ENCLOSURE 5

ENCLOSURE

FINAL SALP REPORT

U. S. NUCLEAR REGULATORY COMMISSION

REGION II

SYSTEMATIC ASSESSMENT OF LICENSEE PERFORMANCE

INSPECTION REPORT NUMBERS

50-269/92-01, 50-270/92-01, 50-287/92-01 AND 72-4/92-01

DUKE POWER COMPANY

OCONEE UNITS 1, 2 AND 3

AUGUST 1, 1990 - FEBRUARY 1, 1992

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I. INTRODUCTION

The Systematic Assessment of Licensee Performance (SALP) program is an integrated NRC staff effort to collect available observations and data on a periodic basis and to evaluate licensee performance on the basis of this information. The program is supplemental to normal regulatory processes used to ensure compliance with NRC rules and regulations. It is intended to be sufficiently diagnostic to provide a rational basis for allocation of NRC resources and to provide meaningful feedback to licensee management regarding the NRC's assessment of their performance in each functional area.

An NRC SALP Board, composed of the staff members listed below, met on March 13, 1992, to review the observations and data on performance, and to assess licensee performance in accordance with the guidance in NRC Manual Chapter NRC-0516, "Systematic Assessment of Licensee Performance". The Board's findings and recommendations were forwarded to the NRC Regional Administrator for approval and issuance.

This report is the NRC's assessment of the licensee's safety performance at the Oconee Units 1, 2 and 3 for the period August 1, 1990, through February 1, 1992.

The SALP Board for Oconee was composed of:

E. W. Merschoff, Deputy Director, Division of Reactor Safety (DRS), Region II (RII), (Chairman)
J. R. Johnson, Deputy Director, Division of Reactor Projects (DRP), RII
B. S. Mallett, Deputy Director, Division of Radiation Safety and Safeguards, RII
A. R. Herdt, Chief, Reactor Projects Branch 3, DRP, RII
D. B. Matthews, Director, Directorate II-3, Office of Nuclear Reactor Regulation (NRR)
L. A. Wiens, Project Manager, Project Directorate II-3, NRR
P. E. Harmon, Senior Resident Inspector, Oconee, DRP, RII

Attendees at SALP Board Meeting:

F. J. Remick, Commissioner
J. Guttmann, Technical Assistant to Commissioner Remick
A. J. Mendiola, Acting Chief, Quality Assurance Section, Division of Licensee Performance and Quality Evaluation, NRR
G. A. Belisle, Chief, Project Section 3A, DRP, RII
W. H. Miller, Jr., Project Engineer, Project Section 3A, DRP, RII
S. Q. Ninh, Project Engineer, Project Section 3A, DRP, RII
B. B. Desai, Resident Inspector, Oconee, DRP, RII
W. K. Poertner, Resident Inspector, Oconee, DRP, RII

II. SUMMARY OF RESULTS

Oconee operated safely during this evaluation period. A loss of decay heat and an overpressurization event during outage activities were the result of inadequate control room command and control and ineffective oversight of shutdown plant operations. In addition to these outage events, problems continue to exist in the areas of configuration control and procedural adherence. During the last three months of this assessment period improvement has been noted in the oversight of control room activities.

Performance in the radiological control area continues to be effective. A strong ALARA program is evident as well as numerous ongoing projects to reduce collective dose. Programs for monitoring/collecting liquid and gaseous effluents, maintenance of effluent monitoring and environmental monitoring were effective.

Performance in the maintenance/surveillance area was inconsistent. Programs such as shifting from reactive to predictive maintenance activities, thermography and Inservice Inspection remain effective. Problems continue in areas such as procedural adherence and reactor trips during surveillance testing.

The licensee continued to maintain a strong emergency response organization. Management attention and support was evident. Several program strengths were identified which included training and completion of a new EOF. During two exercises this SALP period as well as during an ALERT in November 1991 involving a reactor coolant leak, the Emergency Plan was effectively implemented.

Performance in the security area was superior. Security management at both site and corporate was knowledgeable and highly supportive. Due to a continuing problem with closed circuit televisions being out of service, many protected area intrusion detection zones had to be physically assessed. The Fitness for Duty Program is effectively implemented.

Design engineering and other support groups have been adequate and responsive to station needs. Good communications exist between corporate and site engineering. Engineering successfully implemented several major modifications. However, poor modification design led to a water hammer and multiple fittings were inappropriately used to transition between different pipe sizes. A new organization change is planned to move engineering personnel on site in July 1992.

With the exception of shutdown operations, Safety Assessment/Quality Verification performance demonstrated a thorough approach to assessing conditions and activities relating to the operation of the plant. Program initiatives to define the design bases and to investigate significant operating events are considered strengths. Several plant

modifications have been implemented that have enhanced safety, and some improvements have been noted in the quality of licensing submittals. However, corrective actions have not been effective in preventing recurrence of problems.

Overview

Performance ratings assigned for the last rating period and the current period are shown below.

Functional Area	Rating Last Period 2/1/89 - 7/31/90	Rating This Period 8/1/90 - 2/1/92
Plant Operations	1	2
Radiological Controls	1	1
Maintenance/Surveillance	2(Improving)	2
Emergency Preparedness	1	1
Security and Safeguards	2(Improving)	1
Engineering/Technical Support	1	2
Safety Assessment/ Quality Verification	2	2

III. CRITERIA

The evaluation criteria which were used to assess each functional area are described in detail in NRC Manual Chapter MC-0516, which can be found in the Public Document Room files. Therefore, these criteria are not repeated here, but will be presented in detail at the public meeting to be held with licensee management.

IV. PERFORMANCE ANALYSIS

A. Plant Operations

1. Analysis

This functional area addressed the control and performance of activities directly related to operating the facility, including fire protection.

