U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-255/94021(DRP)

Docket No. 50-255 License No. DPR-20

Licensee: Consumers Power Company
212 West Michigan Avenue
Jackson, MI 49201

Facility Name: Palisades Nuclear Generating Facility

Inspection At: Palisades Site, Covert, Michigan

Inspection Conducted: December 3, 1994, through January 6, 1995

Inspectors: M. E. Parker, D. G. Passehl, T. J. Kobetz, J. A. Lennartz, J. A. Isom, W. J. Kropp, M. M. Biamonte, D. S. Butler, R. A. Winter, R. L. Lerch

Approved By: Wayne J. Kropp
W. J. Kropp, Chief
Reactor Projects Section 2A

Date 1/13/95

Inspection Summary

Inspection from December 3, 1994, through January 6, 1995
(Report No. 50-255/94021(DRP))

Areas Inspected: Routine, unannounced safety inspection by resident and regional inspectors of operational safety verification, engineered safety featured systems, onsite event followup, current material condition, housekeeping and plant cleanliness, radiological controls, security, safety assessment/quality verification, maintenance activities, surveillance activities, engineering and technical support, Temporary Instruction 2515/111 - Electrical Distribution System Followup Inspection, Temporary Instruction 2515/126 - Evaluation of Online Maintenance, report review, and meetings.

Results: Within the 15 areas inspected, no cited violations or deviations were identified. One unresolved item pertaining the charpy V notch testing was identified (paragraph 5.b.). One noncited violation was identified (paragraph 4.b). Based upon this inspection, TI 2515/111 and TI2515/126 are closed. The following is a summary of the licensee's performance during this inspection period:

Plant Operations

The licensee's performance in this area was adequate; however, there was a concern identified with the timely and appropriate assessment of the auxiliary feedwater (AFW) system following an unanticipated AFW injection into the steam generators. More timely management, system engineering, and I&C involvement is warranted in this area.

The plant operated at essentially full power throughout the inspection period. The licensee has operated the plant for over 200 consecutive days on-line, breaking the previous record of 176 consecutive days on-line.

The inspectors observed power escalation following scheduled main turbine valve tests. The inspector observed one minor weakness with the power escalation procedure involving the method used to compare indicated to actual reactor power. Plant operators appropriately changed the procedure prior to proceeding with the power escalation.

The licensee declared an Unusual Event on December 8, 1994, when the flow indicating controllers to the auxiliary feedwater (AFW) valves were declared inoperable. The licensee found that the problem was due to a failed electrical relay, resulting in the flow control valves receiving an open demand signal. Plant Instrument and Control technicians replaced the relay and successfully tested the AFW system, terminating the Unusual Event. The same relay was the cause of another reportable event the previous day. During that event, an unanticipated injection of AFW into the steam generators occurred, during surveillance testing of the AFW system, as a result of the AFW flow control valves being in the open position. The main feedwater system compensated for the injection and maintained normal steam generator levels. The test was immediately terminated and the AFW system was returned to a standby configuration. However, the failure to recognize the flow control valve position, resulted in the AFW system being in a potentially degraded condition for an extended period of time. In addition, control room turnovers and panel walkdowns by reactor operators did not identify the degraded condition, until some 24 hours after the relay failure.

Overall material condition was adequate.

The inspector reviewed the radiological survey sheets for Multi-Assembly Sealed Basket #9 and found no problems.

Safety Assessment/Quality Verification

A noncited violation was issued for the licensee's failure to test redundant low pressure safety injection loop isolation valves prior to maintenance.

A training and assessment specialist from the Human Factors Assessment Branch at NRC Headquarters conducted a review of the Palisades Performance Enhancement Program (P^2EP). The individual action plans in the P^2EP were well written with clear due dates and deliverables. However, the inspector found several concerns including (1) A lack of measures of success for each of the action plans; (2) Items included in the P^2EP tended to be too broad with a

focus on consolidating common items under one action plan; and (3) Some of the completed actions were inadequate.

The inspectors reviewed the licensee's proposed actions to consolidate the presently used commitment tracking system (CTS). The current system has not been effective at communicating and ensuring regulatory commitments were identified, documented, and implemented. A departmental action plan for a new CTS was developed that established the actions to be taken and the scheduled completion dates. The database for new CTS has been delayed and was now scheduled for completion in late January 1995.

Maintenance and Surveillance

The inspectors evaluated the licensee's on-line maintenance practices in accordance with Temporary Instruction 2515/126, "Evaluation of Online Maintenance." The inspector concluded that the process in place adequately incorporated Probabilistic Risk Assessment (PRA) insights when scheduling on-line maintenance.

Surveillance activities were conducted satisfactorily.

Engineering and Technical Support

The inspectors observed and reviewed activities associated with the loading of Multi-Assembly Sealed Basket (MSB) #9. The licensee experienced a minor problem during the vacuum drying process. The licensee could only achieve a vacuum of 0.10 psia, versus 0.050 psia as specified in the loading procedure. The licensee found the swagelock fitting on the vent line to be leaking. Plant engineers implemented an approved modification to cover the vent line opening and proceed with vacuum drying. Further leak testing, after the temporary cover was removed and permanent covers welded into place, proceeded acceptably per the normal procedure. No other evidence of leaks were found and all acceptance criteria was appropriately met.

The licensee discovered that the shield lid top material for MSBs used in Ventilated Storage Casks 01 through 04 were not charpy v-notch impact tested per the requirements of the Safety Evaluation Report (SER). The SER requires charpy impact testing of all MSB pressure boundary materials, parts, components at temperatures of -50°F, with toughness not lower than 15 ft-lbs. The impact test requirement on the pressure boundary constitutes the basis for the allowed movement of the MSB above ambient temperatures of 0°F. The licensee intends to have charpy impact testing performed on sample coupons from the original shield lid material for the affected shield lids.

