ENCLOSURE 2

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Irvine, California

Facility Name: San Onofre Nuclear Generating Station, Units 2 and 3

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TABLE OF CONTENTS

EXECUTIVE SUMMARY

The purpose of this inspection was to review the effectiveness of maintenance and surveillance testing activities on plant structures, systems, and components at the San Onofre Nuclear Generating Station. An inspection of outage radiation protection practices was also performed as part of this review. The team inspection focused on implementation of the maintenance program in regard to safety-related and balance-of-plant structures, systems, and components. The inspection was conducted using inspection Procedures 62700, 71500, 83729, and 83750. Guidance from other inspection procedures was also integrated into the review. In addition to the team inspection of maintenance and surveillance testing activities, an inspection of inservice inspection program implementation was also performed using Inspection Procedure 73753. Specific maintenance and surveillance activities that were evaluated during the team inspection are identified in the Table of Contents.

Overall, the team found that the licensee had established a well structured and comprehensive maintenance program. The team concluded from the inspection findings that the implementation of program requirements had recently improved. The performance improvements were attributed primarily to the high level of management and supervisory involvement in the maintenance process. This was principally was evident in the significant scope of assessment activities, in the identification of opportunities for performance improvement, and in the attention to reduce the maintenance backlog.

Managers were observed in the plant actively involved in outage maintenance activities. A strong supervisory involvement was also observed in maintenance activities witnessed by the team.

A broad scope of independent and self assessments of maintenance performance was being performed. Most of the assessment programs and special assessment efforts were yielding significant findings. The team believed that the integrated effort to identify issues related to maintenance performance was both innovative and effective. However, resolution of issues was found to be often lacking in terms of documentation and the scope and applicability of corrective actions. The leadership observation program utilized maintenance supervision for self assessments of maintenance performance. This program was effective in causing ongoing evaluation and assessment of maintenance performance, and management attention was being focused on categories or areas with a high incidence of findings. The inability to track or verify resolution of specific performance findings was viewed, however, by the team as a programmatic weakness. The maintenance division experience report process, used by the maintenance organization to investigate and resolve performance problems, was considered an excellent corrective action tool. A new program of self assessments was initiated by the maintenance organization in early 1994. The limited documentation of findings and corrective actions that was present for assessments performed, to date, was considered a programmatic weakness. The December 1994 station self assessment, which was accomplished by a multi-organization team in a performance-based approach, was considered effective in the identification of maintenance performance issues. However, the proposed corrective actions did not appear to adequately address the specific issues. Additionally, a response was not available for a safety engineering special assessment of maintenance performance that was performed 8 months previously. A response to a second safety engineering special assessment initiative, which had been performed 3 months previously, was also noted to only generally address the issues. Assessments of maintenance activities and function by the nuclear oversight organization were satisfactory.

The material condition of the plant was, in general, fairly good and benefitting from equipment preservation program actions. The omission from the equipment preservation program of conduit which contained safety-related cables, was considered a programmatic weakness. Degraded conditions (i.e., surface rusting due to exposure to marine atmosphere) were also observed on the secondary side of the plant.

The team found that the preventive and predictive maintenance program requirements were being appropriately implemented, and considered the development of the reliability-centered maintenance program to be a strength in regard to establishing technically sound preventive maintenance requirements.

The licensee's work prioritization process was, in general, effective. The team noted that some improvement was needed in the timeliness of resolution of caution tag and control board deficiencies. The team concluded the licensee's emphasis on boric acid leak repair was appropriate and needed to continue to further reduce the backlog of boric acid leaks.

The licensee's approach to scheduling was, in general, conservative, with the use of a risk monitor to evaluate the scheduling of routine maintenance viewed as a strength by the team. The team questioned, however, whether the licensee was appropriately conservative in authorizing switchyard work at a time when Unit 2 was in a mid-loop condition, with a short time to boil if shutdown cooling was lost, and with one emergency diesel generator and reserve auxiliary transformer unavailable. This subject has been referred to the Office of Nuclear Reactor Regulation for review by the technical staff.

Most of the observed maintenance and pre-job briefing (tailboard) activities were well performed. An exception pertained to the team identification that a packing adjustment was about to be performed on a Unit 3 auxiliary feedwater pump on the outboard rather than the inboard packing gland that was specified by the maintenance work order. This was brought to the attention of maintenance personnel, who immediately suspended the work activity. Performance and scheduling of maintenance for the secondary plants in both units were good, with maintenance controlled by the same programs as maintenance on safety-related systems. Development of better work plans for balance-of-plant equipment and actions to optimize component life were considered areas for improvement. The flow-accelerated corrosion program implementation was viewed as a strength by the team.

The "work it now" program, which was established by the licensee to facilitate performance of minor maintenance, was considered effective. The team believed, however, as a result of followup of an observed use of a crescent wrench for the attempted tightening of a bolt in a Unit 3 high pressure safety injection pump flange joint, that the program could be strengthened by further definition of administrative controls and supervisory responsibilities.

Surveillance tests were performed in accordance with procedural requirements, with proper communication maintained with the control room staff. Errors were identified by testing staff in local leak rate testing procedures. The errors were ascertained to have occurred during preparation by operations staff of temporary change notices. The absence of an administrative requirement for a verification and validation process to assure the correctness of procedural revisions was considered a programmatic weakness.

The inservice inspection program was well structured and administratively controlled. The content of contractor nondestructive examination procedures was appropriate for performing applicable examinations, and the procedures were consistent with ASME Code requirements. Observed nondestructive examinations were performed in an excellent manner by appropriately certified contractor personnel.

An indicator of inadequate oversight of contractor welding activities by the engineering organization was noted in regard to fabrication of replacement main feedwater piping subassemblies. Inspection identified that the contractor had used a welding procedure specification that was not appropriately qualified with respect to the interpass temperature provisions of the ASME Code, Section IX. In addition, the contractor field welding checklist showed that interpass temperature was not required to be measured or recorded, thus precluding verification of the interpass temperatures that occurred during welding of the piping subassemblies.

The team noted that the interface between maintenance and operations personnel in the control room was a strength and concluded that, in general, operations personnel were attentive to their duties related to work authorization releases. One exception noted was the verbal authorization of modifications to pipe supports, which was not consistent with existing procedural requirements. The team was also concerned that operations personnel did not initially notify their management of the identification by a maintenance craftsman that the Unit 2 stator water cooling system was not correctly drained at the time of initiation of craft work.

The entry, without obtaining required prior control room authorization, into the switchyard area by non-San Onofre Nuclear Generating Station utility personnel, and the presence of vehicles at locations that were contrary to shift supervisor established limits, were viewed by the team as indicative of inadequate operational controls for this area.

The radiation protection organization prepared properly for the Unit 2 refueling outage. Access controls and job coverage provided by radiation protection personnel were good. Radiation exposure permits were noted by the team to contain some superfluous and confusing language. Additional preparation by maintenance personnel could have reduced person-rem totals during nozzle dam and steam generator bladder installation. The team observed that the results of radiation surveys were not always documented in a timely manner. The team found that contamination controls were good. Radiation workers were observed to consistently follow established procedures for exiting the radiological controlled area. The team noted that radwaste was removed in a timely manner through the early part of the outage.

The depth of component failure analysis performed was considered an engineering strength by the team, and was noted to have contributed to significant, progressive improvements in component reliability. From a limited sample, modification activities appeared to have been well controlled, with appropriate consideration given to impact on licensing and design documents, performance of 10 CFR 50.59 reviews, and establishment of post-modification testing and acceptance criteria.

The team reviewed two surveillance procedures to verify that Technical Specification surveillance requirements and design calculation assumptions for the emergency diesel generators were implemented. The team found that: 1) the licensee was not routinely required to verify capability of the emergency diesel generators to energize auto-connected shutdown loads, following a loss of off-site power; and 2) a conservative load sequencing analysis had not been developed for the emergency diesel generators and (3) not all of the assumptions in the short circuit study were incorporated into plant instructions.

The team was concerned that the prototype, preoperational and surveillance test programs for the emergency diesel generators were developed based on non-conservative loading sequence assumptions. Preliminary analysis of alternative loading sequences indicated that the output voltage of the diesel generators will briefly drop below the design basis value during some accident scenarios. Office of Nuclear Reactor Regulation technical staff concurred with the licensee's determination that the diesel generators were operable in the short term. The licensee made commitments to modify the control logic for the affected loads so that the original loading sequence assumptions would be valid. This area will be reviewed further by NRC. Further inspection is also planned to evaluate the use of a diesel generator loading limit to control potential short circuit currents and the safety significance of the failure to impose the loading limit.

DETAILS

1 PLANT STATUS

During the course of the onsite portion of the inspection, Unit 2 progressed from power operations to Mode 5. At the conclusion of the onsite team inspection, the reserve auxiliary transformers and the Train B emergency diesel generator were out of service, and the reactor was drained to mid loop in preparation for nozzle dam installation in the steam generators. Unit 3 operated at near full power through the inspection period.

2 MAINTENANCE RELIABILITY INITIATIVE INSPECTION (62700, 71500)

2.1 Preventive and Predictive Maintenance

The purpose of this part of the inspection was to evaluate the effectiveness of implementation of the licensee's preventive and predictive maintenance program requirements for safety-related and important-to-safety equipment.

2.1.1 Preventive Maintenance

The team initially performed a review of the licensee's preventive maintenance program to understand how preventive maintenance tasks were developed, revised, and implemented. The program documents examined during this review were Procedures SO123-S-6, "Preventive Maintenance Program Objectives and Responsibilities," Revision 7; SO123-I-1.44, "Administration of Reliability Centered Maintenance (RCM) Manuals and Documents," Revision 0; SO123-I-1.9, "Repetitive Maintenance Implementation and Scheduling," Revision 2; SO123-I-1.7, "Maintenance Order Preparation and Processing," Revision 5; and SO123-I-1.3, "Work Activity Guidelines," Revision 4. It was ascertained during this review that several site organizations played a role in the preventive maintenance process.

2.1.1.1 Reliability-Centered Maintenance

The licensee had established and partially implemented a reliability-centered maintenance program at the San Onofre Nuclear Generating Station (SONGS). This program identified system and component functional design and operational requirements, and translated them into maintenance program requirements. The translation included use of a failure modes and effects analysis for system components, which established maintenance requirements that were based on credible component failure mechanisms and the consequences of each component failure mode. Review by the team indicated that preventive maintenance was specified for components classified as critical or potentially critical, whose failure could affect plant safety or system operability. The team verified that component failure history and vendor recommendations were considered in establishing the required maintenance tasks and their frequencies. In some cases, the licensee identified components as "run-to-failure" and, as a result, eliminated unnecessary preventive maintenance tasks.

The preventive maintenance program bases and licensee evaluation results were included in a system analysis document for each system. Licensee personnel informed the team that a total of 27 systems have been analyzed, with the program currently implemented for 15 systems. The remaining system documents were in the process of review by the Nuclear Engineering Design organization. The team was informed by licensee personnel that these documents will become part of the reliability-centered maintenance "living program," which will provide for the continued improvement and optimization of the preventive maintenance program. These documents will also provide the preventive maintenance basis for support of the Maintenance Rule.

The team reviewed System Analysis Document M-42753 for the auxiliary feedwater system, which was indicated by the licensee representative to have been one of the first systems to be analyzed. Review of this document by the team indicated a thorough, comprehensive analysis had been performed.

The team concluded that the reliability-centered maintenance program was an excellent process for establishing technically sound preventive maintenance requirements, and viewed the program as a strength.

2.1.1.2 Preventive Maintenance Implementation

Specific in-progress preventive maintenance activities were not observed during the inspection. Five completed repetitive maintenance orders (MOs) for the Unit 2 auxiliary feedwater system were, however, reviewed by the team to verify that preventive maintenance activities were being performed in accordance with program requirements. This review indicated that preventive maintenance attributes were being appropriately implemented. The team also verified that procedural controls were established to prevent changes to preventive maintenance tasks (e.g., deletion and frequency changes) without appropriate approvals.

2.1.1.3 Preventive Maintenance Backlog

The team reviewed the licensee's preventive maintenance backlog and ascertained that a total of six safety-related overdue preventive maintenance tasks were outstanding. This amount of backlogged work was not considered excessive by the team.

2.1.2 Predictive Maintenance

The team ascertained that the predictive maintenance program, which was referred to at SONGS as the performance monitoring program, was implemented by the Station Technical organization. Applicable program procedures reviewed were: SO123-V-3.1, "Vibration Monitoring and Analysis," Revision 4; SO123-V-2.4, "Thermal Inspection of Plant Components," Revision 4; and SO123-III-6.5, "Oil Sampling and Analyses Program, Revision 1. The team performed a review of implementation of vibration monitoring and oil sampling and analyses program requirements.

2.1.2.1 Vibration Monitoring

The team observed performance of vibration monitoring of Instrument Air Compressor C-001 and Seal Oil Vacuum Pump S21316MP077, both in Unit 2. The seal oil pump was checked, with the system engineer present, because previous analysis had indicated higher than usual vibration values. High vibration readings were measured on this pump which was preliminarily assessed by the system engineer to be related to the drive belt. The system engineer decided to initiate an MO to investigate the cause of the high vibration, which was considered by the team to be an appropriate action.

The team observed a system engineer perform a monthly inservice test of Auxiliary Feedwater Pump 2P-141 (Train A). This test included monitoring vibration. The system engineer conducted a thorough tailboard briefing with the control room staff before starting the test. The team observed the conduct of the test, and concluded that the system engineer performed the monthly inservice test and vibration monitoring in an excellent manner. The team verified that the MICROLOG data collector and associated components that were used for conducting the test had a current calibration status.

The team concluded from observation of the work activities that the licensee was properly implementing the program, and taking appropriate actions to resolve identified problems.

2.1.2.2 Oil Sampling and Analysis Program

The oil sampling and analysis program was implemented by the chemistry staff, with sampling achieved by use of repetitive MOs. Analyses were performed by an outside laboratory, with the results provided by chemistry to the system engineering organization for review. Discussion with the cognizant chemical engineer responsible for the program indicated that equipment oil sample data was trended. The team reviewed laboratory results and also the actions that were taken in response to sample results that were considered abnormal. One abnormal result reviewed pertained to lube oil in Emergency Diesel Generator 3MG003. The monthly oil analysis report indicated high zinc levels in the lube oil. Nonconformance Report 94050007 was initiated by system engineering to identify the cause. The team determined that licensee personnel took appropriate actions to resolve the nonconformance. The team also reviewed oil sample analyses for the high pressure safety injection pumps in Unit 2. These samples were reviewed because of the identification during a plant tour that the oil was dark in color. Review of the laboratory results by the team confirmed that the oil analysis was normal, and that the oil in the pumps was the type recommended by the vendor.

During review of Chemistry Procedure SO123-III-6.5, "Oil Sampling Analyses Program," Revision 1, the team noted that Section 6.2.2.2 required chemistry engineering to develop a planned and systematic method to notify maintenance of oil samples missed or not received. The team ascertained from discussion with chemistry staff that informal methods (i.e., verbal communication or

E-mail) were used. The team viewed these practices as inconsistent with the procedural requirement, but considered the subject to be of minor significance because of the use of repetitive MOs to obtain the samples and minimal historical problems with missed samples.

In general, the team concluded that the oil sampling and analysis program was being implemented properly.

2.2 Work Control

2.2.1 Plant Equipment Problem Identification

The licensee used MOs to identify equipment deficiencies in the plant that required corrective or routine maintenance. Individuals that discovered deficiencies had the responsibility to initiate an MO and record the deficiency into the SONGS maintenance management system, which was an online computer system. Maintenance management system access terminals were at various locations throughout the plant and were available to all employees with user passwords. The licensee representative stated all maintenance personnel had access to the computer system.