While Oconee operated safely during this evaluation period, recurring procedural violations and events during shutdown and outage activities have caused significant concern. Performance in this area has declined during the assessment period because of these problems due to their number and significance. Improvement was noted in the last three months of the assessment period due in part to increased management attention to conduct of operations and greater attention to detail.

Power Operations

Certain programmatic areas exhibited problems, including configuration control and procedural adherence. The configuration control errors involved mispositioned valves, breaker tagging and equipment being taken out of service on the wrong unit. Events involving procedure violations include mispositioning Low Pressure Service Water valves when a valve checklist was not performed, sluicing core flood tanks without a procedure, spilling radioactive resin and water due to mispositioned valves, and lining up the Lee power station to the standby bus without degraded grid voltage protection. Some of these instances of failing to follow procedures also involved specific decisions to inappropriately deviate from the procedures, in that, in two instances operators bypassed procedural steps without careful consideration of the reason for that step. Deficiencies in procedural compliance were also noted in the previous SALP report as an area that should receive continued management attention. Based on the above examples, management has not been fully successful in resolving this problem.

Operator response to transient and upset conditions from power was good, particularly with respect to runback management and trip response. Runbacks were usually stopped by the operators who were able to diagnose and correct the conditions causing the runbacks. During the November 1991 loss of coolant accident (LOCA), the operators performed well except for a problem associated with the operation of the steam station controls. Overall performance during this event indicated that the operators were well trained and experienced.

Operators and shift supervisory personnel generally exhibited a conservative approach to technical issues. Plant operations assisted as necessary to resolve technical issues, with special emphasis placed on teamwork approaches to the resolutions.

The experience level of the shift personnel and the Operations support group is considered very high. Each of the five shift crews are staffed with two extra reactor operators. Recently there has been a resultant decrease in overtime.

Shutdown Operations

Operations personnel sometimes exhibited a lack of attention to detail. One instance occurred when operations personnel secured the cooling water to the operating control rod drive mechanisms. Another example involved operations personnel not questioning maintenance personnel performing a hydrostatic test at the same time that the Reactor Coolant System (RCS) was

being drained down for midloop operations. Because there was only a single valve boundary during the hydrostatic test, leakage by this valve caused an RCS dilution. Additionally, both source range nuclear instruments were inappropriately deenergized on two occasions.

Control room inattentiveness and poor communications at times resulted in actual events and near misses, including three events that resulted in NRC Augmented Inspection Teams (AITs) being dispatched to review the circumstances involved. The event that led to the AIT in March 1991 involved a loss of decay heat removal and was caused by incorrect labeling, inadequate independent verification, poor communications between operations and technical personnel, procedural inadequacies and incorrectly using plant drawings. The events that led to the second and third AITs in September involved a loss of decay heat removal and overpressurizing the Low Pressure Injection (LPI) system. These events were caused by failure to implement or follow procedures, inadequate communications, inappropriate conduct of operator responsibilities and inadequate facility management oversight. Corrective actions implemented in the latter part of the assessment period produced improvement in attention to routine evolutions and shift duties. In particular, communications between various support groups improved due to work management changes.

The licensee failed to recognize deficiencies in fundamental watch standing practices, and command and control of shift operations which were root causes for the Unit 1 RCS heatup and the LPI overpressurization events. However, efforts have been taken to correct watch standing practices and improvements have been observed during the latter part of this assessment period.

The Operations Support Group was staffed with experienced personnel including a large percentage of licensed, shift-experienced personnel. This group provided a valuable resource to shift crews in several areas including "System Expert" support, work control screening, scheduling and review, and procedure review and revision. Assistance in performing complex and non-routine evolutions such as mid-loop approach and High Pressure Injection (HPI) system full flow testing was considered a strength.

Attention to detail for planned evolutions was not always evident. One example was the spill of 800 gallons of water from the Letdown Storage Tank. This event occurred when operators assumed a valid tank level indication was in error. As a

result, recurring problems were evident in areas of independent verification, spills from mispositioned valves, tagging errors, and other configuration control problems.

Several significant control room modifications were completed during the period, including ATWS Mitigation System Actuation Circuitry (AMSAC), Diverse Scram System, and instrumentation upgrades addressing Regulatory Guide 1.97 issues. Modification training for Operations personnel was generally adequate. Some instances were noted of a lack of operator familiarity with recently completed modifications. These included the diverse scram system, the radiation monitor system and the reactor coolant pump vibration monitor system.

Fire Protection Program

The fire protection program as a whole was well implemented. However, three problems with the use of combustible scaffolding, inoperable fire barrier between redundant safe shutdown components and the failure to perform an adequate operability verification for the Keowee CO2 fire suppression system were identified. New state of the art fire detection and control panels have been installed to replace the old system panels. Procedures to implement the program are adequate. The fire brigade was well trained and equipped and performed satisfactorily during drills. The TS required fire protection program audits performed by the licensee were comprehensive and thorough. Surveillance and maintenance of the fire protection features and systems were adequate. System impairments were generally corrected in a timely manner and appropriate compensatory measures were established for degraded conditions.

Nine violations were identified. Two Severity Level III violations pertaining to two separate September shutdown events were issued after the SALP cycle closed. Two additional violations were identified but not issued in this SALP period.

2. Performance Rating

Category: 2

3. Recommendations

The NRC is concerned with the execution of control room command and control functions as well as the effectiveness of management oversight of plant operations primarily during shutdown conditions and refueling outages. Enhanced NRC inspection during shutdown conditions is recommended.

The licensee should evaluate the effectiveness of control room command and control functions and the effectiveness of work scheduling and plant operations during shutdown conditions and the effect on safety system availability.

B. Radiological Controls

1. Analysis

The functional area addresses those activities related to radiation safety and primary/secondary chemistry control.

