50-298

December 22, 1994

MEMORANDUM TO: William T. Russell, Director, NRR
Leonard J. Callan, Regional Administrator, RIV
Edward. L. Jordan, Director, AEOD
Robert M. Bernero, Director, NMSS
Paul E. Bird, Director, OP

FROM: James M. Taylor
Executive Director for Operations

Original signed by
James M. Taylor

SUBJECT: STAFF ACTIONS RESULTING FROM THE SPECIAL EVALUATION OF COOPER NUCLEAR STATION

A copy of the report for the subject evaluation and the proposed staff actions were transmitted to you by previous memoranda. The report documents performance deficiencies and probable root causes, together with findings and conclusions which form the basis for identifying followup actions.

The purpose of this memorandum is to identify and assign responsibility for generic and plant-specific actions resulting from the special evaluation of the Cooper Nuclear Station. You are requested to resolve each of the items in your area of responsibility and, if appropriate, identify additional staff actions or revisions to the identified actions based on your review of the report. When more than one office is indicated as responsible, the first office listed has lead responsibility. Based on briefings on the special evaluation results, I recognize that actions to address some of these issues may already have been initiated by the staff.

In view of the importance of this subject, I intend to closely monitor and track the status of each item until final resolution. Within 90 days, please provide a written summary of the schedule and status of each item within your area of responsibility, as identified in the attachment, or that you have additionally identified. Further, I request that you provide a written status report on the disposition of your items (and anticipated actions for uncompleted items) by the first week of January of each calendar year, until all items are resolved. Every effort should be made to resolve these issues promptly. Copies of all status reports should be forwarded to Stuart Rubin (Branch Chief, DEIIB/AEOD) to facilitate AEOD's responsibility for status monitoring.

If there are any questions regarding individual action items, please contact Stuart Rubin at 415-7480.

Attachment: As stated

Distribution:
Central Files
IRD R/F
EDO R/F
DEIIB R/F
AEOD R/F

DISK/DOCUMENT NAME: G:\DEIIB\DEPFILES\D1015\STAF-ACT.CNS (2nd document)

To receive a copy of this document, indicate in the box "C" = Copy w/o attachment, "E" = Copy w/attachment, "N" = No copy

OFC	DEIIB:IRD	E	IRD:AEOD	E	D:IRD:AEOD	E	D:NRR	E	RA:RIV	E
NAME	SDRubin:mgc		EWMerschoff		FJCongel		WTRussell		LJCallan	
DATE	12/13/94		12/ /94		12/14/94		12/13/94		12/13/94	
OFC	D:NMSS		D:OP	E	DD:AEOD	E	D:AEOD	E	EDO	
NAME	RMBernero		PEBird		DFRoss		ELJordan		JMTaylor	
DATE	12/ /94		12/14/94		12/ /94		12/14/94		12/ /94	

OFFICIAL RECORD COPY

STAFF ACTIONS RESULTING FROM THE SPECIAL EVALUATION OF THE COOPER NUCLEAR STATION

1. Issue: Clarity and Completeness of Technical Specifications

The Cooper Technical Specifications (TS) lack clarity and completeness in many areas analogous to problems identified by the Palisades DET. Problems include a lack of operability requirements for safety-related equipment during cold shutdown and outage-related activities and a lack of rigorous surveillance requirements for some equipment. For example, TS RHR surveillance and DG operability requirements did not exist during cold shutdown plant operation. In addition, the licensee had historically taken a narrow and sometimes non-conservative approach to TS interpretations, which in some cases appear to be inconsistent with the actual TS. An example would be insufficient ECCS logic system functional TS surveillance testing. The licensee has indicated its intention to consider development of TS which are consistent with the standard TS.

<u>Action</u>:

Evaluate whether interim actions to upgrade the current Cooper TS are warranted pending a final decision on whether the licensee will upgrade their TS to be consistent with the standard TS. Upgrade the TS as appropriate. (NRR, Plant-Specific)

2. Issue: Adequacy of Operator Staffing to Perform Remote Safe Shutdown

A licensee review of Information Notice 91-77, "Shift Staffing At Nuclear Power Plants," identified the need for an additional licensed operator to ensure a safe reactor shutdown under certain conditions. Specifically, a fifth licensed operator, one more than the TS required four, was necessary following a control room evacuation. Since November 1993, the licensee has administratively required and staffed an additional licensed operator in the control room. The TS currently require 2 SROs and 2 ROs in the control room, 3 non-licensed station operators in the plant, and the availability of a non-licensed STA. An additional TS restriction is that 3 of the 4 licensed operators must be independent of the fire brigade.

<u>Action</u>:

Evaluate whether action to revise the TS staffing requirements to reflect the addition of the fifth license is warranted. Upgrade the TS as appropriate. (NRR/RIV, Plant-Specific)

3. Issue: NRC Headquarters Personnel Radiation Dosimetry

Regional representatives of the SET used NRC-issued dosimetry in addition to that supplied by the licensee. The SET team members from other offices did not have NRC issued dosimetry. NRC Manual Chapter 0524, "Standards for Protection Against Ionizing Radiation," provides general guidance for NRC staff and NRR Office Letter No. 1303, Revision 1, Radiation Protection Procedures for NRR Personnel," provides specific guidance to NRR staff. Additionally, regional instructions provide for issuance and use of NRC supplied dosimetry for personnel who travel to licensee facilities. However, the guidance for issuance, use and monitoring of dosimetry by headquarter's personnel does not appear to be generally known. This issue could be critical for individuals visiting plants outside the U.S. who are not subject to the monitoring standards of the Code of Federal Regulations. Currently, the Office of Personnel has lead responsibility for the development of a Management Directive to establish an agency-wide personnel dosimetry program.

Action:

Assess the level of compliance with NRC Manual Chapter 0524 and other Headquarter's guidance regarding the issuance, use and monitoring of personnel dosimetry. Evaluate the need to develop and issue additional guidance and procedures and provide training to ensure a consistent policy is generally known and complied with. (OP/NRR/NMSS/AEOD, NRC-HQ)

4. Issue: Use of temporary modifications in emergency operating procedures without verifying that the modifications could be installed given staffing and timing constraints.

While performing the Special Evaluation of the Cooper Nuclear Station, it was discovered that emergency operating procedures (EOP) contained a total of 58 plant temporary modifications (PTM) which would be implemented during execution of the EOPs. Most of the PTMs involved adding jumpers to or lifting leads from the control room instrument panel back-plane. Several weaknesses include: (1) some PTMs were never tested to verify that they would perform as designed, (2) the radiological evaluation did not consider potential doses to the operator from the TS assumed design basis containment leak rate (or some reduced leak) into the reactor building, (3) 31 of PTMs would be installed outside the control room, and (4) no evaluation was made in the verification and validation of the EOP procedures to determine the time or staff needed to install the PTMs. NRR does not give credit for operator intervention to realign manual fluid systems during the first 20 minutes after the start of an event (e.g., start of drywell spray on a BWR). During the first 20 minutes following an ATWS event, possibly 10 PTMs would have to be installed outside the control room. Information obtained from Senior Resident Inspectors regarding the use of PTMs in EOPs at other stations showed that; Susquehanna had approximately 155 per unit, Limerick had approximately 90 per unit, and Monticello had approximately 115.

Action:

Evaluate (a) the significance and number of PTMs which could reasonably be installed in a plant during the early phases of an event which would require entry into EOPs and not degrade safety, and (b) the need to assess the proficiency of the operations crew to implement PTMs during operator license examinations. Provide guidance as necessary. (NRR, Generic)

5. Issue: Questionable heat transfer capability of the RHR heat exchangers because of tube plugging and increased fouling.

The RHR heat exchangers at CNS have 835 tubes. The tube plugging margin is reached at 4%, which is 33 tubes. As of April 1992, the "A" RHR heat exchanger had 30 tubes plugged, and the "B" exchanger 23 tubes. Performance testing of the heat exchangers in 1987, 1988, 1990, and 1991 produced data that was not reliable because of poor test control of system lineup and low flow conditions. The licensee used the Shell and Tube Exchanger Rating (STER) program to calculate fouling factors. Additional performance testing performed in 1992 of both heat exchangers indicated fouling factors which varied greatly between the two heat exchangers. The STER program had analysis errors within the program but the licensee continued to use the program by adjusting the input data to run the code. Output data from the STER program indicated that the "B" RHR heat exchanger had the highest fouling factor resulting in about a 10% margin in the heat removal capacity needed by the containment analysis. Because of errors within the STER program, the questionable nature of the calculated fouling factors, the closeness of the fouling factors to the design limit, the lack of controls placed upon performance testing, and the unknown current condition of the heat exchangers; further review is necessary to fully evaluate the material condition and heat transfer capabilities of the RHR heat exchangers. In addition, the heat exchangers were originally scheduled to be replaced in the 1993 outage, but were later deferred to the 1995 outage. Further deferral of this work was also being considered.