Initial operability determinations for MOs that documented deficiencies which could impact operability were made by equipment control evaluators. The team ascertained, however, that this function was staffed only on first shift during the week, and not on a weekend. The team questioned whether there was a possibility that an MO, which was originated on a weekend (when equipment control evaluators were not on duty) by personnel from an organization other than operations, would not be evaluated for operability and priority until the following Monday. Licensee personnel stated in response that, as a result of the training provided to plant personnel, it was their belief that all personnel knew they should contact the control room in the event of observing significant equipment problems. The licensee also, however, issued Temporary Change Notice (TCN) 0-2 to Procedure SO123-XX-1, "Initiation and Prioritization of a Maintenance Order/Construction Work Order," effective February 15, 1995. This change required any individual initiating MOs for components that could potentially fail or be inoperable, to immediately report these defects to the operations supervisor. The change also required equipment control evaluators to ensure all MOs documenting defects in safety-related equipment, equipment important to safety, or equipment under the jurisdiction of Technical Specifications had been identified to the operations supervisor.

2.2.2 Work Prioritization

The team evaluated the maintenance prioritization system by reviewing caution tags, control board deficiencies, in-process work activities, and backlog information. Overall, the licensee's prioritization process was found to be effective. The team also interviewed operations personnel regarding their assessment of the support that they received from the maintenance staff. The operations personnel were very positive in their assessment of the support that they received. The team noted that some improvement was still needed in the timeliness of resolution of caution tag and control board deficiencies, as discussed below.

2.2.2.1 Caution Tags

The team reviewed the open caution tag log. When appropriate, MOs had been initiated to correct deficiencies described on the caution tags. For the most part, resolution of deficiencies was timely. However, one caution tag had been outstanding since 1987.

2.2.2.2 Control Board Deficiencies

During the course of the inspection, the team observed licensee response to a ground which affected control room annunciators. The alarm came in repetitively and was a nuisance to the operators. Maintenance personnel promptly responded and repaired the deficiency. The team compared the list of control board deficiencies with control board deficiency tags posted in the control room, and found that the licensee was effectively identifying and tracking control room deficiencies for resolution. Operators were aware of all the deficiencies on the list and MOs had been appropriately initiated for the deficiencies. However, some of the deficiencies, which were initiated as far back as 1988, indicated an untimeliness in deficiency resolution.

2.2.2.3 Backlog Review

In the fourth quarter of 1991, the licensee's maintenance backlog peaked at approximately 3200 items for both units and has trended downward ever since. In early 1992, the licensee integrated all work control activities into a single organization to improve coherency and also changed the criteria for items that were considered backlog. After the change in criteria, to be considered backlog, a given maintenance task had to: be corrective maintenance, involve safety-related equipment, be performed during non-outage periods, be greater than 120 days old, affect plant operation, and also had to be greater than Priority 3C. This prioritization included maintenance that was classified as desirable work that could be performed according to the long range schedule, as well as work considered essential or mandatory. The backlog was reduced to approximately 1700 items in February 1992 following the change in criteria.

The total corrective maintenance backlog for both units was reduced to approximately 310 items as of January 1995. There were approximately 2200 Priority 3 (desirable work) backlogged corrective maintenance items that were less than 120 days old in January 1995.

Procedure SO123-XX-4, "SONGS Work Scheduling and Coordination Process," TCN 0-2 dated August 12, 1994, was noted by the team to assign the responsibility for managing the maintenance backlog to the online scheduling group. It was ascertained, however, that the maintenance organization had recently undergone a reorganization in which the online scheduling group was dissolved and their duties and responsibilities assigned to the work control group. The licensee had not revised Procedure SO123-XX-4 when the reorganization occurred to reflect the realignment. At the conclusion of the inspection, licensee personnel stated that plans had been initiated to revise the procedure.

2.2.2.4 Outage-Related Corrective Maintenance

The licensee's approach to prioritizing outage-related corrective maintenance was considered conservative, in that it was indicated to the team that no Unit 2 outage-related corrective maintenance would be deferred beyond the Unit 2 outage.

2.2.2.5 Multiple Fire Pump MOs

The team noted that outstanding MOs affected multiple fire pumps. The team was concerned that the cumulative effect on fire system reliability may be overlooked in the licensee's process. MO 93050339 001 was the most significant. In May of 1993, licensee personnel initiated this MO to identify that a pump needed overhaul because of degrading performance on required flow test. Licensee personnel did not put the pump on any sort of increased frequency testing while the overhaul was being planned and scheduled. However, the team noted that actual pump performance improved during the interim period.

2.2.2.6 Boric Acid Leaks

The team reviewed a list of open maintenance items and noted multiple outstanding MOs to address boric acid leaks. Based on interviews of licensee personnel and attendance at scheduling meetings, the team determined that the licensee had a special program to prioritize boric acid leak repair. Licensee personnel stated that all leaks were being walked down and the most significant leaks were being repaired first. Licensee personnel further stated that the overall number of leaks was decreasing.

The team also ascertained that stress corrosion cracking of Type 410 stainless steel hinge pin cover studs was identified in March 1992 in a Unit 2 Anchor Darling tilting disc check valve. The degradation mechanism was detected by laboratory examination of a stud which failed during performance of a retorque activity to eliminate leakage. A comprehensive root cause analysis (Root Cause Analysis 93-002) was performed which confirmed that the degradation mode was intergranular stress corrosion cracking. Failure occurred because of the susceptibility of Type 410 stainless steel to stress corrosion cracking at temperatures above 130°F, when exposed to a corrosive environment such as leakage from a borated water system. Licensee personnel prioritized replacement of the Type 410 studs in the Anchor Darling tilting disc check valves into three groups. Group 1, the highest priority, consisted of those check valves which were unisolable from the primary system and operated at temperatures that were conducive to stress corrosion cracking. Group 2 consisted of the 30 ft. elevation check valves that were isolated from the primary system by one check valve, and were exposed only during shutdown cooling to temperatures that were conducive to stress corrosion cracking. Group 3 consisted of the 45 ft. elevation check valves that were isolated from the primary system by one check valve, but not exposed during normal service to temperatures that were expected to promote stress corrosion cracking.

The team noted that the methodology that was initially proposed, for Group 2 and Group 3 valves, required ultrasonic examination of the studs following identification of valve leakage, with replacement performed only if unacceptable indications were found. For Group 1 valves, bolting was required to be replaced if active leakage was present. The team ascertained, however, that the licensee had replaced the Group 1 check valve bolting with a more resistant material in 1993. The team was also informed that replacement of the bolting in the Group 2 check valves would be completed during the 1995 unit refueling outages. The team considered the licensee Group 1 actions and planned Group 2 actions to be appropriate.

The team concluded that the licensee's emphasis on boric acid leak repair was appropriate and needed to continue to further reduce the backlog of boric acid leaks. Review of the licensee's progress in reducing the total number of leaks and its program for controlling boric acid corrosion are considered an inspection followup item (361/9501-01; 362/9501-01).

2.2.3 Work Scheduling

To schedule and prioritize repetitive, preventive, and corrective maintenance activities, the licensee followed the guidance specified in Procedure SO123-XX-4, "SONGS Work Scheduling and Coordination Process," TCN 0-2 dated August 12, 1994. The team reviewed implementation of the process by attending work scheduling meetings, interviewing cognizant personnel, and observing a demonstration of the computer-based risk monitor.

The team identified some work scheduling strengths and one concern. With respect to outage scheduling, the licensee had a fairly detailed defense in depth plan developed to control risk at shutdown. However, as discussed in Section 2.3.4 below, the team was concerned about the prudency of performing switchyard work during reduced inventory conditions, coincident with a diesel generator outage, a reserve auxiliary transformer outage, and high decay heat load. For routine maintenance activities, licensee personnel used a risk monitor to prevent scheduling simultaneous equipment outages which would cause too much risk. A computer model based on a Level 1 probabilistic risk assessment was used to evaluate the schedule 2 weeks in advance to identify the risk associated with various work activities. Licensee personnel stated that this review was effective (i.e., work had previously been rescheduled based on the risk monitor results).

Licensee personnel stated that the long range schedule was originally developed using the emergency operating instructions as a basis for determining risk (i.e., pre-probabilistic risk assessment). The long range schedule was reevaluated using the current computer risk model and was found to be acceptable without change.

The team concluded that the licensee's overall approach to scheduling continued to be conservative. However, the prudency of the time selected for scheduling the switchyard work was questioned by the team.

2.2.3.1 Operations Control Center

The team observed operations personnel authorize work for maintenance, interviewed personnel, and monitored the use of the associated computer support systems. During this inspection, licensee personnel implemented a new computer program to track equipment status. Licensee personnel tested the use of the program prior to the Unit 2 outage and then held discussions to determine whether it was wise to implement the new program during the outage. Licensee personnel did encounter some startup difficulties using the new system. However, for the most part, plant personnel were satisfied that the new system was an improvement.

2.2.3.2 Work Authorization Requests

The team noted that the interface between maintenance and operations personnel in the control room was a strength. Operations personnel routinely queried the maintenance personnel to ensure they were requesting authorization for the correct unit. A maintenance coordinator was located in the control room to ensure that interface problems were promptly addressed.

In general, control room operations personnel were attentive to their duties. For example, the team observed one operator deny an authorization request which would have adversely affected instrumentation that was being relied on to monitor the plant. During the inspection, maintenance personnel identified that the stator water cooling system was not correctly drained at the time of initiation of work by craft personnel on the system. The maintenance personnel correctly contacted the control room for guidance. Operations personnel did not, however, initially notify their management of this event. After the team discussed the event with plant supervision, the licensee reviewed the event in accordance with their near miss program. As a result of that evaluation, they planned to improve their work authorization process. In order to ensure drained systems remained drained, licensee personnel indicated that it was planned to require that operations personnel either 1) maintain a drain and a vent path, or 2) isolate the boundary using two valves at each interface. While this addressed the technical issue, the team was also concerned that the operations personnel involved did not notify their supervision of the event. Licensee personnel stated that it was planned, during the next crew training session, to emphasize to operations personnel the importance of identifying near misses on a continuing basis.

2.2.3.3 Work It Now (WIN) Program

The WIN program was established by the licensee to facilitate performance of work activities of minor safety significance. Activities assigned to this program were those that typically fell into the categories of: required little detailed planning activities, did not involve disposition of a nonconformance report, did not require Technical Specification operability evaluation, and were not applicable to performance of work that was under the jurisdiction of the ASME Code. The WIN program scope was defined in Procedure SO123-XX-3, "Work It Now Program," TCN 1-1. The WIN program was ascertained by the team to be separate from other maintenance division activities, and utilized dedicated maintenance and radiation protection personnel under the supervision of a licensed senior reactor operator.

The team noted the program did not define the job responsibilities of either the program supervisor, or the maintenance supervisor that was assigned to supervise the maintenance technicians. The team ascertained that the program supervisor evaluated WIN activities from an operations perspective prior to performing the maintenance, and integrated WIN activities with other maintenance activities by coordination with the control room staff. The maintenance supervisor stated that one of his major responsibilities was to review and individually walk down jobs to assure the tasks were within the scope of the program. Since the program did not define job responsibilities, the maintenance supervisor had taken the initiative and was separately developing a list of his current job responsibilities. The team additionally noted that there were few administrative controls in place for the WIN program.

Conceptually, the team concluded that the WIN program provided an effective means to perform minor maintenance activities, but viewed the limited administrative controls and lack of defined supervisory responsibilities as an area that could be strengthened.

2.2.4 Plant Status Control

2.2.4.1 Temporary Strainer Drawings

The team toured areas associated with three systems to assess material condition and plant status control. Based on field observations and drawing reviews, the team initially believed that construction strainers were still installed in the suction of the low pressure safety injection pumps, the containment spray pumps, and the high pressure safety injection pumps. The associated piping and instrumentation drawings indicated that the temporary strainers were installed. The licensee furnished detailed isometric drawings and other documentation which showed, however, that the strainers had been removed. The team informed the licensee staff that the piping and instrumentation drawings were misleading. Licensee personnel indicated that this situation would be corrected at the next time that the piping and instrumentation drawings were revised.

2.2.4.2 Technical Specification Fire Zones

While walking through the turbine building, a team member noted that a fire detection panel was in alarm for Zones 1, 2, 3, and 9. The team contacted the licensee's fire captain to determine if licensee personnel were aware of the alarms associated with the fire detection panel and to verify that proper contingency actions had been put into place. Licensee personnel informed the team that they were aware of the alarms and had established an hourly fire watch for the two safety-related zones that were covered under the Technical

Specifications (i.e., Zone 1, turbine building elevation 30 ft., south east area; and Zone 9, 56 ft., Unit 2 west area). Licensee personnel further stated that Zones 2 and 3 were not covered under Technical Specifications and no fire watch had been established, and that the alarms were spurious and had been caused by rain. The team subsequently verified that a fire watch had been established and was making the required hourly tours in the Zone 1 turbine building area.

2.2.4.3 Shift Turnovers

The team monitored a variety of shift turnovers between both operations and maintenance personnel to determine if maintenance status was accurately being conveyed to the oncoming shift staff. No specific problem areas were identified. The team did note that the turnover process between the day-shift maintenance general foreman and swing-shift general foreman was being upgraded in response to previous concerns. The team could not evaluate the effectiveness of the new process because it was not fully developed. Licensee personnel were still learning their roles.

2.3 <u>Maintenance Activities</u>

2.3.1 Electrical and Instrumentation and Control

The team observed several electrical and instrumentation and control maintenance activities during the inspection. Most of the maintenance observed by the team was well conducted. Observed tailboard briefings were well performed and covered the objectives of the work to be performed. Good safety and radiological practices were exhibited. The team noted as a result of field observations and interviews that there was usually a strong supervisory presence during the performance of maintenance activities.

2.3.1.1 Emergency Diesel Generator Cooling System Thermostatic Valve, O-Ring and Element Replacement

The team observed portions of an inspection of the Unit 2 emergency diesel generator cooling water system. The work was conducted in accordance with MO 94051424. The team noted that the supervisor overseeing the work activity signed off the procedure upon the arrival of the team to indicate completion of an inspection of the valve sleeves, lower and upper seats, and the installation of the new thermostatic assemblies. The work was ascertained to have been performed by licensee maintenance employees from a local fossil plant who were brought onsite to assist in the outage. When questioned about the reason for the work steps not being signed by the people performing the work, the supervisor stated that he signed the procedure because the individuals had not gone through the licensee's formal training process and were not certified to work independently. Licensee personnel referred the team to Section 6.2.8 of Procedure SO123-I-1.3, which permitted a supervisor to sign a step as complete based on first-hand knowledge. This meant the supervisor had to either observe the work being performed, verify it was performed, or verify the completed actions were recorded in the same or another field work package.

Licensee personnel also stated that although the individuals performing the work had not gone through the task specific training, they were experienced machinists and were directly supervised by someone task qualified. These factors allowed them to perform the work. The team determined that the maintenance actions were consistent with licensee program requirements.

The team also directly observed the installation of various gaskets and flex tubing, with no anomalies noted.

2.3.1.2 125VDC Station Battery 2D2

The team observed portions of a service test on two newly installed spare battery cells. The activity was authorized by MO 93071304. The team observed a technician perform an inspection of the battery, which consisted of verifying electrolyte levels and performing measurements of specific gravity, calculations of corrected specific gravity, and battery voltage measurements.

The team noted that the battery maintenance and testing work was documented in the maintenance order (MO) as beginning on February 7, 1995. The work was conducted using Procedure SO123-I-9.301, "Spare and Single Battery Inspection and Testing," Revision 2 dated December 9, 1994. The testing observed by the team occurred on February 14, 1995. Subsequent to observation of the work, the team retrieved a copy of the test procedure from the SONGS document management system. It was ascertained that the procedure had been revised by TCN 2-1 on February 12, 1995. The work activity had been started using the most recent revision of the procedure, but was not completed using the most recent revision. The team verified, by questioning the cognizant engineer and review of TCN 2-1, that the changes had minimal safety impact on the batteries.

