U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Reports No. 50-237/88029(DRS); 50-249/88030(DRS)

Docket Nos. 50-237; 50-249 Licenses No. DPR-19; DPR-25

Licensee: Commonwealth Edison Company
Post Office Box 767
Chicago, IL 60690

Facility Name: Dresden Nuclear Power Station - Units 2 and 3

Inspection At: Morris, Illinois

Inspection Conducted: January 23-27, February 6-10, and 16, 1989.

Inspectors:	W. J. Kropp Team Leader	4/4/89 Date
	D. S. Butler	4/4/89 Date
	T. H. Carter	4/4/89 Date
	N. C. Choules	4/4/89 Date
	S. D. Eick	4/4/89 Date
	Z. Falevits	4/4/89 Date
	S. M. Hare	4/4/89 Date
	D. Miller	4/4/89 Date
Contractor:	C. Kido (INEL/EGG Idaho)	4/4/89 Date
Approved By:	F. J. Jablonski, Chief Maintenance and Outage Section	4/4/89 Date

Inspection Summary

Inspection on January 23-27, February 6-10, and 16, 1989 (Reports No. 50-237/88029(DRS); No. 50-249/88030(DRS))

Areas Inspected: Special announced team inspection of maintenance, support of maintenance, and related management activities. The inspection was conducted utilizing Temporary Instruction 2515/97, the attached Maintenance Inspection Tree, and selected portions of Inspection Modules 62700, 62702, 62704, and 62705 to ascertain whether maintenance was effectively accomplished and assessed by the licensee.

Results: Overall, implementation of the licensee's maintenance program was determined to be satisfactory. Areas of strengths and weaknesses were identified as discussed in the Executive Summary. Two violations were identified: failure to adequately evaluate 4.16kV breaker and 250Vdc motor control center failures and failure to follow procedures pertaining to safety evaluations for temporary changes. One unresolved item was identified that pertained to 4.16kV to electrical breakers.

DETAILS

1. Persons Contacted

Commonwealth Edison Company (CECo)

*N. Kalivianakis, General Manager (BWRs)
*E. Eenigenburg, Station Manager
*D. Booth, Master Electrician
*J. Brunner, Assistant Superintendent of Technical Services
*J. Coonan, Maintenance Improvement Coordinator
*R. Meadows, Maintenance Staff Supervisor
*C. Schroeder, Services Superintendent
*M. Strait, Master Mechanic
*D. VanPelt, Assistant Superintendent of Maintenance
*G. Wagner, Production Services Superintendent

U.S. Nuclear Regulatory Commission

*H. Miller, Director, Division of Reactor Safety, RIII
*S. DuPont, Senior Resident Inspector
*F. Jablonski, Chief, Maintenance and Outage Section, RIII
*E. McKenna, Section Chief, Performance and Quality Evaluation, NRR
*M. Ring, Chief, Project Section 1B, RIII
*T. Ross, Project Manager, NRR

*Denotes those present at the exit meeting on February 16, 1989.

Other licensee personnel were contacted as a matter of routine during the inspection.

2. Introduction to the Evaluation and Assessment of Maintenance

This inspection was conducted to evaluate the extent that a maintenance program had been developed and implemented by the licensee at the Dresden Nuclear Plant. Three major areas were evaluated: (1) overall plant performance as affected by maintenance; (2) management support of maintenance; and (3) maintenance implementation.

The goals of this inspection were to evaluate maintenance activities to determine if maintenance was accomplished, effective, and assessed by the licensee to assure the preservation or restoration of the availability and reliability of plant structures, systems, and components to operate on demand. The systems and components selected for this inspection were based on a generic Boiling Water Reactor (BWR) Probabilistic Risk Assessment (PRA) study furnished to the team by the Reliability Applications Section of the Office of Nuclear Reactor Regulation. The systems/components selected were:

Electrical

- 138kV Switchyard Breakers
- 4.16kV Breakers and Cubicles
- Emergency Diesel Generator (EDG) Cooling Components
- Power Transformers
- 125 and 250Vdc Motor Control Centers (MCC)

Mechanical

- High Pressure Cooling Injection (HPCI) Pump and Skid Components
- HPCI makeup water components
- Automatic Depressurization System (ADS) Valves

Instrumentation

- Inverters
- Instrumentation that initiates HPCI

Inspectors reviewed work already accomplished, observed current plant conditions and work in progress, and evaluated the licensee's self assessment and correction of any weaknesses. Major areas of interest included maintenance associated with electrical, mechanical, instrument and control (I&C) and the support areas of radiological control, engineering, quality control, training, procurement, and operations. Problems identified by the NRC inspectors were evaluated for effect on Technical Specification (TS) operability and technological or managerial weakness.

This inspection was based on the guidance provided in NRC Temporary Instruction 2515/97, "Maintenance Inspection," and Drawing 425767-C, "Maintenance Inspection Tree." The drawing, which is attached to this report, was used as a visual aid during the exit meeting to depict the results of the inspection.

2.1 Historic Data

The inspectors prepared for this inspection by review of data that described the Dresden Nuclear Power Station operating history in terms of availability, operability, reliability, and radiation exposure. Included were Licensee Event Reports (LERs), the latest Systematic Assessment of Licensee Performance (SALP) report, completed NRC inspection reports and other industry data. Primarily, the inspectors were sensitive to technical and managerial problems that appeared to be maintenance related. Results of this review indicated that there were potential weakness in:

- Preventive maintenance (PM) of motors (LER 237/88009)
- Thermal overloads (LER 249/88013)
- HPCI flow transmitters (LER 237/88015)
- Auxiliary switches associated with 4.16kV breakers (LER 237/88021)

Based on the results of this review, the inspectors were sensitive to these issues and the potential weaknesses that existed. During this inspection, concerns were identified that related to potential weaknesses with thermal overloads and auxiliary switch contacts. These weaknesses are discussed in other sections of this report.

The inspectors reviewed plant operations history data since January 1, 1988, to assess the licensee's performance in meeting four established goals: unplanned reactor trips; Engineered Safety Feature (ESF) actuations; Safety Systems actuations; and forced outage rate. The goals established for each of the areas were representative of the industry's average in each of the areas. Results were:

- One unplanned reactor trip; the goal was 2.9/year.
- Seven ESF actuations for Unit 2 and seven for Unit 3; the goal was 10/unit/year.
- Zero Safety System Actuations; the goal was 0.9/year.
- Approximate forced outage rate of 0.1% for Unit 2 and Unit 3; the goal was 5.3%.

Overall performance in the above four areas exceeded the established goals and indicated that maintenance had also improved .

2.2 Description of Maintenance Philosophy

The inspectors reviewed site policy statements, administrative procedures, organization charts, established goals, and documents that described improvement programs for the maintenance process.

The licensee had a documented and comprehensive corporate maintenance plan, "Conduct of Maintenance (COM)," which included milestones and completion dates for improvement programs and goals. Specific areas of the COM were assigned to each of the licensee's nuclear facilities to develop procedures and policy. The Dresden Nuclear Power Station was assigned as the "lead" plant in the development of four of the 16 areas including post maintenance testing, maintenance procedures, failure analysis, and types of maintenance. Personnel from each nuclear facility periodically met to discuss each of areas being developed. The goal for complete COM program implementation is 1991.

The HPCI system was the model for Dresden's Maintenance Improvement Program (MIP). The MIP included motor operator valve (MOV) upgrade, PM program enhancement, failure analysis, work planning preparation and scheduling, post maintenance testing, and communications. The HPCI system, as the "model system," was enhanced in terms of maintenance procedures, technical support, material condition, and overall appearance and performance. As of December 1988, approximately 83% of the action items for the HPCI model were completed.

One important aspect of the "model system" concept was the utilization of PRA techniques to identify critical components. This was considered a strength by the team and should be considered for other systems at Dresden. The inspectors noted however, that vendor requirements of the critical components had not been reviewed by the licensee to identify any additional PM tasks. HPCI had an availability factor during 1988. of 96.8% for Unit 2 and 98.8% for Unit 3. The licensee did not have an availability factor for HPCI prior to 1988. However, the team reviewed the number of hours that HPCI was not available between January 1987 - January 1988, and January 1988 - January 1989. There was a noted improvement; 250 hours compared to 64 hours. Regarding availability of other equipment, the cumulative availability factor for EDGs improved between 1987 and 1988 from 95.5% to 99.5%; the industry median for 1987 was 98.1%. There was no industry median available for 1988.

The licensee utilized goals to measure if maintenance was accomplished. The criteria included backlog and PM/CM ratio. However, the licensee had not established goals for measuring effectiveness of maintenance such as the number of limiting conditions for operation due to equipment problems and number of power reductions due to equipment problems.

Overall, the licensee's philosophy was consistent with other licensee's in the areas of PM including predictive maintenance such as in the areas of vibration analysis, lube oil analysis, and computer utilization for work control and scheduling. The licensee was innovative in the use of work history, Time Series Analysis, to identify components that required increased attention. This, along with the PRA approach used for identification of HPCI critical components should be a solid foundation for the maintenance program, if followed through on other systems. During the course of the inspection the team inspected areas that were affected by both COM and MIP, both of which had positive impact on the performance of maintenance at Dresden. Combined with improvement in the availability and operability of HPCI and EDG, the team concluded that the maintenance process has improved overall. Improvement, to some degree was attributed to the MIP; however most of the improvement was the result of aggressive management involvement and the attitude of maintenance personnel.

2.3 Review and Evaluation of Maintenance Accomplished

2.3.1 Backlog Assessment and Evaluation

The inspectors reviewed the amount of work accomplished compared to the amount of work scheduled. The area of interest was work that could affect operability of safety-related equipment or equipment considered important to safety, such as some balance of plant components. Maintenance work item backlogs were evaluated for safety impact of deferrals, and causes such as lack of personnel, lack of trained/qualified personnel, lack of parts or engineering support.

2.3.1.1 Corrective Maintenance Backlog

The majority of non-outage corrective maintenance work requests (CMWRs) were prioritized B2, which was defined in the COM as work that must be scheduled within five days. However, most of the B2 CMWRs were much older than five days. As a result of an inspector's concern, the licensee reviewed the backlog of B2 CMWRs to determine if any affected plant operability or should be immediately completed. A small percentage were reclassified priority B1; however, operability was not affected. The licensee revised the WR prioritization process to agree with the COM.

The backlog of both outage and non-outage CMWRs was tracked by the maintenance department by use of a computerized system. Backlog information could be obtained from the computer at anytime. A tracking report was issued monthly to management on the status of the backlogs. The current as well as previous month's backlogs were listed so increases were readily apparent. The report also indicated the percentage of CMWRs open more than three months. The number of CMWRs on hold for parts was not available to management. A memorandum issued in September 1988 specified that cognizant personnel should provide computer input whenever a CMWR was on hold because parts were not available. Only 2 CMWRs were identified by the computer as awaiting parts even though 16 CMWRs were on hold for parts in the instrument department. The program for the verification of CMWRs on hold for parts had not yet been fully implemented.

The inspectors determined that on January 25, 1989, the non-outage CMWR backlog was 514 for mechanical maintenance (MM), 203 for electrical maintenance (EM), and 172 for instrumentation maintenance (IM). The CM backlog was low and within the capabilities of current staff. The inspectors reviewed several non-outage backlogged CMWRs and determined that none had impact on operability. However, based on the review of actual time spent on CMWRs completed in 1988, which was provided from a computer history, the inspectors determined the actual number of hours to complete a majority of the work requests was about twice the licensee's estimate. Based on the number of craftsmen and doubling the licensee estimated hours to complete the backlog, there was approximately eight weeks work for MM, and three weeks for EM and IM. Even though no problems were identified, underestimates of the number of hours to complete maintenance work could adversely affect an outage schedule.

2.3.1.2 Preventive Maintenance Backlog

Preventive maintenance WRs (PMWRs) were also tracked by a computerized system. Both scheduled and non-scheduled PMs were tracked. Based on review of licensee records, the inspectors determined that on January 23, 1989, the non-scheduled PM backlog was 230 and the scheduled PM backlog was 1. This backlog was low and represented less than one months work. The licensee's ratio of PM hours to total maintenance hours averaged about 57% during 1988, which was higher than the industry average of 42%, and approached the INPO goal of 60%.