Both Radiation Protection and Chemistry were well staffed to perform scheduled operations. Supervisors and managers were well qualified and all positions were filled. To assist the health physics (HP) staff for non-scheduled outages, the utility retained 15 HP vendor technicians at each Duke nuclear site, thereby having another 30 HP technicians available on one day notice to any site. The newly retained vendor HP group has added more stability to radiological coverage at the early onset of unscheduled outages. Late in the assessment period, the licensee planned to, but was not providing continuing training or on-the-job training for the retained vendor technicians.

The licensee's ALARA program was a strength with contributions from engineering support and HP guidance, teamwork, and ALARA techniques inherently designed into modifications and radiological operations. The licensee's initiatives to reduce out of core source term and collective dose were numerous. Two of the more significant initiatives in the assessment period were the replacement of the 4-inch diameter component Drain Header and steam generator "J" leg drains, and the replacement of highly radioactive hot leg shield blocks. As a result, dose rates in the general areas of the containment basement and cavities have been reduced by a factor of four and in some areas by a factor of six. The newly installed valves in the component Drain Header and "J" leg drains are designed to minimize crud build up and the new hot leg shield blocks have multi-coatings to inhibit the adherence of radioactivity. The licensee has also used several other methods to reduce the source term and collective dose, such as, crud burst at shutdown and subsequent filtration, flushing to remove hot spots, temporary lead shielding, and removal of radioactive piping no longer in use.

The licensee established a collective dose goal of 504 person-rem for 1991 with two scheduled outages. The goal was exceeded by 56 person-rem due to three unscheduled outages. The licensee per-unit collective dose average for the years 1989, 1990 and 1991 was 228, 134, and 187 person-rem respectively, for a three year per unit average of 183 person-rem. This three year average is indicative of the aggressiveness of the program to reduce the source term and is low for an older three unit pressurized water reactor.

The licensee's program to control contamination continues to be effective. One example was the effective cleanup and monitoring of a November 1991, spill of reactor coolant due to a failure of a compression fitting. The station's program to reduce contaminated square footage has leveled off over the past two assessment periods at approximately six percent of the 107,750 square feet of radiologically controlled area (RCA) as contaminated. Two examples where the contamination control program was not effective were an increased number of personnel contamination events and low level contaminated items located outside the RCA. The licensee experienced 141 personal contamination events (PCEs) in 1990 and 294 PCEs in 1991. The increase in PCEs can be attributed to two scheduled and three unscheduled outages and the use of 23 new state-of-the-art personnel monitors with increased sensitivity.

The licensee's program for monitoring and controlling liquid and gaseous radioactive effluents was effectively implemented. The whole body doses were less than one millirem/year each from the liquid effluents and from the gaseous effluents released during 1990 and 1991. Those doses were a small percentage of their respective limits. The licensee reduced by 62 percent the fission and activation products released in liquid effluents between the periods January 1989 through June 1990 and July 1990 through December 1991. (These periods most closely coincide with the previous and current assessment periods.) The decrease was due, in part to, the leakage control program; use of multi-element pre-filters to remove cobalt and magnesium; use of resins with greater surface area; and modification of demineralizers to reduce channeling. Also, administrative procedures were changed to set a limit for the maximum permissible concentration of cesium in liquid waste. There was also a 39 percent decrease in noble gas released in the gaseous effluents during the assessment period as compared to the previous period. Although there were some increases in halogens and particulates released in the gaseous effluents during the assessment period as compared to the previous

period, the licensee attributed these increases to the 3 outages during 1991. No unplanned gaseous releases were reported to have occurred during the assessment period but one unplanned liquid release was reported. On November 7, 1990, a container being moved by a truck from one warehouse to another turned over and approximately 7 gallons of water were spilled from the container. One gallon of water containing 9 microcuries was conservately estimated to have entered an open yard drain.

The licensee's maintenance of effluent monitoring capabilities was good during this assessment period. The licensee had completed installation of new Post Accident Liquid Sampling (PALS) systems on Units 1 and 2. The new PALS systems have been brought to operational status for all three units. The Radwaste Facility Ventilation Monitoring System was also returned to operational status during the current assessment period.

Good progress was made in the modification of the Low Pressure Service Water (LPSW) monitoring systems. These systems have been inoperable since 1986 due to clogged sample lines. Correction of the problem required a design change to the system. The modification for Unit 3 was completed and the monitoring system for that unit was returned to service. It is anticipated that the Unit 1 and 2 LPSW monitoring systems will be returned to service by mid 1992.

Significant progress was made during the assessment period in replacement and upgrade of radiation monitoring instrumentation. Digital readouts, with system failure alarms, were installed in the Control Room, the Technical Support Center and the Radiation Protection office area. This program improvement project is more than 50 percent complete.

The licensee's environmental monitoring program was effectively implemented. The program results for 1990 indicated that there was no significant radiological impact on the health and safety of the general public resulting from plant operations. Dose estimates calculated from environmental monitoring program data were in reasonable agreement with dose estimates calculated from effluent release data and were well within 40 CFR 190 dose limits. The licensee's performance in the Environmental Protection Agency's interlaboratory crosscheck program indicated that an effective quality assurance program had been maintained for analysis of environmental samples.

Two violations were identified.

2. Performance Rating

Category: 1

3. Recommendations

None

C. Maintenance/Surveillance

1. Analysis

This functional area addresses those activities related to equipment condition, maintenance, surveillance performance, and equipment testing.

The maintenance/surveillance functional area exhibited inconsistent performance throughout the assessment period. Predictive maintenance and equipment monitoring were agressively persued and were effective whereas weaknesses were noted in areas such as procedural adherence, documentation of problems during troubleshooting and repairs, plant transients and reactor trips induced by maintenance and surveillance activities.

