UNITED STATES NUCLEAR REGULATORY COMMISSION

REGION I

Inspection Report Nos.	50-387/92-06; 50-388/92-06
License Nos.	NPF-14; NPF-22
Licensee:	Pennsylvania Power and Light Company 2 North Ninth Street Allentown, Pennsylvania 18101
Facility Name:	Susquehanna Steam Electric Station
Inspection At:	Salem Township, Pennsylvania
Inspection Conducted:	February 11, 1992 - April 18, 1992
Inspectors:	G. S. Barber, Senior Resident Inspector, SSES D. J. Mannai, Resident Inspector, SSES J. J. Raleigh, NRR, Project Manager R. S. Bhatia, Reactor Engineer, DRS D. M. Skay, Reactor Engineer (Intern) I. B. Moghissi, Reactor Engineer (Intern)
Approved By:	J. White, Chief Reactor Projects Section No. 2A,

5/19/92
Date

Inspection Summary:

Areas Inspected: Safety inspections were conducted in the following areas: operations, radiological controls, maintenance/surveillance testing, emergency preparedness, security, engineering/technical support, safety assessment/quality verification, and Licensee Event Reports, Significant Operating Occurrence Reports, and open item followup.

Results: During this inspection period, the inspectors found that the licensee's activities were directed toward nuclear and radiation safety. One violation and two non-cited violations were identified. The violation involved failure to take prompt corrective action as required by 10 CFR 50, Appendix B, Criterion XVI and the Susquehanna Quality Assurance Program, relative to Reactor Protection System (RPS) Electrical Protection Assembly (EPA) breaker trips. Section 7.2.1 pertains. An Executive Summary is included and provides an overview of specific inspection findings.

EXECUTIVE SUMMARY

Susquehanna Inspection Reports

50-387/92-06; 50-388/92-06

February 11, 1992 - April 18, 1992

Operations (30702, 71707, 71710)

A manual scram was initiated to at 9:49 a.m., March 18, to cope with a loss of the 2C Engineered Safeguards System (ESS) bus (2A203). The scram was performed in anticipation of Main Steam Isolation Valve (MSIV) closure since the nitrogen supply was isolated when the 2C bus was lost. To cope with lost equipment, the licensee established temporary power supplies to three key systems: the Containment Instrument Gas system to restore nitrogen to the MSIVs, the Drywell (DW) Vent/Purge damper to depressurize the DW, and the DW coolers to lower DW Temperature. DW temperature peaked at 194 ^{0}F locally and 165 ^{0}F average. The licensee remained in hot shutdown and did not continue the cooldown while they restored DW cooling. Continuing the cooldown would have minimized the magnitude and duration of the DW temperature transient. A detailed engineering evaluation later showed the overall effects of the transient to be minimal. This transient identified basic weaknesses in the diversity of the electrical design, as well as, the procedures to cope with a sustained loss of an ESS bus. The licensee has committed to upgrade procedures and to review the need for modifications. These activities will be completed by the end of 1992.

The Reactor Water Cleanup (RWCU) system isolated on three separate occasions from 11:40 a.m., March 7 to 6:04 a.m., March 8. The first isolation was caused by a short circuit that resulted when a shield block was being rigged from the Reactor Building to a pre-outage storage location. The second two isolations occurred during restoration activities. The first with the system hot, and the second after filling and venting the system while in cold shutdown. The second isolation resulted from a leaky seal that allowed excessive voiding in an isolated portion of the RWCU system. A recent procedure revision did not fully consider this limitation. The third isolation was from a transmitter failure. The installation of seal-less RWCU pumps will minimize the potential for future seal leaks in Unit 1. Unit 2 procedures have been revised to require filling and venting the system after it has been completely depressurized. The installation of seal-less RWCU pumps is planned for the fall 1992 Unit 2 outage.

The inspector identified a procedural performance deficiency for confined space entry. Operations personnel did not post a confined space entry sign and properly complete the log entry card during performance of remote position indication checks in the Emergency Service Water valve vault as required by Safety Procedure 13, Confined Space Entry. Section 2.2.3 pertains.

Radiological Controls (71707)

The inspector toured the Unit 1 drywell during the Refueling and Inspection Outage. Several weaknesses were noted during the tour. Radiological postings within the drywell were marginal, and there was ineffective use of temporary shielding. Additionally, workers inside the drywell were not aware of radiation levels in their work area when questioned by the inspector. NRC Inspection Report 50-387/92-12 documents these findings. Section 3.2.1 pertains.