DETAILS

1. Persons Contacted

Consumers Power Company

*R. A. Fenech, Vice President, Nuclear Operations
*T. J. Palmisano, Plant General Manager
*K. P. Powers, Plant Engineering and Modifications Manager
*R. M. Swanson, Director, NPAD
*D. W. Rogers, Operations Manager
*S. Y. Wawro, Outage and Planning Manager
*K. M. Haas, Safety & Licensing Director
R. B. Kasper, Maintenance Manager
*R. C. Miller, NECO Deputy and Special Projects Manager
*C. R. Ritt, Administrative Manager
*R. J. Gerling, Reactor and Safety Analysis Manager
*J. L. Hansen, Plant Support Engineering Manager
D. J. Vandewalle, System Engineering Manager
*P. J. Gire, Licensing Engineer
D. G. Malone, Shift Operations Superintendent
*D. J. Malone, Radiological Services Manager
*R. A. Vincent, Licensing Administrator
*D. P. Fadel, NECO Engineering Program Manager
J. P. Broschak, NECO Dry Fuel Storage Engineer
*J. P. Pomaranski, NECO Project Management and Modifications Manager
*K. A. Toner, Design Engineering Manager

Nuclear Regulatory Commission

*M. E. Parker, Senior Resident Inspector
*D. G. Passehl, Resident Inspector
W. J. Kropp, Section Chief, RIII
J. A. Lennartz, Operator Licensing Examiner, RIII
D. S. Butler, Electrical Inspector, RIII
R. A. Winter, Electrical Inspector, RIII
M. M. Biamonte, Human Performance Evaluator, NRR
T. J. Kobetz, Senior Resident Inspector, Point Beach
R. M. Lerch, Operational Programs Inspector, RIII
J. A. Isom, Senior Resident Inspector, D. C. Cook

*Denotes those attending the exit interview conducted on January 6, 1995.

The inspectors also had discussions with other licensee employees, including members of the technical and engineering staffs, reactor and auxiliary operators, shift engineers and electrical, mechanical and instrument maintenance personnel, and contract security personnel.

2. Plant Operations (71707, 93702)

The plant operated at essentially full power throughout the inspection period. The licensee has operated the plant for over 200 consecutive days on-line, breaking the previous record of 176 consecutive days on-line.

a. Operational Safety Verification (71707)

The inspectors verified that the facility was being operated in conformance with the license and regulatory requirements and that the licensee's management control system was effective in ensuring safe operation of the plant. On a sampling basis, the inspectors verified proper control room staffing and coordination of plant activities; verified operator adherence with procedures and technical specifications; monitored control room indications for abnormalities; verified that electrical power was available; and observed the frequency of plant and control room visits by station management. The inspectors reviewed applicable logs and conducted discussions with control room operators throughout the inspection period. The inspectors observed a number of control room shift turnovers. The turnovers were conducted in a professional manner and included log reviews, panel walkdowns, discussions of maintenance and surveillance activities in progress or planned, and associated Limiting Condition for Operation time restraints, as applicable.

1) Auxiliary Feedwater System

On December 7, 1994, at 7:42 p.m. (EST), during surveillance test MO-38, "AFW System Pumps Inservice Test Procedure" of the auxiliary feedwater (AFW) pump P8A, an unanticipated injection of approximately 165 gallons of AFW into the steam generators occurred. This was a result of a failure of an electrical relay that sent an open demand signal to the AFW flow control valves. The AFW flow control valves actually went open upon failure of the electrical relay. Operators immediately recognized that an inadvertent AFW injection occurred and secured the test. The system was returned to the original normal lineup, and event was reported as an engineered safety features (ESF) actuation per 10 CFR 50.72 (b)(2)(ii). However, after securing from the surveillance, the operating shift did not recognize that the AFW flow control valves, CV-0727 and CV-0749, remained in the open position. These valves remaining in the open position could have resulted in a possible pump trip from a runout condition.

In restoring the system following the surveillance, the operating shift believed that the event was caused by the associated test switch (SS-3/P8A/B) not functioning properly. The function of the test switch was to ground out

the flow indicating controllers signal, thus overriding the open demand signal and providing a close signal to the flow control valves. Operators were not cognizant of the flow control valve's position, as the valve position was not available in the control room. Only valve demand signal and AFW flow rates were available. Approximately ten hours later on December 8, 1994, at 5:35 a.m. (EST), control operators recognized a full open signal was being demanded on AFW flow controllers FIC-0727 and 0749 in the control room, and subsequently determined locally that the flow control valves were actually full open.

The AFW flow control valves, normally closed, throttle open on an AFW pump start to control demanded flow. The failed relay had caused the flow control valves to go from the normally full closed position to the full open position. The licensee failed to recognize the open position of the AFW flow control valves during the surveillance test, and subsequent troubleshooting following the test. Following discovery of the open AFW flow control valves, the associated controllers were declared inoperable. An Unusual Event was declared at 6:57 a.m. (EST) based upon the need for heightened awareness and the potential for a plant shutdown required by technical specifications. Instrument and control technicians were able to determine that the open demand signal was caused by a failed electrical relay (SSX-3/P8A/B). The relay was replaced and the Unusual Event was exited, prior to the initiation of a plant shutdown.

In reviewing the event, the inspectors had the following observations:

- The relay had failed on December 7, 1994, at 3:00 a.m. (EST), over 24 hours prior to the declaration of Unusual Event. The inspectors also noted that both FIC-0727 and 0749 have black reference dots associated with them. The reference dots were intended to assist control operators during the conduct of control panel walkdowns. Panel walkdowns were required of control operators every shift. Thus several shift turnovers occurred along with the required panel walkdowns, without the demand signal being recognized out of the normal position.

- The surveillance test, MO-38, was conducted by the operating shift without the support of system engineering. While system engineering assistance was not required to perform the surveillance, the operating shift did brief system engineering by telephone on the event. However, system engineering did not provide subsequent onsite support and relied on the operating shift's assessment of the situation

which did not include any troubleshooting of the equipment involved in the event. On-site support by system engineering could have aided in a more timely identification and could have supported the shift with a more appropriate assessment of the AFW system.

- Since the plant does not have I&C maintenance coverage around the clock at power, there was a delay in troubleshooting efforts and timely restoration of full system operability.

The inspectors will continue to followup on the licensees actions with regard to timely assessments of system operability in response to Licensee Event Report (LER) 255/94020.

2) Power Escalation Following Turbine Valve Testing

The inspectors observed power escalation following scheduled main turbine valve tests. Plant operators reduced reactor power to approximately 85 percent to perform the testing. The evolution was performed without significant complication. Prior to the power escalation, plant operators held a thorough pre-job brief with a good discussion of contingencies. The inspectors observed one minor weakness with the power escalation procedure. Plant operators appropriately changed the procedure, prior to continuing with the power escalation.

General Operating Procedure GOP 5, "Power Escalation After Synchronization," Rev.13, Attachment 4, required the crew to use non-safety related primary coolant system (PCS) loop delta-T recorders to compare with power range nuclear instrument readings. The purpose was to determine how well actual reactor power compared with indicated reactor power, based on PCS loop delta-T.

When the Loop Delta-T recorder temperatures were compared with indicated reactor power on Attachment 4, indicated reactor power was slightly less than actual reactor power and GOP 5 required the power escalation to be stopped.