Review of the scheduled PMWRs backlog identified a small percentage that should have been classified as corrective maintenance. The inspectors did not identify any that would have immediate impact on operability of a component. Since the misclassification represented a small percentage, the inspectors were not concerned with any impact on the backlog.

2.3.2 Review and Evaluation of Completed Maintenance

The inspectors selected the components and systems identified in Section 2.0 of this report for further review. The purpose of this review was to determine if specified electrical, mechanical, and I&C maintenance on those selected systems/components was accomplished as required. This review included:

- Evaluation to determine the extent that Reliability Control Maintenance (RCM) was factored into the established maintenance process.
- Evaluation of the extent that vendor manual recommendations, IE Bulletins (IEB), IE Notices (IEN), Service Information Letter (SILs), Significant Operating Experience Record (SOERs), and other outside source information were utilized.
- Evaluation of the extent that maintenance histories, Nuclear Plant Reliability Data System (NPRDS) information, LERs, negative trends, rework, extended time for outage, frequency of maintenance, and results of diagnostic examinations were analyzed for trends and root-causes for modification of the PM process to preclude recurrence of equipment or component failures.
- Evaluation of completed CMWRs and PMWRs for use of qualified personnel, proper prioritization, Quality Control (QC) involvement, quality of documentation for machinery history, description of problems and resolutions, and post maintenance testing.
- Evaluation of work procedures for inclusion of QC hold points, acceptance criteria, user friendliness, and general conformance to NUREG/CR-1369. "Procedure Evaluation Checklist for Maintenance Test and Calibration Procedures Used for Nuclear Power Plants."
- Backlogs for selected components.

2.3.2.1 Review of Completed Electrical Maintenance

The inspectors determined that the electrical maintenance philosophy did not yet include the concept of RCM. The licensee had initiated or had plans to implement predictive maintenance that included vibration analysis and a thermovision device to detect loose electrical terminations. Electrical maintenance was generally balanced between corrective and preventive, which was based on previous work history and/or vendor recommendations.

The inspectors evaluated the extent that vendor recommendations, bulletins, notices, General Electric (GE) service letters, and other outside source information and correspondence were utilized in electrical maintenance. The component's selected for evaluation were the EDG, 125/250Vdc MCCs and 4.16kV switchgear and breakers, and Reactor Protection System (RPS) Electrical Protection Assembly (EPA) units. The inspector reviewed 14 source documents to determine if recommendations specified in the vendor documents were incorporated into appropriate maintenance documents.

The inspectors determined that the licensee was aggressive in the replacement of Tuf-Loc sleeve bearings for 4.16kV breakers as described in GE Service Advice Letters (GE SALs) 073-313.1 and 318.1A. The inspectors also verified that the licensee had implemented the recommended maintenance defined in GE Service Information Letters (GE SIL) 448 that pertained to AKF-25 480V breakers. Previous industry failures with the breakers were attributed to mis-adjustment or lubrication problems. The maintenance defined in GE SIL 448 was performed on the breakers for the recirculation MG set in April 1988 (Unit 3) and December 1988 (Unit 2).

The inspectors identified a concern with the control of electrical vendor source documents. An individual was not assigned to coordinate vendor data to ensure that recommendations and revisions were reviewed for applicability and possible incorporation into appropriate maintenance procedures. Specifically, the inspector determined that:

- GE SALs 313.1A, 323.1, 326.1, and 343.1 could not be located in document control or technical staff files.

- Maintenance Procedures DMP-6700-3, "Inspection and Maintenance of 4kV Air Circuit Breakers Type AM-4.76-250-OD and AM-4.16-250-9H," Revision 6, and DMP-6700-4, "Inspection and Maintenance of Switchgear Cubicles," Revision 4, were based on vendor manual GEI-88771, dated March 1967. Revisions A, B, C, and D had been issued by the vendor, but as of January 1989, had not been evaluated for possible incorporation into the applicable maintenance procedures. Before October 1988, requirements of Procedure DMP-6700-3 did not conform to G.E. Instructions GEI-88771D,which were issued in 1973. Discussions with the originator of Temporary Changes 88-545 and 88-546 indicated that discrepancies with trip latch and armature travel measurements were noted during the performance of maintenance activities. Breaker maintenance performed prior to October 1988 included verification of trip latch clearance. In October 1988, the licensee changed the requirement to verify the trip armature travel as specified by the vendor in 1973. A technical evaluation was not made for those breakers not inspected subsequent to the vendor change. This item is unresolved pending a complete review on a subsequent inspection (237/88029-01 249/88030-01).

The inspectors also reviewed licensee actions for IENs 88-86, "Operating With Multiple Grounds in Direct Current Distribution Systems," and IEB 88-10, "Nonconforming Molded-Case Circuit Breakers." The licensee addressed the concerns and the activities were tracked on the Nuclear Tracking System (NTS). No problems were noted.

The inspectors reviewed the component failure history for the electrical components and systems selected in Section 2.0 to determine whether methods had been established and implemented for detecting repetitive failures and adverse quality trends, and whether appropriate corrective action had been taken to address adverse trends. The inspectors also utilized NPRDS and LERs in the review to ascertain the effectiveness of the licensee's trend analysis and root-cause analysis. The review disclosed that numerous Deviation Reports (DVRs), WRs, and LERs had been issued because of equipment problems with 4.16kV circuit breakers. Also, NPRDS data included failures associated with closing or tripping of GE 4.16kV breakers. Examples of these historical problems were:

- Failure due to defective, dirty or mis-adjusted position switch (SBM).

DVR-12-2-87-43	CCSW pump 2A failure to start
DVR-12-2-87-56	CCSW pump 2A failure to start
DVR-12-2-87-83	CCSW pump 2A failure to start
LER-237/88021	SGTS automatic initiation
WR 68284	2B RFP failed to operate in test position
WR 65089	2C RFP failed to close
WR 41131	Main feed water to bus failed to close
WR 31207	Unit 3 DG output breaker failure to close

- Failure due to worn, defective, dirty or burned auxiliary switch in the breaker (SBM).

WR 40917	Main feed breaker to bus 24-1 failed to open in test position
WR 55867	3C CB pump breaker failed to close
WR 58809	3C CB pump breaker failed to close
WR 63798	2C LPCI pump breaker failed to close

- Failure due to defective, dirty, stuck stationary auxiliary switch in breaker cubicle (SBM)

WR 54361	Breaker from bus 34-1 to bus 39 failed to close
WR 63138 (LER 237/87009)	Unit 2 DG output breaker failed to close
DVR 12-2-85-13	Unit 2 DG output breaker failed to close

Numerous examples of pump run and trip alarms due to switch failures

- Recent 4.16kV breaker failures (December 1988 to February 1989.

WR 80956	LPCI 2B linkage cubicle fell off its pin, auxiliary switch defective
WR 82012	LPCI 3C breaker failed to closed
WR 82083	Bus 24 to 24-1 breaker trip coil burned up
DVR-2-88-15	2D LPCI pump tripped several times

An evaluation of these historical problems disclosed the following concerns:

- Procedure DMP 6700-3, "Inspection and Maintenance of 4kV Air Circuit Breakers Type AM-476-350-00 and AM-416-250-9H," Revision 6 required that 4.16kV breakers be inspected and overhauled every 500 operations or five years, which ever came first. The inspectors requested the status of the PM work on the 4.16kV breakers. The status was not known by the electrical maintenance department and was not given to the inspectors for several days. Individual breaker work history had to be reviewed to ascertain the PM status of the 4.16kV breaker. It was determined that fifteen 4.16kV breakers in switchgear 24 and 34 did not have PM at the required frequency. The two most significant deficiencies were with the breakers for the 2C and 2D Containment Cooling Service Water Pumps, which were last overhauled in 1976. In addition, breakers important to safety identified as Nos. 3411, 2405, and 2413 were last overhauled in 1973, 1975 and 1977 respectively. Although not safety-related, the breakers were used to satisfy the TS requirements for two sources of offsite power. Failure of these breakers would reduce the number of offsite power supplies available to the plant.

  It should be noted that Operating Experience Report (OPEX) No. 998-042 87-02400, dated July 28, 1987, response to INPO SER-84-27, discussed four events that occurred at another nuclear facility which involved failures of 4.16kV breakers to transfer on demand. The breakers were the same type as those used at Dresden. In each event, voltage to a 4.16kV bus was lost when an alternate feeder breaker failed to automatically close after the normal feeder breaker was opened. Failures were caused by hardened grease and dirt in the stationary auxiliary "SBM" switch linkage within the normal feeder breaker compartments. The report further stated that these events were significant because the stationary auxiliary SBM switch in a normal feeder breaker to a safety-related bus could prevent restoration of voltage to the bus from the alternate or emergency source upon a loss of offsite power source.

  Also, at the time of the inspection, a 4.16kV feeder breaker failed to trip during an undervoltage surveillance test as a result of a burnt trip coil. The cause of the failure was mechanical binding of the breaker mechanism; this breaker had last been overhauled in 1976.

- On February 25, 1988, the technical staff identified that SBM switches utilized in 4.16kV breakers and cubicles had a history of problems. The conclusion was that the SBM auxiliary switches were at near end of life based on the increase in SBM switch failures. The technical staff also noted that the SBM switches were not included in the PM program and had not previously been checked for performance. Based on a review of the Total Job Management (TJM) history and discussions with licensee personnel, the inspectors determined that 15 SBM switches for some 4.16kV breaker switches had been replaced. Replacement was based on the failure of the switches to meet acceptance criteria defined in revised PM procedures. The switches that passed were not replaced and would not be inspected for another three years, the PM frequency on 4.16kV breakers, even though the switches had a long history of failure and were at or near end of life.

- Also in February 1988, DVR-2-88-15 identified that the 4.16kV breaker for the 2D LPCI pump tripped several times during pump starts. The cause was identified as dirt and lack of lubrication on trip latch roller mechanism, which would not have occurred if the breaker had been properly maintained. The licensee's evaluation of the deviation did not address the effects that the PM program had on the failure of the breaker.

During review of DVR 12-3-88-82, the inspector noted dc powered MOV MO3-1301-10, the Unit 3 Isolation Condenser Makeup Supply valve, failed to open in July 1988. The failure mechanism was dirt and sticking auxiliary contacts with builtup non-conductive deposits, which resulted in increased electrical contact resistance. The inspectors determined that the last PM on Unit 3 250Vdc MCCs 3A and 3B was performed in 1975. PM for similar equipment on Unit 2 was performed several times, the last in 1988. However, Procedure DMP-8300-2, "Inspection and Maintenance of DC Operated Cutler-Hammer Reversing and Field Contactors," Revision 2, had not been incorporated into the Unit 3 surveillance program. Since the Unit 3 HPCI torus suction valves were also supplied by the Unit 3 250Vdc MCCs, the inspectors were concerned with the material condition of the circuits associated with opening these valves. As a result, the licensee sampled the material condition of breakers in the Unit 3, 250Vdc MCCS. The inspectors were informed at the exit meeting that the breakers were in acceptable condition and no problems were perceived with Unit 3 HPCI torus suction valves.

In summary the team concluded that the licensee failed to:

- Adequately evaluate the cause of Unit 2 LPCI "D" pump 4.16 kV breaker failure in February 1988. An indepth evaluation would have identified that maintenance of 15 Unit 2 and 3 breakers was not performed at the required frequency. Two 4.16 kV breakers, which supplied the motors for Unit 2 Containment Cooling Service Water Pumps, were last overhauled in 1976.

- Adequately evaluate the cause of Unit 3 Isolation Condenser Makeup valve failure to open in July 1988. Failure to perform preventive maintenance was not identified as a contributing factor. Preventive maintenance had not been performed on Unit 3 250 vdc MCC, 3A and 3B since 1975. These MCCs supply power to HPCI torus suction valves.

- Replace auxiliary switches (SBM) for Unit 2 and 3 4.16 kV breakers and breaker cubicles even though the switches had a history of failures since 1982 and were at or near end of life.

Based on the examples above, the failure to identify root causes of equipment malfunctions and to take prompt corrective action is considered a violation of 10 CFR 50, Appendix B, Criterion XVI (237/88029-02; 249/88030-02).

