U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-341/90013(DRP)

Docket No. 50-341 Operating License No. NPF-43

Licensee: Detroit Edison Company
2000 Second Avenue
Detroit, MI 48226

Facility Name: Fermi 2

Inspection At: Fermi Site, Newport, MI

Inspection Conducted: August 20 through October 19, 1990

Inspectors: W. G. Rogers
S. Stasek
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Contributors: R. DuBord
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Approved By: R. W. DeFayette, Chief NOV 19 [illegible]

Inspection Summary

Inspection on August 20 to October 19, 1990 (Report No. 50-341/90013(DRP))
Areas Inspected: Action on previous inspection findings; operational safety; ESF system walkdown; maintenance; surveillance; followup of events; reactor scram followup; Licensee Event Report (LER) followup; review of conditions adverse to quality; Information Notice followup; drawing control report review; and followup of TMI items.
Results: Onshift operations personnel continued to properly adhere to the administrative controls associated with Limiting Condition of Operation (LCO) tracking but failed to implement the administrative controls in other areas such as tagging and logkeeping. A significant weakness was observed in operating crew performance dealing with a lack of cognizance of plant conditions resulting in weak performance during normal and abnormal situations. Improvements were noted in the ability to manage and control the scope of short duration planned outages. However, this ability may not translate to refueling outages without changes in the work control process. Activities associated with work on the refuel floor reflected the need for additional efforts in controlling contractor maintenance activities. The scheduled surveillance program continued to be properly implemented with no surveillances missed. However, management command and control was lacking in the control of the overlap drawings used to assure complete testing of safety related circuits. The licensee continued to exhibit the ability to identify problems and significantly improved the methodology for post scram evaluations. However,

the licensee continued to exhibit the inability to effect timely, comprehensive resolution of identified problems as reflected in the high radiation door control weaknesses and two ESF actuations. Management initiatives were apparent in the medical response area but weaknesses were still evident in medical drill performance. The drawing control system was properly implemented with minor weaknesses. Weaknesses were noted in the Radiation Protection Department's communication to management and the program directives associated with the control of high radiation doors. Two SIMs items were closed: II.K.3.18 and I.C.6. Three violations were identified, two non-cited (paragraphs 2.m and 10.c) and one cited (three examples, Paragraphs 3e, g, and j). One unresolved item was identified (paragaph 7), and six open items were identified (Paragraphs 3.b, 5.b, 9.b, and 12).

DETAILS

1. Persons Contacted

a. Detroit Edison Company

* R. Anderson, Superintendent, Radiation Protection
P. Anthony, Licensing
* T. Bradish, Supervisor, Production Quality Assurance (PQA)
S. Catola, Vice President, Nuclear Engineering and Services
* J. Clark, Nuclear Shift Supervisor
G. Cranston, General Director, Nuclear Engineering
* R. DeLong, General Supervisor, Radiation Protection
* P. Fessler, Superintendent, Technical Engineering
* D. Gipson, Assistant Vice President, Nuclear Production
* L. Goodman, Director of Licensing
M. Hall, Nuclear Shift Supervisor
* J. Hughes, General Supervisor, Electrical Maintenance
A. Kowalczuk, Superintendent, Maintenance
R. May, Director, Nuclear Materials Management
R. McKeon, Plant Manager
W. Miller, Quality Assurance Manager
J. Mulvehill, Supervisor, Radiological Emergency Preparedness
G. Ohlemacher, Principal Engineer, Licensing
W. Orser, Senior Vice President
J. Pendergast, Compliance Engineer
P. Piggott, Emergency Preparedness Specialist
* J. Plona, Operations Superintendent
G. Reece, Operations Training Supervisor
* T. Riley, Compliance Supervisor
* A. Settles, Director, Plant Safety
R. Stafford, Nuclear Assurance Director
* D. Stone, Nuclear Shift Supervisor
F. Svetkovich, Operations Support Engineer
W. Tucker, Assistant to the Vice President
A. Waite, Nurse
J. Walker, General Supervisor, Plant Engineering
D. Wells, Plant Safety

b. U.S. Nuclear Regulatory Commission

* W. Rogers, Senior Resident Inspector
* S. Stasek, Resident Inspector
G. O'Dwyer, Resident Inspector, Perry Nuclear Power Station

*Denotes those attending the exit meeting on October 19, 1990.

The inspectors also interviewed others of the licensee's staff during this inspection.

2. Action on Previous Inspection Findings (92701)

a. (Open) Open Item (341/88014-02(DRP)): Actions to keep NIAS design basis reconciliation documents current and consistent. The Stone and Webster (S&W) Analysis (letter SWEF-T-310) did not reflect, at the time, the current tabulation of noninterruptible air subsystem (NIAS) users. However, Design Calculation (DC) 4931 was issued by the licensee engineering staff on April 26, 1988 and listed the NIAS users. DC 4931 also addressed the adequacy of: 1) the air receivers to provide sufficient air until the control compressors auto-started; and 2) the air receivers with the cross-tie open and a single compressor operable.

As-Built Notice (ABN) 9031-1, Revision 0, updated the NIAS Air Users List (Drawing No. 6I721-2453-10) and other relevant Base Configuration Design Documents (BCDD), i.e., Piping and Instrumentation Drawings (P&ID), Functional Operating Sketches (FOS), and the Central Equipment Computer Outline (CECO), etc.

Updated Final Safety Analysis Report (UFSAR) Section 9.3.1.2 was updated to state the systems that required NIAS.

Deviation Event Report (DER) 88-1053 stated that the root cause of the design documents not being current was that at the time of the creation of the open item no formal design change verification process existed. In 1978 when the S&W analysis was submitted, the documents were reviewed to ensure the changes did not impact negatively on the quality or serviceability of the documents, but there was no procedural requirement to formally document this review. Since that time, there have been improvements in the design change verification process. DER 88-1053 stated that the corrective actions to prevent recurrence were now contained in the applicable procedures: (1) Fermi Interfacing Procedure (FIP)-CMI-12, "Engineering Design Packages;" (2) FIP-CMI-14, "As-Built Notices;" (3) FIP-CMI-13, "Design Verifications;" (4) FIP-CMI-11, "Design Calculations;" (5) FIP-DCI-03, "Vendor Design Documents;" and (6) FIP-RA2-01, "Licenses, Plans and Programs." DER 88-1053 further stated, in its conclusion, that the above mentioned procedures and the Technical Specification and Safety Evaluation training should ensure this problem is eliminated in the future.

The licensee committed, in DER 88-1053, to revise Design Specification 3071-520 to reflect the UFSAR and engineering's position on the use of the cross-ties by August 30, 1988. However, this had not been done as of September 5, 1990.

This item will remain open until Design Specification 3071-520 is revised as committed to in DER 88-1053.

b. (Open) Open Item (341/90011-01(DRP)): Licensee initiatives to improve the reliability of the reactor building airlock door. Presently, the licensee's Technical Group considers hinge binding to be the major contributor to door failure. The hinges are to be replaced and the door rehung under Work Request 002D900818.

However, prior to completing the required maintenance due to the unavailability of parts, the door failed in the last week of the inspection period. Therefore, access through the second floor airlock door has been lost until the work maintenance is completed.

Another problem associated with the door is its interlock. Presently, other facilities are being surveyed to determine the appropriate corrective actions to take. This review is scheduled to be completed by November 30, 1990. Following these corrective actions, door performance will be monitored to determine if further corrective action is warranted.

c. (Open) Open Item (341/89008-16(DRP)): Licensee actions to improve safety relief valve (SRV) performance. Industry experience with valve seats consisting of PMO-13 material indicated that those seats would not provide appropriate problem resolution. The licensee will return to stellite seats during Refuel Outage 2 (RF02) replacement activities. The best hypothesis for valve sticking is the accumulation of non-condensable gases in the valve internals. This provides an oxygen rich environment for corrosion between the pilot and the seat. Testing at another utility is being performed to confirm the hypothesis. Projected corrective action will be to install a catalyst inside the valve. However, the earliest the corrective action could be implemented is RF03.

d. (Open) Unresolved Item (341/88037-12(DRP)): As-built drawing discrepancies. The inspector reviewed the contractor report and concluded that a final decision on this unresolved item could not be made until the licensee completed the manual to Intergraph Design System (IGDS) drawing review.
Therefore, this matter will remain outstanding pending the results of licensee review of 13 P&ID drawings and any subsequent corrective actions.

e. (Closed) Open Item (341/89018-01(DRP)): Drawing control task force. This item is closed based on the establishment of a configuration control group and procedure improvements to ensure that control room drawings will be updated during the work package closure process in the future.

f. (Open) Open Item (341/89200-01(SSOMI)): As-built drawing discrepancies. The inspector reviewed the contractor report and concluded that this matter can be closed when the licensee completes the drywell and Residual Heat Removal complex reviews, including the stress limit determinations.

g. (Closed) Open Item (341/89200-06(SSOMI)): Seismic capability of emergency diesel generator service water piping. The discrepancy between the calculations and the field condition for the specified seismic supports were reconciled by the licensee.

h. (Open) Open Item (341/90011-05(DRP)): Medical drill improvements. On August 23, 1990, the inspector witnessed a licensee initiated medical drill in conjunction with an emergency

preparedness drill. For the first time, medical response was provided without nursing staff participation. This is considered a positive action to improve first-aid response, since the nursing staff is normally present during the day shift only. The drill scenario was adequately challenging with an adequate number of controllers present.