Action:

Evaluate (a) the adequacy of calculations performed to determine the heat transfer capability of the RHR heat exchangers, (b) the acceptability of their current condition, and (c) the acceptability of the schedule for replacement of the heat exchangers. Take action as necessary. (RIV/NRR, Plant-Specific)

6. Issue: Safety-Related Equipment Testing Did Not Always Assure Operability

Significant weaknesses were recently identified in the licensee's testing and surveillance programs for safety-related systems and components. Deficiencies were found by the SET, regional inspectors, the licensee, and the DSA team. Identified weaknesses included pre-conditioning of equipment to assure passage of tests and incomplete functional testing of safety-related system actuation logic. Additionally, surveillance procedures did not contain all required TS attributes; post-modification and post-maintenance testing was incomplete or not effectively planned; and preventive maintenance was ineffective in assuring equipment operability. Excessive testing resulted in plant challenges or degraded equipment while ineffective test result trending obscured declining equipment performance and the need for actions to correct problems before failure occurred. The SET report documents a number of testing weaknesses which substantially degraded the licensee's system operability assurance process. The SET results, together with previous Diagnostic Evaluation Team (DET) findings for other facilities, indicate that licensee testing and surveillance programs vary significantly in their ability to detect or predict non-functionality or failures of systems and components. This situation appears to continue despite considerable operational experience feedback in the form of Information Notices, Bulletins, Generic Letters, and industry correspondence.

Action:

Review the SET and previous DET reports to evaluate testing weaknesses in assuring operability. Identify any changes that could be made to improve the effectiveness of testing programs for assuring operational safety. (AEOD, Generic)

7. Issue: Licensee Response to the SET Report

The licensee was requested to review the special evaluation report and respond within 60 days describing actions it intends to take to address root causes identified in the DSA and SET reports.

Action:

Review and evaluate the licensee's response to the special evaluation report for completeness. Prepare an appropriate reply for the EDO's signature. (RIV/NRR/AEOD, Plant-Specific)

1/95

~~PRE-DECISIONAL~~

COOPER

I. HISTORY

The Cooper Nuclear Station (CNS) was first discussed at the June 1993 Senior Management Meeting (SMM). The basis for concern was an apparent declining level of performance. In the previous two SALP periods, which ended in January 1992 and April 1993, performance declined in the areas of operations, radiological controls, maintenance/surveillance, engineering/technical support, emergency planning, and safety assessment/quality verification. Marginal performance, particularly in the areas of self-assessment and the implementation of corrective actions for identified problems was apparent. In January and June 1994, the NRC sent the licensee a trending letter requesting that appropriate remedial actions be taken.

The plant entered a forced, unplanned outage on May 25, 1994, which continues to this date. The plant shutdown was initiated because the emergency diesel generators were declared inoperable due to concerns regarding their capability to supply emergency electrical loads in postaccident conditions. Concurrent with the development of this issue and after the plant had been shutdown, the inspection program identified that the control room emergency filtration system had been inoperable since 1989. In addition, the licensee discovered during design basis reconstitution efforts that the containment had been inoperable since 1974. The root cause for the inoperability of these engineered safety feature systems was inadequate testing. The NRC subsequently issued escalated enforcement and proposed a Civil Penalty for these violations.

At the June 1994 SMM, NRC managers recognized the need to obtain additional insight into the performance of CNS management and staff. Accordingly, AEOD established, based on Diagnostic Evaluation Team principles, a Special Evaluation Team (SET) to assess the licensee's performance.

II. CHANGES SINCE LAST SMM

Since July 1994, a new station management team has been assembled. This team includes new Site, Plant, Operations, Planning and Scheduling, QA, Safety Assessment, Plant Engineering, Licensing, and Corrective Action Program (which includes the operational experience review program) Managers. In addition, new managers are being actively recruited for Corporate Engineering and Construction, and Onsite Human Resources. The capabilities of this new management team have not been fully assessed. However, some organizational and performance improvement actions have been made.

Historically, licensee management has not accepted NRC assertions that management oversight and programs/processes at CNS were significantly impaired. In July 1994, the licensee initiated an independent self-assessment by industry peers to obtain an independent performance assessment to confirm the problems previously identified by the NRC. This Diagnostic Self-Assessment (DSA), conducted July 25 through August 19, 1994, concluded that there were significant performance deficiencies that required resolution by the licensee. The major findings of the DSA included: (1) corporate and station management did not foster high standards

C|4

of performance; (2) weaknesses existed in the licensee's long-range planning; (3) management and quality assurance oversight were not effective; and (4) testing, configuration control, and corrective action programs were deficient.

Substantial inspection activity has been performed and insight has been gained into licensee performance since the last SMM. The region initiated enhanced resident inspector coverage and performed two major team assessments. From August 15 through October 7, 1994, the NRC SET evaluated licensee performance and assessed the independence and rigor of the assessment processes and findings of the DSA. The SET held a public exit meeting on November 17, 1994. The SET found that the DSA was an effective and comprehensive assessment, which reached substantive conclusions that were supported by the NRC's independent assessment. The SET's findings, that closely paralleled the DSA's findings, included: (1) management did not provide the leadership and direction necessary to maintain corporate-wide standards of performance; (2) major programs and processes were poorly defined and did not ensure the consistent and effective accomplishment of program goals and objectives; and (3) independent oversight and self-assessment were not effective in monitoring ongoing activities for detecting deficiencies or for ensuring that identified deficiencies were resolved. As a result of the DSA and the SET, senior licensee management recognized that problems and future challenges exist at CNS.

Confirmatory Action Letters (CALs) have been issued to address the specific hardware concerns associated with the emergency diesel generators and associated electrical distribution system, control room envelope, and containment penetrations. The CALs also confirmed the licensee's agreement to evaluate its operational experience and testing programs. A Demand For Information (DFI) was issued to determine whether the Commission could have reasonable assurance that, in the future, the licensee would conduct Station Operations Review Committee (SORC) meetings and other activities in a manner which would assure plant safety and compliance with NRC regulations. A DFI was also issued to each individual holding a position on the SORC. These DFIs were issued as a result of an investigation performed by the Office of Investigations to review the apparent careless disregard of the Technical Specification (TS) requirements for secondary containment.

The NRC established a Restart Panel, per Manual Chapter 0350, and developed an action plan for independent verification that the licensee has adequately addressed issues prior to approval of plant restart. The issues requiring resolution prior to restart are: the efficacy of the operational experience review program; the effectiveness of management's internal review; the adequacy of plant-wide surveillance testing; configuration control; the ability to identify and resolve deficiencies; electrical distribution system testing; control room envelope operability; control of containment integrity; effectiveness of the new management team; and control of the cooldown rate. These issues were discussed with the licensee and mutual agreement has been reached regarding items on the restart list. Emergent items will be added at the discretion of the Panel.

Under the direction of the new management team, the licensee has developed a comprehensive Restart Action Plan which includes a methodology to identify the actions to be completed prior to plant restart. The NRC Restart Panel and the licensee have met in a public forum and have, in principle, agreed on the restart issues; however, the issues may change based on further reviews conducted by the licensee and the NRC.

The licensee has initiated integrated planning at the corporate level to address the short and long-term issues that need to be resolved. The licensee had previously issued three different improvement plans to address performance and correct weaknesses; however, these plans have been abandoned by the new management team. The licensee plans to issue a new comprehensive plan, to be known as the Performance Improvement Plan, to address the actions to be taken to correct the ongoing problems at CNS.

III. FUTURE ACTIVITY

The new licensee management team has acknowledged weaknesses in the custom TS for Cooper. Prior to restart, the licensee plans to establish interim administrative controls to address weaknesses in the TS for control room pressurization, instrument surveillances, and EDG operability requirements. The licensee is currently evaluating options for upgrading the Cooper TS, but has not committed to adopting the BWR/4 Standard TS.