During review of 4.16kV breaker problems, the inspector noted examples of breaker swappings in DVR-12-2-87-37 and DVR-12-2-87-87. Since the breakers were not labeled, and the Master Equipment List identified 4.16kV breakers by cubicle number not by breaker serial number, traceability of completed PMs on the individual 4.16kV breakers was indeterminate. The current maintenance methodology did not allow for assessment of specific breaker operating history.

The inspectors reviewed 25 completed WRs, for use of qualified personnel, proper approvals, adequacy of work instructions, resolution of concerns, proper prioritization, QC involvement, quality of documentation for work history and understanding of problems and post maintenance testing. In general, most WRs were prioritized as B2, schedule within five working days, and most were completed in a timely manner. QC involvement such as required Hold Points was not evident on most of the reviewed WRs and there was no block on the WR for post maintenance testing. Post maintenance tests were mostly written in the "work performed block." Release for work and work instructions appeared to be adequate. However, WRs did not contain the description of the "as-found" condition and the "maintenance cause" was not completed. Lack of "as-found" condition and "maintenance cause" was considered a weakness because trending, rework identification, and root cause analysis would be hindered.

The following maintenance procedures were reviewed for inclusion of QC hold points, acceptance criteria, and user friendliness:

DMP-6700-2, "Inspection and Maintenance of 4KV Air Circuit Breakers Type AM-4.16-350-1C and 1H," Revision 3.

DMP-6700-3, "Inspection and Maintenance of 4KV Air Circuit Breakers Type AMH-4.76-250-OD and AM-4.16-250-9H," Revision 6.

DMP-6700-4, "Inspection and Maintenance of Switchgear Cubicles," Revision 4.

DEP-8300-4, "Unit 2/3 Inspection of DC Motors and Brushes," Revision 0.

DMP-6600-7, "Diesel Generator Six Months Inspection Electrical Maintenance Department," Revision 3.

Some procedures did not provide step by step instructions for corrective maintenance activities and post maintenance testing requirements. Also, checklists were not always consistent with the procedure; however, the MIP addressed these type deficiencies in electrical procedures and the ongoing procedure upgrading process should resolve the concerns.

The inspector reviewed the current backlog for the EDG cooling water components, 4.16kV LPCI breakers, 138 kV switchyard breakers and power transformers. Results showed that there was no backlog of WRs that could immediately affect the operability of the components. However, as previously discussed, lack of PM on 4.16kV breakers and the Unit 3 250Vdc MCCs for an extended period of time was considered a weakness that could affect operability of plant components and systems if not accomplished in a timely and aggressive manner.

2.3.2.2 Evaluation of Completed Electrical Maintenance

Based on the review of completed WRs, backlog, work history, maintenance procedures, and the licensee's actions on source documents, the inspectors concluded that electrical maintenance had not been satisfactorily accomplished. The following weaknesses and strengths were identified.

Weaknesses

- PM was not performed on Unit 2 and 3 safety and non safety-related 4.16kV breakers for an extended period of time.
- Pm was not performed on Unit 3 250Vdc MCCs.
- Root cause analysis was not performed for a subtle trend of problems associated with 4.16kV breaker opening and closing failures.
- An electrical vendor correspondence coordinator was not assigned to address and incorporate vendor recommendations into maintenance procedures, which contributed to inadequate maintenance procedures and followup of vendor recommendations.
- "As Found" and "Probable Cause" data were not documented on the WRs.
- Records of 4.16kV and 250Vdc PMs were not easily retrievable or available; the TJM program did not contain all PM data and was not user friendly.

Strengths

- Aggressive resolution to the 4.16 KV breaker Tuf Loc bushing issue.
- Morale and experience level of the electrical maintenance staff was good.
- Communication between maintenance and operations was good.

2.3.2.3 Review of Completed Mechanical Maintenance

The inspectors determined that the mechanical maintenance philosophy did include some aspects of RCM. The aspects included predictive maintenance such as vibration analysis and lube oil analysis, leak control program, use of sonic equipment to identify instrument air leaks, and MOV diagnostic tests. Mechanical maintenance was generally a balance between CM and PM.

The inspectors evaluated the extent that vendor recommendations, IE Notices, IE Bulletins, and other outside source information was utilized in mechanical maintenance. The components selected for the evaluation were the HPCI main and booster pumps, ADS valves and HPCI MOVs.

The following procedures and vendor manuals were reviewed:

Procedures

DEP 040-9, "Limitorque Lubrication Surveillance Mechanical Maintenance," Revision 3.

DMP 040-16, "Limitorque Operator Repair SMT-000 and SMB-00," Revision 3.

DMP 200-35, "Inspection and Maintenance of Electromatic Relief Valves," Revision 4.

DMP 200-37, "Target Rock Safety/Relief Valve Maintenance," Revision 4.

DMP 2300-1, "HPCI Gland Seal Condenser Hot Well (GSLO) Pump Maintenance," Revision 0.

DMP 2300-2, "HPCI Main Pump Maintenance," Revision 1.

DMP 2300-3, "HPCI Booster Pump Maintenance," Revision 1.

DMP 2300-8, "Inspection and Maintenance of HPCI Pressure Control Valve (2301-46) to Gland Seal Condenser," Revision 0.

Vendor Manuals

V-018 - Target Rock Corporation Safety/Relief Valve Model 67F, EPN 203/3, May 17, 1986.

V-038 - Byron Jackson HPCI Pump, EPN 2302, January 7, 1986.

V-093 - Electromatic Relief Valve, EPN 203, May 5, 1988.

Maintenance procedures contained recommended vendor PMs identified in the vendor manuals and information from Bulletins, Notices, and plant/industry lessons learned. The inspectors verified that vendor manuals were controlled and incorporated the service information from the vendor. Only about one third of the vendor manuals were controlled while the other manuals were kept for general information. The MM supervisor stated that although the uncontrolled vendor manuals were available for general information, the maintenance personnel were instructed to use only controlled manuals and drawings for safety-related work. The inspectors did not identify any concerns with vendor manual control.

The inspectors perceived that PM of the ADS/safety relief (SR) valves was a strength of the maintenance program. During each unit's refueling outage, half of the ADS/SR valves were replaced with rebuilt and bench tested relief valves from the previous outage of the other unit. Also, new pilot valves were installed in the unit's ADS valves that were not replaced. The ADS/SR valves were maintained and tested at intervals that exceeded the vendor recommendations of 36 months. The PM program for the ADS/SR valves was an example of management's commitment and involvement in the maintenance process.

The licensee had also developed a MOV overhaul program for all MOVs in the plant. The overhaul consisted of a complete inspection and PM that included resistance testing of the MOV motor, lubrication of the main gear case, limit switch compartment and valve stem, and proper setting of torque and limit switches. As of January 19, 1989, the status of the MOV overhaul program was as follows:

	Safety-related (Non-EQ)	Safety-related (EQ)	BOP
To be overhauled	81	85	338
Overhauled to date	62	85	33
Balance	19	0	305
Percent Completed	76%	100%	10%

As a result of previous inspections, the licensee committed to the NRC that all safety-related Environmentally Qualified (EQ) and non-EQ MOVs would be refurbished by December 1989. The

licensee's current schedule indicated a completion date of May 1989. Based on the current staff and completion rate, the date appeared to be realistic for completion of the remaining 19 safety-related non-EQ valves.

The inspector reviewed IE Bulletins, Circulars, Notices and LERs. The following documents were reviewed and the licensee's responses were determined to be acceptable.

- IE Bulletin 85-03
- IE Circular 80-07
- IE Notices 82-26, 82-35, 86-14, 86-51, 86-63
- LERs 249/87-17, 237/88-09, 249/88-13, 237/88-21

The licensee performed diagnostic testing for MOVs included in Bulletin 85-03, selected safety-related EQ and non-EQ valves, and selected balance of plant (BOP) valves. Permanently mounted sensors for measuring steam force have been installed on all safety-related EQ and non-EQ MOVs that enable diagnostic tests to be performed. The licensee anticipated better MOV performance and testing convenience from the Valve Operator Testing and Evaluation System (VOTES) testing method. Thirty-six MOVs were diagnostically tested during this outage.

The inspector reviewed the NPRDS and maintenance work history of the HPCI pumps, HPCI MOVs and ADS valves, to ascertain if conditions existed such as negative trends and excessive rework. No problems were identified. During review of this history, the inspectors identified several strengths that reflected management's involvement in maintenance decision process. These strengths were:

- Installation of a new five vane impeller in the HPCI booster pump to reduce vibration levels. This action was taken based on noise levels of the Unit 2 booster pump and the successful operation of the Unit 2 HPCI booster pump using the new impeller design.
- The licensee initiated plans to inspect the Unit 3 HPCI auxiliary oil pump during the next outage based on problems identified with the Unit 2 HPCI Auxiliary oil pump, a "skid" component that was not routinely subjected to PM.

The license had made improvements in the MOV maintenance program since a NRC Diagnostic Evaluation Team inspection that was conducted during August 1987. Improvements included:

- Assignment of a MOV Coordinator to schedule and direct the improvement effort.

- Assignment of a "MOV Team" that consisted of specially trained work analysts, foreman, craftsmen, and outage analysts. Electrical and mechanical maintenance departments were represented. A procurement specialist knowledgeable in the parts needed for MOV overhauls was also assigned to the team.

- Implementation of VOTES, which was a new diagnostic program.

The inspectors reviewed 17 WRs completed in 1987 and 1988 for the HPCI pump, ADS valve, HPCI MOV, and Feedwater components. The WRs were reviewed for use of qualified personnel, proper approvals, adequacy of work instructions, resolution of concerns, proper prioritization, QC involvement, quality of documentation of work history and understanding of problems and post maintenance testing.

In general, all work packages were correctly prioritized and completed in a timely manner. QC involvement was evident and post maintenance tests were conducted as appropriate. Specifically, MOV WRs had appropriate post maintenance test requirements such as valve stroking, current limit switch signatures, and VOTES diagnostic tests. However, three weaknesses were identified as follows:

- The "cause code" block on WRs was not routinely completed, and therefore, the use of the "cause code" for the identification of trends would be ineffective.

- Some of the WRs reviewed contained the "as found" condition in the "work performed" block, but the "as found" condition was not consistently recorded. To ensure consistent input and for the ease of retrievability, a block on the WR for "as found" data would be useful.

- The inspectors also identified a strength with the system established for feedback that consisted of pre-job, post job, and workman's checklists; however, post job checklists were not consistently completed by work analysts.

The inspectors reviewed work procedures for inclusion of QC hold points acceptance criteria and user friendliness. The procedures reviewed were the same procedures that were reviewed for inclusion of vendor recommendations. The procedures were detailed, included required tools, acceptance criteria, and QC hold points. Also, the procedures for MOVs contained information from IEBs, IENs, and plant/industry lessons learned.

There was a backlog of WRs for HPCI pump and skid components and HPCI MOVs; however, the backlog of CMWRs did not have immediate impact on plant safety. There was no backlog of PMs for HPCI pumps and skid components, ADS valves, and HPCI MOVs.

However, the inspectors noted that several PM tasks were completed after the indicated due date and the PM frequency was not always consistent with the scheduled due date. The General Surveillance System (GSRV) file was being updated to show the correct base frequency and due dates for PMs. At present, some PMs used the same date to identify PMs scheduled every 18 months as well as PMs scheduled every refueling outage. Since the refueling outage dates can vary, there was a possibility for the work to be completed after the "scheduled" due date. The inspector reviewed several recent PMs and verified that the justification for deferral was acceptable. The licensee's ongoing efforts to update the GSRV file will resolve the discrepancies in PM base frequency, equipment identification, and PM work description. There were no other concerns identified.

The licensee initiated a leak control program in July 1988 in an effort to identify and control equipment water and oil leaks. Plant walkdowns by maintenance personnel were conducted and approximately 175 WRs were outstanding. The backlog of leak-related WRs was reduced despite the impact on the maintenance work load due to the Unit 2 outage. A maintenance foreman had been assigned the responsibility for leakage reduction as a top priority. The backlog of leak-related work requests was tracked in weekly and monthly reports, which were reviewed by upper plant management and discussed specifically with maintenance groups.