The scenario involved one injured individual (victim of a fall) at the reactor water cleanup [illegible] station in the reactor building. Adequate medical attention was provided. However, some weaknesses were noted specifically:

- Lack of communication with the rest of the organization. As a result, due to increasing radiation levels (based on the drill scenario), the need to remove the individual from the reactor building was not conveyed.

- Turnover of information did not address the interim radiation protection information that was needed during the medical cognizance turnover that took place once outside the reactor building. Written information on the amount and location of contamination levels was not provided during the turnovers. However, had this been a turnover to the ambulance personnel, this information would have been required. Once the individual was taken to the decontamination facility, the controller had to reiterate the contamination information to the decontamination person.

- There was no clearly defined flow path for contaminated personnel through the decontamination facility.

The inspector will continue to follow licensee actions to improve performance during medical drills.

i. (Open) Open Item (341/88003-02(DRP)): Inservice test (IST) requirements for the RHR service water discharge valve. The inspector reviewed the IST program description and noted that the program had not been revised to show valve opening as an IST requirement. In the last update of this open item (Inspection Report 50-341/90005), the licensee had indicated that this matter would be resolved by May 13, 1990. The inspector also noted that a recent Quality Assurance audit report identified that changes to the Inservice Inspection and IST programs were not reviewed in a timely manner. Nuclear Licensing is to respond to this issue by November 20, 1990.

j. (Open) Open Item (341/89008-11(DRP)): Licensee initiatives to prevent a turbine trip from a single failure. The completed licensee review identified one design change to be implemented. The design change, EDP 10868, will add a dual thrust monitor for the main turbine thrust bearing wear trip. This design change is targeted for implementation during RF02.

k. (Closed) Open Item (341/81010-23(DRP)): Modification of automatic depressurization system logic. The licensee implemented a design change, EDP 1022, during RF01. The inspector verified that this modification met the intent of TMI item II.K.3.18 and was implemented.

l. (Open) Open Item (341/90002-05(DRP)): Refueling outage corrective actions. Following RF01, the licensee critiqued its performance of RF01. Three general areas were identified: Pre-outage preparation, outage performance and post outage activities. One weakness, identified in the outage performance area, was package tracking and closure. The inspector evaluated this problem during the current planned outage and noted little change in this process since RF01. During discussions with the operating authority, the inspector ascertained that there are initiatives underway to improve this area prior to RF02. The inspector will continue to review this area.

m. (Closed) Unresolved Item (341/90011-02(DRP)): Inadequacies identified with tagout of the HPCI system. The licensee has subsequently completed a formal operations critique (No. 90-013) on this matter which substantially confirmed the inspector's observations. The corrective actions outlined in the critique included revising administrative procedure NPP-OP1-12, "Tagging and Protective Barriers," reemphasis to the operators of the requirement to adhere to the administrative controls in this area, and the inclusion of the critique itself into required operator reading.

Since Red Tag Record (RTR) 90-803 and Equipment Tag Record (ETR) E90-804 were not prepared in accordance with administrative procedure NPP-OP1-12, "Tagging and Protective Barriers," this is considered a violation (341/90013-01a(DRP)). However, after reviewing this matter, and evaluating the overall safety significance as well as the licensee's corrective actions, the inspector determined that the criteria specified in 10 CFR 2, Appendix C, Section V.A were satisfied and, therefore, no notice of violation will be issued.

3. Operational Safety Verification (71707)

The inspectors observed control room operations, reviewed applicable logs and conducted discussions with control room operators during the period from August 20 to October 19, 1990. The inspectors verified the operability of selected emergency systems, reviewed tagout records and verified proper return to service of affected components. Tours of the reactor building and turbine building were conducted to observe plant equipment conditions, including potential fire hazards, fluid leaks, and excessive vibrations and to verify that maintenance requests had been initiated for equipment in need of maintenance.

The inspectors, by observation and direct interview, verified that the physical security plan was being implemented in accordance with the station security plan.

The inspectors observed plant housekeeping/cleanliness conditions and verified implementation of radiation protection controls. During the inspection, the inspectors walked down the accessible portions of the following systems to verify operability by comparing system lineup with plant drawings, as-built configuration or present valve lineup lists; observing equipment conditions that could degrade performance; and verified that instrumentation was properly valved, functioning, and calibrated.

- Noninterruptible Air Supply (NIAS) System - Divisions I and II
- High Pressure Coolant Injection (HPCI) System
- Control Rod Drive Hydraulic Control Units - North Bank

The inspectors also witnessed portions of the radioactive waste system controls associated with radwaste shipments and barreling.

These reviews and observations were conducted to verify that facility operations were in conformance with the requirements established under technical specifications, 10 CFR, and administrative procedures.

Significant observations and reviews included the following:

a. During a battery room tour, portable eyewash stations were observed unrestrained in both Class 1E rooms. This situation was identified to on-shift management and the stations were adequately restrained.

b. During walkdowns in the reactor and auxiliary buildings, the inspector noted numerous examples of candy wrappers and gum wrappers as well as gum and cigarette butts within the radiological control area (RCA). Most of these were located in areas not normally traversed by plant personnel. Instances included cigarette butts under the Division II Standby Gas Treatment System Housing near the inlet side, and old gum and miscellaneous wrappers found in hollow support stanchions throughout the RCA. The inspectors could not determine when the materials were left; however, some appeared to be from initial construction. When informed of the inspector's observations, the licensee initiated actions to prepare an action plan to programmatically inspect all areas within the RCA and clean any areas in need. At the end of the inspection period, cleanup within the RCA was nearly complete with final management inspection to follow. Once this is accomplished, the licensee intends to perform routine followup inspections to assure that an ongoing problem does not exist. In addition, another in-depth walkdown is scheduled to be done by the licensee prior to the next refuel outage.

c. The inspector reviewed adherence to administrative controls relative to the limiting condition for operation (LCO) tracking for diesel fire pump inoperability and emergency equipment cooling water division I inoperability with no problems observed. The inspector did note that the present Technical Specification (TS) submittal on EECW was used as technical justification for not cascading the TS which would result in declaring ECCS inoperable. This information will be provided to NRC Region III management for further evaluation.

d. On September 19, the inspector conducted a walkdown of control room panel interiors. During the walkdown, it was noted that backcovers for containment temperature recorders T50-R808A and B were not installed but rather were lying loose on the floor inside the panels against terminal boxes. The cause of the covers being removed could not be determined. When this was brought to the attention of the operators, actions were initiated to reinstall them.

e. On October 2, the inspector observed control indication for jet pump no. 5 fail downscale. He informed the control room NSO who initiated a work request to troubleshoot and repair the indicating circuit. The following day the inspector observed that the indication had returned to normal.

f. The inspector had serious concerns about operator lack of awareness of equipment status as indicated in the following cases. Although none of these examples by themselves had significant safety repercussions, they and the items addressed in paragraph "g" following may be indicative of a lack of attention to details by the operators and a relaxing of their vigilance.

1) On October 1, during a routine control room walkdown with the reactor in cold shutdown for a scheduled maintenance outage, the inspector noted dual indication of disc position for feedwater check valves B21-F076A and B21-F032A as well as no lit indication of disc position for feedwater check valve B21-F010A. Alternatively, the three check valves in the other feedwater line all indicated closed, which appeared to be the proper position considering plant conditions. B21-F010A(B) and B21-F076A(B) are classified as containment isolation valves and are listed as such in Technical Specification Table 3.6.3-1. When control room operators were questioned as to the reason for the apparent discrepancies, no explanation could be provided. Subsequently, the check valves were stroke tested and afterwards, indication for the three subject valves returned to normal (full closed). The cause of the indication discrepancy appeared to be a direct result of the evolution that closed the valves. Apparently, the previous evening, feedwater flow was very slowly reduced to the reactor which in turn slowly closed the feedwater check valves. The discs closed so slowly the associated limit switches for position indication did not fully engage. Although the inspector had no further concerns dealing with equipment operability, a concern remained outstanding with operator cognizance of control room panel status in that at least one shift turnover occurred with the questionable valve position indications in existence and the apparent discrepant configuration was not identified. Operations management counselled the involved operators on the matter and reinforced the need for all operators to retain a high level of cognizance over their control room panels.

2) On August 24, during a routine control room walkdown, the inspector noted that the Division I reactor building differential pressure (DP) recorder was indicating a DP nearly

double the Division II recorder (-0.4 inches water column versus -0.2 inches water column). When questioned, the CRNSO indicated that he was unaware of the problem (although the condition had existed for some time), and that it would be addressed. Upon return to the control room later that day, the inspector observed that a Control Room Indicating System (CRIS) dot was placed by the Division I recorder and a work request (WR 002D900824) had been initiated for troubleshooting.