The crew's diagnostics were good. The Shift Supervisor directed the crew to use alternate indications available (i.e. safety-related loop temperatures, feedwater temperature, generator megawatts) to determine if indicated reactor power was indeed less than actual power. When the safety related loop temperatures were utilized to calculate loop delta-T, the crew determined that indicated and actual reactor power were equal and the non-safety related loop delta-T recorders were reading in error. Feedwater temperature and generator megawatts were also consistent

with indicated reactor power. Additionally, the SS informed plant nuclear engineering personnel, who obtained incore data that agreed with the crews assessment.

The SS informed Operations management and stopped the power escalation until the appropriate procedure change could be processed. After the procedure change was in place the power escalation was completed without any additional problems.

b. Engineered Safety Feature (ESF) Systems (71707)

During the inspection period, the inspectors selected accessible portions of several ESF systems to verify status. Consideration was given to the plant mode, applicable Technical Specifications, Limiting Conditions for Operation requirements, and other applicable requirements.

Various observations, where applicable, were made of hangers and supports; housekeeping; whether freeze protection, if required, was installed and operational; valve position and conditions; potential ignition sources; major component labeling, lubrication, cooling, etc.; whether instrumentation was properly installed and functioning and significant process parameter values were consistent with expected values; whether instrumentation was calibrated; whether necessary support systems were operational; and whether locally and remotely indicated breaker and valve positions agreed.

During the inspection, the accessible portions of the following systems were walked down:

- Auxiliary Feedwater Train A
- Emergency Diesel Generator Train B

c. Onsite Event Follow-up (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 any required notification was correct and timely. The inspectors also verified that the licensee initiated prompt and appropriate actions. The specific events were as follows:

- As previously stated, on December 7, 1994, during surveillance testing of the auxiliary feedwater (AFW) system, an unanticipated injection of AFW into the steam generators occurred, as a result of the AFW system control valves being in the open position. This resulted in the AFW

system injecting approximately 165 gallons of water to each steam generator. The main feedwater system compensated for the injection and maintained normal steam generator levels. The test was immediately terminated and the AFW system was returned to its standby configuration.

- On December 8, 1994, the licensee declared an Unusual Event when AFW flow controllers FIC 0727 and FIC 0749 were declared inoperable. The licensee entered Technical Specification 3.5.3 which required that the plant be in hot standby within six hours when both flow controllers were inoperable.

  Instrument and Control technicians later determined that electrical relay SSX-3/P8A/B failed. The Instrument and Control technicians replaced the relay and the licensee exited the Unusual Event approximately two hours later. The failed electrical relay was the root cause for both of the reportable events described above.

d. Current Material Condition (71707)

The inspectors performed general plant as well as selected system and component walkdowns to assess the general and specific material condition of the plant, to verify that work requests had been initiated for identified equipment problems, and to evaluate housekeeping. Walkdowns included an assessment of the buildings, components, and systems for proper identification and tagging, accessibility, fire and security door integrity, scaffolding, radiological controls, and any unusual conditions. Unusual conditions included but were not limited to water, oil, or other liquids on the floor or equipment; indications of leakage through ceiling, walls, or floors; loose insulation; corrosion; excessive noise; unusual temperatures; and abnormal ventilation and lighting.

Overall material condition was adequate. Some minor items were identified and are described below.

- The inspector found one Appendix "R" emergency light, ELU-6, in the "fast charge" mode during a routine tour of the turbine building rather than in the normal "trickle charge" state. The inspector contacted the system engineer. The system engineer reviewed trend information and found the ELU consumed approximately eight ounces of electrolyte per month over the past few months. The system engineer had recently started to trend electrolyte usage, as well as other problems with the emergency lighting units. The system engineer explained that the high ambient temperature at the ELU's location, combined with the unit switching to the fast charge mode, would explain the higher than normal electrolyte usage. The system engineer issued a work

request to perform a full duration test on the ELU. Also, the engineer requested that the ELU be scheduled for replacement in the next few weeks.

The system engineer exhibited a clear sense of ownership in response to this issue. The engineer issued a letter outlining the above actions, possible causes for the observed problems, and planned actions to resolve the issue.

- The inspectors reviewed the licensee's response to the control room annunciator for safety injection tank T-82D Hi-Lo level. Technical Specifications, procedures SHO 1, "Technical Specification Surveillance Procedure," and RI 15C, "Safety Injection Tank Level Channel Calibration," and SOP 3, "Safety Injection Tank Level Alarm Verification," were reviewed with operations and engineering staffs. The licensee had taken appropriate corrective actions including annotation of the surveillance data sheets and issuing a work order to recalibrate the level instrument. The instrument, LIA-0374, was apparently affected by changes in containment temperature. The licensee was considering replacement of the level instrument with a temperature compensated model as long term corrective action.

e. Housekeeping and Plant Cleanliness (71707)

The inspectors monitored the status of housekeeping and plant cleanliness for fire protection and protection of safety-related equipment from intrusion of foreign matter. No significant concerns were identified this inspection period.

f. Radiological Controls (71707)

The inspectors verified that personnel were following health physics procedures for dosimetry, protective clothing, frisking, posting, etc., and randomly examined radiation protection instrumentation for use, operability, and calibration. The inspector reviewed the radiological survey sheets for Multi-Assembly Sealed Basket #9 and found no problems.

g. Security

Each week during routine activities or tours, the inspectors monitored the licensee's security program to ensure that observed actions were being implemented according to the approved security plan. The inspectors noted that persons within the protected area displayed proper photo-identification badges and those individuals requiring escorts were properly escorted. The inspectors also verified that checked vital areas were locked and alarmed. Additionally, the inspectors also observed that personnel and packages entering the protected area were searched by appropriate equipment or by hand.

No violations, deviations, unresolved, or inspection followup items were identified in this area.

3. Safety Assessment/Quality Verification (40500 and 92700)

a. Licensee Event Report (LER) Follow-up (92700, 81502)

Through direct observations, discussions with licensee personnel, and review of records, the following event report was reviewed to determine that reportability requirements were fulfilled, that immediate corrective action was accomplished, and that corrective action to prevent recurrence had been or would be accomplished in accordance with Technical Specifications (TS):

(Closed) LER 255/94019: Failure to Test Redundant Equipment Per Technical Specification 3.3.2.f Prior to Removal of Electrical Breakers From Service For Planned Preventive Maintenance:

On November 9, 1994, plant personnel identified a failure to implement a Plant Technical Specification requirement. The requirement stated that prior to initiating repairs to certain safety injection system components, all valves in the system that provide the duplicate function shall be tested to demonstrate operability.

On November 6, 1994, the electrical supply breaker for one of four low pressure safety injection loop isolation valves (MO-3014) was removed from service for preventive maintenance on the breaker. The licensee failed to test the other three duplicate valves prior to starting the maintenance.