The NRC Restart Panel will coordinate the inspection efforts to verify that the identified restart issues have been satisfactorily addressed prior to approval of plant restart. As a minimum, these inspection efforts will include augmented resident inspection coverage, program reviews of the identified program weaknesses, and a modified Operational Readiness Assessment Team inspection.

As of December 15, 1994, only one license amendment needed prior to restart was under review by the staff: a proposed change to increase the minimum pressure at which the HPCI system is required to be operable. However, the licensee is reviewing surveillance requirements with frequencies of "once/cycle" and "once/refueling outage", to determine if there is a need to request NRC approval for any schedular extensions due to the unforeseen length of the current forced outage. The previous refueling outage ended in July 1993 and the next refueling outage is not scheduled until the Fall of 1995.

DATA SUMMARY

I. OPERATIONAL PERFORMANCE

A. Scram Summary

None.

B. Significant Operator Errors

None.

C. Procedures

Significant deficiencies have been identified with station surveillance procedures. Several deficiencies have been identified where surveillance procedures were not sufficient to demonstrate Technical Specification operability.

II. CONTROL ROOM STAFFING

A. Number of Licensed Operators

SRO	RO	LSRO	TOTAL
32	14	0	46

B. Number and Length of Shifts

Six, 12-hour shifts

C. Role of STA

The STAs at Cooper Nuclear Station are on duty for a 24-hour rotational period. They are not assigned to an operating crew; however, they do receive training with a specific shift crew. STAs do not hold a senior reactor operators license. The STAs primary duty is to act as an accident prevention and mitigation advisor to the shift supervisor. The licensee is considering placing STAs in the normal shift rotation beginning in January 1995.

D. Requalification Program Evaluation

A requalification program evaluation conducted in December 1993 resulted in a satisfactory rating for the program. The next requalification program evaluation is scheduled for November 1995.

III. PLANT-SPECIFIC INFORMATION

A. Plant-Specific Information

Plant	Cooper Nuclear Station (CNS)
Owner	Nebraska Public Power District (NPPD)
Reactor Supplier/Type	GE/BWR
Capacity, MWe	778
AE/Constructor	Burns & Roe
Commercial Operation Date	July 1, 1974

B. Unique Design Information

Containment: Mark I, with a hardened vent

Emergency Core Cooling Systems: Two loops of low pressure core spray, two loops of low pressure coolant injection, one high pressure coolant injection system, one reactor core isolation cooling system, and an automatic depressurization system.

AC Power: Five 345-kV lines, one 161-kV line and one 69-kV line; two turbocharged, V-16, Cooper-Bessemer diesel generators.

DC Power: Four Class 1E batteries with 8-hour capacity (and four battery chargers), two 125-volt and two 250-volt.

IV. SIGNIFICANT MPAs OR PLANT-UNIQUE ISSUES

MPA B-125 (Generic Letter 94-03, IGSCC of Core Shrouds in BWRs): In its August 26, 1994, response to the subject GL, NPPD indicated that it will perform inspections of the Cooper core shroud at the next refueling outage, currently scheduled for the Fall of 1995. In the safety assessment included as part of the response, NPPD concluded that the operation of Cooper until the next refueling outage would pose no undue risk from the potential for core shroud cracking. In support of that conclusion, NPPD maintained that the core shroud has a relatively low susceptibility to cracking due to the maintenance of good water chemistry at Cooper, applied loads to the core shroud during design basis events are low, the plant-specific minimum ligament required to maintain structural margins is 7% of wall thickness, and design margins are maintained even with significant shroud cracking such that safety system effectiveness and core coolable geometry are ensured. Further, the licensee's probabilistic safety assessment concluded that the estimated overall incremental core damage frequency is less than 1E-6 per year, assuming a 360° circumferential through-wall crack for a variety of postulated accidents. The staff has reviewed the licensee's submittal and concluded that it provided adequate justification for plant operation until the next refueling outage.

MPA B-111 (Generic Letter 88-20, Individual Plant Examination): The licensee submitted the IPE for Cooper on March 31, 1993. The Cooper IPE consists of a Level 1 and 2 PRA. The estimated mean core damage frequency is 7.97E-5 per year. On October 21, 1994, the staff issued a Request for

Additional Information (RAI); the licensee's response to the RAI is expected by December 21, 1994. The staff's review is scheduled to be completed by March 1995.

MPA B-110 (Generic Letter 89-10, MOV Testing and Surveillance): The licensee is preparing an extension request for the completion of their MOV dynamic testing program. They had previously committed to complete the program by January 1, 1995. However, due to the extended refueling outage in 1993 and the current forced outage, the next refueling outage has been rescheduled for Fall 1995.

V. STATUS OF THE PHYSICAL PLANT

A. Problems Attributed to Aging

None.

B. Other Hardware Issues

See attached risk impact study on hardware issues.

VI. PRA

A. PRA Insights

Cooper is a BWR-4 with a Mark I containment. BWR PRAs indicate that station blackout is a major contributor to core damage frequency. Offsite power for Cooper is supplied from several 161 kV and 345 kV lines that feed into the start-up transformer, and a 69 kV line that feeds into an emergency transformer. The 69 kV power source supplies emergency loads only. The 69 kV offsite power source previously had a poor record of spurious failures due to lightning strikes. After a safety system features inspection (SSFI) revealed voltage problems on the 69 kV line, a new substation was added to help control the power. Since December 1992, the 69kV power source has been reliable. A complete loss of offsite power event has never occurred at the site.

The emergency diesel generators (EDGs) require control air to maintain a set engine speed and provide protective trip functions. If control air is lost, the EDGs will shut down. Cracking of instrument air tubes has occurred due to vibration resulting in diesel engine trips. Relocation of engine mounted instruments has apparently rectified the situation in that for approximately the past two years there have been no diesel engine trips because of that situation. In the event of a station blackout, the 250 Vdc and 125 Vdc batteries have the capacity to accommodate the loads for a duration of 8 hours without load shedding. At Cooper, both the air system compressors and receivers are classified as essential.

Published PRAs provide a strong indication that service water systems (SWS) are risk significant. In the past, Cooper has experienced microbiologically induced corrosion (MIC) in certain sections of piping associated with the SWS (radiation monitor sample line) as a result of stagnant or low flow conditions. The entire SWS was reviewed to identify sections of piping subject to these same conditions. All identified sections of piping were inspected and no similar conditions were found. At Cooper, the SWS was not originally designed as an ASME Code Class 3 system. Although the SWS is included in the IST program, it has not been included in the ISI program in accordance with the provisions of 10 CFR 50.55a(g). Therefore, the staff has suggested to RES that the treatment of the SWS failure rates should be evaluated carefully during the IPE review process. The licensee plans to include the SWS in the ISI program at the 1995 refueling outage. Also, in 1994, excessive silting was noted in the SWS as well as at the end of the SWS intake structure. The licensee is taking action to address silting concerns, including dredging the river bottom near the intake structure, and designing weir wall modifications to reduce silt buildup.

B. PRA Profile

In response to Generic Letter 88-20, the licensee submitted an IPE for Cooper on March 31, 1993. The IPE was performed by a team made up of licensee staff and contractor personnel. In the IPE submittal, which contains a Level 1 and 2 PRA, the estimated mean core damage frequency is 7.97E-5 per year. The IPE review is expected to be completed in February 1995. The IPE submittal does not provide a summary of the risk profile in terms of initiating events and sequence contributions to core damage frequency. It does provide a risk profile in terms of accident type, which is presented below.

Accident Type	% of Core Damage Frequency
Station Blackout	34.8%
Transient Induced LOCAs	30.3%
Loss of Coolant Injection	18.1%
Loss of Containment Heat Removal	10.9%
ATWS	4.9%
LOCAs	0.9%
Fast Containment Failures	0.1%

Because the IPE was summarized in terms of accident type, a coarse review of the IPE by the staff was performed to try to categorize the risk profile in terms of initiators and sequence contributors to core damage frequency for comparison purposes. On the basis of this review, it appears that the Loss of Containment Heat Removal category refers to sequences initiated by Loss of Service Water. The Loss of Coolant Injection category appears to include sequences involving any type of transient with no injection systems of the required pressure available.