The licensee's efforts continued this period to move from a reactive or corrective maintenance program to a predictive and preventive approach. Maintenance efforts were at a 60/40 ratio of predictive to corrective maintenance. The equipment vibration monitoring, pipe erosion/ corrosion, and valve maintenance and replacement programs are considered strong areas. The piping erosion/ corrosion program, which is related to piping systems with the potential for high energy releases, has been expanded to include both large and small diameter piping. Most findings to date involve secondary system piping. A new thermography program was introduced this period and was instrumental in resolving several issues such as locating system leakage and identifying deficient piping insulation. The station has an obsolete and aging equipment program. This is a joint maintenance and engineering effort.

During this period, significant operational problems attributable to maintenance activities occurred. A loss of coolant event due to improperly installed fittings occurred in November 1991. The actual installation of the defective reactor coolant system fittings occurred several years ago. The licensee's inspection of all fittings identified this as a pervasive problem with approximately 25 percent of all fittings not meeting installation criteria. The program for installation was changed after the event.

The licensee submitted one LER concerning a missed surveillance. One instance of post modification/maintenance requirements not being performed was identified. This involved not verifying the alignment of the turbine driven emergency feedwater pump.

Surveillance activities directly caused or contributed to several plant trips and events. These included valving a reactor coolant system flow transmitter into service incorrectly; incorrectly using test equipment during a surveillance test that caused a reactor trip; and incorrectly returning a low pressure injection pump flow transmitter to service.

Equipment performance has adversely affected plant operations. Specifically, six reactor trips from power were caused by equipment failures. These trips included an inadvertent trip of the condensate booster pump and the failure of the standby pump to start, a rod programmer problem dropped Group 7 rods into the core, and a rod transfer switch failed in mid position during rod transfer.

Several instances of independent verification errors resulted in instrumentation not being properly returned to service nor properly verified. Examples include when instrumentation was isolated during an LPI flow pump test and when instrumentation test tees for the RCMUP were not tightened. Two instances were noted of undocumented work activities involving lifting and landing leads and replacement parts.

As part of the corporate reorganization plan instituted in November 1991, the Construction and Maintenance Department (CMD) was eliminated. All CMD personnel permanently assigned to Oconee were integrated into the maintenance department. Training for CMD workers to site standards was initiated. Use of vendors and contractors was minimal, with most support for modifications, maintenance and outage supplied by Duke Power personnel. The maintenance department was well staffed with knowledgeable and experienced personnel.

A lower tier event investigation, root cause and corrective action program, Maintenance Incident Report or MIR, was implemented midway through this assessment period. Program upgrades were in progress and root cause training had been completed by several maintenance personnel.

The inservice inspection program (ISI) was being effectively implemented. ISI nondestructive examinations were being conducted by qualified personnel. The procedures and examination techniques used to conduct examinations were adequate and documentation of examination results was good. Deficiencies were noted in the areas of pipe support and tendon surveillance. Specifically, improper placement of radiography penetrameters, improper gap between washers and snubber rod bearings and incomplete magnetic particle testing (MT) records were noted. Additionally, the licensee failed to investigate and resolve the cause of a 2.5 inch difference in snubber hot and cold settings from the drawing specifications. Further investigation identified that the hot and the cold settings were reversed on the drawing.

Plant material conditions and routine housekeeping were generally acceptable. Instances of Unit 2 outage related housekeeping problems were noted during a Unit 2 containment closeout walkdown. This was observed early in the assessment period; subsequent walkdowns indicated improvement in this area.

Five violations including one Severity Level III violation were identified.

2. Performance Rating

Category: 2

3. Recommendations

The Board is concerned with the adverse impact of equipment performance and surveillance activities on plant operations. Six reactor trips from power were caused by equipment failures and surveillance activities caused or contributed to plant events and trips. Management attention to this area is appropriate.

D. Emergency Preparedness

1. Analysis

This area addresses those activities related to the Emergency Plan, support for and training of emergency response organizations both on and offsite, and licensee performance during emergency exercises and actual events. During this assessment period the licensee continued to maintain a strong emergency response organization capable of providing sufficient protective measures to ensure public safety in the event of an emergency.

Management attention and support for emergency preparedness was evident throughout the period. Program strengths identified during inspection activity this assessment period included: maintenance of emergency response facilities and equipment in a high state of operational readiness, effective training of onsite and offsite emergency response personnel and completion and turnover of a new Emergency Operations Facility with commitments to initially activate and staff the facility from the Oconee site rather than from the corporate office.

Oconee demonstrated thorough preparation for dealing with site emergency situations during an October 1990 partial participation exercise and during a full participation October 1991 exercise. During both exercises the licensee demonstrated it could effectively implement the Emergency Plan and its implementing procedures, effectively assign emergency response organization responsibilities, and could take suitable actions to mitigate the on and offsite consequences of the accident scenarios. Emergency classification was prompt and correct as the scenarios progressed and operations of the emergency response facilities and equipment observed during the annual exercises were good. Other exercise strengths identified included effective fire brigade response and, during the October 1990 exercise, an effective response to a real medical emergency onsite coincidental with the exercise.

Two exercise weaknesses were identified during the October 1990 exercise. The first weakness was a failure to activate the Technical Support Center in a timely manner. The licensee gave increased attention to activation timeliness between the exercises and, during the October 1991 exercise, the licensee was able to demonstrate prompt activation of the Technical Support Center. The second weakness involved numerous communication problems between the Technical Support Center and the State Forward Emergency Operations Center which were subsequently corrected. Overall, however, the licensee's performance during the two exercises was good, with the licensee meeting their exercise objectives and demonstrating a capability to protect public health and safety in the event of a radiological emergency.