2.3.2.4 Evaluation of Completed Mechanical Maintenance

Based on the review of completed WRs, backlog and work history of PRA selected components, maintenance procedures, and the licensee's actions on source documents the inspectors concluded that mechanical maintenance had been accomplished in a satisfactory manner. The following weaknesses and strengths were identified:

Weaknesses

- Post-job checklists were not consistently used by mechanical maintenance work analysts to assess the content of the work packages and documentation.
- Cause code blocks were not completed on several WRs.
- "As found" conditions were not consistently recorded on WRs.

Strengths

- Pre-job, post-job, and workman's checklists had the potential to provide good feedback to the work analysts if the checklists were consistently used.
- Industry initiatives and LERs were integrated into the maintenance program.

- ADS/SR valves were maintained and tested at a frequency that was more conservative than industry practices.

- Performance of the Unit 2 HPCI booster pump was improved by installing a five vane impeller.

- Backlog for the HPCI system, ADS valves, and HPCI MOVs was low and there were no open corrective WRs that had immediate impact on the operability of the components.

2.3.2.5 Review of Completed Instrumentation Maintenance

The inspectors determined that the instrumentation maintenance philosophy did include an aspect of RCM. This aspect was the trend of plant instrument calibration data to predict instrument replacement prior to failure. IM was balanced between CM and PM maintenance based on a review of previous work history, vendor recommendations and/or equipment qualification requirements.

The inspectors evaluated the extent that vendor recommendations and other outside source information was utilized in IM. The components selected were the HPCI flow transmitters. The inspectors reviewed the following documents:

- Vendor Manual V-33, "Model 1153 Series B Alphaline Pressure Transmitters for Nuclear Service."

- Surveillance Procedure DIS 2300-10, "HPCI Steamline High Flow Isolation Differential Pressure Transmitters 2352 and 2353 Calibration and Maintenance Inspection."

- EQ Binder CQD-13167.

The surveillance procedure adequately implemented vendor recommendations and EQ requirements. The inspector verified that the EQ maintenance requirements were scheduled at the correct surveillance interval.

The inspectors reviewed the component failure history for the component and systems selected to determine whether methods had been established and implemented for detecting repetitive failures and adverse quality trends, and whether appropriate corrective action had been taken to address adverse trends. The inspectors also utilized NPRDS and LERs in the review to ascertain the effectiveness of the licensee's analyses of trends and root-causes. The inspectors reviewed the NPRDS data and maintenance history files associated with the inverters. No adverse trends were identified. The inspectors also identified the following strength. The licensee adequately addressed the main steam line (MSL) tunnel area temperature switch setpoint drift problem identified in DVR 12-3-88-38. Surveillance Test Procedure DIS-250-9, "MSL Tunnel Area Temperature Switch Calibration and Maintenance Inspection," Revision 2,

was user friendly, incorporated vendor maintenance and calibration practices, and utilized an industry unique temperature switch calibration system. The previous revision of DIS 250-9 utilized a temperature calibration methodology that was susceptible to temperature variances within a temperature oven. Revision 2 used a refrigerated circulator that should provide a more stable calibration environment.

The inspectors reviewed the setpoint trending program for drywell pressure switches for Emergency Core Cooling System (ECCS) initiation and reactor pressure switches for high pressure scram. The setpoint trending program for bistable devices was proceduralized and up to date. The records for the switches indicated that the calibrations were within administrative limits and occasional setpoint excursions outside of the limit appeared random.

The inspectors reviewed the General Surveillance System Master File (SSMF) EQ surveillances. The licensee adequately implemented the EQ binder requirements for the temperature switches and the requirements were performed within the scheduled EQ surveillance interval.

The inspectors reviewed LER No. 237/88-015, "HPCI Isolated, Discovery of a Failed High Steam Flow Isolation Flow Transmitter." HPCI steam line flow transmitter 2-2352 exhibited a trip setpoint of 156.25 inches of water differential, but the TS value was $\leq$ 150 inches. The redundant HPCI flow Transmitter was operable and would have provided automatic HPCI system isolation if the HPCI steamline broke. The transmitters were Rosemount Model 1153B. The failed transmitter was returned to the manufacturer for further testing and inspection. The licensee suspected that the transmitter failure was caused by possible metal filings in the sensor dp cell or the glass to metal seal in the transmitter sensor body. These type failures have occurred at other nuclear plants. The licensee adequately addressed LER No. 88-015.

The inspectors reviewed six recently completed IM CMWRs. The CMWRs were reviewed for proper approvals, adequacy of work instruction, resolution of concerns, proper prioritization, QC involvement, quality of documentation for work history, and understanding of post maintenance testing. Maintenance was adequately performed; the licensee obtained proper signoffs, performed reviews, and evaluated the work performed. QC inspectors reviewed the WR prior to the IM conducting the maintenance activity and released the completed WR if the work performed satisfied the work requested. In addition, any parts that were installed were verified against the part Suitability Evaluation List for proper application.

The inspectors reviewed the following surveillance procedures for inclusion of QC hold points, acceptance criteria, user friendliness, and correct measuring and test equipment (M&TE):

DIS 263-1, "Reactor Vessel Low Water Level Scram and Low, Low Water Level Isolation Transmitter Calibration and Maintenance Inspection," Rev. 3.

DIS 500-2, "Reactor Vessel Low Water Level Scram and Low, Low Water Level Isolation Analog Trip System Calibration," Rev. 7.

DIS 500-3, "Reactor Vessel Low Water Level ECCS Initiation Indicating Switch Calibration and Functional Test," Rev. 4.

DIS 2300-1, "HPCI Steamline High Flow Isolation Master Trip Unit Calibration," Rev. 9.

DIS 2300-2, "HPCI Flow Calibration," Rev. 6.

DIS 2300-3, "HPCI Turbine Permissive (Reactor Pressure Greater than 90 PSIG) Master Trip Unit Calibration," Rev. 5.

DIS 23007, "HPCI Area Temperature Switch Calibration and Maintenance Inspection," Rev. 5.

DIS 2300-10, "HPCI Steam Line High Flow Isolation Differential Pressure Transmitters 2352 and 2353 Calibration and Maintenance Inspection," Rev. 1.

DIS 2300-11, "HPCI System Isolation Reactor Pressure Transmitter Calibration and Maintenance Inspection," Rev. 0.

Some procedures did not provide acceptance criteria for the M&TE. The potential existed for the licensee to invalidate a calibration by not controlling the selection of M&TE. The following nondescript examples of M&TE requirements were stated in the procedures:

- "Appropriately sized dial manometers."
- "Dial Manometer."
- "Flute Model 2100A Digital Thermometer or equivalent."
- "Hiese test gauge or equivalent (minimum range 0-250 psig)."
- "Appropriately sized test gauges, 0 to 1500 PSIG."

Procedure DIS 2300-10 was used as reference for calibration of the HPCI steamline flow transmitters to an accuracy of ±0.375 Inches of Water Column (INWC). The test performed on February 6, 1987, selected manometer DL-14 that was certified to ±0.525 INWC. The certified calibration accuracy of DL-14 was less than the device being calibrated. However, the licensee performed a "Before" and After Check" of all pneumatic M&TE used to calibrate critical plant equipment. In the above case, the maximum error that DL-14 exhibited was ±0.2 INWC over its calibrated range. Therefore, the calibration was not affected by the M&TE. In all the other surveillances reviewed, the inspectors determined that the M&TE was of the appropriate range and accuracy to perform the calibration.

The TS setpoint for ECCS initiation was based on reactor low water level of 84 inches; + 4 inches, - 0 inches, which was 119.5 to 111.7 INWC. The administrative setpoint was 112.7 INWC (±1 INWC). The setpoint could range to the lower TS limit. The inspectors reviewed the last calibration of the four reactor level indicating switches. Switches 3-263-72B and 3-263-72D were both left with the setpoint at or near 111.7 INWC. The potential existed for the M&TE inaccuracy to add an additional uncertainty to the "As Left" setpoint that would have resulted in a TS violation. The licensee stated that to allow an administrative setpoint to range to the TS limit was not a station practice. The inspectors reviewed test equipment control records from the past two calibrations of LIS 3-263-72B and D. Manometer LD-19, used for the above calibrations, exhibited zero error near the "As Left" setpoint of the switches. The licensee informed the inspectors that Procedure DIS 2300-1 would be changed to allow for M&TE inaccuracies at the setpoint.

The inspectors reviewed the current IM maintenance backlog. The majority of the WRs involved installation of replacement gauges to improve the ASME Section XI testing program. The only safety-related WR in the backlog was D80055, for main steam line high flow switch 3-261-2C, which exhibited a wide reset differential. The flow switch was operable and able to perform its safety function. A replacement flow switch had been ordered. The inspectors determined that I&C maintenance was adequately accomplished and there was no backlog of WRs that could immediately affect operability of components.

2.3.2.6 Evaluation of Completed Instrumentation Maintenance

Based on the review of completed WRs, backlog, and work history of the components evaluated, maintenance and/or surveillance procedures and the licensee's actions on DVRs, the inspectors concluded that completed IM was satisfactorily accomplished in a good manner. The following weakness and strengths were identified.

Weakness

- Procedures for instrumentation surveillance did not adequately control the selection of M&TE.

Strengths

- Trends of instrument setpoint drifting were analyzed.
- Pneumatic M&TE was calibrated before and after critical plant instrument calibrations.

2.3.3 Engineering Support

The inspectors evaluated the extent that engineering principles and evaluations were integrated into the maintenance process. This was accomplished by review of maintenance work orders, activities

associated with failure analyses, and other maintenance activities. Areas reviewed were engineering support to PM, material qualifications, compliance with codes and regulations, system engineering concepts, industry initiatives, and post maintenance testing.

2.3.3.1. System Engineering

The "system engineer" concept was implemented at Dresden in June 1987. System engineer duties were outlined in procedure DAP 14-1, Technical Staff Organization, Revision 8, Section 20. Each of 29 system engineers was assigned a number of plant systems to monitor performance, perform walkdowns, and assist maintenance personnel in repairs and tests. System engineers had "ownership" and were expected to be cognizant of assigned system status.

System engineers became involved with maintenance problems by initiation of a maintenance Problem Analysis Data Sheet (PADS). For example, WR D76399 described that the HPCI Auxiliary Oil Pump (AOP) pressure switch had drifted, which caused the stop and/or control valves to close and trip the HPCI pump. The IM Department initiated a PADS to determine the correct pressure setpoint for the AOP. With the help of the system engineer, the vendor, and information from the Quad Cities station, a nominal setpoint was selected. The system engineer was in the process of preparing a special test procedure to determine the AOP shutoff setpoint. It appeared that system engineers were involved in resolution maintenance concerns. Effectiveness of the system engineer role in the maintenance process depends on involvement with the PADS, feedback system to work analysts, and the identification of deficiencies during system walkdowns.

2.3.3.2 Technical Support

There were three groups of technical staff engineers that were involved in modifications, inservice inspection (ISI)/inservice testing (IST), and plant performance.

The licensee recently implemented a failure analysis program that utilized PADS. This program required a PAD if failure caused the components to be inoperable, more than 80 hours were expended to repair a component, or a component failed the post maintenance test. There had been approximately 185 PADS issued but only 13 were resolved. Discussions with licensee personnel determined that revisions to the PADS process were under consideration. One consideration was designation of the personnel who would be involved in determining the failure mode and subsequent corrective actions. The inspectors were concerned with the number of open PADS and the slow progress in this area. Since approximately 90% of the PADS were still open, the inspectors could not evaluate the effectiveness of the measures for failure analysis.

The inspectors reviewed the measures established to identify diverse trends in equipment performance. Trends of results were evident for predictive maintenance in the areas of vibration data, lube oil samples, and instrument set point drift. However, a useable trend

program based on work history had not been established because the TJM had not yet been completely updated with equipment identifications (EIDs) and historical work history. Attempts were made by the licensee to utilize work history that currently was put in the TJM. A trend was defined as two corrective WRs issued on a component in a period of six months. The inspectors considered this as a "gross" approach because potential trends over time or trends common to a specific model number would not be identified. The established frequency, two occurrences in six months was the same for all components and did not consider the importance of a component to safety.