3) While performing a routine control room walkdown on October 11, the inspector noted that the High Pressure Coolant Injection (HPCI) system (which was shut down in a standby condition) was aligned to take a suction from the suppression pool rather than the Condensate Storage Tank (CST). With HPCI in standby, the system should have been aligned per System Operating Procedure (SOP) 23.202, "High Pressure Coolant Injection System," in which valve lineup sheets specified E41-F004, "CST to HPCI Pump Supply Valve" as open, and E41-F041, "Suppression Pool Outboard Isolation Valve" and E41-F042, "Suppression Pool Inboard Isolation Valve" as closed. Questioning of onshift operations personnel and subsequent review of the alarm printer revealed that apparently E41-F004 had closed and that E41-F041 and E41-F042 had opened the previous day (October 10) at approximately 12:43 pm. This occurred during performance of surveillance 24.408.01, "Primary Containment Monitoring System (PCMS) Valve Operability and Position Indication Verification Test." This conclusion was based on the fact that control room annunciator 2D69, "Suppression Chamber Level High," was received at that specified time and that the automatic transfer from CST to suppression chamber occurs at that same level. When the annunciator was received, the licensed operator performing the surveillance announced that he had caused the alarm and that it was an expected consequence of closing PCMS valve E41-F400. The control room nuclear supervising operator (CRNSO) then acknowledged the annunciator and verified that suppression chamber water level was normal. Meantime, the NSO doing the surveillance reopened E41-F400 and the annunciator cleared. Alarm response procedure (ARP) 2D69 was not consulted. As a result, the transfer of pump suction was not identified at the time it occurred.

Subsequently, the ESF Status Checklist, which is a documented verification of select ESF items that the control room NSOs perform once per shift (and required by administrative procedure NPP-OP1-05, "Shift Turnover") was completed inappropriately on three consecutive occasions in that E41-F004 was checked as being in its required position (open) although, in reality, it was apparently closed.

In addition, three shift turnovers occurred after the mispositioning without identification of the problem. Each shift turnover consisted of four licensed individuals: A Nuclear Shift Supervisor (NSS), a Nuclear Assistant Shift Supervisor (NASS), a CRNSO, and a P603 panel operator. Also,

three shift turnovers were conducted by Shift Technical Advisors (STA) during the period before discovery of the mispositioned valves by the inspector. Each of the above individuals were required to walk down control room panels and assure they had an adequate understanding of plant status before assuming the shift.

The safety significance of mispositioning these particular valves was minimal. This was based on the fact that Technical Specifications do not address the CST as a requirement for HPCI operability, nor does the FSAR include CST availability for HPCI response to any of those accidents analyzed. However, operator cognizance of safety system status in this case was inadequate. At the close of the inspection period, it was unclear as to the reason for the inadequacy. The licensee is investigating this and also is developing a course of action to prevent recurrence. The results of the investigation will be evaluated by the NRC

Since subsequent actions to return the valves to a normal lineup were not taken in accordance with ARP 2D69 and administrative procedure NPP-OP1-05, "Shift Turnover" was improperly implemented, this is considered a violation of 10 CFR 50 Appendix B Criterion V, "Instructions, Procedures, and Drawings" (341/90013-03(DRP)).

g. In addition to the issues discussed above, the operators demonstrated a less than satisfactory performance relative to administrative procedures. Examples are:

1) On October 9, the inspector observed a reactor heatup per General Operating Procedure (GOP) 22.000.02, "Plant Startup to 25 Percent Power." During the heatup, the inspector observed a number of manual control rod movements. All were performed in accordance with approved procedures. However, during the day shift, operators experienced difficulty in withdrawing two control rods from position 00 (Full In) to position 02. The abnormal operating procedure was appropriately entered, drive water pressure was increased slightly, and the rod in both cases was then able to be withdrawn. Upon reviewing the CRNSO log at the end of the shift, the inspector found that no entries had been made concerning the control rod problems encountered. This was inconsistent with administrative procedure NPP-OP1-02, "Logkeeping" where in step 6.1.3.1.k.6, rods requiring an increase in drive flow to move are required to be logged as such. The matter was communicated to operations management who then counselled the individuals involved on logkeeping expectations in this area.

This matter is similar in cause to the non-cited violation discussed in paragraph 2.m of this report, and is therefore, considered a second example of the same violation. (341/90013-01b(DRP))

2) On September 28, the inspector noted that control room indication for HPCI drain pot drain valve E41-F029, although indicating closed, had a magnetic placard placed on it indicating the valve was really open (as required). When control room operators were questioned on the reason for the placard they responded that during a September 26 surveillance test of the HPCI system, E41-F029 operated correctly but the subject position indication discrepancy was identified. The inspector then indicated that a CRIS dot should have also been placed per administrative procedure NPP-OP1-11, "System and Equipment Status" to provide the necessary information to the operators. The control room staff agreed and shortly thereafter, a CRIS dot was placed and the CRIS log updated.

3) On October 5, the inspector noted a discrepancy in tagging documentation associated with troubleshooting of the Standby Liquid Control/Reactor Water Cleanup Systems. During the week of October 1, 1990 an equipment tag per equipment tagout E90-1092 was hung for the removal of fuse A71B-A18 to facilitate troubleshooting efforts in the SLC/RWCU circuit as a followup to the unplanned ESF actuation of July 16, 1990. At 0600 hours on October 5, 1990 an additional red tag per tagout 90-1110 was hung on the removed fuse. This tagout was to allow replacement of two standby liquid control relays inputting into the RWCU isolation circuitry. At 0630 hours, maintenance personnel signed-on to perform the relay changeout. Later that day the inspector observed the tagout record and noted that the independent verification for the fuse tag was not signed. This was identified to the operating authority who confirmed that the fuse was removed and the tag in place.

In summary, none of the issues identified in paragraphs "f" and "g" of this section by themselves are safety significant. In combination, however, they are indicative that the licensed operators demonstrated less than adequate attention to their duties.

Two violations were identified in this area.

4. ESF Walkdown (71710)

a. During the inspection period, in addition to the system walkdowns performed and discussed in paragraph 3, the inspectors performed a more in-depth walkdown of the accessible portions of the automatic depressurization system to verify operability. The FSAR, plant drawings, system operating procedures and surveillance procedures were reviewed to confirm consistency to the as-built configuration. System components were inspected for proper installation, position, energization, and labelling.

During the procedure review the inspector determined that the drawings used for assuring proper overlap between functional and calibration testing were not being maintained rigorously or in a completely formal manner. In response the licensee:

- Began overlap reverification of the current surveillance procedures to the ones used during the Technical Specification Improvement Program with an expected completion in early November, 1990.

- Created new overlap drawings which conform to the administrative procedure for maintaining surveillance procedures, NPP-CT1-04.

- Revised NPP-CT1-04 to strengthen mandatory maintenance of the overlap drawings with a maintenance technician in charge of procedures designated to maintain control of the overlap drawings.

Also, a discrepancy was noted with Figure 7.3-3 of the FSAR which the licensee committed to correct via a licensing change request.

b. A review of the seismic monitoring system (SMS) was completed during the inspection period by a NRC individual. Those findings which would be of direct interest to the licensee are provided in Attachment 1.

5. Monthly Maintenance Observation (62703)

Station maintenance activities on safety related systems and components listed below were observed to ascertain that they were conducted in accordance with approved procedures, regulatory guides and industry codes or standards and in conformance with technical specifications.

The following items were considered during this review: the limiting conditions for operation were met while components or systems were removed from service; approvals were obtained prior to initiating the work; activities were accomplished using approved procedures and were inspected as applicable; functional testing and/or calibrations were performed prior to returning components or systems to service; quality control records were maintained; activities were accomplished by qualified personnel; parts and materials used were properly certified; radiological controls were implemented; and fire prevention controls were implemented.

Work requests were reviewed to determine the status of outstanding jobs and to assure that priority was assigned to safety related equipment maintenance which may affect system performance.

The following maintenance activities were observed and/or reviewed:

WR J05D900905 Troubleshooting of HPCI isolation and replacement of relays E41K202B and E41K203B.

WR C10D900907 Installation of a capacitor in the HPCI steam flow circuit to attenuate process signal noise under EDP 11819.

WR 003D900820 Process, Package, and Dispose of Control Rod Blades and Other Materials from Spent Fuel Pool.

WR 009D900907 Troubleshooting of diesel fire pump start failure and replacement of the fuel shutoff valve.

WR 001D900907 Division 2 hydrogen/oxygen monitor oxygen sensor replacement.

WR 021D900910 Division 1 hydrogen/oxygen monitor sample pump replacement.

Following completion of maintenance on HPCI, the inspectors verified that the system had been returned to service properly.

a. Regarding WR 008D900820, the following was noted:

The work request did not specify the contractor procedures to be used to accomplish the control rod blade/local power range monitor (LPRM) cutting/disposal and startup source disposal from the fifth floor of the reactor building. The contractors were observed to be performing steps prior to signing off the previous step. The tool control boundary was not clearly identified. Operations management control of fifth floor work was weak. Following these observations plant management clearly enumerated to all fifth floor personnel that procedures would be adhered to and signatures kept current; an additional set of procedures were brought to the fifth floor, the work request instructions were modified to include the appropriate references; operating crew members and fifth floor personnel were sensitized to the need for good communications; and appropriate tool control boundaries were established. Following these corrective actions no other problems of this nature were identified.

During LPRM cutting, a four foot section of the string fell to the bottom of the spent fuel pool and could not be located. A DER, 90-0517, was written on this situation. The inspector contacted the group responsible for the DER and determined that additional efforts would be made to locate and retrieve the section at a later date.

Following shipment of the startup sources to Barnwell, South Carolina, unanticipated neutron doses were identified when reading the Thermoluminescent dosimeters associated with personnel involved in the shipment. Further licensee review identified that the neutron dose for the startup sources had been significantly underestimated. This matter will receive an in-depth review by regional radiation protection inspectors (reference Inspection Report 50-341/90016(DRSS)).