The TCN was also noted by the team to appear to change the protective clothing requirements required when testing and inspecting the batteries. Revision 2 of the procedure stated personnel protective equipment (face shields and/or goggles, aprons, gloves, etc.) shall be used when working with batteries to protect from acid exposure. This requirement was changed by TCN 2-1 to state personnel protective equipment should be used when working with batteries to protect from acid exposure. This appeared to potentially reduce the personnel safety requirements when working with batteries. The licensee responded on this subject by providing the SONGS definitions of "shall" and "should" (i.e., "shall" indicated a regulatory requirement and "should" indicated a management expectation, not a regulatory requirement). Licensee management stated that employee response to either term would be the same. The team viewed the licensee use of the word "should" to vary from the typical, where it signifies a usual but non-mandatory practice.

The team noted the test technician did wear the proper protective equipment and used excellent safety practices. No other anomalies were identified during the maintenance observations.

2.3.1.3 Excore Channel D Calibration

The team observed portions of a surveillance to calibrate Nuclear Instrumentation Excore Channel D. The test was authorized by MO 95010638. The team observed the calibration of various logarithmic and linear functions of the detector. These calibrations were conducted following the guidance outlined in Procedure SO23-II-5.8, "Surveillance Requirement N.I. Safety Channel D Drawer Test Linear Power Subchannel Gains Channel Functional Test and Channel Calibration." During the test, two technicians were stationed at the channel drawer, which was located outside the control room, and a third technician was at the main annunciator board inside the control room. The team verified that the technicians located at the channel drawer utilized appropriate safety precautions and successfully performed the calibration without any anomalies.

After observing the activity, the team reviewed the training matrix for the individuals involved in the calibration. The team noted that the two individuals that were located at the channel drawer had been task qualified to perform the calibration. However, the individual located inside the control room was not task qualified. The team questioned licensee personnel about the individual's qualifications and the function the individual performed during the calibration. The team was informed that the individual's only role was the acknowledgement of annunciators that came in as a result of the calibration. Although the individual was not task qualified to perform the calibration, licensee personnel stated he was in constant communication, via a headset, with the calibration coordinator, who was task qualified. Licensee personnel further stated that since the individual was not directly involved with safety-related maintenance, and since the individual was under the direction via headsets of someone who was task qualified, the individual's participation in the test did not violate any procedure. The team agreed with this reasoning.

2.3.1.4 High Pressure Safety Injection Pump Flange Leak

The team observed WIN personnel perform maintenance on the Unit 3 Train B high pressure safety injection pump. The work was authorized by MO 95020404 and pertained to verification and correction of leakage on both the inlet and outlet flanges of the pump. Prior to the work, the team accompanied the WIN maintenance supervisor on a walkdown of the job to verify that the activity was within the scope of the WIN program.

Once the leak was verified, a technician removed dry boric acid from the flanges and used a crescent wrench to verify the torque of the flange bolts. Excellent radiation protection practices were used to remove the boric acid. The team questioned the maintenance supervisor about the use of a crescent wrench rather than a torque wrench to verify the tightness of the flange bolts. The supervisor responded that he had reviewed the SONGS Torque Manual, M-37204, and the pump overhaul procedure, SO23-I-5.8, prior to the work, and ascertained that use of a flexitallic gasket with no specified torque values had been defined. As previously noted in Section 2.2.3.3, limited administrative controls had been defined for WIN activities, and the team ascertained that there was limited definition of or reference to governing technical requirements. In this specific instance, it appeared to the team that the maintenance supervisor had independently conducted research into the joint technical requirements. The team considered the absence of more explicit guidance regarding review of governing engineering requirements, prior to performance of WIN activities, to be a weakness.

2.3.2 Mechanical

2.3.2.1 Main Steam Safety Valve Replacement

The team observed portions of the ongoing activities associated with replacement of five main steam safety valves (i.e., Valves 2PSV8401, 2PSV8402, 2PSV8404, 2PSV8406, and 2PSV8407). Licensee personnel were in the process of replacing the valves with refurbished valves from the vendor. Licensee personnel stated that the removed valves would be sent to the vendor for refurbishment and bench testing. The team noted that the licensee's foreign material exclusion controls were being implemented, with all openings into the main steam system covered and taped to prevent foreign objects from entering the system. The team also noted that housekeeping controls were good considering the amount of maintenance personnel and activities that was ongoing in the area. The team noted that the general foreman, cognizant engineer, and quality control staff were all observing the maintenance activities. The team interviewed personnel involved with the activities. The general foreman was knowledgeable of all aspects associated with the main steam safety valve replacement and the other ongoing maintenance activities in the immediate area. All maintenance personnel demonstrated an appropriate awareness for the purpose of the work activity and ownership of the equipment. The team also noted that maintenance personnel were following their procedures and signing the procedure as required after each respective step. Assigned quality control personnel were knowledgeable of the task and their inspections were made in accordance with the stated requirements. Work activity was well coordinated between the operations and maintenance organizations.

The team reviewed the work packages associated with the five main steam safety valves maintenance activities. Approved procedures of the latest revision were used. Quality control inspection hold points, independent verification points, and appropriate peer reviews were identified in the MOs and procedures. The activities were described in a level of detail that was commensurate with the complexity of the main steam safety valve replacement and maintenance activity. Provisions for obtaining formal approval from operations were included, as well as methods for notifying operations when the main steam system was opened and closed.

Licensee personnel had previously checked the pressure setpoints of Main Steam Safety Valves 2PSV8401, 2PSV8402, 2PSV8404, 2PSV8406, and 2PSV8407 while in Mode 1 and reducing power for the refueling outage. The team reviewed the completed work package and data results from that test. All of the valves tested were ascertained to be within their respective acceptance criteria, based on the functional test data reviewed. The team additionally verified that appropriate calibrated measuring and test equipment had been used for the testing. The licensee indicated that the newly replaced valves would be retested, following the refueling outage, when the unit reached Mode 1 and started increasing power.

2.3.2.2 Walkdown of Work Authorization Request 2-R8CW003

The team walked down the Work Authorization Request 2-R8CW003 component list which was associated with the salt water cooling system and circulating water system maintenance activities. Work Authorization Request 2-R8CW003 required that four salt water pumps be taken out of service (two for Unit 2 and two for Unit 3). The team verified that all pumps, valves, and breakers, were appropriately aligned, positioned, and labeled. The team also verified that taking the four pumps out of service was consistent with Technical Specification requirements.

During the walkdown, the team noted that the feed breaker fed from Emergency Diesel Generator 2G003 on the 4160V safety bus had a work authorization request tag dated November 8, 1994. The team questioned operations personnel concerning the date on the work authorization request tag. The licensee personnel stated that the date on the tag was the date the tag was printed, and that the diesel feeder breaker had actually been racked out and labeled with the work authorization request tag on February 14, 1995.

The team noted that scaffolding had been erected around the operating Unit 2 salt water pump that was being used for shutdown cooling, but concluded that the scaffolding did not prevent the pump or its surrounding components from operating properly.

2.3.2.3 Salt Water Pump Maintenance

The team observed portions of the multiple ongoing maintenance activities that occurred in the Unit 2 salt water pump room during the inspection period. The room housed two pumps for Unit 3 (Pumps 3P307 and 3P114) and two pumps for Unit 2 (Pumps 2P112 and 2P113). All four pumps in the Unit 2 salt water pump room were taken out of service at the time of the inspection. Scaffolding was erected around all four pumps. The motor for Pump 3P314 was removed and the motor for Pump 3P307 was being removed for shipment to the vendor for overhaul. The team noted that maintenance craft exercised extreme care in the removal of the Ray-Chem material from the motor and feeder leads to ensure no damage was caused to the insulation. The team also noted that all conduits and connection boxes were secured following removal from the motors. Personnel involved with the activities were found by interview to be knowledgeable of the work scope and were observed to be following the MO instructions. The team noted that during the maintenance activities the Unit 2 pump room appeared congested with tools and materials. The team also noted that rain was falling through openings in the overhead, and had caused pools of standing water in areas on the floor where maintenance activities were being performed. The team did note that small laydown areas had been established for each individual task. Therefore, the team concluded that housekeeping was adequate under those circumstances.

The team observed portions of the maintenance activities that were being conducted in the Unit 3 salt water pump room. The Unit 3 salt water pump room also housed two pumps for Unit 2 (2P307 and 2P114) and two pumps for Unit 3 (3P113 and 3P112). The four pumps in the room were being used to satisfy the Technical Specifications for two trains of salt water cooling for both Unit 2 and Unit 3. Maintenance craft personnel were observed erecting scaffolding in the room in preparation for the upcoming inservice inspection activities. Maintenance craft personnel were observed removing rust and debris from bolt connections on the salt water piping that was to be removed later during the refueling outage for inservice inspection. The team concluded that the maintenance activities in and around the pumps did not compromise the pump operability.

2.3.2.4 Degraded Conduit in Salt Water Pump Rooms

During a walkdown of the salt water pump rooms, the team noted several degraded conduit lines which housed safety-related cables. The team questioned personnel about the degraded condition of the conduit. A subsequent tour of the salt water pump rooms was made by both the team and licensee personnel to determine which safety-related systems contained the observed degraded conduit lines. The team questioned personnel concerning licensee programs for equipment preservation and how degraded conduit was identified and subsequently repaired, especially for the salt water pump rooms since equipment would be exposed to a marine atmosphere. Licensee personnel indicated that their equipment preservation program did not currently include identification and preservation of degraded conduit; however, they would revisit and address the issue. Licensee personnel also stated that the degraded conduit that was identified by the team was not perforated, and that the functionality of the conduit had not been compromised. The team concluded that although the degraded conduit may not have been perforated, its condition was questionable. The omission from the licensee's equipment preservation program of conduit which contained safety-related cable was viewed as a weakness by the team. During the exit meeting conducted on February 24, 1995, the maintenance manager committed to perform an evaluation in regard to inclusion of conduit containing safety-related cable into the licensee's equipment preservation program.

2.3.3 Programmatic Guidelines Not Always Followed

The team observed in-progress modifications of safety-related Unit 2 pipe supports that were being performed as part of the snubber reduction program; observed maintenance to repair Unit 3 auxiliary feedwater steam traps; reviewed Unit 2 nonsafety-related oil addition records, for the last five years, for the main circulating water pumps; and walked down parts of the secondary systems of both units.

The team identified that, in some instances, programmatic guidelines were not followed during both primary and secondary plant maintenance. Examples observed were as follows:

- The team noted that on January 17, 1995, and again on January 31, 1995, maintenance to modify pipe supports for Unit 2 emergency core cooling system safety-related piping was granted by the control room operators as a "verbal" authorization. (Maintenance could be authorized as a "verbal," with no written authorization, or as a "work authorization," which contained written authorization and a more thorough evaluation of the maintenance.) This maintenance was controlled under MO 94082406. The team noted that, at both of these times, the Unit 2 emergency core cooling system was required to be operable by Technical Specifications because Unit 2 was in Mode 1. The team reviewed Procedure SO123-XX-5, "Work Authorizations," Revision 1, and noted that it contained a list of examples of appropriate maintenance to be performed under a verbal authorization. It was ascertained by review of this list that it was not a management expectation to use a verbal authorization to perform modifications to pipe supports for systems required to be operable. Based on a review of the safety evaluation for the modification, the team concluded that the system remained operable throughout. This was because the licensee was strengthening the support and it was not weakened at any time during the process. In response to the team's concern, licensee personnel revised the work authorization procedure to allow use of a verbal authorization for pipe modifications, such as the one above, when a safety evaluation had been performed as a part of the design change. The team considered this action to be adequate.

- During observation of the completed pipe support modification discussed above, the team noted evidence of grinding on the surface of a 4-inch diameter safety-related pipe in the Unit 2 low pressure safety injection header to the letdown heat exchanger. The grinding partially obscured adjacent weld identification information, but was not a concern in terms of structural integrity of the pipe. The ground area of pipe was directly below the pipe support that had been modified. No documentation was located by licensee personnel which would explain the circumstances as to either when this occurred, or what controls had been in place. The licensee and the team were unable to determine when the grinding had occurred. The team concluded from interview of craft personnel, who performed the modification to the pipe support, that it did not occur during this activity, and that the grinding was indicative of poorly controlled or documented maintenance at some point in the past.

- On February 9, 1995, the team observed licensee welders in Unit 3, replacing a main steam to Auxiliary Feedwater Pump Strainer 3F-903 drain valve under MO 94081613001. The team reviewed the clearance for this maintenance, which was listed under Work Authorization 3-9404520. The team noted from review of the work authorization that double valve protection from a high energy system (i.e., steam generators) could have been afforded, but was not, while working on another auxiliary feedwater pump steam trap that was included under this work authorization. Valve 2MU688 was worked, but with single valve protection from the steam generating system. Unit 3 was in Mode 1 at the time, with over 800 pounds of pressure in the steam generators. The team noted that

Valve 2MU222 could have been cleared "closed" to afford the double valve protection, but was not. In response to the team's concern, licensee personnel were evaluating the efficacy of making management expectation in this area more clear.

- The team noted that oil was added, as necessary, to all four Unit 2 main circulating water pumps during August 1994 under MO 94062737. The type of oil actually added, and to which pumps, was not recorded in the MO, although the team did note that "Chevron GST-68" was prescribed to be added. The team considered it was management expectation that the actual oil added would be recorded. The team considered that, since the type oil to be added was stipulated in the MO, the correct oil was probably added. Other MOs the team reviewed documented the type of oil actually added.

2.3.4 Switchyard Maintenance

On February 16, 1995, the team noted eight vehicles and one trailer parked in the switchyard area, which was defined by a fence around the switchyard where off-site power entered the units. Three mobile personnel lifters were being used to clean and renew grease around insulators for the Unit 2 reserve auxiliary line. Two private vehicles were parked in the north end, two licensee vehicles were in the Unit 1 area, and one licensee vehicle and one trailer were parked between the Unit 2 and Unit 3 area. Non-SONGS utility personnel were renewing grease on the Unit 2 reserve auxiliary line, and had previously replaced a part on a breaker in the switchyard area for the Chino line that morning. The reserve auxiliary and Chino lines were both out of service for other reasons. During this period, Unit 2 was in Mode 5 and had just drained down to mid loop, with an 18 minute time to boil if shutdown cooling was lost. Unit 2 Emergency Diesel Generator 2G003 was out of service. Unit 3 was at full power with both emergency diesel generators operable.

The team ascertained that the work had been authorized by the shift supervisor earlier that morning, with the provision that the workers remain north of the Santiago line. The Chino line, where the team saw vehicles as described above, was south of the Santiago line. The team also noted that the work had been requested because the lines were out of service.

The team was concerned because of both the number and position of vehicles in the switchyard, as well as the short time to boil for the Unit 2 reactor coolant in the event of a loss of shutdown cooling, and the similarities to an event at Vogtle in 1990. In response to the team's concern, the licensee stationed a licensed operator in the switchyard to monitor the work, had the excess vehicles removed, and later discontinued the work.

The team reviewed the circumstances associated with the work and concluded the following:

- The workers had entered the switchyard earlier that morning from the south entrance, and then after entering, requested authorization to perform the work. This was contrary to a posted sign, and was also contrary to Procedure SO23-6-30, TCN 1-10, "Switchyard Inspection and Operation," which prohibited switchyard entry without first obtaining permission from the control room. The failure to follow procedural requirements is a violation of Technical Specification 6.8.1 (361/9501-02; 362/9501-02). In addition, by not contacting the control room prior to entering the switchyard, the workers did not receive instructions regarding where to enter the switchyard. The workers inadvertently violated the prohibition issued by the shift supervisor against driving through the Unit 3 and Unit 2 sections.