Emergency response facilities were kept in a state of operational readiness, the TSC was remodeled to include an enhanced emergency data system, and a significant upgrade was implemented with the turnover and operation of the new Emergency Operations Facility. Emergency Preparedness (EP) staffing was well qualified and remained constant throughout the period. Late in the assessment period the licensee committed to significantly increase the staffing level onsite as a result of a corporate reorganization, which decentralized

staff and functions from Charlotte to the Oconee site. During the period the licensee made appropriate revisions and upgrades of the Emergency Plan and EPIPs, conducted challenging drills and exercises, assured proper upkeep of EP equipment, and maintained coordination with offsite support groups.

Management attention to program activities was evident throughout the period. For example, senior technical staff and management were assigned to emergency response organization (ERO) functional areas and were required to maintain qualification to support response activities. The ERO training program was thoroughly defined and supported. Lesson plans and training modules were organized and appropriate for meeting stated objectives.

During this assessment period, the licensee's Emergency Plan was implemented twice in response to events, one at the Notification of Unusual Event (NOUE) level and one at the Alert level. In each case, the event detection and classification was prompt and correct, offsite authorities were initially notified in a timely manner, good updates and periodic communications were maintained with state and local emergency operation centers as well as the NRC, and the onsite emergency organization responded in an overall effective manner.

Two exercise weaknesses were identified.

2. Performance Rating

Category 1

3. Recommendations

None

E. Security

1. Analysis

This functional area addresses those security activities related to protection of vital plant systems and equipment, and the Fitness For Duty Program.

Security management at both the site and corporate levels was knowledgeable and highly supportive of program activities. Support was indicated by the implementation of a Protected Area Upgrade Project, a Physical Performance Test Program and by changing the contract security force to a proprietary security force. These initiatives contributed to a reduction in the

security staff turnover rate in this assessment period as compared to the rate during the last period.

The licensee's primary system to assess alarms is a closed circuit television system fixed and pantilt-zoom cameras. The licensee could not fully utilize this system during this SALP period due to equipment malfunctions and maintenance problems. This issue was identified during the previous two SALP periods. As part of a comprehensive Protected Area Upgrade Project, the licensee put in place plans to address problems with the camera assessment capabilities. During this SALP period the licensee improved the quality of a few of the operating cameras and began installation of the rest of a new camera assessment system during the latter part of this SALP period.

During this SALP period, the licensee made improvements in its detection system. For example, the licensee reconfigured the protected area perimeter to improve the zones of detection. Also, the licensee enhanced the physical structure of the protected area perimeter barrier. The licensee was in the final stage of this upgrade project during the end of the assessment period.

Other areas of the licensee security program were effectively operated during this period. For example, the licensee's access control program was enhanced to correct the access control problems mentioned in the last SALP period. The licensee has also improved its program to account for and identify security keys. Alarm stations and communication equipment associated with the stations were operated by capable and knowledgeable personnel. The testing and maintenance of the security equipment were conducted as required.

The licensee had established, maintained and effectively implemented a security program for the Independent Spent Fuel Storage Installation (ISFSI).

The licensee's Fitness for Duty Program was effective in obtaining drug-free workplaces while balancing the rights and privacy of the workforce. It met the objectives of 10 CFR 26.

The licensee submitted three Security, two Contingency, one Training and Qualification, and one Independent Spent Fuel Storage Installation (ISFSI) Security Plan revisions during this period. These revisions were consistent with 10 CFR 50.54(p) and adequately coordinated.

The security force was well staffed, equipped, and trained to perform their assigned duties. The security training staff was dedicated, knowledgeable and motivated.

2. Performance Rating

Category:1

3. Recommendations

None

F. Engineering/Technical Support

1. Analysis

This functional area addresses those activities associated with engineering and technical support, including activities associated with design of plant modifications, engineering, and technical support for operations and operator training.

The licensee's engineering (DE) and other technical support groups have been responsive to station needs. Overall engineering and technical support continues to effectively plan and implement plant modifications. The experience level of engineering and technical personnel and their participation in generic industry initiatives remains high. Communications between DE (General Office) and plant engineering have improved as a result of reorganization of DE and establishment of an onsite DE contingent.

Responsiveness to station needs is evidenced by the monitoring and testing of the reactor building cooling units on line, identification and investigation of problems associated with the testing of pressurizer safety valves, and fire detection system and radiation monitoring equipment upgrades.

Engineering support for successfully implemented modifications included the emergency feedwater system, Anticipated Transient Without a Scram (ATWS) mitigation safety actuation circuit (AMSAC), the diverse scram system and Regulatory Guide 1.97 emergency core cooling system instrumentation. A main steam condensate system water hammer event as well as the failure of a pressure fitting on the Reactor Vessel Level Instrumentation System (RVLIS) instrumentation were examples of inadequate engineering support for modifications. In the former example, the modification was not correctly designed and on first use, resulted in the water hammer. In the latter example, the modification depended upon excessive fittings to transition from a one-inch pipe to a three-eights inch instrument line.

DE was actively involved in various industry initiatives such as resolution of several Generic Letters. DPC was also involved in the Operating Experience Program, Nuclear Plant Reliability Database System, Babcock and Wilcox Owner's Group and various Nuclear Utility Management and Resource Counsel initiatives.

Continued good communication and cooperation between corporate and site engineering groups during this assessment period was evidenced by the motor operated valve test program which required coordination of engineering calculations, system reviews, the development of a program and procedures, and implementation of diagnostic testing of valves under design basis conditions. Strengths were identified with the motor operated (MOV) program. These included well documented and thorough switch setting calculations, the initiation of differential pressure testing and knowledgeable personnel.