Upon receipt of the tools used in the control blade cutting operation at the contractor's storage facility, the initial radiation survey identified a higher than anticipated radiation level. The tools were in a box and the bottom of the box slightly exceeded the dose limit of 200 mr/hr. This matter will also be reviewed in-depth by regional radiation protection inspectors.

b. Regarding WR 021D900910 and WR 001D900907, the following was noted:

On September 6, 1990, during surveillance testing, the division II oxygen sensor for containment atmosphere monitoring failed, placing operators into a seven day reactor shutdown action statement. Three problems were encountered in returning the division to service. These were: 1) A cracked environmentally qualified seal, 2) Lack of easily retrievable spare parts (an O-ring, heat shrink tubing), and 3) Use of the wrong calibration gas causing failure of the first post-maintenance test. Deviation Event Reports were written for all three areas (DERs 90-518, 519 and 528).

Approximately 24 hours prior to returning division II to service the division I hydrogen/oxygen sensor sample pump tripped repeatedly rendering that division inoperable. This placed the plant into a two day reactor shutdown action statement.

Sensor replacement on division II allowed that division to be declared operable and alleviated the two day shutdown action statement. However, the seven day action statement was still in effect. Division I was returned to service after replacement of the sample pump approximately eleven hours prior to expiration of the seven day action statement. A DER was written to determine the reason for the sample pump tripping.

The inspector will follow disposition of the four DERs associated with the hydrogen/oxygen monitors to ascertain whether effective corrective actions were taken. This is considered an open item (341/90013-03(DRP)).

No violations or deviations were identified in this area.

6. Monthly Surveillance Observation (61726)

The inspectors observed surveillance testing required by Technical Specifications and verified that: testing was performed in accordance with adequate procedures, test instrumentation was calibrated, limiting conditions for operation were met, removal and restoration of the affected components were accomplished, test results conformed with technical specifications and procedure requirements and were reviewed by personnel other than the individual directing the test, and any deficiencies identified during the testing were properly reviewed and resolved by appropriate management personnel.

The inspectors witnessed the following test activities:

- 24.307.17 Emergency Diesel Generator No. 14 - Start and Load Test
- 24.608 Rod Worth Minimizer (RWM) Functional Test
- 24.609 Rod Sequence Control System Functional Test
- 44.010.025 RPS and NSSSS Main Steamline Radiation, Division I, Channel A1/A2 Functional Test

Regarding 24.608, the surveillance was performed as a requirement of the normal plant shutdown condition and was to be completed within one hour of reactor power decreasing below the low power setpoint (LPSP). In attendance was the P603 operator (RO licensed), a reactor engineer, the STA and the system engineer. The inspector noted that coordination of

effort to perform the test was weak and that operator familiarity appeared lacking on the anticipated response. With respect to the coordination, the surveillance was delayed while an appropriate control rod could be selected as the subject rod for the surveillance. With respect to the operator's familiarity, when the RWM response deviated from the expected response, he was uncertain as to whether the RWM was indeed inoperable or whether the particular rod selected for testing was inappropriate. Finally, the system engineer pointed out that the window that should indicate the rod giving the withdraw error was not illuminated, and therefore, the RWM was inoperable.

The inspectors performed a record review of completed surveillance tests. The review was to determine that the test was accomplished within the required technical specification time interval, procedural steps were properly initiated, the procedure acceptance criteria were met, independent verifications were accomplished by people other than those performing the test, and the tests were signed in and out of the control room surveillance log book. The surveillance tests reviewed were:

24.000.02	Attachment 1; Shiftly, Daily, and Weekly Required Surveillances
24.000.05	(Section 5.5.2 Only); Monthly Continuity Light and Channel Check
24.000.18	Attachment 2 & 7; Chemistry, Shiftly, 72 Hour and Situation Surveillances
24.139.03	SLC Manual Initiation, RWCU Isolation, and Storage Tank Heater Operability Test
24.204.01	(Valve E1150F047A Only); Div. 1 LPCI and Suppression Pool Cooling/Spray Pump and Operability Test
24.205.10	Div. II RHR Cooling Tower Fan Operability and RHRSW, EESW Valve Line-Up Verification
24.425.02	Containment Air Lock Operability Test
27.112.03	Turbine Generator Mechanical Overspeed on Load Test
27.112.04	Turbine Generator Valves Low Vac on Load Test
27.129.01	Control Air Compressor Auto Start Test
42.302.01	Functional Test of 4160 Volt Emergency Bus Division I Undervoltage Circuits
42.610.01	Electrical Protection Assembly Functional Test
44.020.157	(Instruments G33-N427 & 428 Only); NSSSS-RWCU Area, Area Ventilation Differential and NRHX Temperature, Division II Functional Test
44.080.401	Division 1 Functional Test
44.110.20	Alternative Shutdown System Condensate Storage Tank Level Channel Calibration
54.000.07	Core Performance Parameter Check
74.000.19	Attachment 7; Chemistry Routine and Surveillance

With regards to surveillance 24.205.10, the inability to verify that temperature control valve (TCV) P44-F400B was in automatic control was annotated on the surveillance performance form and in the body of the procedure. The shift supervisor authorized continuation of the

surveillance based on manual control capability. The inspector noted that the TCV verification step was also an acceptance criteria step for the procedure. Previous discussions with the operating authority indicated that discrepancies with acceptance criteria steps would be handled through the procedure change process, and the shift supervisor had not been given the authority to disposition these matters in this fashion. The matter was identified to the operating authority who indicated that the surveillance would be routed to operations personnel for reemphasis of management's expectations. The operability of the system under test was not affected by the TCV being in manual.

No violations or deviations were identified in this area.

7. Followup of Events (93702)

During the inspection period, the licensee experienced several events, some of which required prompt notification of the NRC pursuant to 10 CFR 50.72. The inspectors pursued the events onsite with licensee and/or other NRC officials. In each case, the inspectors verified that the notification was correct and timely, if appropriate, that the licensee was taking prompt and appropriate actions, that activities were conducted within regulatory requirements and that corrective actions would prevent future recurrence. The specific events are as follows:

- August 20, 1990 - Inoperable Emergency Notification System (ENS) phone.

- August 26, 1990 - HPCI inoperable. Declaration due to high vibration recorded during surveillance testing. Subsequent investigation by the licensee determined that the high vibration reading on the HPCI booster pump was due to inadequate monitoring of the vibration by the technician involved. Specifically, the individual placed the monitoring device on the wrong scale. Subsequent testing confirmed that a high vibration condition did not exist. The reportable event was withdrawn on August 30, 1990.

- August 29, 1990 - Unplanned ESF actuation when Control Complex Heating, Ventilation, Air Conditioning (CCHVAC) system transferred to the recirculation mode due to a blown fuse in the damper indication circuitry.

- September 5, 1990 - Unplanned ESF actuation when the HPCI system isolated on high steam differential pressure.

- October 2, 1990 - Unplanned ESF actuation causing loss of the operating RHR division due to an electrical protection assembly (EPA) breaker trip.

  Upon inspector review of the channel functional test used for the EPA breaker testing after the actuation, the inspector questioned the lack of tolerance criteria associated with the trip setpoint. This matter is considered unresolved (341/90013-04(DRP)) pending inspector review of the full scope of maintenance work and all the post maintenance testing associated with the breaker changeout.

- October 16, 1990 - Inoperable HPCI declaration due to failure of a HPCI steam line flow instrument.

No violations or deviations were identified in this area.

8. Reactor Scram Followup

On October 6, 1990, the licensee experienced a reactor scram on low reactor vessel water level. The unit was critical and in the heatup phase at approximately 30 psig at the time of the scram. Prior to the scram the licensee had experienced level transmitter deviations resulting in operators manually controlling on a higher than actual vessel level. All control rods inserted as expected and the post-scram crew response appeared satisfactory. However, onshift crew members did cycle the mode switch unnecessarily following the scram in an attempt to receive the one rod out permissive light (an additional confirmation of control rod insertion). The one rod permissive could not be obtained due to the same material condition deficiency associated with the RWM problem discussed in paragraph 6 of this report.

The licensee established a team to investigate the scram. Its methods were rigorous and complete including a Human Performance Evaluation System evaluation and a sequence of events determination. Subsequent corrective actions involved backfilling the reference legs which reduced the level disparity on the subsequent startup. The causal factors associated with this level deviation will be examined by the inspector during the review of the associated LER.

No violations or deviations were identified.

9. Licensee Event Report Followup (92700)

Through direct observations, discussions with licensee personnel, and review of records, the following event reports were reviewed to determine that reportability requirements were fulfilled, immediate corrective action was accomplished, and corrective action to prevent recurrence had been accomplished in accordance with technical specifications.

a. (Closed) LER 89038 and Revision 1, Reactor Scram When Fire Occurred in the Vicinity of the Main Turbine. The licensee revised the LER corrective actions to include procedure changes directing turbine oil system inspections and oil cleanup. The inspector verified that these procedures were in place and reviewed documentation that the damaged insulation was replaced

b. (Closed) LER 90003, Reactor Scram Following Closure of MSIVs Due to RPS MG-Set Relay Failure. On May 8, 1990, the licensee submitted LER 90-003 on the scram. The inspector reviewed the LER and noted the following discrepancies/omissions:

   - The first paragraph on page 3 indicated that operators entered into the EOPs due to SRV actuation at 0209, whereas, the EOPs were entered into at 0202 with the closure of the MSIVs.