- The workers brought unnecessary private vehicles into the switchyard area.

- The team questioned whether the licensee was appropriately conservative in authorizing the switchyard work at a time when Unit 2 was in mid loop, with a short time to boil if shutdown cooling was lost, and with one emergency diesel generator unavailable. The team also considered that the work might have been scheduled at a later time during the refueling outage. During the onsite exit meeting on February 24, 1995, licensee personnel stated that removing an emergency diesel generator and a reserve auxiliary transformer from service, with the reactor coolant at mid loop and conducting switchyard maintenance had been evaluated using the probabilistic risk assessment model, and that the increase in risk was small. The licensee was informed that the Office of Nuclear Reactor Regulation would be requested to review the appropriateness of the licensee probabilistic risk assessment.

2.4 Independent and Self Assessment of Maintenance

The team ascertained that the licensee was performing both independent and maintenance organization self assessments of the maintenance activities, organization, and function.

2.4.1 Self Assessment by the Maintenance Organization

The Maintenance Division had implemented four programs to perform self assessments of Maintenance Division activities. The team reviewed the recent and past performance of these programs for effectiveness.

2.4.1.1 Monthly Annunciator Window Report

The Maintenance Division issued a monthly color-coded annunciator window report as a tool for managers to judge performance. This report was constructed and issued in accordance with Maintenance Policy Guide SO123-G-23, "Maintenance Performance Annunciators," Revision 1. The window colors ranged from green for the best performance to white, yellow, and finally red for poor performance. According to licensee maintenance personnel, windows could be added or dropped from the report, dependent upon perceived performance. Areas remaining green for long periods were sometimes purged from the report.

Problematic areas identified by other assessment programs or efforts could result in a window being added to the report. Each monthly report trended the area monthly performance for the previous 2 months. A quarterly window report was issued to senior managers that trended performance for the previous three quarters.

The team reviewed the implementing procedure and latest monthly and quarterly reports. The team observed that for every report window, the procedure provided specific criteria for ranking the reported area. When new or temporary windows were added, the specific ranking criteria was developed and provided for that area. A window owner was responsible for developing criteria, and new or changed criteria required approval of the maintenance manager. The team was informed that consideration was being given to making specific criteria more conservative as performance improved. The current report contained 24 windows, with 4 of the windows on the monthly and quarterly reports coded red. Two of these windows had been red for at least 6 months. The long term performance problems being trended by the report were "Maintenance Division Experience Report Action Overdue" and "Work Plan Documentation Completeness." These were both classified as temporary windows. In following up, the team found that a recent change had placed overdue Maintenance Division Experience Report actions on the weekly maintenance staff meeting agenda and the backlog of overdue action items was decreasing. Additionally, an in-house assessment of maintenance planning was in a preliminary stage.

Discussions with management provided verification that the annunciator window report was effective in focusing management attention on problem areas.

2.4.1.2 Leadership Observation Program

The team reviewed the Maintenance Division leadership observation program. This internal self-assessment effort was implemented by Maintenance Policy Guide SO123-G-24, "Maintenance Leadership Observation Program," Revision 6. The leadership observation program was a self-assessment tool used to identify improvement opportunities for Maintenance Division processes, policies, and programs. The procedure required line organization, staff, and support supervisory personnel to observe maintenance activities on an ongoing basis. Individual supervisors were required to perform field observations at least once per week. Grading forms were provided for the activity or condition observed to be rated as a significant strength, satisfactory, improvement needed, or a significant weakness. A comments section was provided for the observer to document details for findings that needed improvement or were identified as weaknesses.

The licensee provided the team with documentation supporting the training of personnel responsible for performing supervisory observation. According to a maintenance division representative, 2 years prior to the inspection, only 19 individuals were trained to perform observations. At the time of the inspection, at least 120 personnel were trained to perform leadership observation.

The completed evaluation forms which documented observations were transmitted to a program coordinator. Individual reports were then sent to an applicable supervisor of plant maintenance or manager responsible for correcting the observed condition. For observations deemed to be significant, a copy was sent directly to the maintenance manager. The Maintenance Division issued a weekly report that trended reported data on a rolling 6-week basis with observations categorized into 16 problem areas. For a weekly series of observations, the results were evaluated and a weekly report was produced and distributed. The report graphically arranged the data for the 16 categories in descending order of quantity of observation findings. This practice served to indicate where management attention should be focused. Ideally, recommendations were provided to management who authorized the implementation of improvement recommendations, if warranted. This practice had only been occurring in the recent past.

The team attempted to verify that program identified issues requiring a training solution would be corrected. There were program requirements for supervisory observations of the on-the-job and lab session training. Also other observations routinely required training to address issues. The team interviewed maintenance training supervision to verify that observations requiring training solutions were being incorporated into the licensee's maintenance training program. The maintenance training organization maintained an individual tracking system into which were entered all incoming corrective action requests related to maintenance training. Based on the discussions with maintenance supervision and a review of the tracking system, the team concluded that items reported to maintenance training since September 1994 were being addressed and incorporated into the licensee's maintenance training program.

The team reviewed a sample of completed field observation forms that were not related to training and weekly reports to management that were inserted into the rolling 6-week report. Additionally, discussions were held with licensee representatives with observation program responsibilities. An impression gained from review and discussion was that the program was not enthusiastically implemented until about one year prior to the inspection. Also, the team was unable to ascertain that individual negative performance observations were evaluated and tracked to the implementation of corrective action.

Based on the review and related discussions, it was concluded that the leadership observation program was causing ongoing evaluation and assessment of maintenance performance, and management attention was being focused in the categories or areas with a high population of findings. However, in the absence of procedural criteria for tracking negative observations to final resolution, the team could not verify whether appropriate corrective actions were being consistently implemented to improve maintenance processes, policies, and programs. The team concluded that this was a current weakness in the maintenance leadership observation program. Maintenance management informed the team that the preponderance of negative observations were very minor in nature and were corrected immediately, and that more significant observations would be entered into the existing corrective action program vehicles. The lack of process criteria precluded, however, assessment of whether significant leadership observation program findings were being channeled into the existing corrective action vehicles. Prior to the end of the inspection, the licensee furnished a draft document to the team which outlined a proposed screening and follow-up process for negative performance observations. Licensee personnel indicated that the process would be finalized by the maintenance business plan steering council.

2.4.1.3 Maintenance Division Experience Reports (MDERs)

The team reviewed the MDER program which had been initiated to investigate, resolve, and disseminate maintenance problems and errors. The program was implemented by Procedure SO123-I-1.42, "Maintenance Division Experience Report (MDER)," Revision 1, and was essentially a corrective action program used exclusively by the Maintenance Division. Procedure SO123-I-1.42 established methodology for investigation and resolution of maintenance problems and errors. Personnel assigned to investigate and report problems and errors were required to have received formal root cause training. Initiation of the process required the approval of either the manager of the Maintenance Division or a supervisor of plant maintenance. The procedure contained an attachment of threshold criteria for initiation of a MDER, and included events that led to unusual plant transients, system or component malfunctions, personnel and environmental hazards, and violations of regulatory requirements.

A report coordinator had been assigned to track corrective actions and to monitor MDER process deadlines. As stated previously in this report, a problem of overdue corrective action resulting from MDERs was being addressed. The team selected and reviewed 10 reports to verify that appropriate evaluations were performed and corrective actions were being promptly implemented and incorporated into maintenance programs, processes, and policies. During this review, the team verified that nine of the selected reports had been processed in accordance with Procedure SO123-I-1.42 and appropriate corrective actions had been performed. In addition, followup monitoring was being performed to ensure that the corrective action remained effective. The tenth report, Report MDER-94-015, dated July 6, 1994, documented an event pertaining to mechanical maintenance personnel erroneously performing work on a wrong component. Followup review of this report indicated that additional assessment of this type of problem was performed in this area by a different organization. This added assessment, which was documented in Safety Engineering Assessment Report SEA 94-009, was evaluated by the team. The results of the evaluation are documented in Section 2.4.2.1 of this report.

The team could not determine that the validity of the program results had ever been evaluated for effectiveness by any licensee group. It appeared that rigorous use of this program, which was considered an excellent corrective action tool by the team, had started 12-18 months prior to the inspection.

2.4.1.4 Maintenance Division Self Assessment

Since early 1994, the Maintenance Division had embarked on a new program of periodic special self assessments in areas where performance issues were believed to exist. This assessment effort was mandated by the "1994 Maintenance Business Plan," Revision 2. A maintenance business plan steering committee was initiated in early 1994, which eventually developed the maintenance business plan to include requirements and guidelines for self assessment. Two of these assessments had been completed and issued in March and December 1994. At the time of the inspection, an assessment of maintenance planning was in the planning stage.

Assessments had been performed in the areas of maintenance training and pre-job briefings and turnovers. The team reviewed assessment methodology, assessment results, and corrective actions that resulted from the assessment findings.

2.4.1.4.1 Maintenance Training Assessment

According to a Maintenance Division representative, the maintenance training assessment was conducted by a 12-person team of line and staff personnel in March 1994. The assessment was performed to ascertain whether training elements met the objectives of industry group standards. The assessment team was provided an 8-hour training course on how to perform this assessment.

Near the end of the first week of the inspection, a 23-page undated, unsigned report was provided in response to a team request to review the assessment findings and corrective actions taken in response to the findings. The team reviewed this document to evaluate the effectiveness of the assessment and resultant corrective action. The document distilled assessment findings into a total of 24 findings and then synthesized the findings into 4 major issues. According to the document, the major issues had been addressed and corrective action had been completed. The document reported the completion of corrective action as indicated below:

Major Issue: "Maintenance guidelines were difficult to understand because they were sometimes unclear and conflicted with nuclear training division procedures."

Action: "Revise the training program descriptions to fully cover the program requirements/administration and limit or eliminate the maintenance policy guidelines (training), where possible."

Status: Completed

The three other identified major issues were treated in a similar manner in the document. There was no indication of management approval of assessment results and planned corrective action.

2.4.1.4.2 Pre-Job Briefing And Turnover Assessment

This assessment was performed in accordance with the assessment elements in the business plan. The team was provided three documents to review for evaluating the effectiveness of the assessment. These documents were:

- A memorandum to file dated January 31, 1995, with attached Maintenance Policy Guideline MPG-SO123-G-15, "Maintenance Division Backshift and Weekend Turnovers," Revision 0.

- A memorandum to file stating that a letter was generated to close out the concerns of the December 1994 self-assessment on tailboards. The letter was not provided.

- A letter to the onsite corporate official for nuclear operations containing a case study on self assessment that alluded to the findings and recommendations for the assessment on tailboards and turnovers.

The team reviewed the documents provided, but were unsure of either the specific nature of the findings which emerged from the assessment, or what management-approved corrective actions had been implemented to address the findings of the assessment.

The overall conclusion of the team in this area was that the Maintenance Division self assessments had identified issues that necessitated corrective actions to improve performance. The limited documentation of findings and lack of approved corrective actions for issues impacted the NRC evaluation of the program and was viewed as a programmatic weakness.

2.4.2 Assessment of Maintenance by Other Site Organizations

Assessment of maintenance division activities by other organizations was performed on a periodic basis and in response to observed conditions and problems.

2.4.2.1 Review of Wrong Unit, Wrong Train, or Wrong Component Events Related to the Performance of Maintenance

As indicated in Section 2.4.1.3 of this report, the team reviewed Safety Engineering Assessment Report SEA 94-009 dated July 5, 1994, which assessed multiple events of personnel performing work on the wrong unit, wrong train or wrong component. Safety engineering performed this evaluation of instrumentation and control and radiation monitoring maintenance-related events that occurred from 1988 through June 1994. The purpose of the evaluation was to identify the causes and identify corrective actions to prevent recurrence of these types of event. The report indicated that from 1988 through June 1994, ten occurrences had been documented on MDERs which involved instrumentation and control or radiation monitoring technicians working on the wrong unit or wrong train. Each of the ten events was evaluated to identify the underlying causes and provide recommendations to preclude these types of events.

The following recommendations were contained in the report:

- Enhance training in self checking.
- Use unit specific color-coded folders for work packages.
- Use color-coded magnetic or sticker type markers on equipment undergoing maintenance.
- Coach technicians on when to implement self checking.
- Require technician that caused an event to provide lessons learned presentation to peers.
- Issue work packages one at a time, when possible.
- Highlight information on work packages for easy equipment identification.

Followup review by the team identified other recent MDERs related to wrong unit, train, or component which were not included in SEA 94-009. The assessment had not included events involving mechanical or electrical discipline personnel, although the licensee's MDER program indicated other disciplines had been involved in events or near misses concerning wrong unit, train, or component.

The team also identified the following two recent events which were documented in NRC Inspection Reports 50-361;362/94-20 and 50-361;362/94-21:

- Salt Water Cooling Pump 3P114 Flow Indicator Isolation Valve Maintenance Performed on Wrong Unit

On July 14, 1994, the licensee performed maintenance on components in the wrong unit. Specifically, a mechanic was to remove and refurbish isolation valves for the Unit 3 Salt Water Cooling Pump 3P114 seal water flow instrument, but actually removed and refurbished the valves associated with Unit 2 Salt Walt Cooling Pump 2P114. The licensee's clearance program required maintenance personnel to walk down applicable clearance boundaries for the job prior to starting work. In this case, the craftperson failed to do so. Verification of clearance boundaries would have revealed that the Unit 2 pump was not cleared, and allowed the error to be corrected before the work began.

- Hydrogen Monitor Channel B Surveillance Performed With the Wrong Unit's Data

On July 12, 1994, an instrumentation and control technician used Unit 2 Train B data for the Unit 3 Train B containment loss of coolant accident hydrogen monitor Channel B functional test.

The team noted that both of these events occurred within days of the issue of SEA 94-009. Maintenance performance in this area appeared to have improved subsequent to issue of the report, in that the only event subsequent to the above, a near miss in September 1994, pertained to operations personnel.

The team requested the response to SEA 94-009 to determine if the recommendations had resulted in the implementation of corrective actions. Licensee personnel indicated that a formal response had not been initiated. Licensee representatives stated that the instrumentation and control and the radiation monitoring maintenance groups had incorporated all of the report recommendations. The team believed that sufficient time had passed since July 5, 1994, for issue of a formal response together with a corrective action plan.

2.4.2.2 Assessment Performed in Response to Corrective Action Request

The team became aware that a corrective action request had been issued regarding maintenance activities. Corrective Action Request 011-94 was issued on July 26, 1994, by the Nuclear Oversight Division in response to the identification of Maintenance Division degraded performance. A series of six significant maintenance performance issues were identified by maintenance and quality assurance personnel as having occurred within a 7-day span.

One of the corrective actions to address degraded maintenance performance was to charter an assessment by safety engineering to determine the common causes of the degraded performance. The assessment was performed in November 1994 and documented in Safety Engineering Assessment SEA 94-014, "Assessment of Common Causes for Maintenance Division Events," dated November 29, 1994. The assessment utilized a human performance evaluation system review of a large sample of recent MDERs reported by the MDER program. According to assessment personnel, there was no separate analysis or investigation of single events performed outside of the previously reported events. All data in the assessment study was retrieved from MDERs.

The team held discussions with safety engineering personnel who performed the assessment, reviewed the results and findings of the report, and reviewed the Maintenance Division response to SEA 94-014. The report identified seven significant common causes and nine less significant causes. The report clustered 33 specific recommendations under the areas below:

- Increase commitment to expectations;
- Increase commitment to procedures;
- Increase commitment to communication;
- Increase commitment to field supervision; and
- Implement positive component identification.

The team believed that the effort to identify common causes for poor and degraded maintenance performance had been successful.