Technical staff engineers performed tests and monitored equipment performance. The inspectors reviewed procedures used to periodically calibrate plant performance monitoring equipment and determined that monitoring instruments were calibrated. The inspectors reviewed a list of instruments that were used to collect quantitative data during operator's rounds. Of the approximately 50 instruments, 22 were not in a formal calibration program including those associated with the Reactor Waterup Clean, Reactor Building Closed Cooling Water, Control Rod Drive, Main Steam Isolation Valves, Main Generator, Turbine Oil, Condensate, and Off-gas. Instruments associated with these systems should have been reviewed for inclusion in the calibration program.

The inspectors reviewed several deviation reports, LERs, PADs, and work packages regarding the failure of feedwater regulator valve 2A due to blockage from debris. The root cause analysis did not appear to correct the problem; however, upon further discussion with the licensee the inspector determined that a new valve design was recently installed in Unit 2, which will prevent the intrusion of debris. The "stacked disc" design was similar to the Unit 3 feedwater regulator valve, for which there have been no problems of blockage. Resolution of the valve operability problem was acceptable.

The inspector determined that the licensee's evaluation was acceptable for LER 237/88-09. One corrective action was to inspect the HPCI Gland Seal Leak Off pump motor every refueling outage and to add Pressure Control Valve 2301-46 to the PM program. The inspector verified that these components were identified for periodic surveillance.

The lubrication program was described in DAP 7-6, Revision 4, and POS 40-2, Revision 14. Of the 21 components, from which oil was required to be sampled, only 14 samples were trended. Paragraph B.2.g of DAP 7-6 required that all oil samples be trended. No justification existed for those samples not trended. The licensee indicated that some oil samples need not be trended, such as the diesel fuel day tanks, for which new oil was analyzed prior to use in the diesel system. Oil samples were plotted, but a formal report had not been issued with an evaluation of the samples. There were several examples of corrective actions, such as oil changes; however, these actions appeared to be isolated cases rather than implementation of a fully developed and comprehensive trending program. The licensee had not

fully developed acceptance criteria for a method to present the trended acceptance criteria for evaluation of adverse trends, nor the correlation of sampling data to significant events, such as oil change, filtering old oil, equipment run time, or equipment availability due to unscheduled maintenance. The inspector did not identify any equipment failures caused by oil degradation.

Coordination and implementation of the lubrication program was handled by several station personnel, technical staff and operations, and by correspondence with the corporate office's System Material Analysis Department (SMAD). On-site expertise for the assessment of the samples and trend analysis was still under development.

2.3.4 Work Control

The inspectors reviewed several maintenance activities to evaluate the effectiveness of the maintenance work control process to assure that plant safety, operability, and reliability were maintained. Areas evaluated were control of maintenance work orders, equipment maintenance records, job planning, prioritization and scheduling of work, control of maintenance backlog, maintenance procedures, post maintenance testing, completed documentation, and review of work in progress. Preparation, prioritization, scheduling, implementation, and post maintenance review of WRs was described in Procedure DAP 15-1, "Work Requests," Revision 20.

The inspectors attended several morning meetings to observe how licensee management coordinated normal plant activities and outage related work. The inspectors attended the morning meeting, the Plan of the Day Meeting, and Outage Meeting. With only minor exceptions, all required onsite organizations were represented at those meeting. The meetings were relatively structured, purposeful, and appeared to coordinate the efforts of all groups in attendance. The licensee utilized activity schedules that tracked all major onsite activities for the week.

The inspector compared work packages completed before and after MIP initiatives were issued and determined that recently completed work packages were better organized and described the activities performed in more detail. The TJM data base preserved information from the work packages, which improved efficiency of the maintenance process.

Specification of the correct post maintenance test was an important final step in the work process to determine if a component or given piece of equipment was operable. The licensee was dependent on the work analyst for specification of the correct post maintenance test, which was accomplished by use of the guidance developed in June 1988, as documented in Maintenance Department Memorandum 47. To date, the licensee had implemented the memorandum only on a pilot basis by use of one mechanical work analyst on selected WRs. The licensee planned to incorporate Memorandum 47 into a formal procedure after additional pilot programs have been completed.

The number of cancelled WRs appeared excessive. Out of a sample of approximately 2000 WRs, October 6 to December 31, 1988, about 20% had been cancelled. Based on comparisons to other licensee's, the inspectors considered this an abnormally high percentage and a drain on the licensee's resources. The primary cause appeared to be that field personnel were inconsistent in use of the two part WR identification tag, the first part of which should have been hung on the equipment and the second part attached to the WR form. This process would have precluded other persons form duplicating WRs.

The inspectors determined that analysts reviewed applicable vendor manuals, walked down equipment and systems that required repair, and ensured that correct drawings and procedures were supplied in the work package if required. In most cases, maintenance procedures were available. Work instructions had been developed for repetitive jobs that were not covered by a procedure. These instructions were stored on a computer diskette for future use. WRs contained adequate work instructions. If the work was outside the scope of the WR, the work instructions were amended and reapproved. Except for the problem noted in Section 2.4.2.3, no significant problems related to maintenance planning were noted.

Overall scheduling and prioritizing of maintenance work appeared to be acceptable. Appropriate emphasis was given to those items of safety significance .

2.3.5 Personnel Control

The inspectors reviewed the licensee's staffing control and staffing needs. Inspection activities included interviews with plant personnel, observations of the training facility, observation of plant activities, and review of documentation. The maintenance training program was accredited by INPO in January 1987. The training career path enabled a candidate to advance from apprentice to a journeyman technician in approximately four years. The inspector interviewed electrical, mechanical, and I&C training coordinators. Each had a "Training Qualification Matrix" that listed the personnel and all general and specific training. The matrices showed that each plant employee received site specific, security, and radiological control training. Refresher classes in these areas were conducted on a regular basis.

Training and qualification records were reviewed for approximately 18 maintenance personnel that participated in maintenance activities witnessed by inspectors. Training records were readily available and documented all training received. The inspectors determined from review of the training records that personnel were qualified to perform the assigned maintenance activities.

The electrical, I&C, and mechanical departments were staffed with 41, 31, and 108 craft personnel respectively, which appeared to be adequate for non-outage work. During planned outages the licensee used a mobile work force to supplement the electrical departments

by about 40%. This work force was made up of personnel from the local fossil stations. Craft personnel only received Dresden Nuclear General Employee Training (NGET) training for access to the site, but the foremen received additional training in administrative and maintenance procedures, in addition to training on plant philosophy. According to conversations with the Assistant Superintendent of Maintenance, the training of contractor personnel, in this case, mobiles, was the next area to be addressed by the INPO accreditation process.

The inspectors reviewed safety-related WRs that had mobile craft personnel participation to ensure that appropriate supervision by station personnel was evident. At all times mobile craft personnel worked on safety-related equipment with a qualified Dresden employee. The licensee's control of mobile work forces was satisfactory.

Shift manning for maintenance was reviewed for all organizations. All primary organizations were manned during the back shifts. In the event some support organizations were not manned, for example, document control, the department head or designee was on call. During the inspection there were no instances observed where maintenance activities were adversely effected due to the licensee's shift manning policies.

2.4 Observations of Current Plant Conditions and Ongoing Work Activities

2.4.1 Observation of Material Condition

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 WRs had been initiated for identified equipment problems, and to evaluate housekeeping. The selected systems and components which were selected are identified in Section 2.0 of this report.

Walkdowns included an assessment of the buildings, systems, and components 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. Note: Unit 3 was in operation. Results of walkdown were as follows:

- Reserve Auxiliary Transformers 22 and 32 local control panels were observed to be very dusty and had rusted termination points, conduits were not sealed and a rusted tool was laying inside the transformer 32 panel. The inspector determined that these cabinets had never had PM performed. Lack of PMs could eventually affect the transformer's control and protective circuits.

- Access to equipment was generally available from the floor or platforms provided.

- Both Unit 2 and 3 HPCI rooms and various levels of Turbine Building were recently painted to improve housekeeping. The licensee had begun a painting program throughout the plant that differentiated Unit 2 from Unit 3 equipment by the use of different colors. The painting program should be beneficial in reducing the number of "wrong unit" type personnel errors and indicated a positive management attitude towards housekeeping.

- Identification of Unit 2 and 3 HPCI equipment was facilitated by new plastic tags that were prominently displayed on or near the equipment. The licensee indicated that all equipment at the station will be similarly identified.

- Walkdown of Unit 2 and 3 HPCI systems on February 9, 1989, showed that most of the scaffolding, hoses, containers, tools, and debris identified during walkdowns on January 23 and 24, 1989, had been removed after the work was finished. All maintenance work was completed on the Unit 2 HPCI equipment pending post-maintenance testing.

- Unit 2, 125Vdc MCC 2A battery to main Bus 2A-1 breaker handle indicated approximately three inches away from the ON position, even though the breaker was energized. The inspector was informed that when the breaker trips, the handle would then point towards the ON position. In addition, the licensee indicated that this appeared to be a known problem with these type of breakers. Operating dc breakers that are not correctly positioned could result in errors and unnecessary trips.

- During a walkdown of the Unit 2 electrical systems, the 125 Vdc MCC 2A ground detector recorder was not inking. A WR identification tag had not been hung on the recorder indicating that a WR had not been initiated. The recorder could have responded to a dc ground potential, but would not have produced a permanent record. Within several days, the recorder was repaired by the IMs.

- The threshold for writing a WR appeared too high to address some oil and water leaks. For example, during the walkdown of the Unit 2 HPCI system, the inspector identified a groundwater leak that was dripping onto several valves and equipment. Funnels and hoses were in place to carry away the liquid. There were no WR identification tags hung on the valves and there was no WR identified to correct the groundwater leak. Subsequently, the HPCI system engineer generated WR D81718 to address the ceiling leak and to check the valves for leaks.

- Unit 3 LPCI "B" Pump Room housekeeping was substandard even for a room that was going to be painted. Contaminated bags and other items were not kept within the roped off area designated for such items. A waste oil drum, solvent cans, and paint cans and rags were lying throughout the room.

- Valve 3-2301-10, suction from Condensate Storage Tank, was leaking several drops per minute into a funnel and hose, but no WR had been written. The HPCI system engineer generated WR D82138 to address the leak.

- The inspectors reviewed the Unit 3 Appendix D, "High Voltage Operator Round Book," for the identification of abnormal operating conditions and the identification of corrective maintenance items. The inspectors identified the following items: U2 Diesel Generator, Auto-OFF Switch in Auto, unmarked position; U2/3 Diesel Generator, Auto-OFF Switch in Auto, unmarked position; and all three Diesel Generator crank case oil level checks low L.

  The inspector discussed the items with the Unit 3 Operating Engineer. There was some confusion about what switch the operators were to verify in AUTO. The licensee determined that it was the Diesel Fuel Oil Transfer switch. The switch was marked with OFF and ON with a spring return to center, an unmarked position (AUTO). The licensee will properly identify these switches and clarify the Appendix D operator rounds log to reflect the equipment identification. The licensee followed up on the low crank case oil readings and verified that there was sufficient crank case oil. There was confusion on how to read the dip stick. The dip stick markings were provided by the manufacturer for an operating diesel. Since diesels at a nuclear plant are normally not operating, the markings were ambiguous. The licensee consulted the vendor manuals and determined what the crank case oil level should read on the dip stick for a non-operating diesel. Also determined was the low level point on the dip stick that would require the addition of one drum of oil. This low level mark was well above the minimum crank case oil level required for the diesels to be operable. The inspectors verified that the markings had been inscribed on the dip sticks. Also, a note was added to the dip stick that stated which markings were to be used for a shutdown diesel.

- 4.16kV EQ switchgear 24-1 contained a differential relay (SA-1) in the DG Cubicle No. 2 that was not labeled. Also, a start relay in Unit 3 DG engine control cabinet was not labeled.

- Unit 3, 480Vac safety-related MCC 38-1, Compartments C4, F3, G1, G2, G3, G4, H1, H2, H3 and H4, and Unit 2 safety-related MCC 29-2, Compartment C contained thermal overload assemblies without reset push buttons. In order to reset the thermal overloads, the operator had to open the compartment door, which

did not appear to be a safe operating practice. Compartment C1 of Unit 2 480Vac MCC 29-2 contained a burned-out main power indicating light and the cap was missing. This condition apparently was not detected during daily operator rounds.

