR), and 23 were classified as "Other."

Based on the additional 17 Limitorque valve operators that were injected with incompatible greases, the inspection team concluded that the licensee's corrective actions to repair all affected valve operators and to prevent recurrence of mixed-grease was ineffective. The inspection team was particularly concerned that the operability and the environmental qualifications for the two NSR valves, V-5-166 (RBCCW Return Isolation Valve) and V-21-3 (Containment Spray Pump 51D Torus Isolation Valve) may have been compromised. The inspection team was also concerned that the licensee had not performed an engineering evaluation of the seven RR valve operators to determine the affect of the mixed-grease on the reliability of the valve operators. In addition, the licensee's corrective actions appeared to have been affected by fiscal constraints as evidenced by the scheduled repair of only one affected valve operator in the 12R outage. The completion of the corrective actions was protracted and may effect the reliability and operability of the systems in which the valve operators were located.

At the conclusion of the inspection and in a letter dated December 23, 1988, the licensee was requested to expeditiously evaluate the reliability and operability of the 32 motor-operated valves which were contaminated by mixed-grease. In a letter dated January 12, 1988, and during subsequent discussions the licensee indicated that one NSR valve (V-5-166) was contaminated with an insignificant amount of noncompatible grease and the remaining NSR valve and the seven RR valves have been flushed and regreased. The failure to fully implement the corrective actions for the original mixed-grease problem (i.e., 15 MOVs remained to be corrected and were not scheduled in the 12R outage) and the failure to prevent recurrence of the mixed grease problem (i.e., an additional 17 MOVs were inadvertently contaminated) are considered

to be violations of 10 CFR 50 Appendix B requirements for corrective actions and as such will be followed as an unresolved item.

2.2.4 Anchor Bolt and Piping Support Upgrades per IE Bulletin 79-14 (BA 402876)

This modification upgraded seismic supports in the reactor building, turbine building, and containment drywell in response to IE Bulletin 79-14. The inspection team inspected nine piping supports and restraints (i.e., 532-60, 532-67, 532-54, 532-45, 532-46, 532-52, 532-58, 532-44, and 532-62) in the emergency service water (ESW) system to determine conformance to design drawing requirements and established engineering acceptance criteria. The supports generally were found to be installed in accordance with design drawings, field change requests (FCRs), and existing engineering installation criteria. However, the inspection team identified two areas of concern related to hardware installations.

The first concern was that acceptance criteria for the support installations were in some cases either not established or were improperly detailed on engineering documentation. For example, the licensee did not specify any tolerances for the attachment location of support structures to base plates or existing steel even though movement of the attachment location from the position analyzed by the designers could result in unacceptable loads on support members and anchor bolts. The inspection team found restraint 532-60 located 1-1/2 inches off center on the base plate when the calculation for this restraint had been made based on the attachment being centered on the base plate. The acceptance criteria for base plate anchors in Sections 6.3.2 and 6.3.3 of Station Procedure 700.5.026, "Installation of Drillco Maxi-Bolt Undercut Anchors," required a 7 inch minimum center-to-center bolt spacing. The inspection team found that the base plate anchor bolts for hangers 213-20 and 95-101 on seismic support 213-BR-NP-1-R6-20, which secured a piping section of the liquid poison system, were installed 4-1/4 and 4-1/2 inches center-to-center respectively. The inspection team also found two loose U-bolts on seismic supports 213-BP-NP-1-R5-14 and 213-BR-NP-2-R7-13. This condition invalidated the function of the seismic support. In addition, the engineering specification detailed the minimum allowable clearance between the pipe and support structures (box guides or U-bolts) as zero inches. Although, no specific examples of this nature were identified, the inspection team was concerned that a zero clearance could permit a binding condition that would introduce unanalyzed axial loads onto the support structures.