The team reviewed the response to the report recommendations, which was dated January 30, 1995, and provided to the team in the latter part of the first week of the inspection. In the report, the last area above stood alone without attached recommendations, and the item was not addressed in the response, but referenced to the planned response for Report SEA 94-009, which addressed maintenance events related to working on the wrong unit, train, or component. As for the other four area recommendations, the Maintenance Division committed to address each concern with several continuing and newly developed initiatives. The team could not ascertain what the specific action would be in all cases at this early date.

2.4.2.3 December 1994 Performance-Based Station Self Assessment

In November 1994, a unique performance-based self assessment was undertaken at SONGS. A mixture of quality assurance personnel and staff and line personnel from numerous organizations conducted a station performance-based self assessment. According to nuclear oversight personnel, this type of assessment represented a new philosophy of making organizations provide their own effective self assessment. The licensee contracted for a performance-based assessment training course of one-week duration for all team members prior to the assessment.

The team reviewed the maintenance portion of the assessment report that was issued in December 1994. According to the report, the maintenance area was assessed by two Nuclear Oversight and two Maintenance Division personnel. Within the maintenance area, the assessment team identified significant issues related to: procedural compliance, personnel safe work practices, personnel radiological practices, consistency of pre-job briefings and turnovers, MO quality, and procedures structure and interfaces. In addition to the assessment findings, the assessment team had provided causes for the identified findings and the projected results of continuing the identified poor practices. The team believed that this self-assessment activity was effective in the discovery of issues or practices that, when corrected, could result in improved maintenance performance.

The team became aware of a memorandum to managers dated December 9, 1994, from the Vice President, Nuclear, acknowledging the results of the assessment. The memorandum directed managers to provide action plans by January 13, 1995. The team requested the maintenance action plan on January 30, 1995, and was told that the response to the performance-based self assessment would be included in the response to Report SEA 94-014, which is discussed previously in Section 2.4.2.2 of this report.

The team compared the Maintenance Division response to Report SEA 94-014 with the findings and stated causes in the November 1994 self-assessment report, and considered that it was questionable whether the response sufficiently addressed the November 1994 report issues.

2.4.2.4 Routine Assessment by Quality Assurance

The quality assurance group within the Nuclear Oversight Division performed routine audits and surveillances that involved maintenance performance. The team reviewed a sample of these efforts and determined that administrative and facility license requirements were being met. The Maintenance Division response to audit and surveillance findings were satisfactory.

The quality assurance group also issued a quarterly station performance report that reported and assessed the performance of all onsite divisions and inter-division performance in functional areas in which more than one division participated. Starting with the third quarter of 1994, this report had been issued jointly by the Nuclear Oversight Division and the Site Technical Services Division. This report now contained the assessment of station performance by quality assurance and the industry group performance indicators.

The team reviewed the assessment portion of recent reports and evaluated the effectiveness of the assessment process. The report was issued as a color-coded annunciator window report with performance trending using mini-windows in the major area windows. The team verified that objective performance based criteria existed for the annunciator windows. However, there were no objective criteria for the inter-division areas. Oversight personnel explained that these windows were considered temporary to provide assessment and trending of areas where performance was dependent on more than one division, and subjective criteria were used to assure conservative assessment.

The team believed the assessment of maintenance activities and function provided by the Nuclear Oversight Division was satisfactory.

2.5 Surveillance and Test

The licensee's surveillance program was implemented by General Technical Procedure SO23-XV-3, "Technical Specification Surveillance Program Implementation," Revision 4 through TCN 4-1. The team assessed the program implementation through performance observation, document review, and personnel interviews. The assessed program elements included test performance, procedures, scheduling, and the interface with the inservice test program.

2.5.1 Surveillance Test Performance

With respect to the following local leak rate tests, the team verified that the applicable surveillance test procedures contained acceptance criteria and responses for local leak rate test failures. The team also reviewed ten MOs (listed below) associated with containment isolation valves requiring corrective action because of local leak rate test failures or problems. These MOs were initiated subsequent to the last containment isolation leak rate tests performed during the Cycle 7 refueling outages for Units 2 and 3. In each case, the valves' corrective actions/repairs were preceded and followed by local leak rate tests on the applicable penetration.

Valve Identity	MO
2HV0511	93071181
S21212MU294	93072001
2HV0513	93072012
2HV0501	93060768
S22423MU055	93041229
2HV6211	93071005
2HV6216	93071006
2HV7258	93070901
S31901MU321	93110136
3HV9971	93111864

2.5.1.1 Local Leak Rate Tests of Penetrations 18 and 19

The team observed performance of local leak rate tests of Penetrations 18 (normal containment purge inlet valves) and 19 (normal containment purge outlet valves), using Surveillance Operating Instruction SO23-3-3.51.1, Revision 0 through TCN 0-2. The procedure consisted of Attachments 1 through 7, with each being applicable to a specific containment penetration. Attachments 6 and 7 pertained to Penetrations 18 and 19, respectively.

During the tailboard session on February 2, 1995, it was identified that TCN 0-2, dated January 11, 1995, had been written such that if the local leak rate test results for both penetrations were acceptable, nothing further was to be done. There was no methodology provided to restore the tested system to its pretest or operable condition. This prompted the initiation of procedure modification permits for each attachment, to allow the proper completion of the test procedure upon achieving satisfactory test results.

During the team's observation of the surveillance tests, it was noted that the test personnel performed the tests in accordance with the surveillance test procedure, and maintained proper communications with the control room staff.

2.5.1.2 Local Leak Rate Test of Penetration 25

The team observed performance of the Penetration 25 local leak rate test (refueling canal fill and drain valves), in which Surveillance Operating Instruction SO23-3-3.51.9, Revision 0 through TCN 0-2 was used. Attachment 3 of the procedure was applicable, and contained the testing sequence for Penetration 25.

During performance of Step 2.1.5, test personnel noted that the identity of the refueling canal fill and drain valve (as specified in the procedure) differed from the identification tag attached to the component. Control room notification was made and the test sequence was stopped. Review of Piping and Instrumentation Drawing 40122A, Revision 13, showed that the component tag identification was correct and the surveillance test procedure incorrect. The team additionally noted that the procedurally misidentified valve actually existed on the piping and instrumentation drawing, but not as part of Penetration 25. Further test personnel review of the procedure revealed two additional procedural identification errors regarding components.

Procedure Modification Permit 2 was initiated on February 14, 1995, to correct the discrepancies and allow resumption of the test. The test was satisfactorily completed in accordance with the surveillance test procedure.

2.5.1.3 Boric Acid Makeup Pump Inservice Test

The team observed the tailboard and the subsequent performance of a quarterly inservice test of Unit 3 Boric Acid Makeup Pump S31218MP175 on February 16, 1995. Attachment 2 of Engineering Procedure SO23-V-3.4.10, "Quarterly Test of Boric Acid Makeup Pump S2(3)1218MP175," Revision 5 through TCN 5-9, provided the test methodology, including prerequisites, precautions, and acceptance criteria. The team verified that the measuring and test equipment had been calibrated and that the equipment was within the established calibration frequency.

The team noted during establishment of the required reference flow rate, that the test engineer found it necessary to tap on the flow indicator, 3FI-9269, because it appeared to be stuck. In addition to verifying that the indicator had been calibrated (December 28, 1994), and was within the annual calibration frequency, the team also verified that it met ASME Code requirements regarding acceptable instrument accuracy of +/- 2 percent of full scale. The team was informed that this particular flow indicator was classified as nonsafety related since it was not seismically qualified, and it was thus normally isolated from the system until its use was required for establishment of the reference flow rate for the quarterly inservice test. While the team did not identify any improper actions, the practice of annual calibration was viewed as questionable for a nonsafety-related instrument which was normally isolated from the system and had a potential for being out of tolerance at the next calibration due date; thus, possibly invalidating the results of at least three quarterly pump inservice tests.

The team observed that proper communication had been established with the control room, performance of the test was in accordance with the test procedure, test results were satisfactory, and the boric acid makeup system was restored to its proper configuration upon completion of the test.

2.5.1.4 Auxiliary Feedwater Pump Inservice Test

The team observed the tailboard and the subsequent performance of a monthly miniflow and vibration data acquisition inservice test of Unit 3 Auxiliary Feedwater Pump S3131805MP141 on February 15, 1995. Attachment 2 of Engineering Procedure SO23-V-3.4.1, "Test of Auxiliary Feedwater Pump S2(3)1305MP141," Revision 6 through TCN 6-13, provided the test methodology, including prerequisites, precautions, and acceptance criteria. The team verified that the measuring and test equipment had been calibrated and that the equipment was within the established calibration frequency. Communication with the control room was established and control room approval was obtained prior to test initiation. The test was performed in accordance with the test procedure and acceptable results were obtained.

During the tailboard, maintenance personnel discussed performance of maintenance (i.e., packing adjustment) to obtain proper leakoff rate of the outboard pump packing gland. This work had been scheduled and was described in the work scope of MO 95010814000. Subsequent to the performance of the monthly inservice test, the maintenance personnel prepared to initiate performance of the work scope and again iterated that the work was to be performed on the outboard pump packing gland. At this time, the team reviewed the MO and noted that the work scope was applicable only to the inboard pump packing gland. This was brought to the attention of the maintenance personnel, who immediately determined that the work could not be performed.

After discussing this with licensee representatives, the team was informed that the maintenance supervisor could have properly made the necessary work order adjustments and proceeded with the work. The team informed the licensee that, while this may have been a proper thing to do, the fact still remained that despite having the tailboard session, and despite having reviewed the MO, the maintenance crew was still prepared to incorrectly perform work on a portion of the pump that was not included in the work order. The team considered this to be an example of poor preparation and indicative of a lack of attention to detail.

2.5.1.5 Battery Charger 2B04 Capacity Test

The team observed portions of a Technical Specification required capacity test for Battery Charger 2D4. The objective of this test was to verify the charger was capable of delivering a minimum output current of 300 amps at a minimum voltage of 130 volts for at least 12 hours.

During the initial performance of the test on February 14, 1995, a technician, in violation of the procedure, changed the charger test console from the manual mode to the automatic mode. This caused a perturbation in the system that resulted in the voltage dropping to below 50 volts and a test failure. In response to the test failure, the licensee initiated Nonconformance Report 95020029 to document the test failure and to outline a troubleshooting strategy.

During subsequent troubleshooting, the licensee identified a problem with an input transformer of the battery charger. This transformer was replaced and the battery charger passed further testing. The 12-hour capacity test was completed on February 15, 1995.

The team noted that the cognizant engineer was present during most of the testing.

2.5.2 Surveillance Test Procedures

Surveillance test procedures were prepared, reviewed, approved, and revised in accordance with Procedure SO23-XV-3, "Surveillance Program Implementation," Revision 4 through TCN 4-1; Procedure SO123-VI-1,"Review/Approval/Cancellation Process for Orders, Procedures and Instructions," Revision 15; Procedure SO123-VI-0.9, "Author's Guide for the Preparation of Orders, Procedures and Instructions," Revision 4 through TCN 4-1; and Procedure SO123-VI-1.0.1, "Temporary Change Notices (TCNs)/ Editorial Corrections (ECs), Preparation, Review, Approval, Incorporation and Distribution," Revision 7. These procedures contained specific and general requirements for development of all procedures, including surveillance test procedures, and their revisions. The team reviewed these procedures and the surveillance test procedures that were observed being used during performance of the above noted surveillance tests. The procedure revision and review process was also discussed with licensee management and other personnel.

As noted above, problems with surveillance test procedures were identified during observation of local leak rate test activities. The team was informed that a transition was taking place with respect to organizational responsibility for performing surveillance tests, and that the errors were recently introduced into the procedures. The testing responsibility had been previously with the Nuclear Engineering organization, with support from Operations Division personnel and others, as required. However, this responsibility was now being transferred to the Operations Division. Due to differing needs, procedural style may vary between organizations. Thus, when responsibilities are transferred between organizations, procedural changes are likely to occur. Since errors had been identified, the team was concerned as to when the errors were introduced. If the errors were introduced recently and detected during the first attempt at performing the specific surveillance, this would clearly indicate a lack of verification during the review process. The team reviewed previous revisions to the affected surveillance procedures and found that the errors did not exist. The team established that the errors were introduced during the revision process involving TCNs.

The team reviewed the procedures that address the control of revisions and TCNs, and found them to be extremely detailed. The issue of procedure complexity and difficulty has been recognized by licensee management, and a procedure simplification effort was underway. In any event, the team could not ascertain, through review of administrative procedures and discussion with licensee management personnel, the existence of any administrative requirement which specified the use of a verification and validation process to assure the correctness of revisions or TCNs. The team considered this to be a programmatic weakness.

The team reviewed two surveillance procedures to verify the Technical Specification surveillance requirements were implemented. The selected procedures were Surveillance Operating Instruction SO23-3-3.12 ISS 2, "Integrated ESF System Refueling Test," TCN 11-1; and Surveillance Operating Instruction SO23-3-3.23.1, "Diesel Generator Refueling Interval Tests," TCN 7-22. The team also reviewed Procedure SO23-3-3.23 to determine if the cautions recommended in Design Calculation E4C-092, Revision 1, had been included.

2.5.2.1 Implementation of Technical Specification Surveillance Requirement 4.8.1.1.2.d.7 in Surveillance Operating Instruction SO23-3-3.12, "Integrated ESF System Refueling Test"

The team performed a limited review of Surveillance Operating Instruction SO23-3-3.12, "Integrated ESF System Refueling Test," and determined that diesel generator performance during loss of off-site power in conjunction with engineered safety feature test signals was being appropriately tested.

2.5.2.2 Implementation of Design Study Administrative Controls in Surveillance Operating Instruction SO23-3-3.23.1, "Diesel Generator Refueling Interval Tests"

In response to NRC concerns identified during the 1988 and 1989 safety system functional inspections, and in support of the design basis documentation effort, licensee personnel prepared new electrical system design calculations for SONGS, Units 2 and 3. In Calculations E4C-092, "Short Circuit Studies," Revision 0, and E4C-090, "Aux. System Voltage Regulation," Revision 0, licensee personnel noted the possibility of short circuit currents in excess of switchgear breaker ratings and the possibility of voltages less than 90 percent of rated voltage in some configurations. Licensee personnel identified that this unacceptable electrical system performance was possible during Modes 5 and 6, when the reserve auxiliary transformers were out of service and the unit auxiliary transformer was being used as the off-site power supply. In Revision 1 of the referenced calculations, electrical system performance was reanalyzed assuming administrative controls that were described in a December 16, 1991, letter entitled "Administrative Controls During Reserve Auxiliary Transformer Outages in Modes 5 and 6." Licensee personnel calculated that the electrical system would perform acceptably in all allowed configurations, if the referenced administrative controls were acceptably implemented. In the design calculation documents, licensee personnel recommended the imposition of these administrative controls to ensure acceptable electrical system performance.

The team determined that the administrative controls necessary to ensure acceptable electrical system performance were for the most part incorporated in appropriate plant instructions. However, Section 2.3.4 of Design Calculation E4C-092, "Short Circuit Studies," Revision 1, was not correctly incorporated into plant instructions. In Section 2.3.4, design personnel recommended that load restrictions be placed on diesel generator testing per the December 16, 1991, letter to ensure that possible electrical faults would not exceed the 4KV switchgear breaker ratings. The letter specified that diesel generator output be restricted to 500KVAR during Mode 5 or 6, when the reserve auxiliary transformers were out of service, and the unit auxiliary transformer was being used as the off-site power supply.

During this inspection, the team noted that diesel generator testing was scheduled to be performed in conflict with the administrative controls in the December 16, 1991, letter. The test was scheduled while Unit 2 was in Mode 5 with the reserve auxiliary transformers out of service. Off-site power was being supplied to Unit 2 from the unit auxiliary transformer. Further, the scheduled test, Surveillance Operating Instruction SO23-3-3.23.1, "Diesel Generator Refueling Interval Tests," included steps which suggested loading significantly in excess of the 500KVAR limit. While, the actual testing did not occur until after the reserve auxiliary transformers were returned to service, the team was concerned that licensee personnel had not incorporated the administrative controls which were assumed in Calculation E4C-092, "Short Circuit Studies," into Surveillance Operating Instruction SO23-3-3.23.1.