DE was responsible for the ongoing Design Basis Documentation (DBD) program. The DBD was started in 1989 to provide accurate design base documentation of all safety related systems. This program continued to involve significant engineering resources. The program is scheduled to be completed in 1995 and has resulted in the identification and correction of several significant electrical system design deficiencies as well as other system discrepancies.

The Operating Experience Review program was effective and led to the identification of susceptibility to certain fault types at the Keowee Hydro units. Additionally, several breaker coordination problems were identified during design reviews of breaker and relay trip settings. The licensee's resolution of these problems was thorough and timely. Followup on the potential for hydrogen intrusion and degradation of high pressure injection (HPI) pumps was not effective in that DE failed to recognize the severity of this issue and actions necessary to resolve the issue were not timely.

In general, DE produced procedures were adequate although instances of inadequate procedures were noted. Specifically, procedures involving the installation of compression fittings and testing of the HPI system were inadequate. The HPI system was determined to have been inoperable for extended periods due to improperly installed flow instruments and orifice plates.

The ISI program was effectively implemented by highly skilled and knowledgeable engineers and technicians, and knowledgeable and technically competent contractor personnel. Inspections were well planned and included use of mock ups for steam generator work, and use of state-of-the-art equipment. Test

results were well documented. The use of previous test results in evaluation of inspection findings and conservative decisions relative to inspection findings were noted.

Concerns were identified in the DE and technical support area. A weakness was identified during the repair of a pipe crack on a Low Pressure Injection (LPI) system dropline. These included failure to detect and resolve LPI pump vibration before the crack developed, failure to adequately review and pre-plan spool piece fabrication to prevent distortion, failure to adequately pre-plan and control purging in the welding process, and inability to readily retrieve replacement component quality records after the repair.

Additional management attention is required in the area of licensed operator training. Sixteen Generic Fundamental Examinations were administered during the assessment period with four failures. Insufficient effort by the Oconee Training Department in support of the requalification program was noted. Some NRC requested changes provided to examinations were omitted, and the simulator scenario bank was developed at the minimum rate. Operational validation of examination material was often lacking and some scenarios were short and simplistic. This examination was a requalification pilot that Oconee had volunteered for and strengths were noted as the facility evaluators did a good job of going beyond the crew evaluations and identifying those individuals with performance deficiencies, and in crew teamwork decision making. Six of six crews passed and 96% of 24 operators passed this exam. Initial examinations were given to 24 candidates in January 1991 and January 1992 with a pass rate of 88%. Poor operations support was identified during the pre-review of the January 1992 Initial Examination written portion which resulted in post examination comments on a large portion of the examination. Strengths during this exam were noted in examination administration and candidate communications. During simulator examinations, weaknesses were noted in manual operation of feedwater controls. The plant specific simulator is certified in accordance with ANSI 3.5, but exhibited deficiencies in Engineered Safeguards component modeling, which resulted in training unlike the operation of the plant, and the inability to fail some major components.

Poor planning of post maintenance testing has resulted in the submittal of several relief requests requiring expedited review by the NRC. During the Unit 1 outage in August 1991, work on a RCP required removal of the pressurizer safety valve tailpiece. A request for relief was submitted late in the outage, when the need for the relief should have been determined when planning for the outage. Similar examples occurred during the Unit 2 outage in October 1990, when three relief requests were submitted at the end of the outage related to the testing of repair welds. These relief requests were submitted only a few days before the approval was needed.

Four violations including two Severity Level III violations were identified.

2. Performance Rating

Category: 2

3. Recommendations

Increased management attention is warranted in the area of licensed operator training. Specifically, support of the requalification examination program is weak and operational validation of examination material is often lacking.

G. Safety Assessment/Quality Verification

1. Analysis

This functional area addresses those activities related to implementation of safety policies; amendments, exemptions and relief requests; response to Generic Letters, Bulletins, and Information Notices; resolution of safety issues; reviews of plant modifications performed under 10 CFR 50.59; safety review committee activities; and the use of feedback from self-assessment programs and activities.

During the assessment period several plant modifications and program changes enhancing plant safety were initiated or completed. Hardware changes included Emergency Feedwater test loop installation, a new Radiation Monitoring system, switchyard access control with fences established, and a new fire detection system installed in the turbine and auxiliary buildings. Design Baseline Documentation (DBD) reviews of several safety systems continued during this assessment period. A "lower tier" event investigation processes for each organizational unit was initiated.

Management decisions were generally conservative and adequately considered plant, system, and personnel safety. Although not strictly required by TS, Unit 3 was shut down to repair the Standby Shutdown Facility (SSF) Reactor Coolant Makeup System, and HPI full flow testing was voluntarily initiated. There were instances where less conservative approaches were employed. These included a decision to continue with RCS draindown without ultrasonic level instruments in service; allowing workers to suspend work required to promptly restore the dewatered Keowee hydro units; and starting up a unit with an intermediate excore neutron detector inoperable.

The corporate and site reorganization has incorporated most independent, safety oversight functions under the Safety Assurance Manager and his staff. These include Regulatory Compliance, Safety Review, Environmental Compliance, and Emergency Preparedness. An accurate assessment of the reorganization's impact on plant safety and safety consciousness was not made due to its implementation late in the assessment period.

The licensee normally demonstrated an aggressive approach to the resolution of those issues which are clearly safety significant. Their actions were generally conservative and thorough, and involved interaction with NRR staff when appropriate. Examples included the installation of modifications to start Emergency Feedwater pumps on low steam generator level and corrective actions for HPI system operation in light of SBLOCA concerns.

The licensee continued to support interaction with the NRC staff to resolve issues, and ensured that knowledgeable technical personnel were available. Numerous conference calls have been held, and a number of significant meetings were conducted, such as to provide an overview of the Oconee IPE submittal, describe the IST program submittal in response to GL 89-04 and discuss the ISI reactor vessel inspection.