The inspection team's second concern involved the adequacy of previous as-built inspections which failed to identify that seismic support 532-46 did not conform to the configuration detailed on the design drawing. This support had been inspected during previous IE Bulletin 79-14 walkthroughs and obvious discrepancies had not been identified. These included (1) two anchor bolts that were excessively bent, (2) two holes through the angle iron frame so enlarged that the holes were visible outside the perimeter of the washers, and (3) one anchor bolt specified as 1-1/4 inch diameter on the drawing that was actually 7/8 inch in diameter. The licensee subsequently issued a material nonconformance report (MNCR) and the support was analyzed and reworked. Additionally, the inspection team noted that although numerous FCRs issued to accomplish Job Order 10568 had a specific requirement that the original pipe location be maintained within 1/16 inch of the as-found location, methods to be used to meet this requirement were not specified and the maintenance personnel could not explain how this requirement had been achieved.

Although there were several weaknesses identified with this modification, the inspection team also identified strengths in this area. For example, the inspection team found that each FCR contained a six-step checklist detailing the needs for temporary supports and out of service requirements. Additionally, inspection team found that controls for system and component operability determinations and example drawings for temporary supports, where required, were adequate and properly evaluated. The inspection team also concluded that QC Department Checklist IN-018, "Installation Inspection: Hangers, Snubbers, Restraints," provided a thorough method for verifying the correct installation of the supports. This checklist provided 10 general inspection areas with 46 subset inspection attributes. QA Procedure 6100-STD-721.01, "Installation Inspection of Component Support Hangers, Snubbers, Restraints," specified that, as a minimum, the attributes in this checklist be used for inspecting pipe supports and restraints.

2.2.5 Drywell Cathodic Protection System Installation (BA 402873)

This modification installed cathodic protection for the containment drywell steel lining that had experienced varying degree of corrosion at the interface of the drywell lining and the sand cushion. The corrosion was caused by water that was found in the drywell sand cushion. The licensee discovered the corrosion problem while performing their ISI of the drywell wall to verify its design thickness. The ISI revealed that at certain locations on the drywell steel lining, the steel was thinner than acceptable values. Investigation into the cause of the thinning revealed that there was water in the drywell sand cushion that was acting as the corrosion medium. The licensee personnel responsible for the installation of the cathodic protection anodes and reference electrodes indicated that as much as 400 gallons of water may have been present in the drywell sand cushion. Additionally, the initial licensee investigation revealed that the drain piping installed to drain any condensation that might occur in the drywell sand cushion was clogged with debris.

In order to reduce future corrosion of the drywell steel lining, the licensee decided to install numerous cathodic protection anodes arranged to provide a line source to negate any possible electrical potential difference created between the drywell steel lining and the drywell sand cushion and thereby minimize the galvanic corrosion. Additionally, licensee will install reference electrodes to provide a feedback loop to monitor the amount of current needed to sufficiently provide corrosion protection and increase the inspection frequency of the ISI to determine whether the cathodic protection has been successful. The physical placement and arrangement of the cathodic protection anodes was determined experimentally in the license's laboratory which simulated the actual physical configuration of the drywell lining and the sand cushion. The installation of the cathodic protection involved drilling into the concrete shield wall that retains the sand cushion and installation of conduits and electrodes. To prevent drilling into the steel lining, the drill site is surveyed to determine the exact drill point and to predict the approximate thickness of the concrete shield wall. Additionally, the drill bit is manufactured such that it will not drill through reinforcement found in the concrete shield wall.

The inspection team reviewed the work authorization, the installation specifications, and the procedures for this modification, and interviewed various station personnel and found no discrepancies.

2.2.6 Control Rod Drive Replacement (BA 408741)

This modification replaced 30 control rod drives (CRDs) as part of a routine replacement program. Several CRD design improvements developed by the nuclear steam system supplier (NSSS) were incorporated by using the BWR/6 type CRD as replacements. The facility external to the CRDs were not changed by this activity. The inspection team reviewed procedures governing the work, and no deficiencies were identified.