Licensee personnel informed the team that it was planned to update the relevant diesel generator test instructions. Licensee personnel also stated that, due to personnel error, the routine monthly diesel generator test was updated to include the administrative controls for Mode 5 or 6 in lieu of Surveillance Operating Instruction SO23-3-3.23.1. The team concluded that the licensee did not incorporate the administrative controls, which were assumed in Calculation E4C-092, into the correct surveillance operating instruction.

During staff discussions following the inspection, the Office of Nuclear Reactor Regulation technical staff questioned the licensee's use of a diesel generator loading limit to control the potential short circuit current. Most short circuit analyses are developed using an impedance model. In that type of calculation, diesel generator loading would not affect the diesel generator contribution to short circuit current. The contribution to short circuit current from a running diesel generator would be limited by subtransient reactance, which is a machine design characteristic which does not vary with load.

Further inspection is planned to determine the effect of limiting diesel generator loading on short circuit current and to determine whether the failure to promulgate administrative controls related to diesel generator loading during reserve auxiliary transformer outages in Modes 5 and 6 affected the design basis of the plant. This item is unresolved (361/9501-03; 362/9501-03).

2.5.2.3 Implementation of Technical Specification Surveillance Requirement 4.8.1.1.2.d.4 in Surveillance Operating Instruction SO23-3-3.23.1, "Diesel Generator Refueling Interval Tests"

The team performed a review of Surveillance Operating Instruction No. SO23-3-3.23.1, "Diesel Generator Refueling Interval Tests," and identified that diesel generator performance during loss of off-site power was not being fully tested. The team was concerned that the Technical Specification did not address the sequencing of auto-connected shutdown loads such as the auxiliary feedwater pumps, the component cooling water pumps, and the salt water cooling pumps. During the licensing process, a standard reference to "verifying the diesel energizes the auto-connected shutdown loads through the load sequencer" was removed from Technical Specification 4.8.1.1.2.d.4 because the electrical design which was installed at SONGS did not use a load sequencer. A control relay scheme was used in lieu of a load sequencer. A comparable verification of the capability of the diesel generators to energize the auto-connected shutdown loads using the control relays was not included. During the inspection, licensee personnel committed to review the background for the development of the current Technical Specification Surveillance Requirement 4.8.1.1.2.d.4 and to review the need for changing this surveillance requirement. Licensee personnel anticipated that this review would be completed by mid-April 1995.

The team and licensee personnel agreed that the pump controls for the auxiliary feedwater pumps, the component cooling water pumps and the salt water cooling pumps were designed so they would load sequence onto the emergency power buses differently during a loss of off-site power than during a loss of off-site power coincident with a safety injection actuation. The team requested licensee personnel to calculate the emergency diesel generator loading following a loss of off-site power, and compare it to the calculated loading which was predicted to occur during a loss of off-site power coincident with a safety injection. Licensee personnel stated a loss of off-site power would result in the loss of the condensate pumps, the loss of the main feedwater pumps, a main steam isolation, a shrink in the steam generator level, and a subsequent auxiliary feedwater pump start caused by low steam generator level. To do the analysis, licensee personnel assumed the auxiliary feedwater system would initiate promptly. Licensee personnel had not previously calculated emergency diesel generator loading during a loss of off-site power with the likely initiation of the auxiliary feedwater system due to predictable system interactions.

On February 23, 1995, the licensee personnel's preliminary analysis indicated that the initial step load during a loss of off-site power alone, assuming prompt auxiliary feedwater initiation, was potentially 50 percent larger than the step load which was previously calculated for a loss of off-site power with all engineered safety features actuated (approximately 2000KW versus 1260KW). The team was concerned that licensee personnel had not previously evaluated the capability of the emergency diesel generators to energize this larger initial step load. Licensee personnel performed additional analysis and determined that, during a loss of off-site power coincident with expected auto-connected shutdown loads, sufficient voltage and frequency were provided by the emergency diesel generators to start, accelerate, and supply the safety-related loads within the time requirements assumed in the plant safety analyses.

The preliminary analysis also indicated that, as a result of the potential increase in the size of the initial step load, the output voltage of the emergency diesel generators would briefly (less than 1 second) drop below the design basis value. The team was concerned that the momentary dip in voltage would adversely impact the control relay scheme for sequencing the pumps, and result in pumps being repeatedly started and stopped. Undervoltage control relays were used in the load sequencing control circuits to stop and restart the pumps. Licensee personnel stated that the undervoltage relays had a time delay of 2 seconds. As a result, licensee personnel predicted the undervoltage relays would not actuate during the momentary dip in voltage. Licensee personnel stated that the control relay scheme for sequencing the pumps would not be adversely affected by the increase in the size of the initial step load.

Prior to questioning by the team, licensee personnel only maintained a loading sequence calculation for a loss of off-site power coincident with actuation of all engineered safety features. That scenario was the most challenging sequence from a total loading perspective. However, the previously calculated initial step load was not as challenging as calculated in the preliminary analysis performed by licensee personnel of loss of off-site power, assuming prompt auxiliary feedwater pump actuation. The team was concerned that the lack of a conservative load sequencing analysis had likely resulted in inadequate prototype and preoperational test specifications.

On March 2, 1995, following discussions with the team, licensee personnel initiated Nonconformance Report 95030010 to document potentially nonconservative prototype testing. Licensee personnel determined that the prototype test specifications did not bound the initial step load which was calculated in the preliminary analysis of loss of off-site power, assuming prompt auxiliary feedwater pump actuation. Licensee personnel determined that the emergency diesel generators remained operable for both units, based on results of the dynamic voltage simulation, a review of past test results, and discussions with the vendors for the generator and the diesel. At the team's request, the licensee forwarded the preliminary analysis and available test data to the Office of Nuclear Reactor Regulation technical staff for review.

On March 9, 1995, the NRC staff evaluated the impact of this potential initial step load increase on the operability of the Unit 3 emergency diesel generators. The staff did not disagree with the licensee's conclusion that there were no short-term operability concerns with these diesels. The licensee based its conclusion on the following considerations: 1) licensee personnel performed analytical analyses which showed that the emergency diesel generators were capable of recovering from the increased initial step load within a short period of time, and that the components energized by the diesel generators would not be adversely affected by the short-term voltage drop; 2) while the prototype test data did not completely envelope all aspects of their preliminary estimate of the initial step load, the prototype test data provided by licensee personnel did show that the diesel generators were capable of coping with the estimated peak amperage loading; 3) licensee personnel contacted the vendors for both the diesel and the generator, and received confirmation from the vendors that the diesel generators could function under the postulated increased initial step load; and 4) licensee personnel noted that due to uncertainties in the timing associated with starting the auto-connected shutdown loads, it is unlikely that the actual initial load step load following a loss of off-site power would be as large as the postulated initial step load.

While the staff did not have a short-term operability concern with the diesel generators at SONGS, the long-term resolution of diesel generator operability would require that licensee personnel either perform the tests, required by their licensing basis, which bounded the most conservative loading identified in the final diesel loading analysis, or modify the control logic for sequencing the pumps onto the 4.16kV emergency bus following loss of off-site power to be consistent with the original loading sequence assumptions.

During the inspection, licensee personnel made the following commitments:

- They planned to complete the final accept-as-is disposition of the Unit 3 nonconformance report by March 19, 1995. This analysis would provide the basis for permitting operation of Unit 3 through the end of Cycle 7.

- They planned to complete design changes to delay starting of the component cooling water pump and auxiliary feedwater pumps for a loss of voltage signal without a safety injection actuation signal. The modifications for the Unit 2 circuitry will be completely installed and tested prior to the completion of the current Unit 2 outage. The modifications for the Unit 3 circuitry for the component cooling water pump will be installed and tested prior to the completion of the current Unit 2 outage. The modifications for the Unit 3 circuitry for the auxiliary feedwater pump will be installed and tested prior to the completion of the Unit 3 refueling outage that is scheduled to begin July of 1995.

- Licensee personnel planned to review the plant design changes to determine if any changes have been improperly made to the starting circuitry since initial licensing. They anticipated that this review will be completed by mid-April 1995.

- Licensee personnel planned to review the licensing basis and the original tests to determine if the diesel generators satisfied the original qualification requirements with the existing plant configuration (i.e., prior to the modifications described above). They anticipated that this review will be completed by mid-April 1995.

The team noted that the saltwater cooling pump start logic following a loss of off-site power is initiated by a control relay contact from the component cooling water pump control circuit. As a result, the modification commitments made by the licensee should ensure the pump loading sequence is consistent with the original loading sequence assumptions for all auto-connected shutdown loads.

Reviews of the design controls related to this issue, the finalized analysis of diesel performance under all design basis conditions, and the evaluation by licensee personnel of the impact of the predicted voltage dip on plant components are considered an unresolved item (361/9501-03; 362/9501-03), which is discussed above in 2.5.2.2.

2.6 Modification Control

The purpose of this part of the inspection was to evaluate the licensee's recorded plant modification activities to assure that procedural controls and responsibilities had been established and implemented.

The principal procedures governing these activities were SO123-XXIV-10.16, "Development, Review, Approval and Release of Conceptual Engineering

Packages (CEPs) and Design Change Packages (DCPs), SONGS 1, 2&3," Revision 1 through Procedure Change Notice 1-1 dated May 11, 1994; SO123-XXIV-10.9, "Design Process Flow and Controls, SONGS Units 1, 2&3," Revision 1 through Procedure Change Notice 1-1 dated June 10, 1994; and SO123-XXIV-10.21, "Field Change Notice (FCN) and Field Interim Design Change Notice (FIDCN)," Revision 4 through Procedure Change Notice 4-2, dated December 9, 1994.

The team noted that Procedure Change Notice 1-1 modified Procedure No. SO123-XXIV-10.9 by creating a distinction in program controls for safety-related, important-to-safety, and nonsafety-related applications. Whereas the procedure pertained to all design work, regardless of safety class within and along the boundary of the plant protected area, the procedure change notice provided a more realistic approach towards the control of structures, systems, and components, without jeopardizing or compromising safety. This was accomplished by defining the structures, systems, and components that would be under the jurisdiction of this procedure (i.e., safety-related, important-to-safety as defined in the Topical Quality Assurance Manual and the licensing basis documents, and specifically identified nonsafety-related structures, systems, and components). Processes for design modifications to other nonsafety-related structures, systems, or components were left to the discretion of the engineering discipline; however, if an alternative process was chosen, the procedure required it to be documented on Form 26-521, "Non-Safety-Related Design Control Form."

The licensee's inclusion of important-to-safety and specified nonsafety-related structures, systems, and components, in the design control program was considered commendable by the team.

The team was provided a nuclear construction work planning document dated January 27, 1995, which identified work requests associated with design change packages and field change notices that were scheduled to be implemented during the Unit 2 Cycle 8 refueling outage. From the list of approximately 21 jobs, the team selected the following four design packages for review: Design Change Package 6984, "Ex-core Neutron Detector Replacement," the only safety-related package in the list; Work Request 2061, which was initiated to implement several field change notices associated with component cooling water mini-flow valves; Work Request 2063, which was initiated to implement several field change notices associated with removal and replacement of the Unit 2 steam generator feedwater distribution boxes with a new design; and Design Change Package 7032, "Health Physics Computer & Meteorological Instrumentation Modifications."

The team's review of these packages was directed towards the licensee's administrative controls and the implementation of procedurally prescribed actions which were considered necessary to ensure the adequacy of the packages. In particular, the team determined that the following actions had been performed and documented: description and reason for the change; impact of the change on licensee programs, with assessment and notification to the affected program management; 10 CFR 50.59 safety evaluation, as applicable; licensing and design document impact; and establishment of post-work testing and acceptance criteria.

The team did not identify any instances where the licensee had faile' :- accomplish the prescribed actions and, in general, considered the ' .see's efforts in this area to be very well done.

2.7 Troubleshooting

The team reviewed various MOs and procedures that controlled specific troubleshooting activities, interviewed pertinent personnel, and reviewed licensee event reports for the last 5 years.

The team noted that the licensee did not have a specific procedure that outlined troubleshooting guidelines, but controlled troubleshooting by the specific MO generated or by procedures that incorporated troubleshooting for specific components. Based on the above inspection activities, the team concluded that, overall, troubleshooting was properly controlled and generally effective in identifying the cause of faults.

The team did note two instances in the last 5 years during which troubleshooting was not controlled properly. This resulted, in one case, in a violation of Technical Specifications (Licensee Event Report 2-93-011), and in the other case an inadvertent toxic gas isolation system actuation (Licensee Event Report 2-91-006). Based on the low number of instances for a 5-year period, as compared to the amount of troubleshooting that normally occurred, the team considered these problems to be isolated instances and not indicative of programmatic problems.

2.8 Component Failure History

The team reviewed a licensee component failure analysis report generated July 22, 1994, for Units 2 and 3. This report covered an 18-month period from October 1992 through March 1994. The team also reviewed the engineering evaluation for this component failure analysis report, in addition to a sample of the status of actions the licensee had taken, or was planning to take. The team also interviewed cognizant personnel and reviewed various MOs, nonconformance reports, and one calculation.

The team noted that the component failure analysis report was produced periodically and used to analyze licensee component failures in comparison to the rest of the industry. The report also grouped these failures in various ways to identify trends. Specifically, licensee component failures were compared to Institute of Nuclear Power Operations Nuclear Plant Reliability Data System data to identify licensee components that were failing at rates greater than typical in the industry; and failures were also grouped by system, manufacturer, and generic type (i.e., controller, heat exchanger, etc.) to identify trends. Multiple failures were also identified. The component failure analysis report was then evaluated by Station Technical and actions were assigned to reduce failure rates for those components above the Nuclear Plant Reliability Data System typical value, in cases where the licensee considered this action appropriate.

Overall, the team concluded that this depth of failure analysis was a strength in the engineering organization and, from review of trending information furnished by the licensee, had contributed to significant, progressive improvements in component reliability.

The team noted that, of six evaluations identified as required as a result of the current component failure analysis report, none were completed at the end of this inspection report period. The team did review four evaluations and the subsequent actions taken as a result of previous reports that were provided by the licensee. Of these four, cognizant engineers indicated that three had been previously identified by means other than the component failure analysis report, and the fourth was identified because of the report. Actions taken included: replacing Rosemount temperature detectors (when they failed or were scheduled for replacement) with Weed temperature detectors, because of the high failure rate of the Rosemount detectors; and a design change to bypass a test push button for the excore nuclear instrumentation that was determined not to be necessary for operation or surveillance and had a high failure rate. The strictly component failure analysis report identified that failure involved the reactor coolant pump speed sensing circuitry, and resulted in changes to maintenance and consideration of changing to another vendor for supply of pulse transmitters.

Based on the above, the team concluded that the licensee was taking action as a result of the component failure analysis report and was also identifying abnormal failure rates by means other than the report.