Maintenance/Surveillance (61726, 62703)

Two unplanned ESF actuations were attributable to maintenance activities associated with 4.16kv bus outage. These ESF actuations occurred during performance of ESS bus scheduled outage procedures. No scrams were attributable to maintenance or surveillance activities. Section 4.5 pertains.

The inspector identified a non-destructive examination (NDE) procedural weakness regarding data recording. NDE procedures lack specific written guidance on when to record NDE data. This presents a potential data recording accuracy problem. Section 4.4.2 pertains.

Engineering/Technical Support (71707, 92720, 93702)

The inspectors reviewed engineering work activities and determined that they were being performed in accordance with applicable procedures and were being properly prioritized and executed.

The recurrent tripping of Electrical Protection Assembly (EPA) breakers that supply power to the Reactor Protection System (RPS) has been a long standing problem. There have been at least 34 separate instances since 1984 where EPA breaker trips were caused by unknown causes or logic card failures. Many of these trips have led to half scrams and system isolations. In the case of the RWCU pumps, system isolations have been determined to be a major contributor to seal failure. The licensee actions to date to correct this problem have been ineffective. This is an apparent violation of 10 CFR 50 Appendix B.

As a result of planned erosion/corrosion inspections, the licensee found excessive erosion/corrosion at certain locations within three distinct systems, i.e., Main Steam (MS), Main Feedwater (FW), and Extraction Steam. Of particular interest was the wall thinning seen in the MS and FW systems since the locations are unisolable. For the FW system, the licensee evaluated this data and determined that continued operation could not be justified for the current fuel cycle. Therefore, the FW pipe was weld repaired per Section XI of the ASME Boiler and Pressure Vessel code in the current Unit 1 refueling outage. The preliminary data for the "C" MS line has led the licensee to conclude that operation for the next cycle is justified based on an extremely conservative erosion rate of .100" per fuel cycle. The licensee determined that although these locations were viewed as susceptible to erosion/corrosion, the magnitude of wall thinning, particularly in the FW system, exceeded expectations. The NRC staff was in the final stages of issuing an Information Notice at the conclusion of this inspection period. A Erosion/Corrosion team inspection was planned for May 4-8, 1992.

Safety Assessment/Assurance of Quality (40500, 90712, 92700, 92701)

The inspector reviewed 99 Significant Operating Occurrence Reports (SOORs), and 11 Licensee Event Reports (LERs) during the period. Two non-cited violations were documented as a result of the LER review. Nine SOORs were followed up and results are documented in this inspection report.

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1. SUMMARY OF OPERATIONS

1.1 Inspection Activities

The purpose of this inspection was to assess licensee activities at Susquehanna Steam Electric Station (SSES) as they related to public health and safety, including reactor safety and worker radiation protection. Within each inspection area, the inspectors documented the specific purpose of the area under review, the scope of inspection activities and findings, along with appropriate conclusions. This assessment is based on actual observation of licensee activities, interviews with licensee personnel, measurement of radiation levels, independent calculation, and selective review of applicable documents.

Abbreviations are used throughout the text. Attachment 1 provides a listing of these abbreviations.

1.2 Susquehanna Unit 1 Summary

Unit 1 entered the inspection period in coastdown at 94.5% power. On February 25, power was reduced to 60% for the remainder of the cycle to remain within the licensing envelope for the next fuel reload. The sixth refueling outage commenced on March 6 when the main generator was taken off-line at 11:40 p.m.. On March 7 the mode switch was placed in shutdown at 6:14 p.m., cold shutdown was reached on March 8 at 5:20 a.m.. The refueling mode was entered on March 10 at 11:39 p.m.. During the shutdown an Engineered Safety Feature (ESF) actuation occurred when the Reactor Water Cleanup (RWCU) system isolated at high flow. Section 2.2.2 pertains. Additional ESF actuations that occurred during the inspection period are listed below:

-- On February 20 operations was unable to open Unit 1 or Unit 2 drywell nitrogen makeup valves or drywell vent bypass outboard isolation valves due to a failed relay circuit board in the SGTS radiation monitoring system. (Section 8.1, LER 92-004-00 pertains)

-- On February 23 normal power to the Unit 1 "B" reactor protection system (RPS) bus was lost when both of its electrical protection assembly (EPA) breakers tripped resulting in a half scram, ESF actuations, and containment isolations. Isolations and initiations occurred as designed. Section 7.2.1 pertains.

-- On March 28 the "A" train of the standby gas treatment (SGTS) auto started along with the "A" train of control room emergency outside air supply system (CREOASS) during planned restoration of the "A" ESS bus following outage work. Section 4.5 pertains.

-- On March 31 a Zone III isolation and autostart of the "B" train of SGTS and "B" train of CREOASS occurred during removal of an ESS bus from service in preparation for planned outage work. Section 4.5 pertains.