2.2.7 Control Room Ventilation System Installation (BA 402854)

This modification fabricated and installed a new train (i.e., train B) of heating, ventilation, and air conditioning (HVAC) system for the control room. The new system was designed to tie into the existing ductwork of the train A control room HVAC system. This modification was implemented during the cycle 12R refueling outage to meet licensee commitments to NUREG-0737, Item III.D.3.4, "Control Room Habitability." The modification required installation of a new air conditioning unit, supply and return ducting and dampers, intrusion-resistant devices, circuit breakers, and associated raceways, cables, and supports. No deficiencies were identified as a result of the review of the documentation or walkthrough of the installation.

The inspection team reviewed the functional test performed as a result of the addition of the new train B HVAC system to verify that the test adequately demonstrated the system's functions. Some of the features that the test was intended to verify included (1) the proper function of the new control room HVAC system and its components (including controls, indications, annunciators and alarms); (2) operability of the system with isolation dampers installed and control circuit modifications accomplished; (3) ability of the system to maintain a positive pressure of 0.125 inch water gauge (WG) in the control room relative to the outside atmosphere with the HVAC unit in the partial recirculation mode and infiltration and makeup air flows of 2000 cubic feet per minute (CFM); (4) proper operation of control switches and indicating lights after their relocation on control panel 11R; (5) ability of the system to maintain control room temperature requirements during the heating season; and (6) ability of the new HVAC system to meet control room temperature requirements during the cooling season with outside ambient temperature of 89 degrees F. The inspection team found the following deficiencies during the review of Test Procedure TP 254/11 and other test documents associated with this modification.

- There were insufficient criteria for acceptance values for heating and cooling the control room envelope by the train B HVAC system.

- The test procedure did not incorporate temperature measurements in the lower cable spreading room during the test.

- Because of the test methodology specified in TP 254/11, the train B HVAC system could not be declared operable until completion of the entire test package, which was not scheduled until the outside ambient temperature reached 89 degrees F.

The inspection team reviewed the previous tests performed on the control room HVAC system to determine the impact of the modification on the train A HVAC system. Based on the test results for Test Procedure TP 200.0.1, "Control Room Habitability Differential Pressure and Airflow Measurements," which was performed March 23, 1988, the inspection team was concerned that the existing train A HVAC system might not have been operable because the test data indicated that the train A had not met technical specification and USAR requirements for positive pressure, volume and in-leakage. The test results showed an in-leakage of 2044 CFM and a total system airflow rate of 11,909 CFM versus requirements of less than or equal to 2000 CFM in-leakage and at least a 13,500 CFM total airflow rate. At the conclusion of the inspection, the licensee committed to revise Test Procedure TP 254/11 to correct the deficiencies identified above and to evaluate the operability of the train A HVAC system, including consideration of all the design, technical specification, and reporting requirements.

At the conclusion of the inspection and in a letter dated December 23, 1988, the licensee was requested to expeditiously evaluate the control room HVAC system flows and bypass leakage. In a letter dated January 12, 1989, the licensee responded to the inspection team's concerns with regard to the existing control room HVAC system operability. The licensee indicated that the testing performed on March 23, 1988, was performed to answer a previous NRC concern that manually securing the kitchen-toilet exhaust fan EF-1-24 during radiological releases was not viable as a permanent setup. The test demonstrated that the HVAC system could satisfactorily maintain the required control room differential pressure in this configuration; however, the infiltration rate was excessive and the total supply fan capacity was less than required by the USAR. The licensee concluded that the excessive in-leakage was due to the kitchen-toilet fan running which is normally off. In addition, the licensee confirmed that the total air flow was less than required by the USAR; however, due to conservatism in the original heat load calculations for the control room, the impact of the reduced air flow on the control room temperature is negligible. Further licensee action is necessary to revise the USAR to reflect these new calculations.