A similar event occurred again on November 8, 1994. This time low pressure safety injection loop isolation valve MO-3012 was rendered inoperable without performing the required operability testing on the other three duplicate valves.

As reported in the LER, there were three causes for this event:

- During a prior revision to the breaker preventive maintenance document, maintenance personnel failed to include the redundant equipment testing requirement from the Technical Specifications.

- The licensee's second level review of the proposed revision to the preventive maintenance document failed to identify the discrepancy.

- Plant operators failed to identify the required testing prior to approving the work order for start of the work.

The failure to test the remaining low pressure safety injection loop isolation valves is a licensee identified violation of

Technical Specification 3.3.2.f with low safety significance. At the time MO-3014 was inoperable, there was no other inoperable safety injection equipment. Similarly, at the time MO-3012 was inoperable, there was no other inoperable safety injection equipment. The licensee returned MO-3014 and MO-3012 to operable status well within the allowable Limiting Condition for Operation timeframe.

Corrective actions included properly revising the preventive maintenance documents so that required Technical Specification testing is performed. In addition, the plant administrative procedure No. 5.14, "Periodic and Predetermined Activity Control," that addresses second level reviews, was appropriately revised.

This violation will not be subject to enforcement action because the licensee's efforts in identifying and correcting the violation met the criteria specified in 10 CFR 2, Appendix C, Section VII.B(2). Therefore, the violation will not be cited. This LER is closed.

b. Palisades' Performance Enhancement Program (40500)

During the week of December 5, 1994, a training and assessment specialist from the Human Factors Assessment Branch at NRC Headquarters conducted a review of the Palisades Performance Enhancement Program (P^2EP). The inspector identified several strengths in the P^2EP. First, the scope of the program was limited and designed to address items with similar root causes rather then just to address individual symptoms. Secondly, the individual action plans were well written with clear due dates and deliverables. However, the inspector did identify the following three concerns with P^2EP:

- There was a lack of measures of success for each of the P^2EP action plans. Although many of the action plans contain a step that requires developing a verification and validation (V & V) method, this method was not required until the actions in the plan were complete. Discussions with the individuals responsible for action plans determined that there was not always a common understanding of the specific improvements desired from each of the plans. Given the lack of a common understanding of the goals, the V & V process when developed after the fact, could become a measure of the completeness of the activities rather than a measure of success to bring about the original desired change.

- Items included in the P^2EP tend to be broad with a focus on consolidating common items under one action plan. This was a concern since this often results in generic fixes that do not always appear to address the cause of specific problems. For example, errors due to equipment tagging problems have occurred several times over the last 6 months. There were

three P^2EP action plans related to tagging, with two of the three already closed. Further investigation determined that although the closed P^2EP items provided underlying support, such as clearer management expectations to improved tagging, specific changes to the tagging process were still outstanding. These changes were included in a group of action plans (DMAPs) which were separate from the P^2EP and were assigned to individual departments. Therefore, individual actions in the P^2EP have been closed without adequately completing all of the appropriate corrective actions to prevent equipment tagging errors from occurring.

- The P^2EP contains action plans designed to improve the root cause process. Some focus has been placed on improving the efficiency of the process. However, several current practices present challenges to the overall effectiveness of the root cause determination process and may impact the licensee ability to correct human performance issues after a single occurrence. Although the root cause action plan calls for additional staff to be trained in root cause analysis, untrained staff was currently allowed to perform a root cause determination. Additionally, management does not require that a root cause determination always be made by following the standard methods of investigation, thereby circumventing the system designed to ensure the appropriate level of analysis to determine the true root cause. Further, individual departments involved in the issue or event were conducting the root cause determinations. The lack of independent analysis combined with the lack of training and the lax process standards were indications that the licensee has not yet succeeded in improving the root cause process. Current practices suggest that the licensee may not be able to adequately determine the root cause and, therefore, may still experience recurring problems in the area of human performance.

Discussions with licensee management on the completeness and effectiveness of P^2EP action plans resulted in the identification of several management initiatives, including the monthly NPAD report, that the licensee believes will adequately monitor ongoing performance and assure overall success. Licensee management also noted that the Management and Safety Review Committee (MSRC), an independent group established by the licensee in response to Diagnostic Evaluation Team findings, also focuses on monitoring performance. These efforts appear comprehensive but were at a higher level than the actions planned in the P^2EP. However, minutes of the September 13, 1994 meeting of the MSRC indicate that there was a discussion on measuring effectiveness of corrective actions in the P^2EP. The director of NPAD, noted that P^2EP actions could be completed without really solving underlying problems. The meeting minutes further noted that the focus of all performance improvement efforts must remain on fixing the

underlying problems. Although the P^2EP action plans were weak in the area of measuring the effectiveness of completed action, the licensee has proven a sensitivity to the issue and believes other monitoring measures will indicate if success has been achieved in the appropriate areas. Initial reviews of the equipment tagging issue suggest that the level of monitoring was being successful in identifying on-going tagging problems but not in preventing recurrence. Further observation of licensee management oversight was needed to determine the effectiveness of the monitoring in detecting declining trends of human performance before those trends contribute to an operational issue.

c. Commitment Tracking (40500)

The inspectors reviewed the licensee's proposed actions to consolidate the presently used commitment tracking system (CTS) into a more user friendly and effective system. The system now being used by the licensee has not been effective at communicating and ensuring regulatory commitments were identified, documented, and implemented. At present the licensee has assigned two individuals, an administrator and a clerk, to develop the new CTS. A departmental action plan for a new CTS was developed that established the actions to be taken and the scheduled completion dates. The database for new CTS has been delayed and was now scheduled for completion in late January 1995. The inspectors believe the new CTS will improve the effectiveness of ensuring closure of regulatory commitments. Until the new CTS has been determined to be effective, the licensee will continue to utilize the old CTS. To improve the effectiveness of the present system, the licensee has assigned three individuals to overview the closure of regulatory commitments. This overview consists of independently verifying the basis for closure. The inspectors will continue to monitor the licensee's progress in establishing an effective CTS.

One noncited violation was identified. No deviations, unresolved, or inspection followup items were identified in this area.

4. Maintenance/Surveillance (62703 and 61726)

a. Maintenance Activities (62703)

Routinely, station maintenance activities were observed and/or reviewed to ascertain that the activities were conducted in accordance with approved procedures, regulatory guides and industry codes or standards, and in conformance with technical specifications.

The following items were also considered during this review: LCOs were met while components or systems were removed from service; approvals were obtained prior to initiating the work; functional testing and/or calibrations were performed prior to returning

components or systems to service; quality control records were maintained; and activities were accomplished by qualified personnel.