-- On April 7 an ESF actuation occurred when power was lost to "B" RPS bus when both RPS "B" normal power supply EPA breakers tripped. Section 7.2.1 pertains.

1.3 Susquehanna Unit 2 Summary

Unit 2 operated at or near full power during the inspection period except for March 18 through March 27. On March 18 the unit was manually scrammed due to a degraded plant condition following an ESF actuation that resulted in the deenergization and lockout of 4.16kv 2C engineered safety system (ESS) bus. Section 2.2.1 pertains.

2. OPERATIONS

2.1 Inspection Activities

The inspectors verified that the facility was operated safely and in conformance with regulatory requirements. Pennsylvania Power and Light (PP&L) Company management control was evaluated by direct observation of activities, tours of the facility, interviews and discussions with personnel, independent verification of safety system status and Limiting Conditions for Operation, and review of facility records. These inspection activities were conducted in accordance with NRC inspection procedure 71707.

The inspectors performed 27.5 hours of deep backshift inspections. These deep backshift inspections covered licensee activities between 10:00 p.m. and 6:00 a.m. on weekdays, weekends and holidays.

2.2 Inspection Findings and Review of Events

2.2.1 Manual Reactor Scram due to a Loss of the Unit 2 "C" ESS Bus

Introduction

On March 18, at 9:49 a.m., the Unit 2 "C" 4KV Engineered Safeguard System bus (2A203) tripped while an operator was resetting a relay target on the bus. As a result of the bus loss, certain valves either lost power or failed closed. One of these valves directs nitrogen to the Main Steam Isolation Valves (MSIVs) to hold the valves open against spring pressure. The loss of nitrogen supply to the MSIVs was viewed as a potential precursor to MSIV closure. As a result, the licensee conservatively ordered a manual scram of the Unit 2 reactor at 10:06 a.m., March 18 in anticipation of MSIV closure. Operators conducted actions per the reactor scram procedure (EO-200-101) and the unit was eventually stabilized in hot shutdown. The bus loss caused a loss of drywell (DW) cooling which resulted in a heatup and pressurization of the drywell. The licensee compensated for the heatup by installing temporary power to various components to: 1) prevent MSIV closure, 2) allow DW depressurization, and 3) lower DW temperature. Power was restored to the "2C" bus at 8:53 p.m., March 18. The inspector was in the control room at the time of the event and directly observed and assessed licensee actions throughout the event.

A chronology of the event is provided in Attachment 2. This chronology was based on personal observation of operator actions and plant indications, discussions with licensee personnel, review of operator logs and other pertinent references.

Event Response

The inspector was in the control room at 9:49 a.m., March 18 conducting on-going safety inspections when the initial alarms annunciated a loss of the "2C" ESS bus. Operators promptly identified the loss of the Unit 2 "C" ESS bus and began considering the effects on various power plant components and establishing priorities. To minimize the likelihood of error, the dayshift shift supervisor (operations supervisor) promptly encouraged the use of offnormal procedures, a walkdown of the control boards, and thoughtful actions. As this was being done, a nuclear plant operator reported a flash inside the 87A1-B relay on the "2C" ESS bus when he had reset it. The relay had just been reset to allow substitution of the "E" Diesel Generator (DG) for the "B" DG to compensate for an unrelated problem.

Control room operators assessed the equipment affected and determined that there were a number of valves that had either lost power or had failed closed. The loss of these valves, in many cases, caused a loss of the system function. Among these, was the Containment Instrument Gas (CIG) to the Main Steam Isolation Valves (MSIVs) (SV-22651). Its closure interrupted nitrogen supply to the MSIVs, but sufficient pressure remained to maintain the MSIVs open. Nitrogen pressure supplied by the CIG system was designed to hold the valves open against spring pressure. Thus, as a conservative measure, to minimize the potential effects of MSIV closure, the operations supervisor prudently directed the shift supervisor to initiate a manual scram. As a precursor to the scram, operators performed actions per the Scram Imminent Operating Procedure (OP) by reducing Reactor Recirculation (Recirc) flow to minimize the pre-scram power level, transferring auxiliary busses to the startup transformers, and contacting the Power Control Center. At 10:06 a.m., March 18, the reactor was manually scrammed when the mode switch was taken to shutdown. Operators performed immediate actions per EO-200-101. All control rods inserted, the main generator tripped and no safety relief valves opened.