2.2.8 Plant Material Condition

The inspection team performed a walkthrough of all levels in the reactor building and identified numerous examples of excessive and uncontrolled transient combustibles. Examples of transient combustibles included poly-vinyl chloride (PVC) plastics, paper, rags, wood, anti-contamination clothing, and combustible trash. Station Procedures 120.5, "Control of Combustibles," and 119, "Housekeeping," were reviewed and interviews were conducted with the site fire protection coordinator, job supervisors and a job planner. The inspection team's walkthrough and these interviews confirmed several apparent violations of Station Procedures 120.5 and 119, which were due to weaknesses in training, recognition of personnel responsibilities, and acceptance of individual accountabilities. The inspection team was concerned that the buildup of transient combustibles due to the observed breakdown of the program could lead to the exceeding of plant fire loading capabilities if not corrected. The following specific deficiencies were identified.

- Section 5.2.3 of Station Procedure 120.5 required the notification of the site fire protection engineer by the job supervisor or job planner if work or support activities introduced transient fire loads into the secondary containment. The inspection team was concerned that despite what appeared to be a significant transient fire load condition inside the secondary containment, the fire protection coordinator had never been contacted.

- Section 5.2.4 of Station Procedure 120.5 required the removal of combustibles associated with specific work activities at the completion of the activity or at the end of each work shift, whichever occurred sooner. The inspection team noted multiple observations over the course of the inspection in which combustibles were not removed as required.

- Section 5.4.1 of Station Procedure 120.5 required restricted use of plastics, with exceptions to be reviewed by the site fire protection coordinator on a case by case basis. The inspection team found that plastic waste had accumulated in secondary containment and interviews with the plant staff confirmed that the required reviews were not accomplished.

- Section 3.3.1 of Station Procedure 119 required minimizing trash and cleanup of areas after completion of work. The inspection team found many areas where cleanup was not accomplished and where trash was not minimized.

- Section 3.4 of Station Procedure 119 required weekly inspections of plant areas by the operations and maintenance managers to ensure proper attention to housekeeping requirements. Documentation of the inspections was not maintained and plant conditions did not support the effectiveness of these inspections.

- Section 3.5 of Station Procedure 119 identified the responsibilities of plant supervisors for maintaining housekeeping standards for work performed under their supervision. The inspection team's findings did not support the effectiveness of the implementation of these requirements.

- Section 4.6 of Station Procedure 119 identified the responsibility of the site fire protection coordinator for maintaining the control of combustible materials. As noted above, the inspection team found that the site fire protection coordinator was not complying with these requirements.

- Attachment III of Station Procedure 119 detailed the housekeeping responsibilities for areas of the plant and the individuals assigned to each area. The procedure was in conflict with posted signs in the plant, leading to instances where the designated individuals did not know their assignments.

The inspection team discussed the findings with the licensee, who committed to the following corrective actions. Station Procedure 120.5 will be revised to clearly establish responsibility for plant personnel to properly control transient combustibles. Station Procedure 119.1 will be revised to clearly establish responsibility for plant personnel to properly control housekeeping conditions in the plant. The licensee will conduct training of and assign required reading to appropriate plant personnel to correct the deficiencies in

awareness of required combustible controls. Station Procedure 120.5 will be incorporated into the Supervisor's Manual. General employee training and maintenance training programs will be reviewed and strengthened, if necessary, to ensure knowledge of the requirements of Station Procedure 120.5. Further NRC review is required to ensure that these corrective actions are effective, therefore, this item will be followed as an unresolved item.

2.2.9 Plant Modifications Performed by Job Orders

The inspection team reviewed a sample of job orders performed during 1987 and 1988 to ensure that plant modifications were not performed by job orders. From a list of approximately 4400 job orders, the inspection team selected 15 job orders that dealt with maintenance of motor-operated valves or the use of sealant to repair steam leaks. From the 15 job orders, the inspection team reviewed those that involved safety-related systems. The inspection team did not identify any work activities which should have been performed as a plant modification.