After reviewing the multiple failures section of the report, the team noted that the Series E7000 Agastat time delay relay for the Unit 3 Motor-Driven Auxiliary Feedwater Pump 3MP141 was tested during each refueling outage and had been out of the time specification (29.0 to 30.5 seconds) during the Cycle 7 test. The initial test showed a 37-second response, the relay was replaced, and then tested satisfactory. The relay was tested 22 days later and again failed the test at 31.3 seconds. The relay was replaced again and tested satisfactory. The team reviewed maintenance data for this particular relay and noted that this relay location had failed the timed test during the Cycle 5 refueling outage in June 1990 and again during the Cycle 6 refueling outage in March 1992. The relay was recalibrated in both instances in response to these failures. The team also reviewed Information Notice 92-77, "Questionable Selection and Review to Determine Suitability of Electropneumatic Relays for Certain Applications," which warned of problems with the accuracy of these Series 7000 Agastat relays, and described how other licensees had replaced the relays with more accurate solid-state relays. The team also reviewed Nonconformance Report 93070031, which the licensee had generated as a result of Information Notice 92-77. The team noted that the licensee took no action to change these relays to a more accurate model. As described in the nonconformance report, the licensee determined that the potential overlap of emergency diesel generator loads caused by inaccurate Agastat relays was evaluated, and that the performance of the emergency diesel generator and the emergency systems would not be impaired. The team reviewed the analysis on emergency diesel generator loading, which was documented in Design Calculation E4C-082.

The team requested and received the results from the last 5 years of integrated engineered safeguards features surveillance testing and loss of voltage surveillance testing, as they pertained to Agastat relays. Review of this data (and any licensee assessments performed in response), plus assessment of the licensee handling of Agastat relay time response deficiencies that is discussed above, are considered an inspection followup item (361/9501-04; 362/9501-04).

2.9 Balance of Plant

The team reviewed records of maintenance that was performed in the last 5 years on the condensate, feed, main circulating, and heater drain pumps in both units; observed maintenance and design changes in progress for the Unit 2 secondary plant; and reviewed calibration data for heater drain tank level controllers, main circulating seal-flow gauges, and gland-sealing steam controllers in both units. The team also performed walkdowns of the secondary plant in both units; reviewed aspects of the flow-accelerated corrosion program and observed measurement of pipe thickness in progress; reviewed pertinent procedures and vendor manuals; interviewed personnel; and reviewed aspects of the work authorization process.

The team concluded that maintenance was being scheduled and performed on secondary equipment to reasonably prevent challenges to primary systems. Overall, performance and scheduling of maintenance for the secondary plants in both units were considered good. The team noted that maintenance in the secondary plant was controlled using the same programs as maintenance on safety-related systems. The team did observe degrading material conditions in the secondary plants of both units (i.e., surface rust due to the marine environment), but noted that the licensee had a program in place to preserve the secondary plant and that there did not appear to be substantial degradation of the primary flowpath piping and valves.

Based on inspection of records for Unit 2 and observation of pipe wall thickness measurements and pipe replacement in progress, the team considered the flow-accelerated corrosion program implementation to be a strength.

The team noted the following two areas where improvements could be made in maintenance of secondary equipment, but did not consider these areas as significant:

1. Sometimes the licensee potentially sacrificed component life due to conditions that were not optimal for various equipment. In some instances, this was a conscious decision. Examples noted by the team were as follows:

   - Licensee personnel noted cavitation on Unit 2 Condensate Pump 2P053 during August 1993, but maintenance was deferred until the Unit 2 Cycle 8 refueling outage which began in February 1995. The applicable vendor recommendation was, however, to not allow the pump to cavitate. The team ascertained that the pump was overhauled during the Unit 2 Cycle 7 outage, with cavitation noted on return to power from the outage. This indicated to the team that poor performance of the overhaul may have been the cause of the cavitation. The team recognized that licensee personnel could not, however, perform maintenance to resolve the pump cavitation problem with the unit in Mode 1.

- On February 8, 1995, the team noted zero pump seal leakoff flow from Unit 3 Main Circulating Water Pump 3P118 and pump seal injection flow to two main circulating water pumps (i.e., Unit 3, 3P115; Unit 2, 2P115) that was less than the vendor recommendation. Most seal injection flow indicators were difficult to read due to condensation and degradation. The vendor recommended maintaining leakoff from the pump seals in order to avoid packing damage and damage to the pump shaft. The vendor also recommended in the vendor technical manual for the pumps to maintain at least 8 gpm of seal injection in order to cool and lubricate the pump seals. Actual seal injection flow to the two pumps mentioned above was 7.5 gpm. The team concluded that the licensee could have adjusted packing to provide seal leakoff, as well as increased seal injection by increasing service water flow to the pump. The cognizant engineer and mechanical maintenance manager informed the team that possible minor shaft damage (scoring) and packing overheating was acceptable when weighed against perceived difficulties in adjusting seal leakoff and injection flow.

- The team identified that the licensee procedure for overhauling main circulating water pumps, Procedure SO23-I-5.58, "Circulating Water Pump Overhaul," Revision 4, used an assumption for a dimension that the vendor recommended to be measured. Step 6.7.24 used a value of 0.008 inches as the proper stretch for the bolts used to secure the suction bell to the pump casing flange. The vendor technical manual for the pump recommended that the thickness of the suction head-casing flange be measured and then a graph be used to determine proper elongation. As a result of the concern, the licensee was evaluating changing this procedure.

2. The team noted that certain work plans that were provided to the craft for maintenance and design changes were not optimal, and could not be strictly followed. Examples are as follows:

   - On February 2, 1995, the team observed work performed per Construction Work Order 94121928, which pertained to a design change to the Unit 2 liquid radioactive waste system. This construction work order contained inspection requirements after a step to install a pipe spool (Step 4), and inspection requirements after a step to weld in a pipe tee (Step 5). The inspection requirements were not performed after each operation (i.e., they were performed for both steps simultaneously at a later time). Most of the inspection steps were considered to be not applicable by the craft, with only 4 out of 18 quality control inspector signature blocks to be performed. The team considered the above to be indicative of a generic approach to inspection planning, rather than establishing inspection requirements that were specific to a job. The sequence of inspections was not followed because the craft did not consider the sequence as optimal.

- During the week of February 6, 1995, Unit 2 Main Feed Pump 2P063 was being overhauled with the intent of replacing the rotating element. MO 94051423, which was the repetitive MO that was used for pump overhaul, was noted as being used to control the pump work. No specific steps had been inserted in the repetitive MO in regard to replacement of the rotating element, and it was required that the craft use judgement as to both what "as-found" data to record and what inspections to perform on the new rotating element. The MO referenced Procedure SO23-I-5.88, "Turbine Driven Pump Overhaul," TCN 2-8, to control the overhaul. The team noted that this procedure also contained a step that required skipping the next step, thus precluding its accomplishment (i.e., Step 6.3.4 required going to Step 6.3.6 which precluded performance of the bearing housing alignment specified in Step 6.3.5). The team also noted that the work was also being done simultaneously with the feed pump turbine overhaul, which was being conducted under a separate MO. This required coordination of supervisors because the two procedures overlapped. As a result of the concern, the licensee was evaluating changing the pump overhaul procedure.

- During the week of February 6, 1995, the licensee was replacing a pipe under MO 94090692 due to flow-accelerated corrosion. The MO for replacement of the pipe stipulated setting a firewatch prior to cutting the pipe. The team noted the pipe cut was not "hot work" and that no firewatch was posted. During observation of the pipe cut, the team mentioned this to the field engineer and the field engineer changed the work order so as to make it match the work as performed.

The overall conclusion of the team was that maintenance in the balance-of-plant area was generally good, and that the flow-accelerated corrosion program implementation appeared to be a strength. The team also concluded that optimizing component lifetime and developing optimal work plans were areas for improvement, as noted above.

3 RADIATION PROTECTION (83729, 83750)

3.1 Planning and Preparation

The team reviewed the radiation protection organization's preparation for the refueling outage and determined that sufficient time had been allowed by the licensee's schedule for radiation protection personnel to review the proposed work activities and to incorporate radiation dose saving techniques in order to maintain radiation exposures as low as reasonably achievable. Team members observed that sufficient numbers of protective clothing, consumable supplies, and radiological monitoring equipment were available for the outage. Based on observations of maintenance activities, an appropriate number of contract radiation protection technicians were used to supplement the permanent staff.

Pre-job briefings presented before the reactor coolant pump seal work and before steam generator nozzle dam installation provided suitable guidance for conducting work in radiation areas. Ample opportunity was given the crafts personnel to ask questions and to ensure that they knew their assignments and responsibilities. A team member noted, during a meeting of radiation protection personnel following the second prejob briefing, that some radiation protection technicians were confused by the wording of protective clothing requirements in the health physics work control plan for primary side steam generator work. The requirements involved the number of layers of protective clothing required for partial entry into the primary manway. Although the technicians at first found the wording to be confusing, the issue was discussed and resolved satisfactorily.

3.2 Exposure Control

The team reviewed examples of radiation exposure permits and concluded that some contained superfluous and confusing language. For example, the section entitled, "General Rad Conditions Summary" did not summarize the actual general radiological conditions in the work areas. Instead, it listed the conditions under which the radiation exposure permit was applicable. Another section entitled, "Adhere To The Following Postings," listed areas in which the permit was not applicable. The section entitled, "Special Instructions," was easier understood and provided good guidance to radiation workers.

Access controls to the radiological controlled area were good. Workers identification badges carried unique bar codes which, when scanned, resulted in the automatic review of the radiation workers qualifications, ensuring that any required training or briefing had been received by the worker. A sufficient number of personnel were assigned to the access control area to ensure that entries were made properly and that the required dosimetry was worn by the workers. Additional personnel were stationed at the containment entrance to ensure entry requirements were met. A room outside the personnel hatch was used as a staging area for workers waiting to enter the containment building to perform maintenance activities.

The team reviewed the radiation protection organization's response to changing radiological conditions in portions of the plant caused by the commencement of shutdown cooling. Areas in the penetration and safety equipment buildings were properly posted and controlled. Radiation surveys were performed routinely to identify high radiation area boundaries. During a review of high radiation areas, a team member noted that there was inconsistency in the design of entry doors into areas which could have radiation levels greater than 1000 millirems per hour. For example, all of the doors discussed here were constructed of steel bars covered with expanded metal, but the northeast door to Room 111 of the penetration building was also equipped with shielding to prevent tampering with the crash bar from outside, thus preventing defeat of the locking mechanism. The "south central" door to Room 111 and the door of the regenerative heat exchanger room in the containment building did not have such shielding. However, all doors were adequate to prevent inadvertent entry into the areas (thus meeting the guidance of Regulatory Guide 8.38).

The team observed work activities within containment and noted that job coverages by radiation protection personnel during reactor coolant pump work and steam generator diaphragm and manway removal were good. Additional oversight was provided by radiation protection personnel at the 45 ft. control point within the containment building through the use of cameras mounted near the work areas. Electronic dosimetry supplemented thermoluminescent dosimetry and was used to track radiation doses. Radiation dose results were updated and reviewed daily. Workers in high noise areas were required to use sound amplification devices attached to the electronic dosimetry.

Licensee personnel projected that work on the reactor coolant pump would result in 9.5 to 10 person-rems. The actual dose accrual was approximately 6.5 to 7 person-rems. However, the actual dose of approximately 7 person-rems that was accrued for nozzle dam installation in the steam generators exceeded the licensee's projected dose of 5.5 person-rems. Licensee personnel stated that they had experienced trouble with the nozzle dam installation and that it was the first time nozzle dams of this particular design had been installed in Unit 2 by nonvendor personnel. Another work activity resulting in unforeseen radiation exposure was the installation of a bladder in the secondary side of the steam generators. A design problem prevented the completion of installation of the new bladders. Installation was halted and a bladder of the old design, as used in the Unit 3 outage, was installed. The additional work resulted in approximately an additional 3 person-rems. Licensee personnel stated that this would be included as an outage lesson learned.

3.3 Surveying and Monitoring

Radiation instrumentation in use was calibrated and performance tested as required. Results of radiation surveys were not always documented in a timely manner. As an example, a radiation protection technician was assigned to accompany two team members into the shutdown cooling tunnel. A job coverage survey was performed at 10:00 a.m. on February 13, 1995, but not documented until 3:30 p.m. of the same day. Documentation was made following a request by a team member to see the results of the survey. The final survey results included radiation readings at 13 different locations. According to the team members accompanied by the radiation protection technician, the technician took no notes and apparently relied only on memory. It was determined that, in this example, the technician had been assigned to do only one survey that day. Health Physics Procedure SO123-VII-20.9, "Radiological Surveys," Revision 0, contained no guidance related to the timely documentation of radiation survey results. When briefed on this matter, the radiation protection manager stated that, by documenting the survey results within the work shift, the technician had met the manager's expectations. However, the radiation protection manager added that the procedure would be evaluated to determine if additional guidance or stronger controls were needed to ensure that survey information was correctly recorded.

3.4 Radioactive Materials and Contamination Controls

Good practice was noted when technicians were observed surveying and releasing material from the radiological controlled area. Ample supplies of modesty clothing were available. Radiation workers consistently followed established procedures for exiting the radiological controlled area. A sufficient number of personnel were assigned to oversee workers leaving the containment building. Through the early part of the outage, used protective clothing and radioactive trash were removed in a timely manner.

4 INSERVICE INSPECTION (73753)

The objective of this part of the inspection was to determine whether: (a) the performance of inservice inspection examinations and any repair or replacement of Class 1, 2, and 3 pressure retaining components were accomplished in accordance with the applicable ASME Code, and (b) the licensee had appropriately satisfied industry initiatives. This part of the inspection was performed during February 20-24, 1995.

4.1 Inservice Inspection Program

Order SO123-IN-1, "Inservice Inspection Program," Revision 3 through TCN 3-1, defined the policy, licensing commitment requirements, and management responsibilities for the inservice inspection program in order to meet the requirements of the ASME Code, Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components." Procedure SO123-XVII-1, "Inservice Inspection Program Implementation," Revision 6 through TCN 6-6, provided the methodology for implementing the inservice inspection program. Procedure SO123-XVII-1.1, "Inservice Inspection Program Maintenance," Revision 2 through TCN 2-2, defined the method by which the SONGS Units 1, 2, and 3 inservice inspection program plans, as required by 10 CFR 50.55a, Technical Specifications, and Order SO123-IN-1, would be updated and revised to incorporate changes in plant configuration, inspection schedules, and ASME Code and regulatory requirements.

The inservice inspection program contained Document 90063, "Second 10 Year Inservice Inspection Program Plan, San Onofre Nuclear Generating Station, Unit 2," Revision 1. This document identified all ASME Code Class 1, 2, and 3 components and component supports, and provided all information necessary for qualified examiners to prepare detailed examination sheets for performing the various required examinations. The inservice inspection program was submitted to the NRC under cover letter dated October 4, 1993, and represented the second 10-year inspection interval. The program became effective on April 1, 1994, and incorporated the requirements of the 1989 Edition of the ASME Code with no addenda. Its initial use was scheduled for the current refueling outage (i.e., Unit 2 Cycle 8). Additional information was requested and provided in ensuing correspondence between NRC and the licensee. The last available correspondence was a letter from the licensee dated January 13, 1995, that responded to an NRC letter dated November 14, 1994, in which additional information was requested for eight items. The licensee addressed the eight items, but final NRC approval had not yet been received.

The inspector briefly reviewed the SONGS Unit 2 inservice inspection summary report dated November 8, 1993, which concluded the first 10-year inspection interval. This document was compiled following the Unit 2 Cycle 7 refueling outage, and was submitted to NRC under cover letter dated November 8, 1993. It identified and statused all tests and examinations scheduled and completed during the first 10-year inspection interval. The inspector did not verify the accuracy of the summary report.

4.2 Observation of Nondestructive Examinations

The performance of inservice examinations was authorized and controlled by construction work orders; one for inside containment and one for outside containment. The inspector observed the following weld examinations: one magnetic particle examination on February 23, 1995; four liquid penetrant examinations on February 22, 1995; and one ultrasonic examination on February 23, 1995. All of these welds were in components that were located inside containment, and were identified by zone numbers in the inservice inspection program plan and Construction Work Order 94082504000. The work order provided the prerequisite steps and precautions, and served as a signoff to show that each examination had been performed. However, in order for the signoff to occur, a corresponding acceptable examination report had to be available to demonstrate performance, completion, and acceptance of the weld examination.