The most dominant contributors to accident sequences that lead to core damage were found to be failure of the EDGs to continue to run, mechanical failures of the HPCI and RCIC systems and RCIC turbine, common cause failure (CCF) of all four SW pumps to run, CCF of the EDGs, failure of the operators to use the SRVs, and CCF of the SRVs.

The IPEEE is scheduled for submission in December 1995.

C. Core Damage Precursor Events

On the basis of the precursors identified by Oak Ridge National Laboratory (ORNL) for 1992 and 1993 (NUREG/CR-4674, vols. 17 thru 19), the staff did not identify any precursor events for the unit that have a conditional core damage probability of 1E-5 per year or greater.

The following event has been classified as a "Potentially Significant Event Considered Impractical to Analyze" in the 1993 NUREG/CR-4674, and as a "Significant Event" for the Performance Indicator Program. From May 1992 until March 1993, Cooper continued to operate with RCS leakage, at a rate of approximately 0.4 gpm, through both isolation valves of the shutdown cooling suction line. This rate was sufficient to require the operators to establish a relief path from the suction line to the ECCS keep-fill system. During the March 1993 refueling outage, the licensee disassembled and inspected both valves (for the first time) and found cracks in the seats and discs. The staff reviewed this event for its implications with respect to interfacing system LOCA. It is not possible to calculate a conditional core damage probability for this event since there is no means available to determine the probability of failure for the suction isolation valves during the period of interest at Cooper, given the degree of leakage observed and cracks found. If Cooper had experienced gross failure of the RHR suction line isolation valves, the event would have been highly risk significant. Therefore, the physical condition of the plant may or may not have created a significant level of risk. However, the actions of the licensee indicated a lack of appreciation for the risk associated with an interfacing systems LOCA.

The following event was classified as an "Event of Interest" for the Performance Indicator Program. On November 8, 1993, during a test of both EDG output breaker autoclose permissive relays, the contacts failed to close at the required setpoint. Investigation determined the cause was miscalibration five months earlier. It was later determined that the EDGs would not have been affected by the relay miscalibrations during a loss of offsite power event that required them to start and immediately tie onto the safety buses. However, the output breakers would not have automatically closed if offsite power were initially available and then subsequently lost after the EDGs were running in standby mode. The output breakers for the EDGs could have been manually closed by the operators in the control room. An initial accident sequence precursor (ASP) evaluation of the event modeled both EDGs failed for a five month period with operator recovery credit and calculated a conditional core damage probability (CCDP) of 5.3E-5. This CCDP is conservative since the EDGs would only have failed under the scenario described above.

The following event was classified as a "Significant Event" for the Performance Indicator Program. On May 25, 1994, both EDGs were declared inoperable when load shedding of all nonsafety-related loads from the vital buses could not be verified. The load shedding could not be verified due to preconditioning during past surveillance tests by removing certain nonsafety-related loads from the vital buses prior to the EDG testing. Thus, under worst case loading conditions, the EDGs may have been inoperable. The worst case loading conditions are expected to exist during a LOOP/LOCA which has a very low frequency of occurrence. Subsequent testing demonstrated that not all nonsafety-related loads would have shed. Calculations by the licensee showed that a margin existed for the EDGs to be operable if those loads had remained tied onto the buses. Although the staff could not independently confirm the licensee's calculations, the diesel manufacturer verified that the diesel could be operated for brief periods without damage at loads substantially above the maximum design rating. On this basis, the staff concluded that the diesel generators would probably have performed their intended function even if nonessential loads had not been automatically shed from the emergency buses.

The following was classified as an "Interesting" event in the 1993 NUREG/CR-4674. On February 25, 1993, a design basis review of the SWS and the reactor equipment cooling (REC) system identified that Division I SW supplied the Division II REC heat exchanger and Division II SW supplied the Division I REC heat exchanger. Given the design errors found, had Cooper experienced a LOOP along with a failure of EDG-1, nonessential SW and REC loads could not have been isolated by remote means and the MOV supplying critical loop "A" REC loads would not have opened. Consequently, for the conditions assumed, adequate cooling to the operable EDG, the functional REC heat exchanger, the RHR SW booster pump, and other loads could not have been assured. Similar concerns exist for the failure of the Division II EDG.

D. Expanded PRA Insights

Conclusions on the Cooper Nuclear Station Overall Risk Impact of the Hardware Issues Reported in 1994

The events analyzed include Safety System Failures (SSFs) in the Performance Indicator Program as well as start-up issues. For the 11 events analyzed, hardware failures were observed or had the potential to fail. In addition to the events, the MOV issues were reviewed. The event description, safety significance, and risk impact are addressed in the following pages. The conclusions are stated below.

HARDWARE ISSUES

Distribution of Hardware Issues

Hardware issues were distributed among the following systems:

Emergency Diesel Generators (EDG)	(1)
High Pressure Coolant Injection (HPCI)	(3)
Reactor Core Isolation Cooling (RCIC)	(1)
Core Spray (CS)	(1)
Low Pressure Coolant Injection (LPCI)	(1)
Service Water (SW)	(1)
Reactor Equipment Cooling (REC)	(2)
Standby Liquid Control (SLC)	(1)

Thus, the hardware issues are not contained to a particular system.

Significant Events

On May 25, 1994, both EDGs were declared inoperable because load shedding of all normal loads prior to starting the diesels during surveillance had not been achieved. This was classified as a Significant Event.

Safety System Failures

The number of SSFs in 1994 are above the BWR industry average. The distribution of SSFs in 1994 are as follows:

Control Room Ventilation (1)
Control Room Emergency Filtration (1)
Standby Gas Treatment/ Control Room Emergency Filtration (1)
Emergency Diesel Generators (1)
High Pressure Coolant Injection (2)

Method of discovery

About 50% of the hardware issues were found through surveillance testing or by review of surveillance test requirements.

This method of discovery for the HPCI problems is consistent with the results published in NUREG/CR "Aging Study of Boiling Water Reactor High Pressure Injection Systems (DRAFT)" which determined that the majority of HPCI failures were found through testing and inspection at BWRs.

The EDG issue was identified by the NRC. The other issues were identified by the licensee through design reviews and walkdowns.

System Testing

System testing in the past appeared to be inadequate. Past surveillance testing practices were observed to not adequately demonstrate EDG and CS system reliability under certain accident conditions. Also, as part of the design basis reconstitution of the primary containment, the licensee discovered during walkdowns that several containment penetrations had never been tested by local leak rate testing (LLRT) or as a boundary during the integrated leak rate testing (ILRT). In addition, certain Reactor Equipment Cooling piping had never been included in the ASME Section XI inservice inspection program and had been found to be leaking.

MOV Program

The Cooper MOV program is considered an acceptable GL 89-10 program, but is considered the weakest in Region IV. The majority of MOV issues are programmatic and procedural. The discovery of potential overthrust conditions created in 1986 by modifications to 10 valve actuators is an example of a recent problem correction, rather than a problem creation.

MOV problems seen in the events were of a control and timing nature. The "A" LPCI train outboard injection valve, though, experienced some leakage due to a foreign material exclusion problem.

RISK INSIGHTS

Station Blackout (SBO) is a major contributor to the Cooper core damage frequency (CDF). The EDG operability issue due to past surveillance testing preconditioning practices and the RCIC turbine trip throttle valve AC dependency would be expected to slightly increase the SBO contribution to the CDF.

The IPE indicates that common cause failure of all four SW pumps has a high risk achievement worth. The observed silting in the river near the end of the intake structure would have been a common cause failure for the SW pumps at minimum river levels.

The IPE indicates that the HPCI system failure to start and failure to continue to run are key contributors to the CDF. The sensitivity studies indicated that the HPCI system CDF contribution could be reduced if certain system modifications were implemented; however,the implementation of those modifications would not have prevented the potential HPCI system inoperability due to the HPCI system hardware issues observed in 1994.

VII. ENFORCEMENT HISTORY

3/93 CIVIL PENALTIES — The action was based on two Severity Level III violations associated with: (1) providing inaccurate information to the NRC in response to a Notice of Violation; and (2) the failure to identify and correct a potentially significant condition adverse to quality, after the 1992 discovery of a strainer that had been left in a safety system since initial plant start-up. Civil Penalties were issued to emphasize the licensee's need to improve its problem identification and resolution programs. Although mitigation was appropriate for the licensee's previous good performance regarding the accuracy of submitted information, it was offset by the escalation for NRC identification and the licensee's failure to act upon information which indicated that its submission was inaccurate. Mitigation of the Civil Penalty was appropriate for licensee identification, but was offset by the escalation for failure to act upon prior opportunities to identify the presence of strainers and poor licensee performance in the area of corrective actions. The total Civil Penalty was $200,000.