- During the walkdown of the Unit 3 HPCI system, the inspector found various oil leaks at the HPCI main pump inboard seal and oil return lines. The seals and flanges were not perceptively leaking, but a sizeable puddle of oil had collected on the skid. WRs D81747, 81748, 81749, and 81750 were subsequently generated to address the leaks.

- Out of six WR identification tags identified in the field during the BOP portion of the facility walkthrough, one did not have a WR generated for the component, and another had the associated WR cancelled approximately five months earlier but the tag was still attached to the equipment.

- A walkdown of the control boards was performed on the Unit 3 HPCI and LPCI systems. All control switches were correctly positioned. There were no annunciator windows lit or equipment caution and/or red tags hung on any of the equipment associated with the systems.

- A walkdown of electrical components was performed on the Unit 3 LPCI system. The area around the breaker cubicles was free of debris; the breakers were adequately identified and correctly positioned.

- A walkdown of instrument and control components was performed on Unit 3 LPCI system. Generally, equipment was properly identified and maintained; instrumentation cables and primary sensor lines were adequately secured; pressure sensing instrumentation was properly valved into service and none of the valves and fittings was leaking; and electrical conduit connections to the instrumentation were properly sealed.

The inspectors were informed that plant management performed periodic walkdowns of the plant but did not routinely observe work in progress. Also, the inspectors determined through discussions with licensee personnel and the review of records that craft supervisors need to perform more spot inspections in the electrical area.

Generally, equipment problems identified by the inspectors during plant and system walkdowns had been identified by the licensee's WR process or were otherwise corrected except in the electrical maintenance area. Overall, the material condition was considered satisfactory to maintain operability of components at a level commensurate with the components' function. However, greater management attention to ongoing work and component deficiencies should enhance the material condition of the plant.

2.4.2 Observation of Ongoing Work Activities

The inspectors observed ongoing work in electrical, instrumentation, and mechanical maintenance areas. The inspectors selected activities from the Plan of the Day listings, work assignments in individual maintenance shops and through discussions with individual foremen. Where possible, safety significant activities were chosen for followup.

All maintenance activities were witnessed/observed to determine if activities were performed in accordance with required administrative and technical requirements. Work activities were assessed in the following areas:

- Administrative approval prior to start of work.
- Equipment properly tagged.
- Replacement parts acceptable.
- Approved procedures available and properly implemented.
- Work accomplished by experienced and knowledgeable personnel.
- Appropriate post maintenance testing included and conducted.

2.4.2.1 Electrical Maintenance

The inspectors observed portions of four electrical maintenance activities as discussed below:

WR 73948 - 1B Recirc MG set generator collector rings.

WR 81443 - Valves FCV-5202C and FCV-5402D indicating lights.

WR 81765 - HPCI Turning Gear Motor brushes.

WR 81947 - 4.16kV Bus 24-24-1 Feeder Breaker 2411 burned coil.

During observation and review of work performed as required by Unit 2 WR 73948 the inspector noted that part of the LPCI logic was to be bypassed so that MG set work could be performed. The temporary system alteration procedure was used by the Electrical Maintenance Department to add a jumper. However, the same procedure was not used when the jumper did not accomplish the desired result. Electrical maintenance personnel removed an instrument plug connector, without authorization, to establish the necessary LPCI logic to allow the work to be accomplished. The root cause of this problem appeared to be the unfamiliarity of the electrical work analyst and foreman with the requirements of Procedure DAP 7-4, "Control of Temporary System Alterations," Revision 11. This procedure stated in Paragraph 4.(5) that a temporary system alteration evaluation must be performed by engineering prior to alterations to the system, such as plug removals. Failure to follow procedures is considered a violation of Criterion V of 10 CFR 50, Appendix B (237/88029-03).

This violation was very similar to the one discussed in Section 2.4.2.3 where corrective action to prevent recurrence is described.

During replacement of the trip coil in Breaker 2411, as described in WR 81947, the inspector observed that the electrical maintenance craft person appeared to have difficulty in measuring and adjusting the "Trip Armature Clearance." The maintenance procedures did not provide detailed notes and cautions for disassembly and reassembly of the trip coil. In addition, the required safety-related splice units to reconnect the trip coil were not available in the storeroom.

The inspectors witnessed work on the 2A RPS MG set contactor breaker as instructed in WR D-81657. The breaker had been overhauled and was being tested in accordance with Procedure DMP-73005. This procedure required a test of the phase A and the phase B overload relays. The maintenance foreman told the inspector that if the trip time acceptance criterion was exceeded, the procedure instructed the tester to "reset the relay and immediately repeat the test." This practice was justified by the licensee because the acceptance criterion was based on a vendor testing temperature of 40 degree centigrade (104 degree Fahrenheit) which more closely matched the design testing temperature and would be a more realistic assessment of the true time to trip.

Although the tests did not affect Technical Specification operability, the inspectors were concerned that tests were performed in an ambient temperature that utilized acceptance criterion based on a 104 degree F environment without documented justification and the apparent philosophy that allows changing initial test conditions to meet test acceptance criterion without any technical bases.

The inspectors concluded that, generally, the performance of electrical maintenance activities was effectively accomplished.

2.4.2.2 Mechanical Maintenance

The inspectors observed portions of 11 mechanical maintenance activities as discussed below:

WR 73503	Rebuild limitorque operator for valve 2-3004A.
WR 81059	Replace CRD strainer drain lines.
WR 81529	Test spring pack for Isolation Condenser Valve 2-1259.
WR 81647	Rebuild limitorque operator for Valve 2-3201B.
WR D47113	Modify piping on Unit 2 Offgas Hydrogen Analyzer.
WR D73224	Align coupling on Unit 2 Turbine and Generator.

WR D77760	Install flange on torus drain.
WR D77761-1	Install snubber on torus drain piping.
WR D78559-1	Install U-bolt on torus drain piping.
WR D79006	VOTES diagnostic valve testing.
WR D80492	Rebuild auxiliary and emergency oil pump on HPCI.

The inspectors observed portions of the work performed, examined work package documentation, and interviewed the personnel involved. The following observations were made:

- Work packages were complete and generally well organized.
- Travellers included step-by-step discussion, QC hold points for signatures, and specific instructions to guide the workmen through the work package.
- Drawings and Field Change Requests (FCRs) were up-to-date.
- Special process permits were included for welding and designated fire watch.
- Work procedure instructions were augmented by QC hold points for tightening fasteners.
- Personnel training logs were included in the work package.
- Engineering analyses were included for hoisting and rigging.
- Periodic HP surveillances were witnessed by the inspector during the work activity in the Unit 2 torus basement.
- Personnel access log was signed and a workman was posted at the access hatchway to the torus basement.
- Information was transferred to other inspection team members, who verified acceptability of materials, personnel training records, and control of calibrated instruments.

The inspectors witnessed portions of work on the CRD system as described in WR 81059, which involved replacement of the CRD strainer drain lines with a flexible metal hose. The work request contained work instructions to remove the existing pipe and valves, and install new valves, fittings and flexible hoses. Attachments to the work request delineated the required valves and flex hoses, but the required fittings were not delineated, which resulted in an approximate two hour delay in the job. The delay was significant because the Health Physics (HP) technician responsible for surveying the job remained at the job site until the required fittings were

obtained from the warehouse. This occurred when HP support was limited at the end of the outage. Another delay was encountered because the work instructions were insufficient. The flexible hose installation created a personnel tripping hazard. The work analyst would not discuss the matter with the foreman nor come to the work area. After a lengthy discussion with the foreman the analyst came to the work site and concluded that the planned routing was insufficient and would require modification.

Work on the testing of a Limitorque valve operator spring pack, as described in WR D81529, was delayed for approximately two hours due to the unavailability of a QC inspector. Since no other instances were encountered of this type, the incident appeared to be isolated.

The inspectors concluded that performance of mechanical activities was effectively accomplished by skilled maintenance personnel. The maintenance personnel appeared conscientious and knowledgeable of the work performed. The performance of these tasks was witnessed entirely or in part by the respective foremen. Involvement of QC personnel was observed during the torus drain work performed by Project and Construction Services (PACS) and substation construction personnel. Work on the turbine generator coupling by plant personnel was witnessed by the GE representative who verified critical measurements and provided technical advice for achieving final alignment.

Throughout the performance of these tasks, the inspector was favorably impressed by the morale and experience level displayed by the personnel involved. There was good communication between maintenance and operations groups. None of the jobs witnessed were delayed by problems of material availability or conflicting activities. There were no problems identified during the observation of the above tasks.

2.4.2.3 Instrumentation Maintenance

The inspectors observed portions of four instrumentation maintenance activities as discussed below:

WR D53914	Color band control room indicators with normal/abnormal operating ranges.
WR D77549	Calibrate Local Power Range Monitor alarm.
WR D81632	Calibrate HPCI area temperature switches.
SP 89-1-12	Test RPS response time.

Work instructions for WR D81632 detailed the removal of two HPCI area temperature switches and installation of a jumper to change the configuration of the plant. Step 2 of the instructions was confusing, in that it stated, "Place a jumper as per the attached

checkoff sheets. If DAP 7-4 is required note the Jumper Log Number of the checkoff sheet." Procedure DAP 7-4, "Control of Temporary System Alterations," Revision 11, was used to control temporary system alterations and provide the steps to perform a Safety Evaluation. Evaluation and on-site review was required prior to the installation of a temporary alteration. In the above case, the evaluation had been initiated; however, the temperature switch removal and jumper installation had commenced prior to approval of the Safety Evaluation. This appeared to be the result of confusing work instructions. Failure to follow Administrative Procedure DAP 7-4 is considered an example of a violation of Criterion V of 10 CFR 50, Appendix B (249/88030-03).

The licensee took immediate corrective actions. The work was stopped and Discrepancy Record 89-013 was initiated. The following training was provided to all IM department management: (1) work analysts were instructed to be more precise in work instructions as to when a Temporary System Alteration Authorization Sheet was required; (2) a training synopsis was presented to clarify the need for a Temporary System Alteration Authorization Sheet; and (3) foreman were required to check for the requirement to use Temporary System Alteration Authorization Sheets during pre-job package reviews and if the use of a sheet was suspected, but not specified, the work package would be returned to the work analyst for review and clarification.

The inspectors determined that the training would be adequate to prevent recurrence and also verified that all IM management personnel had received the training. There was no impact on safety from the jumper installation. A similar violation of Procedure DAP 7-4 is described in Section 2.4.2.1. The corrective actions described above were considered sufficient to resolve both issues.

The inspectors concluded that performance of IM activities were effectively accomplished by skilled IM personnel. Except as noted, IM personnel appeared conscientious and knowledgeable of the work performed.

2.4.3 Radiological Controls

The inspectors observed work being performed in contaminated/radiation areas, movements of tools/equipment to and from these areas, and interactions of workers with radiological controls personnel. Generally, health physics support and oversight of ongoing work or with ALARA review of specific tasks was adequate.

Radiological controls, posting, and labeling were generally good. Cleanliness and housekeeping appeared generally good for extensive outage conditions.

Through observation of work in progress and discussions with licensee personnel, the inspector determined that radiological controls were generally integrated into the maintenance process as evidenced by:

- Proposed facility changes were formally reviewed by the ALARA group.

- An experienced radiation protection person reviewed WRs to determine the need for a Radiation Work Permit (RWP) and an ALARA review.

- An ALARA group representative attended job-planning meetings.

- A computerized RWP/TLD-SRD dose tracking system was used as an ALARA tool.

- QA audits of the radiation protection program, including ALARA, were performed and findings were addressed.

- Station dose goals were established, and work group doses were tracked.

- Monitoring to support RWP issuance, RWP job coverage, and use of dosimetry appeared good. On jobs where the RWP was adequately developed through communications between the affected departments, the RWP and/or the work order and procedure was adequately detailed to assure adequate job coverage, and enough advanced notice was given to the radiation protection department so that adequate Radiation Control Technician (RCT) support was available.

The inspectors noted that improvements in the following areas could be made:

- Work packages and/or associated RWPs for work performed in radiologically significant areas did not always contain detailed radiation protection precautions and hold points to assure that proper radiation protection practices and requirements were followed.