Portions of the following maintenance activities were observed or reviewed:

- Work Order 24414828: Remove Diesel Generator 1-2 Fuel Oil Priming Pump, Disassemble and Rebuild

- Work Order 24414701: Replace Valve and Tubing for MV-DE-662, Diesel Generator 1-2 Lube Oil Pressure Switch PS-1487 Isolation Valve

- Work Order 24414506: Perform Preventive Maintenance on Diesel Generator 1-2 Air Compressor C-3B

- Work Order 24412151, "Load Ventilated Storage Cask No. 05 with Multi-Assembly Sealed Basket No.9"

- Work Order 24202678, "Replace Relay SSX-3/P-8A/B" on the AFW system

The inspector observed portions of the above activities (Work Orders 24414828, 24414701, and 24414506) during a scheduled maintenance outage on Diesel Generator 1-2. Following the maintenance outage, the inspector found several work request tags for minor maintenance hanging on the Diesel Generator. Followup revealed that the work requests had either been canceled or changed. The system engineer agreed to remove and update the tags as necessary.

b. Surveillance Activities (61726)

During the inspection period, the inspectors observed technical specification required surveillance testing and verified that testing was performed in accordance with adequate procedures, that test instrumentation was calibrated, that results conformed with technical specifications and procedure requirements and were reviewed, and that any deficiencies identified during the testing were properly resolved.

The inspectors also witnessed or reviewed portions of the following surveillances:

- SHO 1, "Technical Specification Surveillance Procedure"

- RI 15C, Safety Injection Tank Level Channel Calibration

- MO-38, Auxiliary Feedwater System Pumps Inservice Test Procedure

- MO-7A-1, EDG 1-1 (K-6A)
- MO-7A-2, EDG 1-2 (K-6B)
- SOP-8, Testing of Main Turbine Valves/Protective Trips

No violations, deviations, unresolved, or inspection followup items were identified in this area.

5. Engineering and Technical Support (83750, 37700, 92720)

The inspectors monitored engineering and technical support activities at the site including any support from the corporate office. The purpose was to assess the adequacy of these functions in contributing properly to other functions such as operations, maintenance, testing, training, fire protection, and configuration management.

a. Fuel Loading of Multi-Assembly Sealed Basket (MSB) #9

The inspectors observed the following licensee activities associated with the loading of MSB #9:

- Loading of the MSB and licensee verification of fuel bundles and location in the MSB;
- Installation of the shield lid onto the MSB;
- Movement of MSB Transfer Cask out of the spent fuel pool into the washdown pit;
- Decontamination of the MSB Transfer Cask and MSB;
- Vacuum drying, welding, and helium backfilling of the MSB;
- Transporting the MSB and Ventilated Storage Cask (VSC) to the storage pad.

Briefings for the work were well conducted. Most activities proceeded as planned. The licensee experienced a minor problem during the vacuum drying process. Procedure FHS-M-32, "Loading And Placing The VSC Into Storage," Rev.10, required that the MSB achieve and maintain for 30 minutes a vacuum of 0.050 psia. The licensee could only achieve a vacuum of 0.10 psia. Plant management suspended further activities and promptly conducted a formal review.

Plant management approved a course of action to backfill the MSB with helium to pinpoint the location of the leak. The licensee found the swagelock fitting on the vent line to be leaking. The vent line is used to draw the vacuum and facilitate drying of the MSB. After further review by plant management, plant engineers implemented an approved modification to cover the vent line

opening and proceed with vacuum drying. The licensee then successfully conducted the vacuum drying evolution.

The inspectors found the licensee's actions to be acceptable, as the confinement capability of the MSB was not compromised. No credit is taken in the safety analysis for the swagelock fitting as a pressure retaining component. Further leak testing, after the temporary cover was removed and permanent covers welded into place, proceeded acceptably per the normal procedure. No other evidence of leaks were found and all acceptance criteria was appropriately met.

The inspectors discussed the above issue with cognizant personnel from NRC Region III and NRC Office of Nuclear Material Safety and Safeguards (NMSS). Both groups found the licensee's handling of this issue to be acceptable. The licensee has implemented appropriate corrective actions to preclude a reoccurrence of this problem.

b. Multi-Assembly Sealed Basket Shield Lid Top Plate Charpy Impact Tests

On December 22, 1994, the licensee identified that the shield lid top material for Multi-Assembly Sealed Baskets (MSB) used in Ventilated Storage Casks (VSC) 01 through 04 were not tested to the requirements of paragraph 3.3.1.a of Safety Evaluation Report dated, April 28, 1993, for the VSC system. That paragraph of the Safety Evaluation Report required charpy impact testing of the MSB pressure boundary materials, parts, components at temperatures of -50°F, with toughness not lower than 15 ft-lbs. The impact test requirement on the pressure boundary constitutes the basis for the allowed movement of the MSB above ambient temperatures of 0°F.

The licensee intends to have charpy impact testing performed on sample coupons from the original shield lid material for the affected shield lids.

The licensee considers the Multi-Assembly Sealed Baskets used in Ventilated Storage Casks 01 through 04 to be operable while at rest on the storage pad based on the following:

- A tip over of the MSBs were not possible on the storage pad based on licensee calculations;
- The MSB shield lid top plate was a secondary pressure boundary, while the MSB structural lid plate, bottom lid, and shell were the primary pressure boundary. All primary pressure boundary components meet the charpy impact test requirements.
- The VSC system continues to meet the postulated accident scenarios as described in the Safety Analysis Report.

The licensee expects to receive the charpy impact test results for the affected MSBs within the next several weeks. The lack of charpy impact testing of the MSB pressure boundary materials, parts, components at temperatures of -50°F, with toughness not lower than 15 ft-lbs is considered an unresolved pending further NRC review (50-255/94021-01).

No violations, deviations, unresolved, or inspection followup items were identified in this area.

6. (Closed) Temporary Instruction 2515/111, "Electrical Distribution System Functional Inspection Followup

a. (Closed) Information Followup Item (255/91019-01(DRS)): The EDSFI team identified that the 1988 and 1989 Electrical Load Study did not use the worst case cable loading conditions when calculating the cable voltage drops. The following concerns were identified:

- The study assumed a 75°C temperature for cable sizes No. 8 and smaller, and 65°C for cable sizes No. 6 and larger, when the maximum conductor rating was 90°C for installed cables.

- Reactance values used were not applicable to the type of cable installed in the plant.

- Circuit breaker contacts and fuse impedances were not considered in the load study.

- The "worst case loads" had not included all running motors.

- The impedance used for buried cables from the switchyard to Safeguards transformer were different than actual cable impedances.