10/93 CIVIL PENALTIES — The action was based on three Severity Level III violations associated with: (1) several violations of 10 CFR 50 which collectively indicate a breakdown in the licensee's corrective action program; (2) failure to maintain the containment hydrogen/oxygen analyzers in an operable condition; and (3) failure to include the service water and reactor equipment cooling systems in the inservice inspection program since initial plant operations. Civil Penalties were issued to emphasize the significance that the NRC attaches to these violations and the importance that the NRC attaches to NPPD's efforts to resolve deeply rooted and fundamental weaknesses in employee attitudes toward identifying and resolving problems. The Civil Penalty associated with the corrective action program was escalated for NRC identification. ($75,000) The Civil Penalty associated with the inoperable hydrogen/oxygen analyzers was escalated for NRC identification and multiple licensee opportunities to identify the problem but mitigated for the licensee's corrective actions ($75,000). The Civil Penalty associated with the failure to include the service water and reactor equipment cooling systems in the inservice inspection program was not adjusted ($50,000). The total Civil Penalty was $200,000.

3/94 ENFORCEMENT CONFERENCE — Two Severity Level IV violations were issued for inadequate procedures and weaknesses in the licensee's corrective action program.

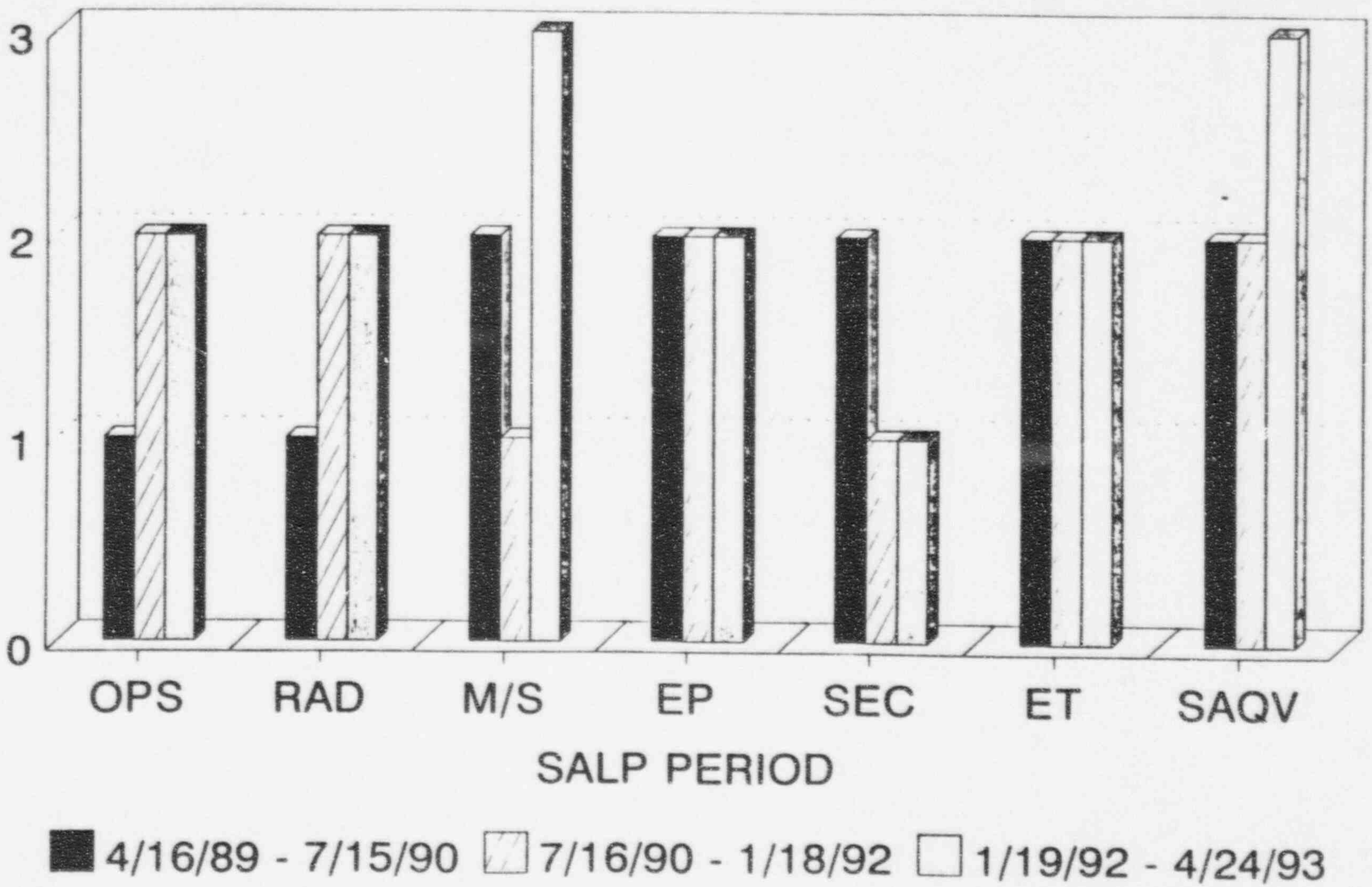
4/94 ENFORCEMENT CONFERENCE — Several Severity Level IV violations were issued concerning the failure to follow plant procedures; the failure to provide required quarterly training for the fire brigade; and the failure to maintain configuration control.

11/94 DEMAND FOR INFORMATION — The staff issued a Demand For Information related to licensee management personnel involving careless disregard for TS requirements governing the establishment of secondary containment prior to the movement of loads that could potentially damage irradiated fuel.

12/94 CIVIL PENALTIES AND ENFORCEMENT DISCRETION — This action was based on three inspections conducted from May 3, 1994, to August 12, 1994 that identified eight violations that were subsequently grouped into three problems; each problem being categorized at Severity Level III. The first problem consisted of violations related to the primary containment system and failures to maintain operability, adequately test, and maintain design control of the system. The second problem involved violations associated with 480 volt and 4160 volt critical buses and failures to adequately test and maintain system operability. The third problem consisted of violations pertaining to the control room emergency filtration system and failures to maintain operability and to adequately test the system. To emphasize the need for licensee senior managers to identify and undertake sustained actions to improve the overall level of safety performance at Cooper Nuclear Station, a Civil Penalty was issued for the three Severity Level III problems described above. Although application of the Civil Penalty adjustment factors could have resulted in a significantly higher civil penalty, discretion was exercised to set the total Civil Penalties at $300,000, or $100,000 for each of the three Severity Level III problems. Discretion was exercised because of the licensee's initiative to shut down the unit until successful implementation of an improvement program to address underlying root causes of performance deficiencies, the licensee's commitment not to restart the plant without prior NRC approval, and the significant changes in licensee's management oversight of site activities. This action was also the subject of Commission paper SECY-94-285. The total Civil Penalty was $300,000.