- Work packages, for work in radiologically significant areas, did not always contain tool/equipment/staging requirements; therefore, unnecessary dose could be received in radiation/high radiation areas because of inefficiency. (Refer to Section 2.4.2.2 for a specific example.)

- It appeared that additional, enhanced, radiation worker training was needed for persons who perform work in radiologically controlled areas. This need was made evident when shortcomings were observed in handling potentially radioactive materials and equipment such as used protective clothing, tools, respirators, and radwaste. Similar shortcomings were described in licensee radiological occurrence and personal contamination reports.

Management support for radiological controls and ALARA programs appeared adequate, which was evident by reductions in personal doses, personal contamination events, and the extent of contaminated areas

over the past few years. Further improvements, such as space management during major outages appeared necessary to effect further reductions.

2.4.4. Maintenance Facilities, Material Control, and Control of Tools and Measuring Equipment

The inspectors reviewed activities in the areas of facilities, equipment, and material control to assess support given to the maintenance process. Interviews were conducted with various maintenance management and craft personnel to determine the policies, goals, and objectives; and followup observations were performed to determine the extent to which the plan practices, procedures, equipment, and layout supported the maintenance process. The three maintenance groups had separate workshop areas.

2.4.4.1 Facilities

The mechanical, electrical, and instrument maintenance workshop areas were located in the Shop and Warehouse building inside the protected area, but outside the radiologically controlled area. The mechanical shop contained a machine tool area, small hot shop, small hot storage area, tool crib, hot tool crib, vendor manual library, offices for the master mechanic, maintenance foreman, and other support staff. The inspector observed that large plastic tents were in place around tools and equipment which had the potential to create an airborne contamination area. Although no work was in process, the inspector observed that several workers were eating food next to a roped off area by one of the tents, which did not appear to be a radiologically sound practice.

There was an area specifically designated for the rebuilding of CRD assemblies immediately adjacent to the reactor building. In addition, the Unit 1 turbine floor was used for the rebuilding of Limitorque valve operators. The licensee's policy about work on contaminated objects was that the item must be surveyed for contamination prior to exiting the radiologically controlled area and entering any shop. The tool washdown/decontamination facility was centrally located. These practices minimized the spread of contamination and allowed better utilization of a relatively small mechanical maintenance shop, which was not equipped to routinely handle these tasks.

As a result of a recent INPO inspection, the licensee had taken action to remove flammable material from the maintenance shop area at night and when not in use. No unattended flammable materials were noted during the inspectors walkdown of maintenance facilities.

Mockup facilities were not in use during the inspection, although the inspectors did observe a mockup for CRD removal and mechanical stress improvement program (MSIP). Mockups of Limitorque valve operators were used to train and qualify electricians and mechanics.

Access to the electrical shop was from outdoors or through the mechanical shop. There were plans to add a new electrical maintenance shop, which will be on the first floor and have better plant access. The current shop area was clean, had a good layout of work benches with several bench tools, and a tool crib. There were also offices for the master electrician and foremen.

The instrument shop was more centrally located and closer to the control room and plant. The shop was well lit and each IM had a work bench. The general foreman and scheduler shared the same office, which appeared to provide means for initiating good work planning and communications. The room also contained equipment calibration records, surveillance test packages, and vendor manuals. The IM master and IM assistants were located near by and were frequently observed in the shop area assisting with maintenance items.

As part of the MIP, the licensee plans to expand the maintenance facilities. On average, this includes an increase in shop size of about 20% for each shop in addition to added office space to accommodate maintenance engineers, planners, and schedulers, who are currently located in trailers or other areas remote from the shops. Laydown areas appeared to be sufficient but cramped.

All maintenance foremen were assigned a beeper that could be accessed anywhere in the plant. Throughout this inspection, this communication system demonstrated its effectiveness.

2.4.4.2 Material, Equipment, and Tool Control

The warehouse facility included good Level A and Level B storage space. Physical control of access to the warehouse facility was good, environmental controls were effective, cleanliness and housekeeping aspects were very good. Policies and procedures were documented and implemented for procurement of parts and materials. Guidelines were established and effectively implemented to address lead time for procurement, specification for parts and materials, documentation requirements, testing, inspections, acceptance records and stock quantities. Guidelines were also established to expedite emergency procurement through the Pool Inventory Management System (PIMS). Reorder points were set by the Maintenance Department but controlled by warehousing.

A "Physical Inventory List" was generated by computer and used by the inspector to access controls and identification of material. The Inventory List described the item, identification number, physical location, date last inventoried, and shelf life. Shelf life controls were in effect as well as controls for consumable materials such as solvents, lubricants, gasket materials, and welding rods. A separate storage facility was established for flammable material and other materials that required special handling. Guidelines and controls were established for the issuance and return, of unused material.

Overall, program concepts and performance in this area were good, however, two concerns were identified.

- Material was delivered to the mechanical contractor's warehouse facility where the material was receipt inspected and controlled; however, material for other contractors was also delivered there and stored in a roped off "Hold" area. No "List of Material" on "Hold" was maintained which made it possible for material to be picked up and misplaced. Misplacing of electrical switches did delay control room work for an extended period of time.

- Safety-related items were procured from a vendor not listed on the Quality Approved Bidders List. BWR corporate engineering purchase requisition NU-8428 (Purchase Order 763497) was issued to procure four GE type SBM switches, but failed to adequately identify the approved vendor's location on the requisition. The requisition was intended for GE in San Jose, California, but instead went to GE in Schenectady, New York because the Quality Assurance (QA) coordinator and purchasing agent failed to identify the approved vendor plant location. GE Schenectady was not listed on the "Quality Approved Bidder List" to supply the switches. The switches arrived at the warehouse, but were not receipt inspected. Also, the switches were issued without proper documentation and misplaced until found by a tech staff engineer. The procurement problem was identified before the switches were installed.

The inspector reviewed the procurement process by selecting three purchase orders (POs) including 501335DR80 and 502042XX287. The inspector verified that the vendor was an approved source; reviewed the method utilized for acceptance of the procured item; and ascertained that the correct quality and technical requirements were in the PO. No problems were identified.

2.4.4.3 Control and Calibration of Measuring and Test Equipment (M&TE)

Each department maintained its own tool crib and tool issue/return lot. The log listed information such as: job and tool description, issue return dates, and personnel names. Tools were returned on a daily basis and log sheets were maintained for two years. Procedures were developed and implemented for the issue, return, and recall of M&TE. The inspector performed a walkdown of all three tool cribs and verified that equipment identification and storage requirements were met. All equipment was identified by labels with equipment name, identification number, calibration date, next calibration due date, and equipment location. A yellow "Certified M&TE" tag was attached to M&TE certified offsite by System Operational Analysis Department (SOAD); a yellow "Certified" sticker was attached to M&TE certified onsite; and a green "General Usage Equipment" tag was attached to equipment that required attention to keep it in safe and serviceable condition.

Control and storage of M&TE was good in that defective or "calibration due" instruments were stored in a separate room away from those that were in calibration and acceptable for use. The inspector checked the status of three M&TE items used for work observed by other inspectors. The issuance and return process was verified for Digital Multimeter DW-4, Digital Multimeter 127290D, and Temperature Monitor DT-24 used for WRs 77549, 79163, and 81632 respectively. Maintenance supervisors maintained good records and made it possible to review documentation that otherwise would have had to be reviewed at SOAD. A "Tech Center Instrument System Monthly Report" was generated by SOAD that listed the calibration schedule and identified the tools which were to be certified. Tools were picked up by SOAD, located offsite, during the month calibration was due and returned to the station after calibration.

The inspector interviewed the electrical, mechanical, and instrumentation maintenance supervisors who were responsible for M&TE control. The activities and records related to control calibration, and management of M&TE met program requirements and commitments.

2.5 Licensee's Assessment of Maintenance (Quality Verification)

The inspector evaluated the licensee's quality verification process in the maintenance area by the review of audit reports, surveillance reports, trending and corrective action documents, and the maintenance self assessment. The documents were reviewed to assess technical adequacy, root cause analysis, timeliness of corrective action, and justification for closeout of corrective documents.

2.5.1 Review of Audits and Surveillance

The inspector reviewed 10 QA audits and 12 QA surveillances of maintenance activities performed during 1988. The QA audits and surveillances were performance based and management gave adequate attention to the areas of closing audit findings and followup of corrective actions. The licensee utilized experienced personnel and technical experts to conduct audits and surveillances which were performed in accordance to schedules. A total of 56 onsite and 4 offsite audits were completed. The audit findings were analyzed and assigned to a matrix containing the 18 requirements found in 10 CFR 50, Appendix B - "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." Apparent trends were noted in areas of Criterion V - Instructions, Procedures, and Drawings and Criterion VI - Document Control. The QA program for trending was effective in audit findings and identifying significant trends that may develop. The areas identified by the inspector, were also found by the licensee and reported in the Quarterly Trend Report.

The QA group also performed 252 surveillance inspections during 1988 with an emphasis on operations and maintenance areas. QA deficiencies were tracked by computer, which generated a printout for quarterly followup. The printout described the problem, type

of audit/surveillance, root cause code, auditee's response and new status. The status of the deficiencies was documented and filed by the assigned QA inspector.

2.5.2 Review of Corrective Action

Findings from Maintenance Audits 12-88-17, 12-88-18, and 12-88-23 were followed up, reviewed for corrective action and closed by the licensee. A total of 10 findings were reviewed by the inspector and appeared to be adequate. For example, audit finding 3 from Maintenance Audit 12-88-17 identified spare parts for Environmentally Qualified electrical equipment found in the storeroom, which did not meet current QA Manual Documentation requirements. Monthly followups were performed by QA and the audit was closed based on review of EQ records, completed receipt inspections of existing items, and a better set of purchase requirements by BWR Engineering.

2.5.3 Review of Maintenance Self-Assessment

The inspector reviewed the report of the licensee's self-assessment of maintenance performed in June 1987, which consisted of team members from the six CECo plants and INPO. This self-assessment included evaluations of 16 maintenance areas. A second assessment was performed in September 1987, by a team that consisted of INPO, EPRI, and GE personnel along with Dresden Station management. This second assessment was performed in the seven weakest maintenance areas identified during the first assessment. As a result of the assessments, a "Conduct of Maintenance" program, which has been discussed throughout this report, was initiated to improve corrective, preventive, and predictive maintenance. Estimated implementation date of the program is April 1991.

Overall, the licensee's self-assessment of maintenance was effective. QA audits of maintenance were performance based. Also, deficiencies identified and corrective actions were being tracked.

2.6 Overall Plant Performance

2.6.1 Performance Indicators

The inspectors reviewed historical data that included licensee event reports, availability factor for selected systems, forced outage rate and reliability data such as reactor trips and engineered safety feature actuations, which for 1988, were below the industry averages. High pressure coolant injection and emergency diesel generator availability factors indicated improvement overall. Plant performance for 1988 was good.

2.6.2 Plant Walkdowns

The material condition of the plant was satisfactory and no condition was noted that would have immediate adverse impact on operability of equipment. Housekeeping, overall, was satisfactory. The following strength and weaknesses were identified.

- Equipment identification was good as compared to other plants inspected.

- Threshold for writing work requests appeared too high to address equipment deficiencies.

- Hardware deficiencies were not identified on a work request including a Unit 2 125Vdc battery feed breaker handle, missing Unit 3 motor control center overload reset buttons, water leaking into Unit 2 high pressure coolant injection room, and an oil leak from the booster pump bearing.

- Emergency diesel generators 2, 3, and 2/3 excitation field breakers and reactor protection system breakers were not included in the preventive maintenance program.

2.7 Management Support of Maintenance

2.7.1 Management Commitment/Involvement

Management was committed to improve maintenance activities at Dresden as shown by several improvements that were initiated. The Maintenance Improvement Program was a broad based program to improve maintenance.

The inspectors identified strengths in the maintenance program that indicated management was committed to the improvement of maintenance at Dresden. For example:

- Active participation in industry initiatives such as Institute of Nuclear Power Operations, Boiling Water Reactor Owners Group, Electrical Power Research Institute, Nuclear Utility Management and Human Resource Committee.

- Initiation of the Maintenance Improvement Program.

- Personnel knowledgeable of and dedicated to the Maintenance Improvement Program.

- Use of time series analysis of equipment failures to determine preventive maintenance requirements.