In response, the licensee revised Engineering Analysis EA-ELEC-VOLT-014, Rev 1, to address the above concerns. The difference in cable voltage drop from the original analysis was minimal. The inspectors reviewed the engineering analysis and concluded the licensee had adequately addressed the above concerns. This item is closed.

b. (Closed) Information Followup Item (255/91019-02(DRS)): The EDSFI team was concerned that system operating procedures did not address potential safeguards buses high voltage conditions that could result from a stuck safeguards transformer tap changer.

In response, the licensee determined that the 2400 volt Class 1E buses should be maintained < 2530 volts to prevent exceeding the voltage limitations of the 2300V and 460V motors. Standard operating procedures were tentatively scheduled to be updated by April 11, 1995. The operators log the safeguards buses voltage

once per shift. In addition, the expected switchyard voltages were well documented over the past 10 years and no excessive voltage conditions were identified on the safeguards buses. The inspectors concluded the licensee had adequately addressed this issue. This item is closed.

c. (Closed) Information Followup Item (255/91019-03(DRS)): The EDSFI team was concerned that Startup Transformer 1-2 feeder cables to the safeguards buses could exceed their 90°C continuous duty temperature rating when supplying design basis accident loads.

In response, the licensee performed a calculation to determine the time that the cables could be operated at the 105°C emergency overload temperature. The analysis indicated that the cables would not exceed the 105°C limit. However, analyses were ongoing to determine the length of time that the cables could be overloaded. Once completed, the time limits will be incorporated in the appropriate operating procedures.

The normal offsite power supply to the safeguards buses was through Safeguards Transformer 1-1. The team verified Transformer 1-1 feeder cables were adequately sized. In addition, the emergency diesel generators were also available to supply the safeguards buses. The inspectors concluded that ample power sources were available to supply the safeguards buses until the operating procedures were updated. This item is closed.

d. (Closed) Information Followup Item (255/91019-04(DRS)): The EDSFI team questioned the ability for two feeder cables between the plant and station power transformer No. 2 to withstand postulated fault currents. The potential exists for the two rubber insulated cables to exceed their 200°C emergency overload temperature prior to the fault being cleared.

In response, the licensee revised the FSAR to clarify that the two cables in question (A1108/A11-X51/1 and A1306/A13-X50/1) could exceed the 200°C requirement for a short period of time until breakers cleared the fault. The licensee reviewed the cables routing and determined the cables were not routed with any Class 1E cables. In addition, the licensee contacted an industry cable expert. The expert concluded the cables could withstand the fault current; however, the cables would require replacement following exposure to the maximum available fault current. The inspectors reviewed the licensee's analysis and concluded the undersized cables did not represent an operability concern. This item is closed.

e. (Closed) Information Followup Item (255/91019-05(DRS)): The EDSFI team concluded that nonconservative values for system voltage and cable temperature were used in engineering analysis No. EA-E-ELECT-FLT-10/91-1. The analysis was prepared to determine the fault duties for the 4160, 2400 and 480 volt circuit breakers.

In response, the licensee performed engineering analysis No. EA-ELECT-FLT-007, Rev 0, to determine if the 4160, 2400 and 480 volt circuit breakers could withstand and interrupt the maximum available short circuit current. As a result, Breaker 52-1112 was recommended for replacement to provide greater interrupting margin. The inspectors reviewed the licensee's proposed corrective actions and found them to be acceptable. This item is closed.

f. (Closed) Information Followup Item (255/91019-06(DRS)): The EDSFI team noted that existing plant procedures did not provide adequate guidance on how to identify a ground fault on the ungrounded 2400 volt system.

In response, the licensee revised Alarm Response Procedure (ARP) No. 3, "Electrical Auxiliaries and Diesel Generator Scheme EK-05," to provide guidance on identifying and isolating a ground fault on the 2400 volt system. The inspectors reviewed the procedure revision and concluded the changes were acceptable. This item is closed.

g. (Closed) Information Followup Item (255/91019-07(DRS)): The EDSFI team was concerned that the 2400 volt electrical system, which was designed to be ungrounded, was susceptible to high voltage transients caused by intermittent ground faults. This item was referred to NRR for review.

In response, NRR identified that 23 other nuclear and non-nuclear utilities used ungrounded low and medium voltage distribution systems. A survey of these utilities did not identify any adverse problems attributed with ungrounded systems. NRR concluded that the use of an ungrounded 2.4 KV distribution system at Palisades was acceptable. This item is closed.

h. (Closed) Information Followup Item (255/91019-08(DRS)): The EDSFI team was concerned that insufficient procedure guidance was provided to the operators as to what switchyard voltage would be acceptable for transferring from the EDGs to offsite power.

In response, the licensee calculated the minimum switchyard voltages for transferring to the safeguards, startup or station power transformers. Standard operating procedure No. 30, "Station Power," was currently under revision to incorporate the appropriate switchyard values. The inspectors reviewed the proposed procedure changes and concluded the changes were reasonable. This item is closed.

i. (Closed) Information Followup Item (255/91019-09(DRS)): The EDSFI team was concerned that the EDG loading calculation did not reflect actual magnitude, start time, and duration of manually started EDG loads.

In response, the licensee reviewed the current EDG loading profile with Operations. A revised EDG loading calculation was issued and appropriate operating procedures were revised to control EDG loading. The inspectors reviewed the operating procedures and the loading calculation, and concluded the licensee had adequately addressed this issue. This item is closed.

j. (Closed) Information Followup Item (255/91019-10(DRS)): The EDSFI team noted that certain EDG trips did not use coincident logic. The potential exits for spurious tripping of the EDGs when required to mitigate a design basis accident. These trips included the following:

- Generator trip on underspeed (< 600 rpm) through the field shutdown timer.
- Engine and generator trip on engine underspeed (< 120 rpm).
- Engine and generator trip on jacket water low pressure, start circuit B only.
- Engine and generator trip on generator overcurrent.

In response, the licensee stated that several modifications were being prepared to improve EDG reliability. The above items were included in Facility Change (FC) No. 940. This modification was tentatively scheduled for implementation during the 1995 refueling outage. The inspectors reviewed the proposed logic changes and concluded the changes should correct the EDSFI team concerns. This item is closed.

k. (Closed) Unresolved Item (255/19019-11(DRS)): The EDSFI team noted that the load shedding capability of certain equipment were not positively identified during surveillance testing.