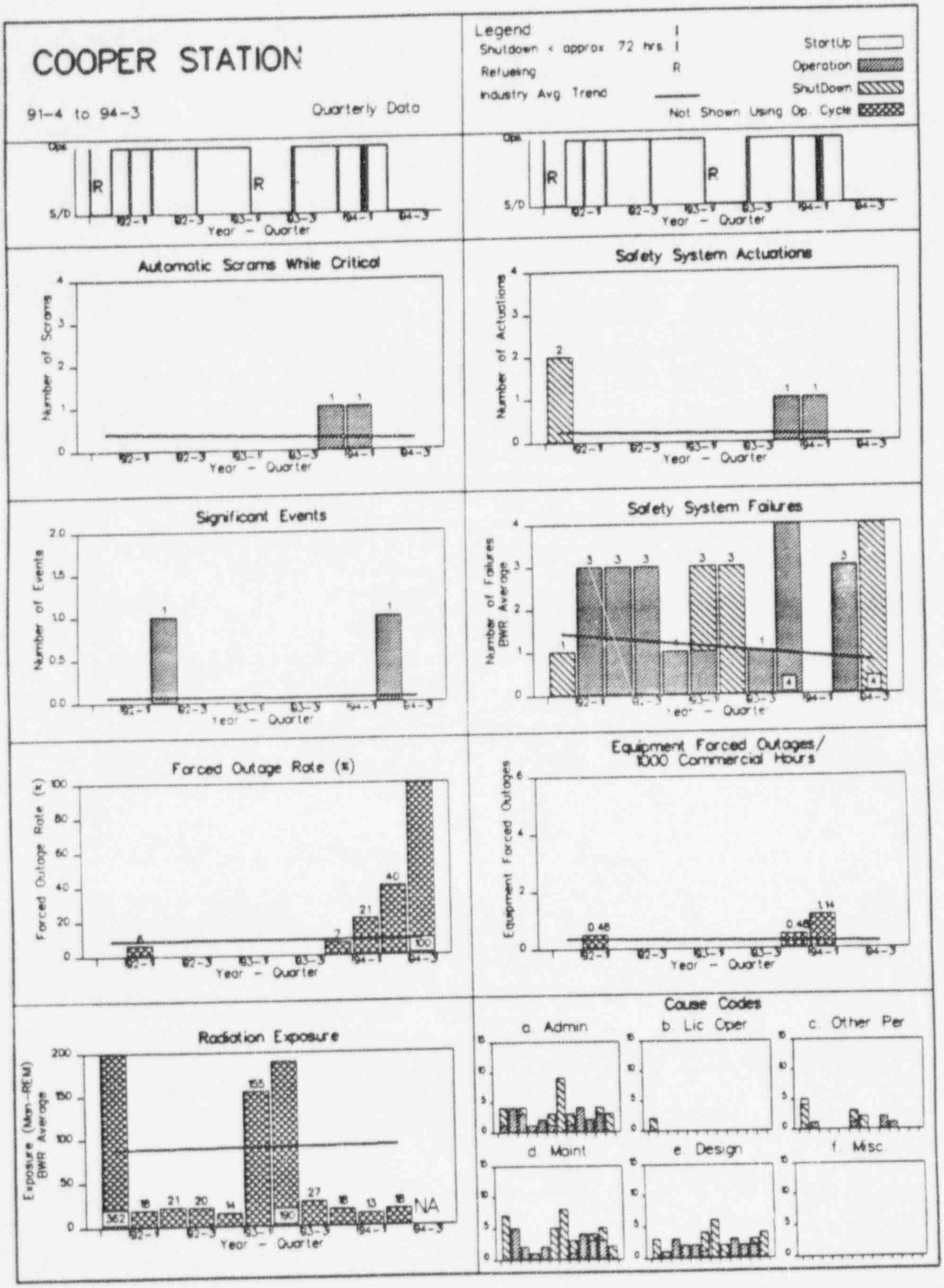
COOPER

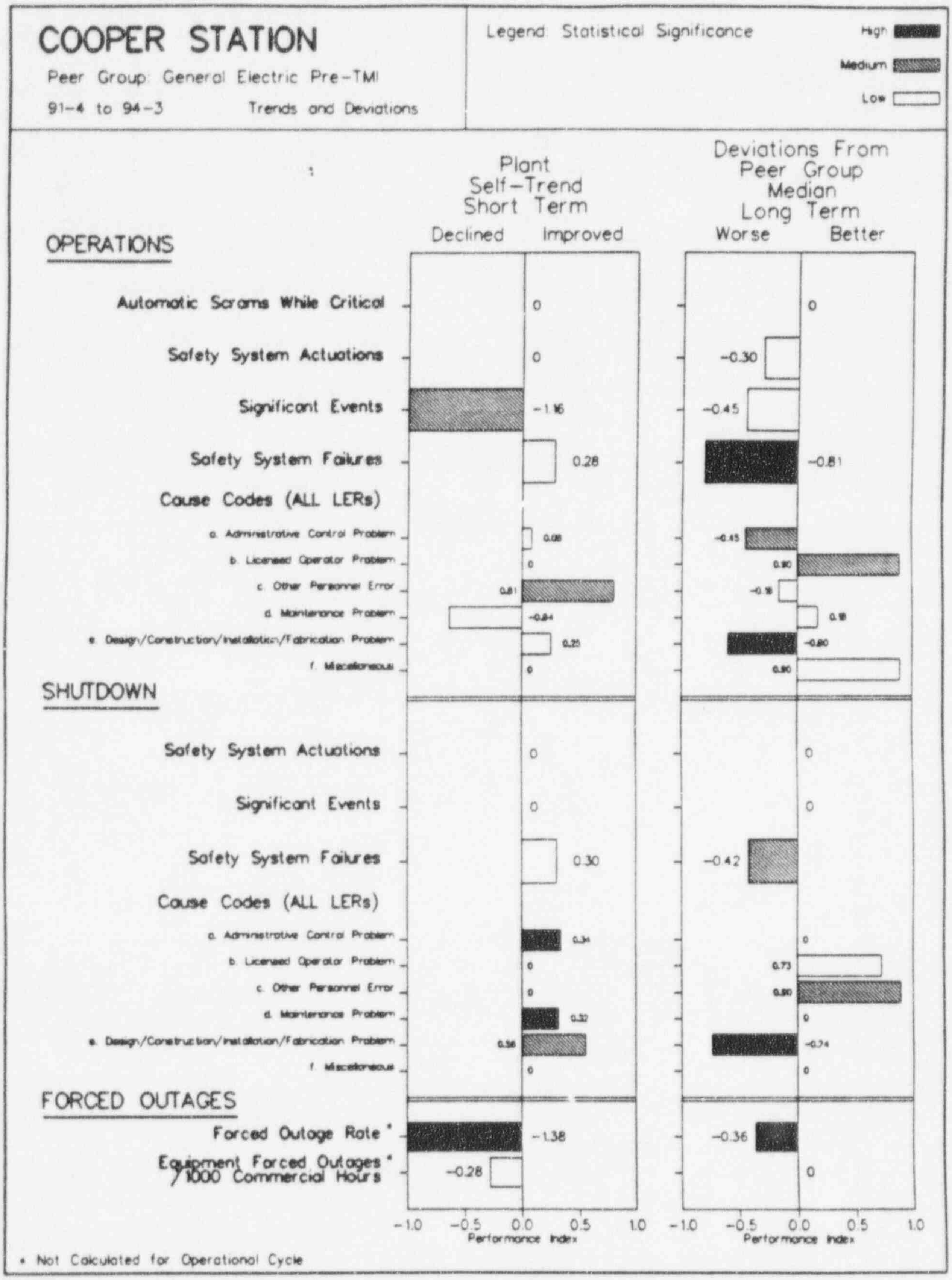
MOST RECENT SALP RATINGS



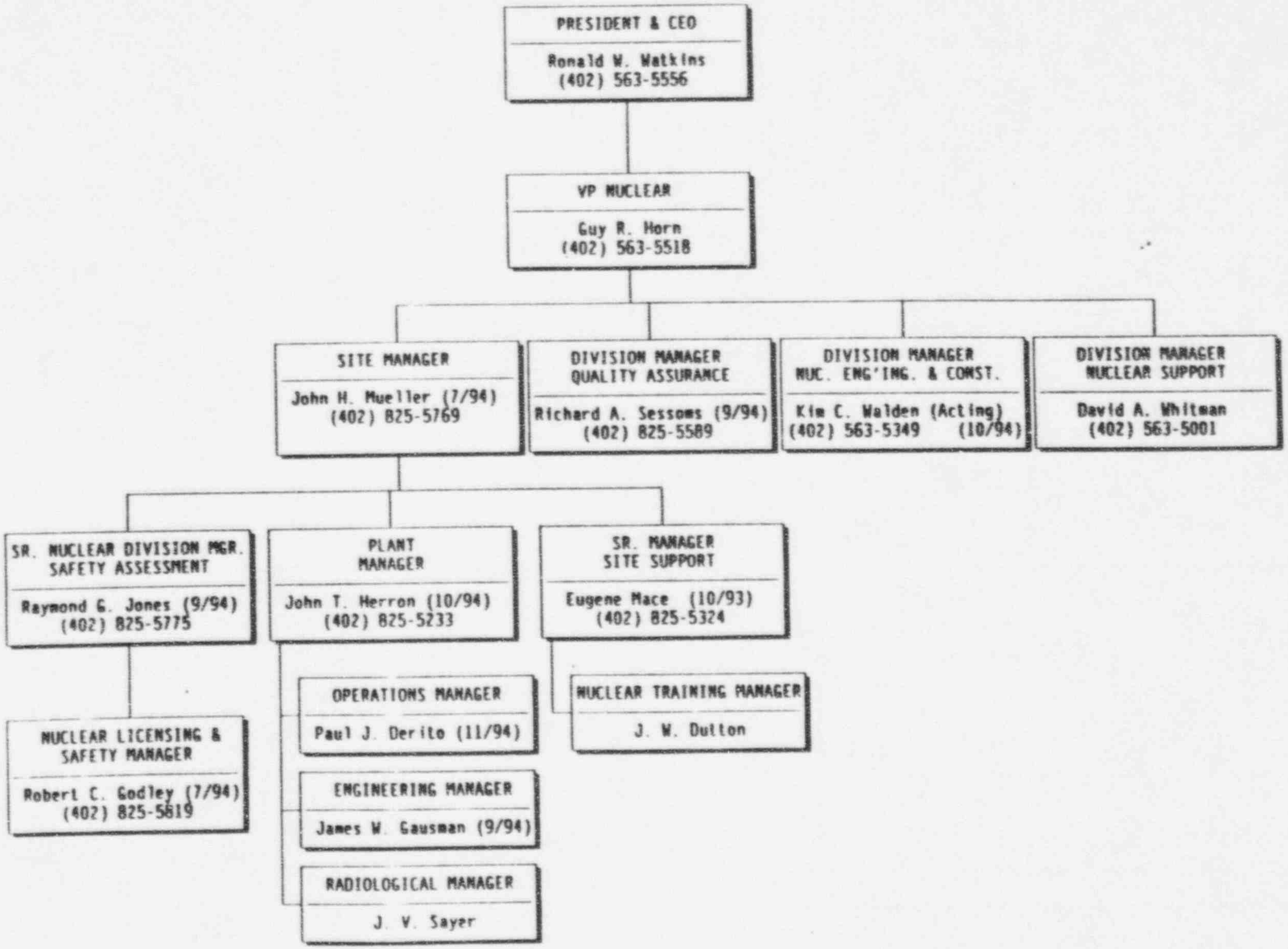
M/S, EP & SEC IMPROVING

RAD IMPROVING
EP DECLINING


COOPER STATION
91-4 to 94-3
Quarterly Data
Legend:
Shutdown < approx. 72 hrs.
Refueling
Industry Avg. Trend
StartUp
Operation
ShutDown
Not Shown Using Op. Cycle
Year - Quarter
Automatic Scrams While Critical
Number of Scrams
Safety System Actuations
Number of Actuations
Significant Events
Number of Events
Safety System Failures
Number of Failures
BWR Average
Forced Outage Rate (%)
Equipment Forced Outages/1000 Commercial Hours
Equipment Forced Outages
Radiation Exposure
Exposure (Man-REM)
BWR Average
Cause Codes
a. Admin
b. Lic Oper
c. Other Per
d. Maint
e. Design
f. Misc


COOPER STATION
Peer Group: General Electric Pre-TMI
91-4 to 94-3
Trends and Deviations
Legend: Statistical Significance
High
Medium
Low
Plant Self-Trend Short Term
Declined
Improved
Deviations From Peer Group Median Long Term
Worse
Better
OPERATIONS
Automatic Scrams While Critical
Safety System Actuations
Significant Events
Safety System Failures
Cause Codes (ALL LERs)
a. Administrative Control Problem
b. Licensed Operator Problem
c. Other Personnel Error
d. Maintenance Problem
e. Design/Construction/Installation/Fabrication Problem
f. Miscellaneous
SHUTDOWN
Safety System Actuations
Significant Events
Safety System Failures
Cause Codes (ALL LERs)
a. Administrative Control Problem
b. Licensed Operator Problem
c. Other Personnel Error
d. Maintenance Problem
e. Design/Construction/Installation/Fabrication Problem
f. Miscellaneous
FORCED OUTAGES
Forced Outage Rate *
Equipment Forced Outages * /1000 Commercial Hours
0
0
-1.16
0.28
0.30
-0.28
-1.38
-0.30
-0.45
-0.81
-0.42
-0.36
0.73
-1.0
-0.5
0.0
0.5
1.0
Performance Index
* Not Calculated for Operational Cycle

NEBRASKA PUBLIC POWER DISTRICT
COOPER STATION



12/21/94

EMERGENCY DIESEL GENERATORS		
EVENT/DESCRIPTION	SAFETY SIGNIFICANCE	RISK IMPACT
5/25/94 Both EDGs declared inoperable On 5/25/94, the licensee declared an NOUE after determining that both EDGs were inoperable. Cooper stayed in the NOUE for 56 days. The licensee discovered that past surveillance tests of the EDGs failed to verify that all loads were shed from the 480V and 4160V vital buses given an undervoltage condition on these buses. This verification had not been accomplished in past tests due to the preconditioning practice of removing certain nonsafety-related loads from the buses prior to testing. Subsequent testing to verify proper load shedding revealed that not all nonsafety-related loads would have shed.	The concern was that if the additional loads had remained on the buses, then neither of the EDGs would be capable of providing sufficient power to vital equipment. Thus, EDG operability was questionable under worst case loading conditions such as those experienced during a LOOP/LOCA scenario. The licensee submitted a calculation to show that even with the non-safety-related loads connected to the buses, the EDGs would have been operable. The staff concluded that the EDGs would have performed their intended function.	Small CDF increase expected. Since the EDGs would have been operable, the increase in the CDF would be small. The small increase would be attributable to operator actions. The licensee had concluded that operators would need to manually shed loads if the maximum loading on the EDGs was greater than the continuous rating of 4000 kW after two hours.