Post-scram reactor water level control was challenging. Since power was lowered immediately preceding the scram, post-scram feed flow was excessive with three reactor feedwater pumps (RFPs) running. Two minutes after the scram, the "C" RFP was tripped after level exceeded 40 inches with an increasing trend. Even with level setdown in effect (resets target level to +18 inches), level eventually peaked at 53 inches by control room indication; one inch below the level 8 trip of all running RFPs. The poor control of reactor water level was indicative of a continuing weakness in operator control of analog parameters. This same weakness was observed by the inspector during the post-scram level and pressure control from the July 31 scram with MSIV closure.

To evaluate the effects of the 2C bus loss, an engineering team was promptly assembled. They met initially in the Technical Support Center (TSC), one level above the control room. They were initially tasked with installing temporary power supplies to key components. The first temporary power supply was installed on SV-22651 at 12:54 p.m.. As a result, SV-22651 was opened and nitrogen pressure was restored to the MSIVs. The second temporary supply was an alternate pneumatic supply to the Drywell/Wetwell Vent and Purge damper (HD-27508A). The restoration of this supply at 1:20 p.m. allowed the licensee to depressurize the DW. The DW was subsequently depressurized over the next 4 hours. Peak pressure reached was 1.25 psig which was less than the high DW pressure (LOCA) setpoint of 1.72 psig. The third concern involved numerous valves associated with Unit 2 drywell cooling. The licensee also installed temporary power to the 2C bus. Consequently, DW cooling was restored at approximately 7:15 p.m.. The bus was eventually restored at 8:53 p.m..

Followup Activities

The inspector noted that DW temperature continued to increase immediately after the scram until DW cooling was established at approximately 7:15 p.m., March 18. Peak temperature detected was 194 °F, while maximum average temperature was 165 °F. The licensee chose to remain in hot shutdown while actions were being taken to restore DW cooling. By cooling down to cold shutdown (<200 °F), the licensee could have significantly reduced the heat input from the RPV, recirculation pumps and other related piping and equipment. The inspector noted that continuing the cooldown would have reduced the magnitude and duration of the DW temperature transient.

As a normal followup action, the licensee initiated a scram action items list to document issues to be resolved prior to startup. The need for engineering evaluation of the DW temperature transient was not initially included on the list. When questioned by the inspector, the licensee stated that temperature transient would be evaluated with the overall plant response. After considering this response, the inspector elevated this concern to licensee engineering management. During this discussion at 8:15 a.m., March 19, the inspector determined that the licensee had only planned a limited evaluation of the temperature transient, and that the review would not consider the effects on the structural components of the drywell or necessitate a containment walkdown. Following this discussion, the licensee agreed to perform a thorough evaluation of the DW upon plant cooldown. In addition, Unit 2 was cooled down and depressurized to perform a walkdown of the drywell.

The licensee conducted a conference call with the NRC on March 20 to discuss the March 18 scram, corrective actions to date and preliminary conclusions reached. This call was reviewed as a good interchange between PP&L and the NRC.

After reevaluating the potential significance of the transient, the licensee began a detailed evaluation on March 19. The scope included system level environmental qualification (EQ) assessment of affected valves, pumps, heat exchangers and other components. It also included the effects of the elevated temperature on structural components, such as, containment coatings, structural steel and concrete, piping, penetrations and hatches and the liner plate. This evaluation projected a peak localized temperature of 200 °F to be used as the basis for assessing effects. The licensee determined the most likely effect would be on elastomers, Buna-N, Viton, and Silicon seals and gaskets. The licensee reviewed their applications and uses and determined that all three of these materials were capable of withstanding service temperatures above 200 °F. The functioning of other structures and system was also reviewed and found to be bounded by the post-LOCA environment. The licensee did not assign lifetime penalties to any EQ equipment or other components.

As a part of this evaluation, a DW walkdown checklist was developed. It targeted components that could have been affected by the temperature excursion. During the walkdown, the checklist was used and no attendant discrepancies were noted. Other discrepancies, that were believed to have been unrelated, were satisfactorily resolved prior to heatup.

Electrical Distribution System Performance

The onsite electrical power distribution system for each unit is divided into four independent Class 1E load group channels, channels A, B, C, and D. Each Engineered Safety System (ESS) bus shares a diesel generator with its counterpart load group from the other unit. Each load group has its distribution loads assigned to it. Minimum engineered safety feature loads required to shutdown the unit safely and maintain it in a safe shutdown condition are met by any combination of three out of four load group channels. The four class 1E load groups are also grouped to form two divisions for meeting the design basis of one-out-of-two ESF load requirements.