Responses to NRC requests were usually provided within the time frame requested and written notice was provided if circumstances prevented meeting the requested schedule. Although the responses were normally timely, the licensee has been slow to complete some actions. Examples include implementing the recommendations of GL 88-14 concerning instrument air systems, which is still not completely implemented and delays in implementing the program recommended by GL 89-04 on IST programs. Improvements in the licensee's program for the procurement and dedication of commercial grade components was not implemented in accordance with the recommended NUMARC schedule, which was endorsed by the NRC.

Licensee proposals and responses were generally well-prepared, accurate, and thorough. In particular, the quality of proposed license amendments has improved during this SALP cycle. Proposed amendments submitted early in the evaluation period required supplements to provide clarification, missing information, or correct errors in the original submittal, but more recent submittals have generally required no revision or additions. The quality of ISI and IST relief requests were poor. Some requests were written such that it was difficult to

determine what was being requested or the justification for the relief. Examples included a relief request associated with the removal of a temporary expandable plug in a LPSW pipe and a request to modify the inspection schedule of reactor coolant outlet nozzles.

The licensee's response to Generic Letter (GL) 88-20, "Individual Plant Examination," was thorough, well documented, and included an analysis of external events, which was not required to be submitted with the original IPE response. The initial response to NRC Bulletin 88-08, "Thermal Stresses in Piping Connected to the Reactor Coolant System," although intended to address all three units only satisfied the Bulletin recommendations for one Oconee unit. The licensee is currently preparing a response to a Request For Additional Information concerning this issue for Units 2 and 3.

The licensee's response to many other issues has been good. After the NRC raised concerns about the time required to activate the Oconee Crisis Management Center, the licensee expeditiously revised the appropriate procedures. After deficiencies were identified in the Oconee Technical Specifications relating to shutdown requirements, the Oconee staff performed a self-evaluation of their Technical Specifications and presented the results of their review to the NRC, including proposed corrective actions. The response was prepared in a very short time period and was thorough.

The licensee submitted three Security, two Contingency, one Training and Qualification, and one Independent Spent Fuel Storage Installation Security (ISFSI) Plan revisions during this period. These revisions were consistent with 10 CFR 50.54(p) and adequately coordinated. The ISFSI revision was forwarded to headquarters for review.

The licensee has developed a program where a Significant Event Investigation Team (SEIT) is dispatched to a site after notification of a significant event. The SEIT assists the station safety review group in determining the cause of the event, safety implications, and necessary corrective actions. These teams evaluated the shutdown events that occurred at Oconee Unit 1 in September 1991 and the instrument line leak that occurred at Unit 3 in November 1991. The teams appeared to be effective and in the case of the shutdown events, had findings similar to the NRC AIT findings.

During this assessment period, several events occurred which reflected management's failure to recognize deficiencies in fundamental watchstanding practices, and command and control of shift operations. These events were the loss of decay heat removal in March and September 1991, and the overpressurization of the LPI system in November 1991.

Following these events, the licensee took steps to improve the command and control function for control room operations as well as to strengthen procedures for assuring safety during shutdown operations. Although some improvement was noted during a Unit 2 refueling outage at the end of this assessment period, the effectiveness of long term actions has not been determined.

No violations were identified.

2. Performance Rating

Category: 2

3. Recommendations

None

V. SUPPORTING DATA AND SUMMARIES

A. Licensee Activities

A major reorganization was announced in November 1991, including relocating Design Engineering to the site. Implementation of the reorganization has not been fully completed.

During this assessment period, Unit 1 completed a scheduled refueling outage in September 1991. The ten year Inservice Inspection (ISI), including inspection of the Reactor Coolant System, was completed during the outage. Several events while shutdown resulted in two AITs during this outage. In addition, problems with the SSF resulted in a short duration outage.

Unit 2 completed a scheduled refueling outage in October 1990. A refueling outage was entered in January 1992.

Unit 3 completed a scheduled refueling outage in March 1991. A loss of LPI resulted in an AIT on Unit 3 during this outage. An RCS leak and a subsequent loss of 87,000 gallons of reactor coolant occurred in November 1991. This event caused the unit to be shutdown for over a month.

During the subsequent startup, a through-wall crack in the decay heat removal dropline, requiring replacement of a portion of the LPI piping, was discovered.

A total of eight automatic and one manual reactor trip occurred during the assessment period; three trips on Unit 1 and six trips on Unit 3. In addition several outages of short duration occurred during the assessment period.

B. Direct Inspection and Review Activities

In addition to the ongoing routine resident inspections, 33 regional inspections performed at the Oconee facility by the NRC staff, six special inspections were conducted as follows:

March 12-15, 1991: Augmented Inspection Team inspection of loss of decay heat removal event of March 8, 1991.

July 15-19, 1991: Procurement Assessment.

September 9-13, 1991: Augmented Inspection Team inspection on degradation of the low pressure injection system event of September 7, 1991.

September 20-23, 1991: Augmented Inspection Team inspection on over-pressurization of low pressure injection system event of September 19-20, 1991.

November 23 - December 21, 1991: Special inspection of circumstances associated with primary system leakage due to failed mechanical fitting on an instrument line for the reactor coolant system.

December 9-13, 1991: Shutdown Risk Inspection

C. Escalated Enforcement Activities

1. Orders

None.

2. Civil Penalties (CP)

A Severity Level III violation (EA 90-119) was issued for ESF valves which would have failed in the closed position in lieu of the open position upon loss of instrument air. ($25,000 CP)

A Severity Level III violation (EA 91-049) was issued for three violations associated with the Unit 3 loss of decay heat removal and discharge of approximately 14,000 gallons of water into the Unit 3 containment (No CP).