- The corrective actions section on page 5 stated that the leakage on indexer B was repaired during the forced outage following the scram. This is incorrect. Work request 004D900419 was initiated on April 17, 1990, to repair the indexer. The work request is coded for cold shutdown and has yet to be performed.

- The LER did not discuss the failure to vent the Reactor Core Isolation Cooling (RCIC) discharge line to the CST or the undersized motor associated with valve E41-F011. Upon reading the LER, one concludes that the reason for E41-F011 failure was exclusively an equipment failure and had nothing to do with system design or operator training.

- The additional training that was provided to all operating shifts, was not discussed in the corrective action section of the LER. Coupled with that, no mention was made of the fact that when operators reset the scram the first two times it was not in accordance with previous training. Exclusive use of SRV A was inconsistent with operator training and the operators entered the EOP on a wrong entry condition.

- There was no discussion of the 62,000 gallon spill in the turbine building.

- In the cause of event section, the LER stated "The amount of leakage through the traversing incore probe (TIP) indexer boxes had not been quantified previously and there is no acceptance criteria for leakage established for this system." The corrective actions section did not discuss the controls used to assure that the nitrogen leakage was consistent with the simulator leakage nor the required operator training for an event of this nature.

These observations were discussed with the licensee and revision 1 to the LER was submitted on August 22, 1990. All but the future leakage control measures/simulator-operator training assumptions were addressed. This matter will be pursued with the licensee as an open item (341/90013-05(DRP)).

c. (Closed) LER 90003 Revision 1, Reactor Scram Following Closure of MSIVs Due to RPS MG-Set Relay Failure. The inspector previously confirmed a number of the corrective actions, including the MG-set relay replacement procedure changes, requirements to check the heater rooms following transients; E41F011 motor replacement; operations personnel training as a result of this scram; and modifications to the TIP system to reduce leakage.

Outstanding licensee actions include:

- Replacement of similar relays (CR120As) in safety related applications by the end of the RF02 and establishing a periodic replacement program for these type of relays. This is considered an open item (341/90013-06(DRP)).

- Evaluation of the scram discharge vent design. This is considered an open item (341/90013-07(DRP)).

- Evaluation of design modifications to enhance the use of HPCI and RCIC for reactor pressure control. This is considered an open item (341/90013-08(DRP)).

d. (Closed) LER 90008, HPCI Inadvertent Isolation. The inspector reviewed the licensee's troubleshooting efforts and verified that trip unit actuated relays were replaced due to the potential of exceeding qualified life and a low pass signal filter was installed in the HPCI steam flow circuitry reducing the process signal noise causing relay actuation.

No violations or deviations were identified in this area.

10. Condition Adverse to Quality System Review

During the inspection period, the inspector reviewed the licensee's corrective action program required by 10 CFR 50, Appendix B, Criterion XVI. The inspector selected several licensee condition adverse to quality reports (Deviation Event Reports (DER)) for review, or the licensee informed the inspector of the adverse condition. The inspector's review of the DERs included verification of administrative compliance to the delineated program, evaluation that appropriate events were being captured by the DER system, determination for significant DER conditions, quality of the root cause evaluation, and appropriateness of the corrective actions.

a. DER 90-0332, Failure of reactor coolant system Hi/Lo interface pressure switches - The DER identified the actuation at higher than anticipated pressure of both technical specification core spray division high/low interface pressure switches during surveillance testing on May 15, 1990. These switches provide an alarm function indicating check valve leakage between the reactor coolant system and the core spray system. These switches were eventually replaced after another dual failure of the switches on May 21, 1990, but in the low direction.

The inspector noted that the root cause analysis stopped prior to identification of the switches failure mechanism. Following inspector discussion the licensee continued the evaluation but was not completed by the end of the inspection period. The inspector will continue to review the root cause analysis in a future inspection.

b. DER 90-407, Lack of N-2 data reports - The licensee informed the inspector that 25 valves of 1 inch or less in size were provided to the licensee without ASME N-2 data reports. The licensee performed engineering evaluations on all of these valves based upon the documentation available and concluded that the valves were operable. The licensee's evaluation was provided to the appropriate Region III Division of Reactor Safety personnel for their review, and the results of their review will be documented in a future inspection report.

c. DER 90-460, High radiation door left unlocked - The DER identified that a Technical Specification High Radiation Door, on the northeast turbine deck, had been left open and unattended for approximately 45 minutes. This is a violation (341/90013-9(DRP)) of Technical Specification 6.12.2 which requires locked access doors to areas where any individual could receive a radiation dose of greater than 1000 mrem in one hour. The situation was caused when an operator entered the area and did not ensure that the door was locked after leaving the area. Subsequently, a health physics technician checked the door as part of the high radiation door program, determined it to be unlocked, guarded it until it could be locked, and then initiated a DER.

The original DER corrective action, dispositioned the by operations department, centered upon personnel action against the individual leaving the door unlocked and installing a self-locking core for the door. During the inspector's review into this matter a number of concerns arose dealing with the intra-departmental communications between the radiation protection manager and his staff, inter-departmental communications between operations and radiation protection personnel on this event, quality of the management directives on high radiation door controls established by the health physics staff, management failure to timely implement long term corrective action on high radiation doors following a similar event in April 1990 in which a non-TS high radiation door was left open, and, with the lack of prioritization for long term high radiation door corrective actions following high radiation door problems in 1988.

In response to the high radiation door violation the licensee:

1) Replaced all technical specification high radiation door locking mechanism covers with self-locking cores.

2) Plans to revise the high radiation door control procedure by November 15, 1990.

3) Prepared a potential design change to install key captive deadbolts on all TS high radiation doors.

4) Changed the procedure for changing radiation postings to include observation of doors for obstructions.

5) Will establish the level of training necessary for personnel using high radiation doors by December 30, 1990.

Based upon these corrective actions, the licensee's identification of the high radiation door violation, and no one having entered the unlocked high radiation area, the inspector considers this a non-cited violation in accordance with 10 CFR 2, Appendix C, Section V.G.

The significant causal factors of this violation were inattention to detail and untimely corrective action to a similar condition in 1988.

d. DER 90-492, Breach of the RHR system - The DER described a situation wherein maintenance personnel worked on RHR seal water tubing but the tagout and radiation work permit (RWP) were based upon working on an EECW line. The DER also described work delays due to the unavailability of required tools at the job site.

The inconsistency between the tagging/RWP and the actual job activity was due to a difference in the problem description on the work request and the work request job steps. Personnel establishing the tagging and RWP requirements used the problem description exclusively.

During the original review of the DER the inspector noted that the significant condition adverse to quality, root cause, and corrective action to prevent recurrence section were blank. The inspector ascertained that corrective actions had been taken, though not documented on the DER, following a fact finding meeting on the event. The corrective actions included:

- A planned procedure change by the end of the year to ensure the problem description and job steps were consistent.
- Tagging to be based upon job steps
- Tool crib management controls on the number of tools

The reason for the incomplete DER was due to new clerical personnel prematurely submitting the DER to the plant safety group. The clerk was retrained and the DER appropriately updated.

e. DER 90-443, Part 21 notification from Limitorque Corporation of a potential defect in the worm gear of type H3BC valve actuators - The inspector noted a discrepancy in the level of plant safety overview assigned to this matter. The licensee adjusted the level of review and stated that other DERs of a similar nature had been assigned in the same manner. The licensee showed the inspector a change in the form used to assign the overview level, which should alleviate oversights of this nature in the future.

11. Information Notice Followup

(Closed) Information Notice 88-51, Failures of Main Steam Isolation Valves. The licensee provided the inspector with documentation that the force balance calculation was completed with the conclusion that no air system modifications were needed. Also, the inspector determined that there were procedures, 24.137.02 and 35.137.003, for accumulator and actuator leak tightness testing.

12. Drawing Control Report Review

Attachment 2 to this inspection report contains a NRC contractor inspection and assessment of a large portion of the licensee's drawing control system. The inspector determined that certain areas require additional followup. These areas are:

- Termination cabinet wiring configuration discrepancies. This is considered an open item (341/90013-10(DRP)).

- The use of uncontrolled handwritten labels in electrical cabinets. This is considered an open item (341/90013-11(DRP)).

- Abandoned stanchion supports. The licensee wrote DER 90-0495 on this situation to determine if the abandoned supports had been considered in the piping stress calculations. This is considered an open item (341/90013-12(DRP)).

13. Follow up of TMI Items

a. (Closed) II.K.3.18., Modification of Automatic Depressurization System (ADS) Logic - Feasibility for Increased Diversity for Some Event Sequences. NUREG 0737 required a feasibility study be performed to determine the optimum approach to reduce the need for manual ADS actuation. A generic study was performed, by General Electric, providing a number of options to meet the NUREG 0737 requirement. General Electric Option 4 was selected by Detroit Edison. This option involved the addition of a timer/bypass circuitry to automatically initiate ADS exclusively on low reactor water level after approximately eight minutes and the addition of manually actuated inhibit switches that would defeat automatic ADS actuation. The NRC accepted option 4 in supplement 5 of the Safety Evaluation Report, NUREG 0798, provided four requirements were met. These were: (1) installation of option 4 during RF01, (2) amend the Technical Specifications to reflect installation of option 4, (3) address the use of the ADS inhibit switches in the emergency operating procedures and (4) provide a plant specific analysis for the ADS bypass timer setting.