In response, the licensee revised surveillance procedure No. RT-8C, "Engineered Safeguards System - Left Channel," and No. RT-8D, "Engineered Safeguards System - Right Channel," to better document equipment load shedding capability. In addition, the licensee identified that relay No. 194-41 (left channel) contacts that trip feed breaker No. 152-303 would not be tested during the performance of RT-8C. Instead, the breaker would be verified to trip from relay No. 194-42 (right channel) contacts only. The inspectors informed the licensee that all safety related contacts need to be tested, including parallel logic schemes. The licensee agreed that breaker No. 152-303 and No. 152-302 (similar testing arrangement) should have both logic paths tested. The licensee indicated that a testing method would be developed and implemented during the 1995 refueling outage. This was acceptable to the inspectors. The inspectors did note that the above surveillance procedures did verify that the breakers would trip from the one parallel set of logic contacts. In addition, the procedures

positively identified that the above relays had functionally operated. Based on the above, the inspectors concluded the breakers and relays were functionally operable. This item is closed.

l. (Closed) Violation (255/91091-12(DRS)): The EDSFI team was concerned that EDG surveillance procedure No. MO-7A-1, "Emergency Diesel Generator 1-1 (K-6A)," and No. MO-7A-2, "Emergency Diesel Generator 1-2 (K-6B)," start time testing did not include all of the emergency start circuit components in the response time determination (10 seconds).

In response, the licensee evaluated the response time of the untested components, such as the engine start relay (ESR) and the cranking relay (CR). The licensee determined that the ESR and CR relays actuated in 0.125 seconds. As a result, the licensee revised the monthly EDG surveillance procedures acceptance criteria to verify the EDGs start within 9.5 seconds. This was acceptable to the inspectors since the acceptance criteria was conservative to actual measured values. This item is closed.

m. (Closed) Violation (255/91019-13(DRS)): The EDSFI team determined that post modification test procedure No. T-FC-687-001 did not test the control functions associated with Handswitch HS-152-106RLTS contacts 3/3C, 4/4C, 5/5C and 11/11C.

In response, the licensee reviewed the above test procedure against the electrical schematics. The licensee concluded that contacts 3/3C and 11/11C were adequately tested in the test procedure. The licensee also verified that contacts 4/4C and 5/5C, though not verified to reopen in the test procedure, were in fact verified open during normal operator verification of Safeguards Bus 1C operating current. The inspectors reviewed the test procedure and concluded contacts 3/3C and 11/11C had been adequately tested. In addition, the inspectors agreed that the opening of contacts 4/4C and 5/5C would be verified by the operators during normal bus current verification. However, 10 CFR 50, Appendix B, Criterion XI, requires that applicable acceptance limits be incorporated into test procedures. Verification that contacts 4/4C and 5/5C had opened should have been part of the test procedure acceptance criteria. This item is closed.

n. (Closed) Deviation (255/91019-15(DRS)): The EDSFI team concluded that the current EDG starting circuit design did not conform to FSAR Section 8.4.1.3 requirements. The FSAR indicated that each EDG had two independent start circuits on separate DC sources. When in fact, if either the B starting circuit source breaker or the field flashing unit fuse failed, the EDG would not be capable of starting within the required 10 seconds.

In response, the licensee indicated that the original purchase specification required dual electric control circuits only for the

air start motors. The current design does meet this requirement. The licensee is revising the FSAR to clarify the current EDG control circuit design. This was acceptable to the inspectors and this item is closed.

o. (Closed) Violation (255/91019-16(DRS)): The EDSFI team noted that on July 18, 1989, September 17, 1990 and September 17, 1991, the Emergency Diesel Generators (EDG) Technical Specification (TS) limit of 750 amperes load was exceeded during surveillance testing.

In response, the licensee revised monthly EDG surveillance Procedure Nos. MO-7A-1 and MO-7A-2. The maximum allowable current is now more clearly controlled by these procedures. The inspectors reviewed the procedures and concluded they were acceptable. This item is closed.

p. (Closed) Information Followup Item (255/91019-17(DRS)): The EDSFI team identified several minor discrepancies that existed between single line diagram E-8, Sheets 1 and 2, and other relevant engineering documents.

In response, the licensee corrected the discrepancies by DCRs 950-91-1194 and 950-92-287. The licensee performed additional drawing reviews. Several minor discrepancies were identified and were corrected by DCRs 950-93-382, 950-93-347 and 950-93-370. This was acceptable to the inspectors and this item is closed.

q. (Closed) Violation (255/91019-20(DRS)): The EDSFI team was concerned that a testing program had not been established to verify the safety related battery chargers could meet their 200 ampere rating.

In response, the licensee verified that each charger's rated output could be provided. In addition, steps were added to the refueling outage battery performance and service tests to monitor the battery charger output current. The inspectors reviewed the last battery tests and verified each charger could provide 200 amperes of current. A Periodic and Predetermined Activity Control (PPAC) document was being prepared to schedule a special performance test of each charger once per 5 years. This was acceptable to the inspectors and this item is closed.

r. (Closed) Deviation (255/91019-21(DRS)): The EDSFI team identified that the EDG Remote/Local handswitch alarm, "Control Switch Not in Automatic," did not exist in the control room as stated in FSAR Section 8.4.1.3.

In response, the licensee conducted a review of other EDG process parameters, indicators and alarms to determine if other licensing commitments had been missed. The licensee concluded that certain

EDG process parameters would require upgrading. Modifications were tentatively scheduled for the 1998 refueling outage to upgrade the EDG process control systems. The inspectors walked down the EDG Remote/Local, Unit/Parallel and voltage regulator Auto/Manual handswitches. Black dots were used to identify the correct position of critical control switches. Critical control switch positions were independently verified five times per shift. In addition, the above switches were verified to be in the correct position prior to heat-up at the completion of an outage via operation's checklist No. CL 22.1. Use of the switches were procedurally controlled through standard operating procedure No. SOP-22 or EDG monthly surveillance procedure Nos. MO-7A-1 and MO-7A-2. The inspectors concluded the licensee had adequate administrative controls in place until appropriate modifications could be implemented. This item is closed.

s. (Closed) Information Followup Item (255/91019-22(DRS)): The EDSFI team identified several discrepancies in the design documentation associated with the EDG fuel oil storage tanks. The discrepancies included the following:

- Fuel consumption tests were not documented.
- Calculations were inconsistent regarding the capacities of the EDG daytanks and belly tanks.
- The low level daytank alarm setpoints did not provide for sufficient daytank inventory.
- The FSAR, TS and various engineering analyses stated different EDG running time capabilities.
- The surveillance program did not include a test to verify the EDG daytanks could be emergency filled.