A Severity Level III violation (EA 91-052) was issued for improper installation of flow orifice instrumentation in the Units 1 and 2 high pressure injection systems. (No CP)

D. Management Conferences

October 18, 1990: A management meeting was held at the Oconee Station to discuss the SALP Board assessment of Oconee's performance.

December 11, 1990, and September 4, 1991: A Duke/NRC Interface Meeting was held at the McGuire facility to discuss issues of interest to both organizations.

February 12, 1991: A meeting was held at NRC Headquarters for Duke to give a presentation on the Individual Plant Examination (IPE) review for the Oconee Station.

February 14, 1991: A management meeting was held at the Oconee Crisis Management Center (CMC) to discuss the activation timeliness for the CMC in the event of an emergency at the Oconee facility.

March 21, 1991: A management meeting was held in Region II for the licensee to present details of their investigation of the March 8, 1991, event concerning the loss of decay heat removal capability while the unit was in cold shutdown.

May 7, 1991: An enforcement conference was held in Region II to discuss the circumstances surrounding the March 8, 1991, loss of decay heat removal capability while the unit was in cold shutdown.

May 22, 1991: An enforcement conference was held in Region II to discuss the concerns associated with one high pressure injection crossover valve in both Units 2 and 3 being incapable of performing its intended safety function for an extended period of time.

September 25, 1991: A management meeting was held in Region II to discuss the Unit 1 events associated with the September 7, 1991, degradation of the decay heat removal and the September 19-20, 1991, over-pressurization of the low pressure injection system, and the action taken by Duke on the NRC Confirmation of Action Letter dated September 20, 1991.

November 5, 1991: A management meeting was held for the licensee to give a self-assessment of the performance at the Oconee Station from August 1, 1990.

December 18, 1991: An enforcement conference was held in Region II to discuss the Unit 1 September 7, 1991, reactor coolant system heat-up event and the September 19-20, 1991, over-pressurization of the Unit 1 low pressure injection system event.

E. Confirmation of Action Letters (CAL)

September 20, 1991: A CAL was issued which outlined the actions to be taken prior to the startup of Unit 1 following the September 7, 1991, degradation of decay heat removal event and the September 19-20, 1991, over-pressurization of the low pressure injection system event.

F. Reactor Trips

Unit 1

Three automatic reactor trips occurred:

August 28, 1990: Reactor tripped from 100 percent power due to high RCS pressure caused by the trip of Condensate Booster Pump 1B due to spurious signal indicating a closed pump discharge valve.

May 16, 1991: Reactor tripped from 100 percent power due to Flux/Flow imbalance. All four reactor protection system channels tripped. The unit event recorder failed immediately prior to the trip.

October 2, 1991: Reactor tripped from 73 percent power following a turbine trip on a false generator lockout signal caused by a loose electrical connector.

Unit 2

No automatic reactor trips occurred.

Unit 3

Five automatic and one manual reactor trip occurred:

November 13, 1990: The operators manually tripped the reactor from 100 percent prior to an automatic trip when all group seven rods dropped into the core, due to a faulty rod programmer.

April 1, 1991: Reactor tripped from 70 percent power during power escalation due to spurious activated alarms on diverse scram system channels 1 and 2.

June 9, 1991: Reactor tripped from 100 percent power when when Group 5 control rods dropped into core during exercise of Rod 12 of Group 12.

July 3, 1991: Reactor tripped from 100 percent power due to loss of suction to condensate booster pumps caused by faulty powdex master controller while bypass valve was not in automatic.

November 23, 1991: Reactor tripped from 35 percent power following a turbine trip on loss of both main feedwater pumps while shutting down the unit. The unit was being shutdown due to RCS leakage into containment. Pressure swings in the feedwater system caused both feedwater pumps to trip.

January 14, 1992: Reactor tripped from 94 percent power due to high steam generator level when both main feedwater pumps tripped during maintenance troubleshooting operations.

G. Review of Licensee Event Reports (LER)

During the assessment period 32 LERs were analyzed. The distribution of these events by cause as determined by the NRC staff was as follows:

Cause	Totals	Unit 1 or Common	Unit 2	Unit 3
Component Failure	6	1	2	3
Design/Procedures	11	10		1
Construction/Fabrication Installation	4	1	1	2
Personnel				
- Operating Activity	1			1
- Maintenance Activity	2	1		1
- Test/Calibration Activity	3	1	1	1
- Other	1	1		
Other	4	2	1	1
Totals	32	17	5	10

Notes:

1. With regard to the area of personnel, the NRC considers lack of procedures, inadequate procedures, and erroneous procedures to be classified as personnel error.

2. The Other category is comprised of LERs where there was a spurious signal a totally unknown cause.

3. Eight Special Reports were submitted but are not included in the above tabulation.

4. The above information was derived from a review of LERs performed by the NRC staff and may not completely coincide with the licensee's cause assignments.

H. Licensing Activities

In addition to QA and security submittals, there were approximately 147 active licensing actions for the three Oconee units during this SALP period. Of these, 69 were completed. A total of 33 licensing amendments were submitted and 21 were issued.

I. Enforcement Activity

	No. of Deviations and Violations in Each Functional Area				
	Dev.	V	IV	III	II	I
Plant Operations (1)			9			
Radiological Controls			2			
Maintenance/Surveillance (2)			4	1		
Emergency Preparedness						
Security						
Engineering/Technical Support (3)			2	2		
Safety Assessment/Quality Verification						
TOTAL			17	3		

Notes: (1) Two Severity Level III violations pertaining to two separate September shutdown incidents were issued after the SALP Cycle closed.

(2) The Severity Level III violation consisted of three separate violations, the aggregate of which was determined to be a Severity Level III.

(3) One Severity Level III violation (269,270,287/90-17-01) was fully discussed in the previous SALP period but not counted.