References: LER #94-009-00
NRC IR 50-298/94-16

HIGH PRESSURE COOLANT INJECTION		
EVENT/DESCRIPTION	SAFETY SIGNIFICANCE	RISK IMPACT
EN #26993 03/25/94 HPCI declared inoperable following a surveillance test due to the HPCI steam stop valve opening in 51 seconds. The required time to open is < 38 seconds per IST requirements.	The HPCI steam stop valve is required to open to establish a path for steam to the turbine. The valve opening delay causes a delay in the turbine start.	The associated risk is the potential for increased HPCI system unreliability if hardware problems are not found through surveillance testing.
LER #94-007-00 04/13/94 HPCI was declared inoperable following surveillance testing when the lube oil cooler pressure control valve failed to re-open after the HPCI turbine had tripped. The failure of the valve was attributable to a disconnected tubing associated with the valve controller.	This condition could have lead to HPCI turbine bearing failure due to loss of lube oil cooling if turbine operation had continued. If the condition was not corrected by an operator and HPCI turbine operation continued, the HPCI system could have become inoperable.	The HPCI turbine may become inoperable following a trip after successfully starting and running. The recovery is complicated by the operator potentially failing to reattach the tubing. The risk depends on the duration that this condition existed.
LER #94-012-00 07/08/94 The licensee noted a conflict between the established setpoint for the HPCI low steam line isolation pressure switch set at 127 psig and the TS operability requirement that the HPCI system be operable at pressures > 113 psig.	If the HPCI system were to isolate at 127 psig, HPCI makeup would not be available between 113 psig and 127 psig. However, sufficient overlap makeup capacity exists from the LPCI and the CS systems in this range.	No risk impact.

REACTOR CORE ISOLATION COOLING		
EVENT/DESCRIPTION	SAFETY SIGNIFICANCE	RISK IMPACT
LER #94-018-00 08/20/94 The licensee discovered that the RCIC Turbine Trip and Throttle Valve (TTV) was powered by an AC motor. This valve should have been powered by a DC motor since the RCIC system is designed to be independent of AC power.	In the event of a SBO, RCIC provides core cooling for the duration of battery life. If the RCIC Turbine Trip and Throttle Valve had closed during an SBO, neither automatic nor remote manual reset of the valve would have been possible. Local operator action would have been required; however, no guidance on this function was included in SBO procedures.	CDF increase expected. RCIC would have been unavailable during a SBO if the Turbine Trip and Throttle Valve had closed. This condition would increase the Core Damage Frequency contribution from the SBO. The SBO contribution is 34.8%. The second greatest CDF contributor sequence is: SBO, loss of HPCI due to loss of room cooling, loss of RCIC before battery depletion, failure to recover offsite power. The AC dependency of the turbine TTV is not modeled in the IPE. If the TTV were to close before battery depletion, RCIC would be lost.