The inspector confirmed through record review of work requests and post modification testing, and panel walkdowns that GE option 4 was installed prior to completion of RF01 and that, therefore, requirements were met.

b. (Closed) I.C.6., Verification of Correct Performance of Operating Activities. This task action item required that licensee procedures incorporate, as applicable, administrative controls to assure an effective system of verifying the correct performance of operating activities. The inspector reviewed Fermi Management Directives FMD-CT1 "Calibration, Testing and Surveillance," FMD-OP1 "Operations," and FMD PR1 "Procedures, Manuals, and Orders," as well as Nuclear Production Procedures NPP-MA1-03, "Interim Alteration of Electrical Circuitry," NPP-OP1-08 "Control of Equipment," and NPP-OP1-02 "Logkeeping," and verified that the requirements of NUREG-0737 had been appropriately incorporated. Additionally, discussions with plant personnel (which included licensed and non-licensed operators, maintenance personnel, and engineering support personnel), ascertained an acceptable level of familiarity with those aspects of independent verification, equipment removal, and return to service requirements as is required by this task action item.

14. Management Meetings

On August 21, 1990 the licensee and NRC management met in NRC Region III for a periodic management meeting. The agenda included:

- Plant/Performance - The licensee provided its latest performance along with trending on deviation event reports. The data reflected a reduction in the number of DERs by one half from December 1989 to August 1990. However, the average age of a DER was approximately one year. The licensee indicated that an evaluation of DERs was being accomplished to determine how many are contingent upon actions during RF02. Also, the NRC requested licensee insight into the increasing number of rejected safety evaluation reviews. The licensee responded that this was due to an increase in review member expectations of safety evaluations.

- Management Changes - The licensee discussed the recent changes that were discussed in paragraph 10 of Inspection Report 50-341/90011(DRP).

- Maintenance - The licensee presented data showing a 50 percent reduction in non-outage corrective maintenance backlog since January 1990, a Preventive Maintenance/Corrective Maintenance (PM/CM) ratio of greater than 50 percent and a history on accomplishing PMs. The licensee indicated that maintenance schedule adherence has increased from 50 percent in January 1990 to presently 70 percent. The philosophy on BOP maintenance and system outages was provided. Some discussion was held on safety system unavailability, including integration of PM and surveillance activities. With regards to the highest overall radiation exposure contributor, RWCU pump repairs, the licensee provided a historical account of troubleshooting efforts and corrective actions.

- ALARA for Maintenance Activities - The licensee provided the NRC with information that showed that management decisions on maintenance workforce allocation were not restricted by radiation dose as discussed in paragraph 4 of Inspection Report 50-341/90009. The cumulative annual dose presently received is within the licensee's goal.

- Outage Performance and Preparation for RF02 - The licensee discussed the recent outage performance (outage 90-02 and 03) and scope of work activities. The licensee provided an overview of the present scope of RF02 activities which are scheduled to commence March 15, 1991, for a 75 day duration.

- Operator Training - The licensee presented a history of operator test performance, the weaknesses associated with the most current (June 1990) operator requalification effort, the evaluations of those weaknesses and the projected corrective actions. The NRC requested the time table on correcting immediate actions associated with the Abnormal Operating Procedures (AOPs). The licensee responded that the AOPs would be modified by the end of the year. The NRC questioned the licensee on the strained training resource issue, especially in light of the loss of two individuals in the

operator training area after the June examinations. The licensee responded that efforts will be made to increase the number of personnel in this area. Some discussion ensued as to when the next requalification exam would occur.

- Engineering - The licensee provided a status of design changes associated with RF02. The licensee showed that contractor dependence is being reduced by increasing the licensee engineering staff. The licensee indicated that the most recent Safety System Functional Inspection of the Control Complex HVAC system and the standby Gas Treatment system did not identify any attribute that would have prevented the systems from performing their safety function.

15. Unresolved Items

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items, violations or deviations. An unresolved item disclosed during the inspection is discussed in Paragraph 7.

16. Open Items

Open items are matters which have been discussed with the licensee, which will be reviewed further by the inspector, and which involve some action on the part of the NRC or licensee or both. Open items disclosed during the inspection are discussed in Paragraphs 3.b, 5.b, 9.b, 9.c, and 12.

17. Exit Interview (30703)

The inspectors met with licensee representatives (denoted in paragraph 1) on October 19, 1990, and informally throughout the inspection period and summarized the scope and findings of the inspection activities. The inspectors specifically requested on-shift licensed operators to attend the exit and representatives were in attendance. The reason was to assure that the findings specific to administrative controls implementation weaknesses and weaknesses in cognizance of plant status were conveyed to the licensed operator ranks. The inspectors also discussed the likely informational content of the inspection report with regard to documents or processes reviewed by the inspectors during the inspection. The licensee did not identify any such documents/processes as proprietary. The licensee acknowledged the findings of the inspection.

Attachment 1

SEISMIC MONITORING SYSTEM

DESCRIPTION

The Seismic Monitoring System (SMS) at Fermi 2 is designed to alert plant operators in the event of an earthquake and to provide a permanent record of the ground acceleration and plant structural responses resulting from the earthquake. The system is calibrated to immediately detect and respond to any ground acceleration above 0.01g. If such an event is detected, the Seismic Monitoring System will alert the control room and record the magnitude of the event and the response of major plant systems. This data can be quickly examined to determine if the plant has exceeded ground acceleration limits.

10 CFR 100 Appendix A defines the Operating Basis Earthquake (OBE) as that earthquake which could reasonably be expected to occur within the lifetime of the plant. Based on Fermi 2's site history, horizontal ground acceleration is set at 0.08g, while vertical ground acceleration is set at two-thirds of horizontal, 0.053g. Within these limits all plant equipment necessary for the safe operation of the plant must remain functional. If an earthquake does not exceed the OBE, shutdown is not required and the plant may continue to operate.

The Safe Shutdown Earthquake (SSE) is the maximum possible earthquake that could conceivably occur at the site. All structures, systems, and components that are required to remain functional in the event of a SSE are designated as Category I. Briefly, these structures either preserve the integrity of the reactor pressure vessel boundary, assist in shutting down the reactor and maintaining it in a safe shutdown condition, or prevent or mitigate offsite exposures due to possible accidents. Fermi 2 SSE limits are a horizontal ground acceleration of 0.15g and a vertical ground acceleration two-thirds that of horizontal, 0.10g.

The SMS will provide a record of seismic data which can be used to analyze the actual effects of an earthquake on plant structures. These effects can be compared to seismic design qualification calculations to test for accuracy.

The SMS is composed of both an active and a passive system. The Active System requires a power supply, while the Passive System does not. The Active System provides control room notification in the event of an earthquake and an immediate record of ground acceleration. The Passive System has no alarm functions and requires more data analysis to extract the desired information.

Active Seismic Monitoring System

The Active SMS is initiated by the Omnitrigger. This is an accelerometer which will alert the main control room and initiate data recording by the Active Accelerometers if it senses either a horizontal or vertical acceleration greater than 0.01g. Two Active Accelerometers measure ground acceleration and send signals to the Data Recorder. This data can then be read using the Oscillograph and the Monitor/Playback System. The SMS power supply, control functions, Data Recorder, Monitor/Playback System and alarm

panel are located in a relay rack housing in the Relay Room. The seismic trigger and accelerometers throughout the plant are protected by waterproof housings and connected to the SMS console through cables.

The two Active Accelerometers are force-balance accelerometers originally manufactured by Teledyne Geotech. One is located in the reactor/aux building subbasement in the HPCI room, the other is located at the bottom of the Reactor Pressure Vessel (RPV) pedestal, adjacent to the floor at the base of the drywell. Each unit has a total of three individual accelerometers, one measuring vertical motion and two measuring horizontal motion.

The Omnitrigger, originally manufactured by Teledyne Geotech, is located in the HPCI room next to the Active Accelerometer. The instrument measures ground acceleration by one vertical geophone and two horizontal geophones. If the Omnitrigger senses a ground acceleration greater than 0.01g in any one of the vertical or two horizontal directions, it will actuate the main control room annuciator 6D2, "Seismic System Event/Trouble" through the Data Recorder. It will also start the Data Recording System and the Oscillograph within 1/10 of a second.

The Teledyne Geotech Monitor/Playback System performs two functions. The monitor function automatically records the HPCI room accelerometer data whenever an Omnitrigger signal is received. It is also used to transcribe magnetic tape records from the Data Recorder.

Power for the SMS is supplied by rechargeable batteries to avoid losing system operability during a loss of AC power. Two battery chargers supply continuous float charging to the batteries. A dc/ac inverter is available to supply power to the Oscillograph. The control room seismic alarm will annunciate if a simultaneous low battery and charger voltage condition occurs or the charger becomes unplugged.

Passive Seismic Monitoring System

The Passive SMS manufactured by Engdahl Enterprises consists of six triaxial response spectrum recorders. Each recorder measures acceleration in three directions, one vertical axis and two perpendicular horizontal axes. The units require no power and are self contained in large metal grating cages to avoid accidental contact that could result in spurious recordings. Three are located in the reactor/aux building: one in the HPCI room, one in the Relay Room, and one at the top of the reactor/aux building on the fifth floor. The three other recorders are located in the RHR complex: one measures excitation to the diesel generators and RHR pumps, one measures the response of structures higher in the RHR complex, and the last measures excitation to the mechanical draft cooling towers.