In response, the licensee determined the EDGs fuel oil consumption rates and performed an analysis to determine the fuel oil storage tank and daytank usable volumes. Based on the test results, the licensee concluded the existing fuel oil storage tank low level setpoints were acceptable. Analyses were performed which confirmed that sufficient usable volume existed in the various fuel oil tanks. In addition, the licensee proceduralized the various emergency fill methods. The inspectors reviewed the above items and concluded the licensee had adequately addressed the discrepancies. This item is closed.

t. (Closed) Information Followup Item (255/91019-25(DRS)): The EDSFI team identified that the EDGs ability to start at minimum hot standby conditions (90°F lube oil and jacket water temperature, and 65°F room temperature) had not been demonstrated.

In response, the licensee performed a test at an EDG room temperature of 58 ± 2°F, and a jacket water, lube oil and engine block temperature of 85°F. The EDGs successfully started at these minimum design conditions. In addition, the licensee added the minimum design temperature conditions to the operator round sheets. The inspectors reviewed the test procedure and concluded the licensee had adequately demonstrated the EDGs capability to start at their minimum design temperature. This item is closed.

u. (Closed) Information Followup Item (255/91019-26(DRS)): The EDSFI team noted that plant procedures did not specifically dictate switchyard work policy when an EDG had been removed from service for maintenance or testing.

In response, the licensee provided administrative procedure No. 402, "Control of Equipment." Specifically, paragraph No. 9.5, "Maintenance LCO Policy," provided guidelines on how to minimize plant risk if an EDG was removed from service. The inspectors reviewed the procedure and concluded the procedure would adequately control switchyard work if an EDG was removed from service. This item is closed.

v. (Closed) Violation (255/91019-27(DRS)): The EDSFI team identified that the post modification test for FC-839 inadequately tested the blocking function of charging pump No. P55B low suction pressure and low lube oil pressure trips when the pump was powered from the alternate power source.

In response, the licensee satisfactorily tested the above trip functions. As part of the corrective actions, the licensee evaluated seven additional post modification tests. The seven modifications were adequately tested. In addition, engineering guideline No. EGAD-PMC&T-02, "Guideline For Preparing Modification Test Procedures," was strengthened to include negative testing reviews. This review was used to identify improper logic inputs and to identify the effects of improper outputs. Specifically, to identify that all logic states (open and closed, or on and off) were verified and that no unexpected operating states were introduced. The inspectors reviewed the revised test procedure for FC-839 and concluded the licensee had adequately retested the above trip functions. This item is closed.

The actions of TI 2515/111 were complete. No violations, deviations, unresolved, or inspection followup items were identified in this area.

7. (Closed) Temporary Instruction 2515/126, "Evaluation of Online Maintenance"

An evaluation of the impact on safety of the licensee's procedures and practices regarding the removal of equipment from service for on-line

maintenance was conducted in accordance with inspection procedures contained in Temporary Instruction (TI) 2515/126. The inspectors had the following observations:

- Probabilistic Risk Assessment (PRA) insights had been incorporated into the scheduling of on-line maintenance including examples of deferred maintenance/testing due to PRA input. The PRA was conducted using the IPE to determine how significant the increase in risk was for that particular day given the equipment that would be unavailable for testing/maintenance.

  However, the initial PRA was conducted at the request of the operations department through an informal process which did not require the PRA group to receive information regarding degraded and/or inoperable equipment and no threshold of "significant increase of risk" had been established. Additionally, nothing in place would require a second PRA to be performed if equipment that affected risk became degraded and/or inoperable subsequent to the initial PRA.

- The licensee's conduct of operations during on-line maintenance avoided other testing and maintenance that would increase the likelihood of a transient such as no maintenance allowed on PRA risk significant systems during turbine valve testing. Additionally, the licensee's on-line maintenance guidelines did restrict maintenance activities on systems required to mitigate events if the probability of that particular event was increased. For example, maintenance was not allowed on systems required to mitigate a LOOP event if the probability of that event was increased (i.e. weather conditions).

- The licensee's process to plan and schedule on-line maintenance would appropriately modify the testing and maintenance schedules to account for degraded or inoperable equipment. The process included meetings conducted twice weekly to discuss the scheduled maintenance at various planning stages which were observed by the inspectors. One meeting discussed T-6 and T-4 schedules (six and four weeks prior to performing scheduled maintenance) and the second meeting discussed T-2 and T-1 schedules (two and one week prior to performing scheduled maintenance). Information specific to each maintenance week such as changing plant conditions, equipment availability, engineering issues, and parts availability, were discussed and the maintenance schedules were modified as necessary.

- The inspectors interviewed various plant personnel and determined that maintenance and operations personnel involved with the planning and scheduling of on-line maintenance were very knowledgeable of the process and its intended implementation structure. However, plant personnel not directly involved with scheduling and planning (i.e. shift operators, system engineering) did not fully understand the intended implementation structure.

The inspectors attributed this to the current on-line maintenance process being relatively new (only six weeks old) and that all appropriate plant personnel have not been adequately informed about the new process and its intended implementation structure.

The inspectors concluded that the process in place adequately incorporated risk insights when scheduling on-line maintenance and that the schedule would be changed appropriately to account for degraded/inoperable equipment. Additionally, personnel directly involved with planning and scheduling of on-line maintenance were very knowledgeable of the process. However, the licensee's program had been in place for only six weeks and was not proceduralized. (The licensee intended to proceduralize the on-line maintenance program around February 1995). On-line maintenance "guidelines" were being used to implement the process and were subject to continuous review and change as part of the developmental stages. Additionally, all appropriate plant personnel have not been adequately informed of the new process and its intended implementation structure.

The actions of TI 2515/126 are complete. No violations, deviations, unresolved, or inspection followup items were identified in this area.

8. Report Review

During the inspection period, the inspectors reviewed the licensee's monthly operating report for November 1994. The inspectors confirmed that the information provided met the reporting requirements of TS 6.9.1.C and Regulatory Guide 1.16, "Reporting of Operating information."

No violations, deviations, unresolved, or inspection followup items were identified in this area.

9. 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 5.b.

10. Meetings and Other Activities (30703)

On December 13, 1994, a public meeting was held in Region III to discuss ongoing engineering programs at Palisades. The meeting was attended by G. E. Grant, Director, Division of Reactor Safety, T. O. Martin, Deputy Director, Division of Reactor Projects and K. P. Powers, Engineering Manager, Consumers Power Company, and their respective staffs. The meeting was held to discuss the state of various engineering programs at Palisades and the licensees actions with regard to these programs.

11. Exit Interview

The inspectors met with the licensee representatives denoted in paragraph 1 during the inspection period and at the conclusion of the inspection on January 6, 1995. The inspectors summarized the scope and results of the inspection and discussed the likely content of this inspection report. The licensee acknowledged the information and did not indicate that any of the information disclosed during the inspection could be considered proprietary in nature.