CORE SPRAY		
EVENT/DESCRIPTION	SAFETY SIGNIFICANCE	RISK IMPACT
LER #94-002-02 02/01/94 Cycling of the CS minimum flow isolation valves on both trains during minimum flow operation was observed. The B loop valve closed during surveillance testing on Feb. 1, 1994 and on Apr. 27, 1994. The A loop valve closed on July 23, 1994.	The function of the minimum flow valves is to provide minimum flow protection for the pumps. Excessive cycling could lead to loss of minimum flow pump protection.	Excessive cycling of the valves during minimum flow operation contributes to the CS system unreliability due to the potential to deadhead the pumps. An NRC inspection concluded that the licensee's CS system testing did not confirm the capability of the CS pumps to operate in a minimum flow configuration for a full 30 minutes, as required for certain postulated accident scenarios.

LOW PRESSURE COOLANT INJECTION		
EVENT/DESCRIPTION	SAFETY SIGNIFICANCE	RISK IMPACT
EN #26948 03/16/94 The "A" LPCI train was declared inoperable when leakage was discovered past the LPCI Outboard Injection Valve RHR-MOV-MO27A. Votes testing and an LLRT were used to confirm this condition.	This valve is normally open. In the event that the valve is needed to isolate the LPCI injection line, the valve may not have fully performed that function. There are three other valves between the outboard injection valve and the reactor vessel which could isolate the line also.	Due to the redundant means of isolating the LPCI injection line, the risk of this event is minimal.

SERVICE WATER		
EVENT/DESCRIPTION	SAFETY SIGNIFICANCE	RISK IMPACT
EN #27971 11/01/94 Minimum design river level assumed in the USFAR has been invalidated by silting in the river. The silting may have been caused by the Missouri River flooding in 1993.	At minimum river levels, sufficient water would not have been available to provide the required NPSH for the service water pumps.	This event reveals a potential common cause failure of all four SW pumps. The IPE indicates that common cause failure of the SW pumps has a high risk achievement worth, and that actions taken to reduce the frequency of the loss of all Service Water has a high risk reduction worth. The licensee waited approximately a year after the Missouri River flooding before taking action to reduce the potential common cause failure of the SW pumps by dredging the southern end of the intake structure.

REACTOR EQUIPMENT COOLING SYSTEM		
EVENT/DESCRIPTION	SAFETY SIGNIFICANCE	RISK IMPACT
MR #4-94-0072 08/01/94 The licensee discovered a through wall leak in a 12" REC pipe. The crack propagated through a weld. GE noted that sodium nitrate, a corrosion inhibitor used by the licensee from 1974-1980 contributed to the cracking.	Potential for failure of the REC system and subsequent loss of cooling water to safety related equipment.	The risk from the actual event was minimal since the leakage was small and discovered before the cracking worsened. The use of the corrosion inhibitor, however, increased the probability of a REC pipe leak.

LER #94-017-00 EN #27666 08/09/94 The licensee is performing a reassessment of a potential event in which the 8" REC piping in the drywell adjacent to the RR pump discharge piping may be a potential containment bypass path. As described in IN 89-055, the water in the return REC piping would be discharged out of the surge tank located in secondary containment if a high energy line break occurred inside primary containment.	Potential for a REC piping containment bypass path if a high energy line break occurred inside containment.	The expected frequency of a RR line break is very small. The consequences, though, would disable the REC system and create a containment bypass pathway.

STANDBY LIQUID CONTROL		
EVENT/DESCRIPTION	SAFETY SIGNIFICANCE	RISK IMPACT
LER #94-026-00 10/09/94 The licensee discovered that the temperature of the SLC piping was not being maintained above the TS limits for the concentration of sodium pentaborate in the system. Also, the pump head was not heat traced and insulated in accordance with the system design specifications.	The SLC system is designed to shutdown the reactor if shutdown can not be obtained with the control rods. At temperatures lower than the TS limits, the sodium pentaborate concentration decreases due to crystallization. Too low of a concentration would not bring the reactor to shutdown. At the minimum room design temperature, the licensee believes that the SLC system would be operable due to a higher solution concentration in the SLC tank since the tank is heated by internal heaters, and the pumps would be able to perform with the expected crystallization in the piping.	In the event of an ATWS, control rods could also be inserted by the Alternate Rod Insertion System. If control rods can not be inserted, SLC can be used. The ATWS accounts for 4.9% of the CDF. If the SLC pump operability is affected by the expected crystallization under cold room temperatures, then the ATWS CDF contribution may be increased. Also, reviews of core shroud cracking responses to GL 94-03 indicate that SLC is important given that some worst case scenarios may affect the ability to insert control rods. Cooper plans on performing core shroud inspections at the next refueling outage.

COOPER NUCLEAR STATION - NRR STATUS UPDATE
JANUARY 11, 1995

BACKGROUND:

- Unit shut down since May 25, 1994 (230 days). Two CALs remain open.
- Licensee DSA report issued 9/6, NRC SET report, 11/29. EDO attended SET and DSA public exits, 11/17. Staff Actions Memo issued 12/22/94.
- Restart Panel and Action Plan formed, in accordance with IMC 0350. 5 internal meetings, 3 public meetings at site. 12 NRC restart issues identified, 34 by licensee (including all NRC issues).

ENFORCEMENT STATUS:

- Proposed $300K CP and NOV issued 12/12/94 for violations involving inadequate testing of the electrical distribution system, control room envelope and containment integrity. Licensee's response pending.
- Licensee responded on 12/12/94 to the NRC's 11/10/94 Demand For Information concerning potential 50.9 and TS violations, and poor performance of the Station Operations Review Committee. OE, NRR and Region IV will reach a consensus on further action shortly. Also under consideration are a number of other potential 50.9 violations; in 1993, the licensee had received a $100K CP for 50.9 violations.

ONGOING ACTIVITIES AND ISSUES:

- Current schedule for restart is January 29, 1995; may be delayed due to MOV testing in progress. Licensee to static test all remaining MOVs, with completion of dynamic testing during Fall 95 RFO.
- At the January 5, 1995 public Restart Panel meeting, the Panel expressed concerns over delays in receiving licensee closeout documentation. These delays could impact Regional inspection and NRR review activities. A two week, Region-led restart team inspection is currently scheduled for January 16-27, with a final Restart Panel meeting planned to coincide with the exit meeting for that inspection.
- 4 licensing actions needed to support restart; 3 late submittals. TS changes for HPCI LP setpoint, LCO definition (GL 87-09); ISI relief request on HPCI turbine exhaust weld, MOV program schedule extension request. In addition, CR fan upgrade TS change to be issued by restart.
- 3 issues identified by the licensee as not requiring formal NRC action (fire protection program discrepancies, IST reliefs and cyclical surveillances). Will be reviewed by NRR to confirm the licensee's positions. Information on two of these items has not been provided yet.

c/5

OTHER:

- 8 of 10 key managers below VP-Nuclear replaced since July 1994.

- Emergency Exercise 11/15/94 acceptable; 1 deficiency to State of Nebraska for dissemination of information to public; 3 weaknesses: conflicting info to offsite agencies, weak scenario, errors in EPIPs for assessing EALs.

- Initial Regional inspections of restart items indicate acceptable performance, resolution of issues.

- Licensee initiatives - replacement of Asco SSPVs, identification of Appendix R discrepancies, Agastat relay maintenance, planned TS improvement.

- Positive licensee responses - MOV testing, staffing for OER review and corrective action programs.

Item 1

From: Daniel M. Barss (DMB1), NRR
To: JRH (James Randal Hall), NRR
Date: Thursday, January 19, 1995 2:29 pm
Subject: No EP concerns for Cooper Restart

I have contacted both FEMA and NRC Region IV concerning emergency preparedness (EP) issues which could affect the proposed restart of Cooper Nuclear Station on, or about, January 29, 1995. There have been no onsite or offsite EP issues identified which would affect the proposed restart.

A Record of Conversations detailing the above mentioned contacts has been drafted. You are on distribution and should receive a copy soon.

CC: THE (Tom Essig, NRR)

C/6