The observed magnetic particle examination was performed on the steam generator feedwater nozzle to extension weld, Weld 02-043-043, on Steam Generator 2-ME-089 (Zone 43). The examiner was properly certified and used qualified Procedure SO23-XXVII-20.47, Revision 0 (see Section 4.4 below). The examiner verified the yoke-lifting capacity and established the yoke leg spacing at six inches. Upon successful completion of the examination, the examiner documented the results of the examination in Examination Report 295-08IMT-002.

The four observed liquid penetrant examinations were performed on safety injection piping welds (i.e., Welds 02-020-047 and 02-020-063, Zone 20; and Welds 02-073-072A and 02-073-072B; Zone 73). The examiners were properly certified and used qualified Procedure SO23-XXVII-20.48, Revision 0. The inspector verified that the examiners checked component temperature, cleaned the surface of the welds, properly applied penetrant materials, and allowed the appropriate dwell times before examining the welds. Upon successful completion of the examinations, the examiners documented the results in Examination Reports 295-08IPT-057, 055, and 056, respectively. The inspector also verified by review of the applicable certifications, that the penetrant materials met ASME code requirements regarding halogen and sulfur content.

The observed ultrasonic examination was performed on the feedwater nozzle weld, Weld 02-043-043, of Steam Generator 2-ME-089 (Zone 43). The examiners were properly certified and used qualified Procedure SO23-XXVII-20.54, Revision 0. The inspector verified that the examiners checked surface temperature and properly cleaned the area to be examined. The examination of the circumferential weld was conducted in two directions, perpendicular and parallel to the weld axis, using a 45°, 2.25 MHZ shear wave transducer. The examiners also performed a calibration check at the beginning and end of the examination. Upon successful completion of the examination, the examiners documented the results in Examination Report 295-08IUT-097. Since the licensee required that all indications, regardless of size, be documented, the examiners documented the existence of four nonrecordable indications (i.e., less than 20 percent of the distance amplitude correction curve). These nonrecordable indications were verified by review of the construction radiographs to be acceptable slag indications.

Before the ultrasonic examination was conducted, the inspector observed the system calibration which included both axial and circumferential scans. The transducer selection, sensitivity calibration, and construction of the distance amplitude correction curve were performed in accordance with Procedure SO23-XXVII-20.54. The inspector also verified, by review of the certified material test report, that the correct calibration block was used (i.e., similar to the component to be examined in terms of material, diameter, and wall thickness). The examiners documented the system calibration results on Ultrasonic Calibration Report JLD-030.

4.3 Personnel Qualifications and Certifications

The inspector was informed that the licensee had contracted with Lambert-MacGill-Thomas, Inc., to provide nondestructive examination personnel, equipment, and services, in order to perform the inservice inspections scheduled for the Unit 2 Cycle 8 refueling outage. The scope of this effort was defined in the Technical and Quality Requirements section of Purchase Order 6M284901 dated August 4, 1994.

The initial inservice inspections were performed during the week of February 20, 1995, by three Lambert-MacGill-Thomas examiners, one of whom was the designated contractor supervisor. The inspector was informed that eight contractor examiners were expected to be used during the inservice inspection effort. Additional contractor examiners arrived onsite at the end of the week; however, since they did not perform any examinations, the inspector did not review their certification records.

The inspector reviewed the qualification files of the three nondestructive examination personnel who performed the observed examinations. The files contained certifications for the examination methods that the inspector observed. The contractor supervisor was certified as a Level III examiner in all methods except radiography; one individual was certified as a Level III examiner for magnetic particle and liquid penetrant examinations and as a Level II examiner for ultrasonic examinations; while the third individual was certified as a Level II examiner for liquid penetrant and ultrasonic examinations. The records showed that they had been certified in accordance with American Society of Nondestructive Testing Recommended Practice SNT-TC-1A, 1984. Since the licensee had revised its inservice inspection program to meet the 1989 Edition of the ASME Code, new requirements regarding Level III ultrasonic examiners became mandatory. These requirements are described in the ASME Code, Section XI, Appendix VII, "Qualification of Nondestructive Examination Personnel for Ultrasonic Examination." The inspector verified that the contractor supervisor, who was designated as the ultrasonic Level III examiner, had been qualified in accordance with mandatory Appendix VII requirements. In addition, the inspector verified that each of the examiners had received the ASME code-required annual near distance acuity and color vision examinations.

4.4 Inservice Inspection Procedures Review

The inspector reviewed the nondestructive examination procedures used during the performance of the observed examinations, to verify that they were consistent with the requirements of the 1989 Edition of the ASME Code. These included: Liquid Penetrant Procedure SO23-XXVII-20.48, Revision 0; Magnetic Particle Examination Procedure SO23-XXVII-20.47, Revision 0; and Ultrasonic Examination of Nuclear Coolant System Ferritic Piping Procedure No. SO23-XXVII-20.54, Revision 0. These procedures were in a Lambert-MacGill-Thomas, Inc., procedural format, but assigned a SONGS procedure identification number. The inspector verified that the procedures had been reviewed and approved by the appropriate licensee personnel in the Nuclear Services Department, Site Technical Services Division, and by the authorized nuclear inservice inspector.

The procedures were found to be well written and contained sufficient detail and instructions to perform the intended examinations.

4.5 Section XI Repair and Replacement

The inspector was informed that ASME Code Section XI replacement work (i.e., the removal and replacement of main feedwater piping and elbows) had been scheduled for this outage. Construction Work Orders 94111649000 and 94111654000 authorized and provided the controls for removing and replacing piping Subassemblies 2-FW-189-6 and 2-FW-190-6 for Steam Generators 2-ME-088 and 2-ME-089, respectively.

Discussion with licensee representatives resulted in the determination that the piping subassemblies had already been removed, the new piping subassemblies had been fabricated (i.e., Weld BG in Subassembly 2-FW-189-6 and Weld BK in Subassembly 2-FW-190-6), and radiography of the welds had been performed. The welding was performed during February 11-13, 1995, by Bechtel Power Corporation, and the radiography was performed on February 19, 1995, by licensee nondestructive examination personnel. The inspector requested the radiographic examination procedure, technique sheet, film interpretation data report (reader sheet), and the radiographic film associated with Welds BG and BK.

Procedure NDEP-RT-002, "Radiographic Examination," Revision 2, had been reviewed and approved by the appropriate licensee personnel, and by the authorized nuclear inservice inspector. The procedure provided detailed information and guidance to allow qualified nondestructive examination personnel to perform the specified radiographic examination. Acceptance criteria were clearly identified, either directly or by reference to the appropriate ASME Code appendix and section.

The radiographic examination technique sheet, 2RT-014-95, page 2 of 2 dated February 19, 1995, provided detailed information regarding the exposure arrangement and technique. The recorded information complied with the requirements of Procedure NDEP-RT-002. The inspector reviewed the film interpretation data report, 2RT-014-95, page 1 of 2 dated February 19, 1995, and compared the recorded results to the radiographic film packages. The results documented on the data report coincided with what could be observed on the radiographic film. The inspector also verified film and penetrameter density, and geometric unsharpness.

The inspector also reviewed the Bechtel welding procedure specification, procedure qualification records, and the field welding checklist which was used to document the actual welding conditions and parameters. Welding Procedure Specification P1-AT-Lh(CVN), Revision 0, was a multi-process welding procedure (i.e., manual gas tungsten arc and shielded metal arc welding processes) for carbon steel materials with stipulated notch toughness properties. Since System Design Specification DS-1305 required the pipe and elbows to be manufactured from material that had been Charpy-V impact tested, and with a lowest service temperature of +40°F as defined by Section III of the ASME Code, this welding procedure specification was applicable. The welding procedure specification had been qualified for several different applications by the following procedure qualification records: PQR 695, PQR 892, PQR 1043, and PQR 1044. For this particular work, the applicable procedure qualification record was PQR 892 dated March 28, 1984. The inspector noted that the welding procedure specification permitted a maximum interpass temperature of 225°F for the gas tungsten arc welding process and 600°F for the shielded metal arc welding process, while the procedure qualification record, PQR 892, showed a recorded maximum interpass temperature of 450°F for both welding processes.

Paragraph QW-200.1 of Article II in Section IX of the ASME Code requires welding procedure specifications to describe all of the essential, nonessential, and, when required, supplementary essential variables for each welding process used in the welding procedure specification. Supplementary essential variables are invoked whenever welding of materials having specified notch toughness properties occurs. QW-200 further stipulates that changes in essential or required supplementary essential variables require requalification of the welding procedure specification (i.e., new or additional procedure qualification records to support the change in essential of supplementary essential variables). The inspector's review of the welding variables tables for the shielded metal arc and gas tungsten metal arc welding processes showed that interpass temperature is a supplementary essential variable (QW-406.3). Paragraph QW-406.3 requires welding procedure specification requalification if there is an increase of more than 100°F above the maximum interpass temperature recorded on the supporting procedure qualification record, unless the welding procedure specification is qualified with a postweld heat treatment above the upper transformation temperature, or when an austenitic material is solution annealed after welding. Neither of these conditions were applicable.

The permitted use in the welding procedure specification of a maximum interpass temperature of 600°F for the shielded metal arc welding process exceeded the allowed 100°F increase over the qualified interpass temperature specified in PQR 892, and is a violation of 10 CFR 50, Appendix B, Criterion IX (361/9501-05).

The inspector also noted that the Bechtel field welding checklist (Job 22701), which was used to record the specified, pertinent information for this welding activity, stated "N/R" (i.e., not required) under the requirements for interpass temperature. This resulted in interpass temperature not being measured or recorded during welding of the replacement piping subassemblies. The actual interpass temperatures that occurred during welding are thus unknown. The failure to appropriately control interpass temperature is a violation of 10 CFR 50, Appendix B, Criterion IX, and is considered a second example of Violation 361/9501-05.

The inspector informed licensee management that a technical concern existed regarding the potential for degradation of material toughness properties if elevated interpass temperatures were used. The contractor's use of an inadequately qualified welding procedure specification, coupled with a failure to assure conformance to a maximum interpass temperature limit during welding of the feedwater piping subassemblies, were also considered an indicator of inadequate licensee review and oversight of contractor welding activities.

ATTACHMENT 1

PERSONS CONTACTED AND EXIT MEETING

1 PERSONS CONTACTED

1.1 Licensee Personnel

T. Adler, General Supervisor, Health Physics Operations
L. Bareng, Production Coordinator
#R. Berkshire, Supervisor, Electrical, Nuclear Engineering Design Organization
H. Bickford, Program Supervisor, Work It Now
J. Blake, Cognizant Engineer, Boric Acid Makeup System
++D. Breig, Manager, Station Technical
D. Brown, Maintenance Specialist
*J. Clark, Manager, Chemistry
*J. Cronk, Superintendent, Plant Maintenance
T. Elkins, Supervisor, Nuclear Construction
*D. Farnsworth, Outage Manager, Unit 3
++J. Fee, Manager, Maintenance
*J. Garza, Supervisor, Unit 3 Equipment Control
*S. Genschaw, Superintendent, Plant Maintenance
++G. Gibson, Supervisor, Onsite Nuclear Licensing
*J. Grimes, Superintendent, Plant Maintenance
D. Hansen, Outage Manager, Unit 2
D. Hansford, Group Supervisor, Operations Procedures
*C. Harberts, Manager, Outage Management
R. Haverkamp, Nuclear Construction Engineer
R. Holmes, Site Codes and Welding Engineer
++D. Irvine, Supervisor, Technical Support, Station Technical
M. Jennex, Cognizant Engineer for Appendix J Program
++K. Johnson, Manager, Electrical Controls, Nuclear Engineering Design Organization
*J. Joy, Maintenance Supervisor, Business Administration
++R. Kaplan, Onsite Nuclear Licensing Engineer
++P. Knapp, Manager, Health Physics
++R. Krieger, Vice President, Nuclear
*C. LaPorte, Superintendent, Plant Maintenance
*R. Lee, Supervisor, Nuclear Safety Group
M. Lisitza, Supervisor, Control Room
J. Madigan, Health Physics Special Projects
J. Marr, Cognizant Engineer, Auxiliary Feedwater System
#W. Marsh, Manager, Nuclear Regulatory Affairs
*A. Mihatov, Superintendent, Plant Maintenance
*M. Motamed, Supervisor, Risk Management
*K. O'Connor, Manager, Construction
#G. Plumlee, Lead Engineer, Onsite Nuclear Licensing
E. Regala, Lead Inservice Inspection Engineer
*J. Reilly, Manager, Nuclear Engineering and Construction
M. Rodin, Supervisor, Site Technical Services
++R. Rosenblum, Vice President, Nuclear Engineering and Technical Support

R. Schofield, Supervisor, Health Physics Engineering
S. Shaw, Supervisor, Nuclear Services
++M. Short, Manager, Site Technical Services
*K. Slagle, Manager, Nuclear Oversight
*R. Stoker, Senior Engineer, Independent Safety Evaluation Group
*W. Strom, Supervisor, Independent Safety Evaluation Group
#A. Thiel, Supervisor, Electrical, Station Technical
++R. Waldo, Manager, Operations
++M. Wharton, Manager, Nuclear Engineering Design Organization
*C. Williams, Onsite Nuclear Licensing Engineer
R. Wood, ALARA Supervisor

1.2 Bechtel Power Corporation

J. Breza, Welding Engineer
M. Ensminger, Supervisor, Quality Control

1.3 Lambert-MacGill-Thomas, Inc.

A. Whealdon, Nondestructive Examination Level III Examiner

1.4 NRC Personnel

*D. Acker, Project Inspector, Project Branch F, Division of Reactor Projects
M. Fields, Project Manager, Office of Nuclear Reactor Regulation
*T. Gwynn, Director, Division of Reactor Safety
*D. Powers, Chief, Maintenance Branch, Division of Reactor Safety
*J. Sloan, Senior Resident Inspector
*D. Solorio, Resident Inspector

In addition to the personnel listed above, the team contacted other personnel during this inspection period.

* Denotes personnel that attended the February 24, 1995, exit meeting.
++ Denotes personnel that attended the February 24 and March 14, 1995, exit meetings.
\# Denotes personnel that attended the March 14, 1995, exit meeting.

2 EXIT MEETING

Exit meetings were held onsite on February 24, 1995, and by telephone on March 14, 1995. During the onsite meeting, the team leader and the inspector responsible for the review of inservice inspection activities summarized the scope and conclusions of the inspection. Licensee personnel acknowledged the conclusions presented at the exit meeting and a commitment made to evaluate conduit containing safety-related cable for inclusion in the equipment preservation program. A presentation was also made by licensee personnel regarding why the preplanning for the switchyard work was considered appropriate. NRC personnel acknowledged the licensee presentation and indicated it was planned to refer the matter to the Office of Nuclear Reactor Regulation.

During the March 14, 1995, telephone exit meeting, licensee personnel were informed of the results of the review of component failure history and also of a proposed violation and unresolved item pertaining to emergency diesel generator testing. Licensee personnel acknowledged the commitments documented in Section 2.5.2.3 of the inspection report pertaining to planned emergency diesel generator actions. Licensee personnel were subsequently informed by telephone on April 19, 1995, that, as a result of in-office review of the specifics concerning emergency diesel generator testing, a determination had been made that the proposed violation should not be cited.

ATTACHMENT 2

INSPECTION FINDINGS INDEX

- Inspection Followup Item 361/9501-01; 362/9501-01 was opened (Section 2.2.2.6).
- Violation 361/9501-02; 362/9501-02 was opened (Section 2.3.4).
- Unresolved Item 361/9501-03; 362/9501-03 was opened (Sections 2.5.2.2 and 2.5.2.3).
- Inspection Followup Item 361/9501-04; 362/9501-04 was opened (Section 2.8).
- Violation 361/9501-05 was opened (Section 4.5).