- Use of probabilistic risk analysis of the high pressure coolant injection system.

- Periodic assessment of the Maintenance Improvement Program by corporate personnel and subsequent corrective action by station personnel.

- Improved reliability of motor operated valves by use of teams for preventive maintenance.

- Initiation of a strong preventive maintenance program for safety-related valves.

- Aggressive resolution of the 4.16kV breaker Tuf-Loc bushing problem.

However, continued involvement and strong commitment by management is necessary to improve maintenance activities to the level desired by Commonwealth Edison. For example:

- Non aggressive preventive maintenance program for 4.16kV circuit breakers and Unit 3 250 Vdc motor control center.
- Inadequate resolution of problems with "SBM" switches.
- Slow progress in establishing an equipment trending program.

2.7.2 Management Organizations and Administration

The inspection indicated there was strong performance of the management organization in the administration of the maintenance program.

Examples of strengths in the management organization and administration were:

- A long range maintenance plan had been established as specified in the Conduct of Maintenance manual.
- Personnel were dedicated to the Maintenance Improvement Program.
- Plant improvements were evident, such as, resolution of the Tuf-Loc bushing problem, replacement of the high pressure coolant injection booster pump impeller, and the plant painting program.
- Maintenance of safety relief valves and motor-operated valves was good.

However, there were areas that needed increased management attention. For example:

- Resources had not been adequately allocated to close out PADs.
- Administration of a preventive maintenance program for 4.16 kV breakers and Unit 3 250Vdc motor control centers was weak. Some components had not had preventive maintenance since 1975.
- Performance indicators did not measure effectiveness of maintenance.
- Plant aging consideration for electrical components had not been addressed.

2.7.3 Technical Support

Technical support of maintenance was satisfactory. The inspectors identified the following strengths:

- A probabilistic risk assessment of the high pressure coolant injection system.
- Procedures for motor-operated valve maintenance and testing were detailed, user friendly and incorporated previous lessons learned.

However, some weaknesses were identified:

- Inadequate root cause analysis and corrective action for the 2D low pressure coolant injection breaker and the isolation condenser motor-operated valve.
- Trending program did not consider component significance.
- Inadequate quality control observance of electrical work activities.

The following observations were noted concerning the MIP.

- The program analysis date system had not been fully implemented.
- Critical high pressure coolant injection system skid mounted components had not been identified.
- Only about 1/3 of the vendor manuals were controlled.
- Only about 3 of 15 systems had been walkdown to verify equipment identification numbers for incorporation in the total Job Management Program. Completion of this work was not expected before early 1991.
- A new post maintenance testing program was being developed.

2.8 Maintenance Implementation

2.8.1 Work Control

Work control activities were satisfactory. The inspectors identified the following strengths:

- Backlog of corrective maintenance was low.
- Post job checklists provided work analysts with useful information for planning future work activities.

However, weaknesses did exist as follows:

- Work was initiated without adequate engineering review.
- Total Job Maintenance histories were incomplete for completed work requests.
- Planning adversely affected several work activities due to lack of spare parts, identification of needed parts, unavailability of QC and unplanned operations which caused increased area radiation.
- Time required for maintenance was actually twice that estimated.
- Work requests for corrective maintenance were incorrectly identified as preventive maintenance.
- Work request probable cause blocks were inconsistently completed and not used for trending.
- Measuring and testing equipment range and accuracy was inconsistently specified.

2.8.2 Plant Maintenance Organization

Performance in this are was good. Examples of strengths were:

- Morale and experience level of maintenance personnel was high.
- Pneumatic measuring and testing equipment was calibrated before and after critical plant instrument calibrations.
- Setpoint trending program was good.
- Communications between maintenance and operations was good.

Some weaknesses were noted:

- Preventive maintenance status of 4.16kV breakers and 250 Vdc MCCs was not known by the electrical department.
- 4.16kV breaker maintenance performed prior to October 1988 was not technically evaluated.
- A coordinator did not exist for electrical vendor manual updates.
- Testing techniques for thermal overload devices partially defeated the purpose of performing the test.
- A trend program based on equipment histories had not been established.

2.8.3 Maintenance Facilities, Equipment, and Material Control

Performance in this area was satisfactory. The following strength and weaknesses were identified.

- Traceability of materials used was good.
- Lists of material on hold at contractor facilities did not exist.
- Electrical switches were purchased by the corporate organization from an unapproved source; no copy of the purchase order was sent to the site.

2.8.4 Personnel Control

Personnel at various management levels were interviewed and were knowledgeable of responsibilities and accountability. The staffing requirements for mechanical electrical and instrument departments appeared to be adequate for non-outage work. The mechanical and electrical departments were adequately supplemented with a mobile work force during planned outages. The following strengths were identified.

- A "Personnel Training Matrix" was a useful tool to identify personnel qualified to perform specific tasks.
- Training records were readily available and documented all training.
- Mockups were a useful training tool.

3. 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 this inspection is included in Paragraph 2.3.2.1 of this report.

4. Exit Meeting

The inspectors met with licensee representatives (denoted in Paragraph 1) on February 16, 1989, at the Dresden Plant and summarized the purpose, scope, and findings of the inspection. The inspectors 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 or processes as proprietary.

APPENDIX A

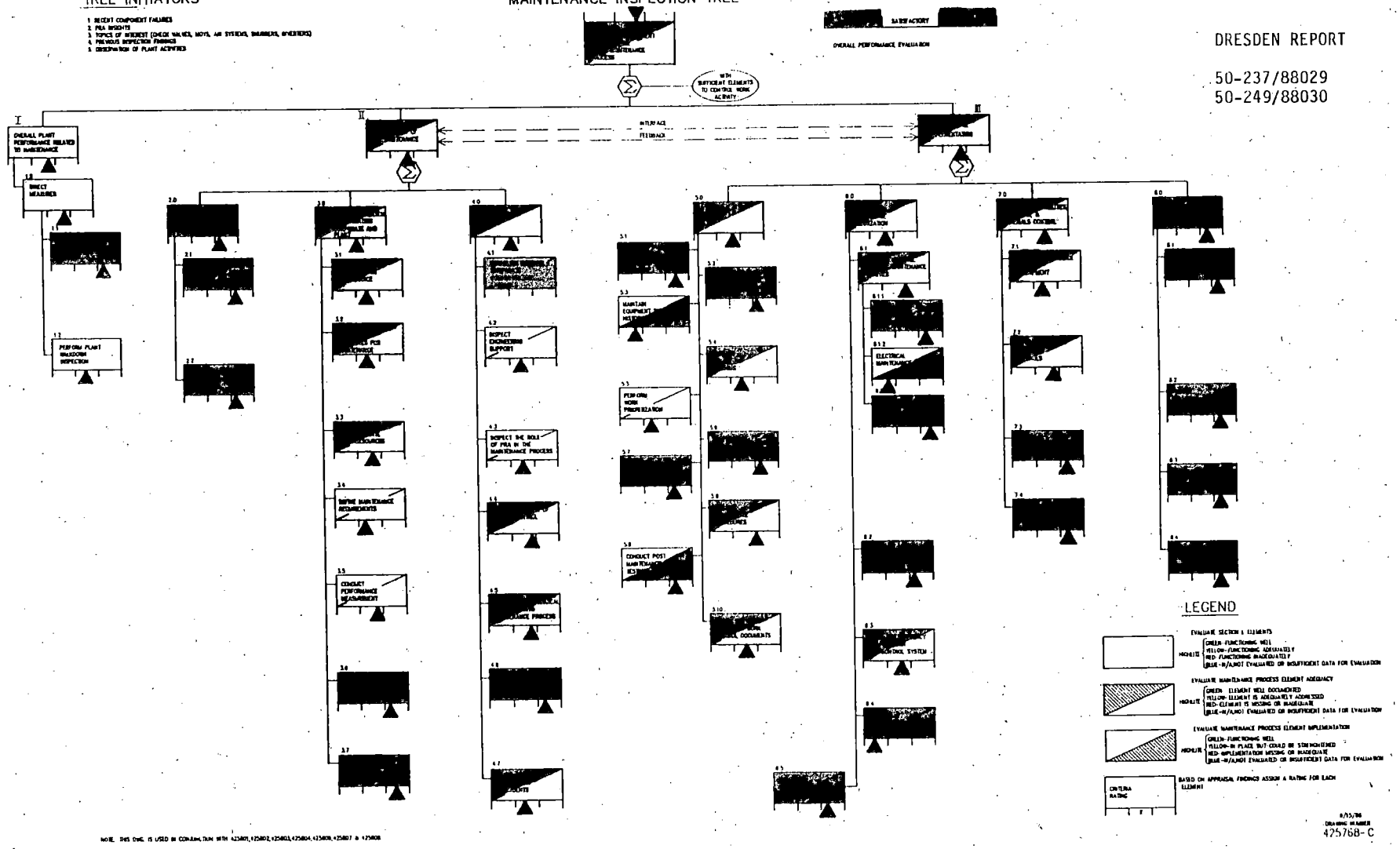
AC	Alternating Current
ADS	Automatic Depressurization System
ALARA	As Low As Reasonably Achievable
AOP	Auxiliary Oil Pump
BOP	Balance of Plant
BWR	Boiling Water Reactor
CECO	Commonwealth Edison Company
CM	Corrective Maintenance
CMWR	Corrective Maintenance Work Request
COM	Conduct of Maintenance
CRD	Control Rod Drive
DC	Direct Current
DG	Diesel Generator
DVR	Deviation Report
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EID	Equipment Identification
EM	Electrical Maintenance
EPA	Electrical Protection Assembly
EPRI	Electrical Power Research Institute
ESF	Engineered Safety Feature
EQ	Environmental Qualification
FCR	Field Change Request
GE	General Electric
GEI	General Electric Instruction
GEK	General Electric Vendor Manual
GE SAL	General Electric Engineering Service Advice Letter
GE SIL	General Electric Service Information Letter
GSLO	Gland Seal Condenser Hot Well
GSUR	General Surveillance
HPCI	High Pressure Coolant Injection
HP	Health Physics
I&C	Instrument and Control
IEB	IE Bulletin
IEN	IE Notice
IM	Instrumentation Maintenance
INPO	Institute for Nuclear Power Operations
INWC	Inches of Water Column
ISI/IST	Inservice Inspection/Inservice Testing
K	Kilo
LER	Licensee Event Reports
LPCI	Low Pressure Coolant Injection
MCC	Motor Control Center
MG	Motor Generator
MIP	Maintenance Improvement Plan
MM	Mechanical Maintenance
MOV	Motor Operated Valve
MSIP	Mechanical Stress Improvement Program
MSL	Main Steam Line
M&TE	Measuring and Test Equipment

NGET	Nuclear General Employee Training
NPRDS	Nuclear Power Reliability Data System
NRC	Nuclear Regulatory Commission
NTS	Nuclear Tracking System
NUMARC	Nuclear Utility Management and Human Resource Committee
OPEX	Operating Experience Report
PACS	Project and Construction Services
PAD	Program Analysis Data Sheet
PIMS	Pool Inventory Management System
PM	Preventive Maintenance
PMWR	Preventive Maintenance Work Request
PO	Purchase Order
PRA	Probability Risk Assessment
QA	Quality Assurance
QC	Quality Control
RBCCW	Reactor Building Closed Cooling Water
RCM	Reliability Centered Maintenance
RCT	Radiation Control Technician
RPS	Reactor Protection System
RWCU	Reactor Water Cleanup
RWP	Radiation Work Permit
SAL	Service Advice Letter
SALP	Systematic Assessment of Licensee Performance
SER	Significant Event Report
SIL	Service Information Letter
SMAD	System Material Analysis Department
SOAD	System Operational Analysis Department
SOER	Significant Operating Experience Report
SRV	Safety Relief Valve
SSMF	General Surveillance System Master File
TJM	Total Job Management
TS	Technical Specification
V	Volt
VOTES	Valve Operator Testing and Evaluation System
WR	Work Request

PRESENTATION TREE
MAINTENANCE INSPECTION TREE

DRESDEN REPORT

50-237/88029
50-249/88030



NOTE: THIS DWG. IS USED IN CONJUNCTION WITH 425801,425802,425803,425804,425805,425807 & 425808