REQUIREMENTS FOR THE SEISMIC MONITORING SYSTEM

The requirements and regulations governing seismic monitoring equipment are stated in 10 CFR 100 Appendix A.

"Suitable instrumentation shall be provided so that the seismic response of nuclear power plant features important to safety can be determined promptly to permit comparison of such response with that used as the design basis."

Regulatory Guide 1.12, "Instrumentation for Earthquakes", Revision 1, April 1974 is the current standard for satisfying 10 CFR 100 Appendix A. Reg. Guide 1.12 Revision 1 is based on ANSI Standard N18.5, "Earthquake Instrumentation Criteria for Nuclear Power Plants," with a few instrument location specifications changed. ANSI N18.5 lists the location and number of seismic instruments, instrument characteristics, instrumentation station installations, alternative instruments, and maintenance requirements necessary in nuclear power plants.

The SMS for Fermi 2 does not conform exactly to Reg. Guide 1.12 Revision 1, because the system was documented in 1972 before Reg. Guide 1.12 was issued. However, the licensee reviewed the Fermi 2 SMS for compliance and found that the system satisfied the intent of Reg. Guide 1.12.

Limiting Condition for Operation

Section 3.3.7.2 of the SMS Tech Specs, Limiting Condition for Operation, requires that the SMS shall be operable at all times. If one or more parts of the SMS is inoperable for more than 30 days, a Special Report must be submitted to the Commission within 10 days. The report must outline the cause of the malfunction and plans for restoring the instrument(s) to operable status. TS provisions 3.0.3 and 3.0.4 do not apply, meaning that even if the LCO for the SMS is not met for an extended period of time, a change in the Operational Condition of the plant is not required; a report must simply be submitted every 30 days.

Surveillance Requirements

Section 4.3.7.2, Surveillance Requirements, is composed of two parts. Part 1 lists the types and frequencies of operability inspections that must be performed under normal plant conditions. The procedures listed in part 2 only apply if a seismic event of 0.01g or greater has occurred.

Tech Spec Section 4.3.7.2.1 states that all SMS equipment must be "demonstrated OPERABLE by the performance of the Channel Check, Channel Functional Test and Channel Calibration operations." Table 3.1 shows the frequency required for each procedure. None of the Active SMS tests may be performed if the SMS has been activated or if any of the Passive System equipment is inactive or under test. The Channel Check is performed once per 31 days on the Data Recorder, the Monitor/Playback System, and the Oscillograph.

The Active Seismic Monitoring System Functional Test, licensee Surveillance Procedure NPP-44.090.001, is performed once per 184 days. The accelerometers, the recording system including the seismic trigger, and the playback system are all tested.

The Active Seismic Monitoring System Calibration, licensee Surveillance Procedure NPP-44.090.002, is performed once every 18 months (550 days).

The Passive System has only one Surveillance Procedure, the Passive Triaxial Peak Shock Recorders Calibration, NPP-44.090.004. It is performed once per 18 months. This surveillance may not be performed if the Active SMS is, or has been, activated and has not been returned to its normal status.

Tech Spec Section 4.3.7.2.2 states that each SMS instrument actuated during a seismic event shall be restored to operable status within 24 hours, and shall be given a channel calibration within 5 days. Data from the actuated instruments shall be retrieved and analyzed. A special report shall be submitted to the Commission within 10 days describing the magnitude, frequency spectrum, and resultant effect of the seismic event upon unit features important to safety. Two procedures control the actions taken after a seismic event. The Fermi 2 System Operating Procedure NPP-23.612, Seismic Monitoring, governs collecting and analyzing data from the Active and Passive SMS. If an analysis of the data reveals that a horizontal ground acceleration of 0.05g has been exceeded, Abnormal Operating Procedure NPP-20.000.01, Acts of Nature, is put into effect.

The "Seismic Monitoring" procedure details what actions to take immediately upon receipt of a Seismic System Event/Trouble Alarm.
If any displacement corresponding to or exceeding an acceleration of 0.05goccurred, the "Acts of Nature" procedure should be performed. If a seismic event greater than or equal to an acceleration of 0.01g has occurred, data from the Passive System also should be analyzed. The process for correlating recorder displacement measurements with ground acceleration for both the Active and Passive System is given in the "Seismic Monitoring" procedure.

The "Acts of Nature" procedure states that immediately upon receipt of a seismic alarm, all plant parameters important to safety should be checked. Damage indications necessitate an immediate shutdown. If no immediate damage is apparent, each of the four mechanical Draft Cooling Tower Fans should be started and checked for proper running indications. These fans contain relays which are not seismically qualified. After verifying their operation the fans should be shut down. An attempt also should be made to obtain confirmation of the magnitude of the seismic event by calling the University of Michigan Seismic Observatory and the Davis Besse Control Room.

If the event produced an acceleration equal to or greater than 0.05g, the operators will begin a controlled shutdown of the reactor to Condition 4 and the plant engineering staff will perform a "thorough and rigorous examination of all plant systems and structures for damage". The procedure, however, does not specify whether the 0.05g acceleration is in the horizontal direction, the vertical direction, or either direction.

If the Operating Basis Earthquake (OBE) of 0.08g was exceeded, an additional inspection of the shore barrier would be performed with plant inspection continuing until the NSS was satisfied that the plant was in a safe condition. However, previous events have identified concerns with the vibration frequency at which the OBE was exceeded, and the duration of the event. A normal earthquake spectrum may exceed the OBE at certain frequencies, especially higher frequencies above 10 Hz, and remain below the OBE at lower frequencies. Two examples of this type of earthquake motion have occurred recently in Region III:

- On June 10, 1987, Clinton Nuclear Power Plant experienced a earthquake in which high-frequency vibrations lasting less than 1 second exceeded the OBE in the 20 to 25 Hz range. No plant damage was found.

- On January 31, 1986, Perry Nuclear Power Plant experienced ground motions lasting approximately 1 second that exceeded the OBE and even the SSE at frequencies above 15 Hz. Again, the event did not result in any significant damage.

In general, high frequency ground motions are usually associated with low energy and do not appear to be as significant as frequencies in the 2 to 10 Hz range. Presently, no guidelines for determining if a plant's OBE has been exceeded have been endorsed by the NRC and no specific criteria have been developed to determine when an earthquake spectrum should be considered damaging. However, the NRC is currently completing a review of EPRI Report NP-5930, "A Criterion for Determining Exceedance of the Operating Basis Earthquake."

PLANT EXPERIENCE

The Seismic Monitoring System (SMS) at Fermi 2 Nuclear Power Plant is an old system. The Fermi 2 SMS was designed in 1972 by Teledyne Geotech. By the time the system was actually installed in early 1985, Teledyne Geotech had sold the product line to Terra Technology, which promptly discontinued the product line as being outdated. Thus, replacement parts are not available for the system and the vendor does not support the system technically. Several years ago the Davis-Besse Nuclear Power Plant replaced an identical system, and Fermi 2 has used some of these parts as spares. Maintenance personnel have relied on internal troubleshooting to keep the system operable. They have avoided replacing major parts through repair work and the replacement of small items that are available.

Fermi 2 does own an entirely new system that has been in warehouse storage since approximately 1981. A Plant Design Change (PDC) package was submitted about a year ago detailing installation of the spare system, but it was rejected and there are no plans for replacement of the old system in the near future.

The system history kept by the plant was not very complete and lacked detail. However, a time history from the available records was compiled and is provided as Table 1. A calculation of the SMS downtime is attached as Figure 2. Nine different instances of failed surveillance tests were found, and one spurious alarm caused by a dirty End-of-Tape sensor. This includes the initial installation tests that required a system modification. System down time to perform necessary repairs ranged from about one and a half days to a period of several weeks. Only once, in February 1989, was the LCO to return the system to operable status within 30 days exceeded. Of the 10 instances when corrective action was required, only 2 were uncovered by monthly Channel Checks. Three out of approximately 10 Functional tests found problems, and 3 out of 4 initial Calibration tests failed.

An examination of the Fermi 2 SMS shows three main recurring modes of failure. The oldest problem is the absence of time mark traces on Monitor/Playback printouts. The time marks are generated on Tape Track # 4 and recorded along with the accelerometer signals to provide a timeline for comparison with ground motion data. It appears that the time marks are created on Track # 4, but do not show up during playback. Obtaining time mark traces was one of the problems found during initial system installation on February 3, 1985. Even after modifications were performed on the system, time mark recovery was

described as "sensitive" and required "fine-tuning". The problem recurred on July 4, 1987, and the compensation module stability was adjusted. The problem occurred again on January 27, 1989, when both the compensation module stability and the Monitor/Playback tape deck head alignment were adjusted. After June 17, 1990, when time marks were again not appearing, shims were installed to properly align the tape deck head. The system engineer believed that this problem was due to improper tape head alignment, and that the recent shim installation would permanently correct the problem.

Another recurring problem is the need to replace the 12 volt batteries associated with the Monitor/Playback system. These batteries were replaced on July 4, 1987, February 1, 1988, January 27, 1989, and July 11, 1989. The system engineer said that frequent battery replacement should not have been necessary because the batteries are equipped with a charging module. Replacement resulted from a variety of problems, including low battery voltage indications and battery charger problems.