2.2.10 Conclusions

The inspection team concluded that the hardware installations were generally in conformance with drawings and exhibited good quality workmanship. However, the inspection team noted several weaknesses. For example, the inspection team found several examples in which individuals did not follow procedures or conducted work without proper review and approval. The inspection team was concerned that flexible procedural adherence may lead to possible problems with equipment and components in the future.

The inspection team also found in one instance that the licensee had taken ineffective corrective actions for the mixed-grease problems on motor-operated valves and as a result had caused additional valve operators to become contaminated with mixed-grease. Although the cause of grease contamination involved subtleties regarding the construction of the Limitorque valve operators, the inspection team was concerned because the licensee had not detected this problem prior to the inspection team's investigation into the initial corrective actions.

Based on the limited review of the testing performed on the modifications during this outage, the inspection team did not have any overall conclusions regarding the adequacy of post-maintenance testing. The inspection team was concerned that, in some instances, the acceptance criteria for post-maintenance testing of modified systems was not sufficient and the licensee's resolution of discrepancies with test requirements and other design criteria were inadequate. In addition, the inspection team was concerned that some post-maintenance testing was performed without approved procedures. The inspection team found that testing for the new control room HVAC system was deficient because the test procedure did not ensure that the new system would perform as required. The inspection team found several unresolved examples of conflicting testing requirements during the review of core spray valve stroke times. In addition, the inspection team found that the licensee's IST acceptance values for the stroke times of the core spray discharge valves were greater than required by the USAR with no apparent justification. The team was concerned that failing to resolve conflicting test requirements and the lack of understanding of system requirements and features may adversely affect the operability of

modified systems. Although the testing performed on the diesel generator appeared to be technically correct, the inspection team was concerned that independent operations and engineering reviews to ensure that equipment and personnel are not damaged while performing post-maintenance testing was circumvented.

3.0 MANAGEMENT EXIT MEETING

The inspection team conducted an exit meeting on December 16, 1988, with licensee management. During this meeting, the inspection team identified the inspection findings and provided the licensee with an opportunity to question the observations. The inspection team also detailed the scope of the inspection and informed the licensee of the conclusions detailed in this report. Mr. Jim Konklin, Section Chief, Team Inspection Section C, Office of Nuclear Reactor Regulation, and Mr. Curt Cowgill, Section Chief, Reactor Projects Section 1A, Region I, represented NRC management at the final exit meeting. Appendix A identifies the licensee personnel who participated in this meeting.

APPENDIX A

LICENSEE PERSONNEL CONTACTED

Name	Organization
General Public Utilities Nuclear Corporation Personnel	
*E. Fitzpatrick	Vice President and Director
*R. Barrett	Director, Plant Operations
*W. Behrle	Director, Startup and Test
*L. Lammers	Director, Plant Material
*W. Popow	Director, MCF Production
*E. Scheyder	Director, MCF
*A. Rone	Director, Plant Engineering
A. Asarpota	Manager, Oyster Creek Projects
R. Blouch	Manager, Technical Support
R. Brown	Manager, Operations
*T. Brownridge	Manager, MCF Construction
*G. Busch	Manager, Licensing
T. Corrie	Manager, Quality Control
*J. DeBlasio	Manager, Plant Engineering
*R. Fenti	Manager, Quality Assurance
*V. Foglia	Manager, Technical Function
*R. Good	Manager, MCF Planning, Scheduling and Estimating
*T. Jenkins	Manager, MCF Construction
M. Laggert	Manager, Licensing
*D. MacFarlance	Manager, Site Audits
*R. Markowski	Manger, Quality Assurance Program Development/Audit
*L. Schreiber	Manager, Startup & Test
J. Solakiewicz	Manager, Operations Quality Assurance
*D. Pysher	Manager, Facilities
*D. Ranft	Manager, Plant Engineering
E. Johnson	Superintendent, Instrumentation and Control
*T. Gaffney	Supervisor, Instrumentation and Control
T. Hedigan	Supervisor, Instrumentation and Control
L. Hohnes	Supervisor, QC Programs
M. Knipple	Supervisor, Document Control
L. Lohnes	Supervisor, Quality Control Programs
P. Manning	Supervisor Quality Control Field Inspection
F. Seiffert	Supervisor, Mechanical Maintenance Group
*G. Sevcik	Supervisor, Mechanical Material Assessment
D. Quilty	Supervisor, Warehouse Operations
D. VanBlancom	Group Shift Supervisor, Operations
A. Baig	Project Engineer
*K. Barnes	Engineer, Licensing
D. Custodio	Senior Electrical Engineer
W. Fitts	Project Engineer

Name	Organization
*S. Gomulka	Staff Analyst
W. Haas	Engineer, Technical Functions
R. Henriken	Operations Engineer
*R. Huddy	Corporate Audits, Quality Assurance
*M. Jacobs	Nuclear Engineer
D. Jones	Senior Engineer, Plant Engineering
E. Ohara	Senior Engineer, MCF
O. Perez	Engineer, Mechanical
J. Piazza	Senior Engineer, MCF
W. Ramsey	Startup Test Engineer
J. Siegel	Fire Protection Program Coordinator
D. Stovey	Planner, MCF Construction
*K. Tosch	Nuclear Engineer
J. Ventosa	Site Fire Protection Coordinator

Catalytic Incorporated Personnel

C. Davis	Lead Hanger Supervisor
R. Hamlin, Jr.	Lead Electrical Supervisor
J. Leto	Supervisor
J. Sullivan	Lead Electrical Reviewer
B. Zimmerman	Electrical Planner, MCF

* Denotes those personnel who attended the exit meeting of December 16, 1988.

APPENDIX B

REFERENCES

I. Administrative Procedures

Document No.	Rev.	Title	Date
1000-ADM-1291.01	4	Procedure for Nuclear Safety Environmental Impact Review and Approval of Documents	06/15/88
1000-ADM-7215.01	2	GPUN Material Nonconformance Reports and Receipt Deficiency Notices	07/11/88
1000-ADM-7215.02	1	GPUN Quality Deficiency Reports	11/11/88
1000-PLN-7200.01	1	Operational Quality Assurance Plan	
1000-POL-1218.01	2	GPU Nuclear Corporation Policy, Plan and Procedure System	11/16/87
5000-ADM-1291.01	3	Nuclear Safety/Environmental Impact Determinations and Evaluation	04/13/87
5000-ADM-7350.02	2	Installation/Specifications	02/29/88
5000-ADM-7350.03	4	Field Questionnaires, Change Notices and Change Requests	10/31/88
5000-ADM-7313.01	3	Modification and System Design Descriptions	11/16/87
5000-ADM-7316.02	1	Vendor Document Review	06/13/86
5000-ADM-7316.04	2	Professional Services Document and Review	07/18/88
5000-ADM-7335.02	3	Test Procedure Generation Approval and Change	12/21/87
5000-ADM-7350.02	2	Installation Specifications	02/09/88
5000-ADM-7350.03	4	Field Questionnaires, Change Notices and Change Requests	10/31/88
9800-QAP-7203.01	1	GPUN QA Review of Engineering Specifications, Installation Specifications, Modifications and System Design Descriptions	03/01/88