Troubleshooting was performed on July 11, 1989, on the battery chargers, and both the Monitor/Playback batteries and the 12 volt Gell Cell in the float charging module were replaced. The Gell Cell was suspected as being faulty. No problems have been reported since that time.

A third common system problem is failure of an integrated circuit chip located in the Monitor/Playback unit tape playback circuit. Failure of the chip leads to tape operation problems; for instance, in the Standby mode the Monitor/Playback unit will keep running, and in the Playback mode the unit may not initiate properly on an Omnitrigger signal. The chip is a CMOS type chip that is extremely sensitive to voltage spikes. There are two versions of the chip, the "A" series and the "B" series. The "A" series is sensitive to static and fails very easily in the circuit. The "B" series chip has protective diodes but will still fail if the power is turned on and off repeatedly on the Monitor/Playback circuit. This chip was replaced on January 27, 1989, March 29, 1989, July 11, 1989, and three different times during the work performed after June 17, 1990.

The system engineer explained that some of these failures were due to accidental installation of the "A" series instead of the "B" series. Apparently "B" series chips were requested, but "A" series chips were ordered and installed.

Even with the better "B" series chip installed, failures have occurred. The system engineer said that the Monitor/Playback power is often turned on and off during troubleshooting, for example, when removing logic circuit cards to perform repairs. However, the Monitor/Playback power is also turned on and off 6 times during the Calibration surveillance procedure when calibrating the tape playback function. The system engineer said that he would consider looking into the necessity of this part of the surveillance procedure.

No modifications are planned to help avoid chip failure except to ensure that only the "B" series chip is used. The circuit would have to be completely redesigned in order to eliminate this sensitive chip. Chip replacement has been facilitated by the installation of a socket for the chip instead of using solder. The system engineer did not believe this chip was a

major problem for the SMS because once the system is placed in its normal Standby mode, a real seismic triggering event should not cause the chip to fail.

In general, the Monitor/Playback unit seemed to have the most problems. The system engineer said one of the most troublesome SMS components was the tape deck drive. This drive has several mechanical problems, including the capstan pinching against the tape and the tape drive not running at a constant frequency. The frequency of the tape drive should not be a problem during an actual event because the time mark generator is supposed to compensate for any frequency fluctuations.

On August 22, 1990, the system engineer submitted a PDC package to try to correct another problem with the SMS. The system is designed to measure an acceleration range from + to - 1.0g on a 40 mm scale making it extremely difficult to read the SMS chart accurately for small ground acceleration rates. The system engineer has proposed increasing the gain to give the SMS a range from + to - 0.25g. This range still encompasses the Safe Shutdown Earthquake horizontal acceleration criterion of 0.15g, and would make the SMS more accurately readable.

It appears that Fermi 2 cannot keep the SMS operational indefinitely without replacement parts or vendor support. The plant could have had a significant replacement problem in June, 1990, when a Voltage Controlled Oscillator needed replacement and the part had been deleted from the parts list. The licensee was able to find and use an installed spare.

In summary, the Fermi 2 SMS is operable and functional, but has had problems of a recurring nature in each of the years since its installation. The system was designed 18 years ago and some flaws exist, such as the IC chip problem and difficulty in reading the system output. The SMS operational history was not very complete or detailed, making it difficult for the licensee to assess how often the system is malfunctioning. There is no replacement plan developed if the current SMS were to fail and could not be repaired.

Table 1

TIME HISTORY - SEISMIC MONITORING SYSTEM

2/3-5/85 Functional Test (initial)

Problem:
- "Circuit modifications were required for the successful completion of this test."
- large noise levels in Playback mode (masked basic signals entirely)
- problems with time mark recovery and carrier detection circuits

Work:
- EER 85-075 Design Change Request
- noise levels reduced by the modification
- marginal time mark recovery and carrier detection circuits operation - both are sensitive and require "fine-tuning"

Time:
- not counted (initial run)

8/13/86 Functional Test

Problem:
- step 6.3.2 event light and 6D2 control room annuciator failed to alarm

Work:
- control center trouble report CRIS #325 iss
- control module circuit card replaced

Time:
- 10 hours (estimate, work hours only)

7/4/87 Calibration Test

Problem:
- step 6.2.7.7 time marks 0.125, should be 0.5 +- 0.01
- 2040 Hz discriminator and 1020 Hz discriminator could not be calibrated to required tolerances, Monitor/ Playback unit batteries don't hold charge
- step 6.5.18 unable to obtain paper recorded traces, time lines not present

Work:
- Work Request # 002A070587

- replaced Monitor/Playback batteries (+ & -)
- found a blown fuse
- found and repaired a bad connection, improved traces
- adjusted compensation stability, improved time marks
- cleaned heads on Data Recorder and Monitor/Playback unit.
- 0.125 time marks was a test set-up problem only

Time:

- 85 hours (7/4/87 - 7/7/87)

10/13/87 Channel Check Test

Problem:

- step 6.3.2.3b, Monitor/Playback tape deck did not run when in Playback mode

Work:

- Work Request # 028A871013
- found faulty motor control card and replaced

Time:

- 105.5 hours (10/13/87 - 10/17/87)

2/1/88 Functional Test

Problem:

- step 6.2.2.2 shows a low battery voltage
- step 6.2.3.D, Graphic Recorder (Oscillograph) did not print

Work:

- Work Request # 008B020288
- replaced Monitor/Playback batteries (+ & -)

Time:

- 60 hours (2/1/88 - 2/4/88)

1/27/89 Calibration Test

Problem:

- steps 6.2.2.4 and 6.2.2.5, Data Recorder tape deck would not work in Run mode
- no time marks present on Oscillograph trace (suspect old paper is the cause)
- attachment 2 page 1 step 9, could not perform calibration as written, no reset switch on Monitor/Playback unit
- Monitor/Playback unit will not run

Work:

- Work Request # 002C890204
- performed extensive work on tape deck:
- replaced Monitor/Playback unit batteries (+ & -)
- replaced bad OP AMP 23 on motor control board
- replaced IC chips on power control module including a new type of Z1 chip
- replaced 1020/1360 discriminator
- repaired 2040 discriminator
- adjusted compensation module stability (for time marks)
- worked on Monitor/Playback unit head alignment but did not install shims as suggested
- adjusted R2 to minimize Trace 2 noise

Time:

- 764 hours (1/28/89 - 2/27/89, exceeded 30 day LCO)

3/29/89 Channel Check Test

Problem:

- step 6.2.5, Data Recorder tape deck failed to stop

Work:

- Work Request # 001C890330
- replaced Z1 chip on power control board

Time:

- 48 hours (3/29/89 - 3/31/89)

7/11/89 Seismic Monitoring Procedure 23.612

Problem:

- Data Recorder battery charger did not indicate allowable voltage values
- Monitor/Playback battery charging module did not indicate allowable voltage values

Work:

- Work Request # 005C890710
- replaced 12 V Gell Cell in battery charger module
- replaced Monitor/Playback batteries (+ & -)
- replaced Z1 chip on power control board

Time:

- 217 hours (7/11/89 - 7/20/89)

8/15/89 Spurious 6D2 Alarm

Problem:

- dirty EOT sensor on Data Recorder
- seismic monitor needs repair

Work:

- Work Request # D02C890815
- cleaned EOT contact
- adjusted pressure roller tension

Time:

- 35 hours (8/15/89 - 8/17/89)

6/17/90 Calibration Test

Problem:

- page 9 table 6, tolerance for Voltage Controlled Oscillator is 1825 Hz, should be 1822 Hz, change to procedure to follow
- steps 6.3.6.6 and 6.3.6.15, were unable to obtain 2.5 V peak-to-peak during discriminator calibration
- step 6.5.18.1, time mark trace recordings were unsatisfactory

Work:

- Work Request # 001D900617
- planned to replace D30KA06 Voltage Controlled Oscillator circuit board, but part no longer available
- found D30KA05, an installed spare, and used to replace circuit board
- replaced broken capstan drive belt for tape Playback fct.
- reworked Monitor/Playback head alignment to improve time mark traces - put shims under head - adjusted several times - results "adequate"
- replaced Z1 chip three different times
- replaced Monitor/Playback unit battery fuse
- during surveillance the Data Recorder "ate" 3 tapes - EOT sensor was jamming against tape case
- tried to adjust discriminators for steps 6.3.6.6 and 6.3.6.15 - unable to calibrate. TCN'd Calibration procedure to allow discriminators to be 2.5 V peak-to-peak or maximum attainable

Time:

- 322 hours (6/17/90 - 7/1/90)

Table 2

SEISMIC MONITORING SYSTEM DOWN TIME

(3/85 - 7/90)

DATE	TIME (HOURS)	
8/13/86	10	(estimate, work hours only)
7/4/87	85	
10/13/87	106	
2/1/88	60	
1/27/89	764	
3/29/89	48	
7/11/89	217	
8/15/89	35	
6/17/90	322	
	+	
TOTAL HOURS:	1647	
TOTAL DAYS:	68.6	

* System down time was calculated from the time a surveillance test failed or a spurious alarm was received to the time when testing was completed satisfactorily. Time between surveillances when the system was not operational is unknown and thus cannot be accounted for in this data.