Document No.	Rev.	Title	Date
9830-QAP-7205.02	0	Quality Control Document Review	04/01/88
9830-QAP-7206.01	4	O.C. Mod/Ops Document Review Procedure	04/01/88
9830-QAP-7210.03	5	QA Mod/Ops Section Inspection Program	04/22/88
A000-ADM-1220.3	3	Work Authorization	08/08/86
A000-ADM-1220.8	2	M & C Job Order	07/14/87
A000-ADM-1220.09	2	Work Closeout	11/07/86
A000-ADM-1220.11	0	Revision Process	02/14/84
A000-ADM-7175.01	0	Post Maintenance Testing	12/01/86
A000-WMS-1218.03	0	Work Procedure Control	02/29/88
A000-WMS-1220.01	6	Work Request	12/11/86
A000-WMS-1220.08	3	MCF Job Order	12/23/88
A000-WMS-1220.13	2	Short Form	09/27/88
A000-WMS-1220.14	2	Preparation, Review and Approval of Work Procedures	02/29/88
A000-WMS-1291.01	1	Procedure for Nuclear Safety and Environmental Impact Review and Approval of Documents	03/21/88
A100-ADM-3053.01	0	Calibration of Maintenance Test and Inspection Tools, Gauges, and Instruments	03/29/88
A100-GME-3918.51	0	Motor Operated Valve Testing Using MOVATS	10/24/88
A100-GME-3918.52	0	Limitorque Operator Maintenance Electrical	10/24/88

II. Installation and Inspection Specifications

700.5.026	5	Installation of Drillco Maxi-Bolt Undercut Anchors	06/13/88
700.5.027	8	Installation of Ramset AUK Undercut Anchors	07/15/88

Document No.	Rev.	Title	Date
700.5.029	3	Installation of and Repairing with Grout	02/11/88
700.5.031	2	General Cable Installation Testing, and Termination Procedure	07/04/87
700.7.023	4	Limitorque Motor Operator Maintenance Model SMB Series	05/22/88
732.2.006	9	OCNGS Relay Replacement Procedure	06/17/88
775.1.008	2	Inspection and Adjustment of Spring Type Pipe Supports	05/05/88
1302-42-010	2	Oyster Creek Hanger Mods and Upgrades	07/08/88
6100-STD-7210.01	2	Installation Inspection of Component Supports, Hangers, Snubbers, and Restraints	07/11/88
6100-STD-7210.04	2	Installation Inspection of Cable and/or Tubing Trays and Conduit	07/11/88
6100-STD-7210.05	2	Installation and Termination Inspection of Control Instrumentation and Power Cable	07/11/88
6100-STD-7210.06	1	Installation Inspection of Instrumentation Tubing	06/01/88
AS-004	2	GPUN Generic Specifications and Standards for Design and Installation	05/09/88
OCMM-323512-001	0	Limitorque Motor Operated Valves Limit Switch Modification	06/01/88
OCMM-323545-002	0	Elimination of Lifted Leads and Jumpers for Core Spray System II Instrument Channel Calibration	09/30/88
OCMM-402887-001	0	Installation Specification for Reactor Protection System Relays Power Supply Modification	04/01/88
OCMM-402815-001	1	Installation Specification for Containment Particulate Monitor System Modification	04/19/88

Document No.	Rev.	Title	Date
SP-9000-41-005	2	Installation Specification for Cables and Raceways	11/04/88
SP-9000-44-001	1	Installation Specification for Instrument and Control Equipment	12/12/84

III. Station Procedures

SP 101	17	Organization and Responsibility	10/17/88
SP 103	21	Station Document Control	12/06/87
SP 104	11	Control of Non-conformances and Corrective Action	12/12/87
SP 105	29	Conduct of Maintenance	02/07/88
SP 105.3	4	Maintenance of Oyster Creek Environmental Qualified (EQ) Equipment	08/17/88
SP 106	50	Conduct of Operations	09/23/88
SP 107	33	Procedure Control	09/03/88
SP 107.1	5	Drawing Procedure Control	09/19/88
SP 107.2	2	Drawing Status Verification Procedure	09/04/88
SP 107.3	1	Use and Control of Technical Manuals	09/01/88
SP 108.3	5	Plant Equipment Deficiency Tags	02/11/88
SP 113	12	Conduct of Installed Instrument Surveillance Calibration and Maintenance	09/27/87
SP 114	5	Testing	03/19/87
SP 116	23	Surveillance Test Program	10/01/88
SP 119	7	Housekeeping	06/14/87
SP 119.1	7	Fire Protection Inspection	05/22/85
SP 120.5	2	Control of Combustibles	01/21/88

Document No.	Rev.	Title	Date
SP 124	9	Plant Modification Control	11/10/88
SP 124.2	0	Control of Plant Engineering Directed Replacements and Modifications	04/30/88
SP 124.3		Work Control and Record Closeout Process for Specific 12R Outage Work	10/16/88
SP 125	7	Conduct of Plant Engineering	02/22/88
ES 011	12	Quality Classification List	03/07/88
ES 012	7	Format and Content of Engineering Data Base	11/21/88
ES 017	10	Identification of GPUN Power Plant Systems	03/07/88
IST 607.4.003	20	Containment Spray and Emergency Service Water Pump Operability and Inservice Test	11/16/88
IST 610.4.003	14	Core Spray Valve Operability and Inservice Test	10/23/88
IST 678.4.001	3	Primary Containment Isolation Valve Operability and IST	04/01/88
TP 200/0.1	0	Test Procedure - Control Room Habitability Differential Pressure and Airflow Measurements	03/31/88
TP 254/11	0	Control Room HVAC Functional Test	11/21/88

APPENDIX C

ABBREVIATIONS

BA	budget activity
CIP	continuous instrument panel
CFR	Code of Federal Regulations
CPM	containment particulate monitor
CR	control room
CRD	control rod drive
DVR	deviation report
EDG	emergency diesel generator
ESF	engineered safety features
FCN	field change notice
FCR	field change request
GSS	Group Shift Supervisor
GMS-2	Generation Maintenance System 2
GPUN	GPU Nuclear Corporation
HVAC	heating, ventilation and cooling
I&C	instrumentation and control
IE	Office of Inspection and Enforcement, NRC
INPO	Institute of Nuclear Power Operation
ISI	inservice inspection
IST	inservice testing
MCC	motor control center
MCF	Maintenance, Construction and Facilities Department, GPUN
MNCR	material nonconformance report
MOVATS	Motor Operated Valve Analysis and Test Systems
NRC	Nuclear Regulatory Commission
NSR	nuclear safety related
PMT	post-maintenance testing
QA	quality assurance
QC	quality control
RBCCW	reactor building closed cooling water
RPS	reactor protection system
SOER	significant operating experience report, INPO
SP	station procedure
SSOMI	safety systems outage modifications inspection

TF	Technical Functions Department, GPUN
TP	test procedure
TS	technical specifications
USAR	updated safety analysis report
VACP	vital a.c. panel
WG	water gauge
WR	work request

APPENDIX D

VALVE STROKE TIME ACCEPTANCE CRITERIA

VALVE NUMBER	USAR VALUE (1) (seconds)	IST VALUE (1) (seconds)	TEST DATA (2) (seconds)
Containment Spray System			
V-2-5	30	90	69.0
V-2-11	30	90	68.4
V-2-13	30	60	n/a
V-2-17	30	60	n/a
Core Spray System			
V-2-21	20	22	19.8
V-2-41	20	22	19.5
V-2-15	20	22	21.7
V-2-40	20	22	21.2
V-2-4	30	(note 3)	
V-2-33	30	60	n/a
V-2-3	30	60	n/a
Containment Isolation System			
V-2-13	8.4	60	n/a
V-2-14	9.0	60	n/a
V-2-15	3.5	60	n/a
V-2-16	12	60	n/a
V-2-1	1.5	60	n/a
V-2-2	1.0	60	n/a
V-2-3	2.2	60	n/a
V-2-4	2.0	60	n/a
V-2-17	24.7	60	n/a

Notes:

(1) All values for the updated safety analysis report (USAR) and the in-service test (IST) program are less than or equal to the limits listed.

(2) Values listed as not available (n/a) were not immediately available during the inspection.

(3) The IST program did not list a stroke time for core spray valve V-2-4.