Each of the class 1E load group has a 4.16kv ESS bus which has connections to two independent offsite power supplies and to a single onsite Emergency Diesel Generator (DG). Each load group is interlocked so that only one of the power supplies can be connected at any one time except during DG testing when the DG is synchronized to one of the offsite sources. If the preferred offsite power source becomes unavailable, an automatic transfer is automatically initiated to the alternate power source. If due to any reason, both offsite power sources become unavailable, the respective bus DG starts, and loads the bus to supply emergency loads.

Each ESS bus is equipped with protective relay schemes for bus overcurrent and bus differential. When any one of the these relay protection scheme actuates it trips and lockouts all circuit breakers connected to the bus. The main purpose of these relay protection schemes is to isolate faulted equipment and/or circuits from unfaulted equipment and/or circuits. The 2C ESS bus has three bus differential relays (87A1-A, B and C) to protect the bus from an internal fault. When a fault is sensed by any one of these relays, the bus feeder breakers and DG output breaker are prohibited from closing onto the bus by electrical interlock. Simultaneously, all the associated load breakers connected to the bus, are tripped open to protect equipment (bus lockout condition).

Based on the inspector's review of plant protective design drawings and discussion with the involved licensee staff, it appears that the differential relay on the 2C bus was inadvertently actuated when the seal-in contact (SI) contact portion of relay was closed while the 2C bus differential relay (87A1-B) target was being reset by the operator. The seal-in contact is mounted in the upper left corner of the relay. This contact has its own coil in series and its contacts in parallel with the main relay contacts. Typically, when the main contact closes, the relay seals in the fault condition. When the seal-in unit picks up, it raises a target (plastic orange strip) into view. The target latches up and remains exposed until it is released by a manual operation of reset button, which is located at the lower left corner of the relay cover. The-seal in contact of the 87A1-B relay is part of the seal-in target assembly. The action of depressing the target reset applies a force in the direction of seal-in contact closure. Therefore, upon closure of this seal-in contact the bus lockout relays associated with the 2C bus energized and tripped all the bus breakers closed, per the design.

After a detailed review of electrical distribution system's performance, the inspector also concluded that all electrical protective equipment functioned in accordance with plant design. The 2C ESS bus electrical protective features operated per design and locked out the 2C bus, as expected. Also, in this case, the 2C bus loss of voltage initiated an emergency start of the "C" DG in response to the undervoltage condition detected at the 2C bus. Additionally, the "C" DG started and did not load onto the 2C bus, per design.

The inspector reviewed licensee corrective actions to ensure that related equipment and bus work was not damaged or degraded. The licensee's corrective action included meggering the bus, functionally checking the potential transformer circuitry and differential relay (87A1-B). The 87A1-B relay "as found" set point was compared with the historical data. No deficiencies were found. After ensuring all electrical components and associated circuitry with the 2C bus was functioning properly, the bus and related equipment were returned to their normal configuration.

As a result of power loss on the ESS 2C bus, power distribution panel 2Y236 also lost power. Circuit breakers No. 8 and 10 of this panel supply 120V ac power to Containment Instrument Gas (CIG) system and Reactor Building Chilled Water (RBCW) Containment Isolation Valves. Solenoid valve SV-22651, supplies CIG to systems inside the Drywell (DW) including the Main Steam Isolation Valves(MSIV's). The CIG system SV is energized to open and fails closed on a loss of power. The licensee took actions to energize this SV by a temporary power supply so that its supply to all MSIV could be maintained. The licensee also decided to install a 120V ac temporary power supply to six RBCW CIVs (per Work Authorization, WA No.V20140). The energization of these valves was required to restore one of the drywell cooling system loops to reinitiate drywell cooling.

The inspector reviewed the bypasses (temporary modifications) that installed these temporary power supplies and found them to be adequate. The bypasses had appropriate safety evaluations, proper documentation, and satisfactory pre- and post-modification testing.

Findings and Conclusions

The following depicts a summary of the inspectors' findings and conclusions from the March 18 loss of 2C ESS bus and resultant manual reactor scram:

-- The inspector noted that after initial discussions of the priorities, the operators began fully implementing applicable procedures. Reactor water level, temperature, and pressure was stabilized within 10 minutes after the scram. With one exception, the operators did an excellent job of responding to the event. FW level control was a noted problem area from an operator response standpoint. An operator was slow to take actions to stop the reactor water level increase. The level increase came within one inch of tripping all running RFPs. The licensee agreed with this weakness and has planned increased simulator time to improve analog parameter control. This will be completed by December 31, 1992.

-- The licensee decided to stop the Unit 2 cooldown, while trying to establish the temporary power supplies needed to ameliorate the effects of the 2C bus loss. This unnecessarily increased the ambient heat input into the drywell. Continuing the cooldown to less than 200 °F would have significantly reduced the duration and magnitude of the drywell temperature transient. At the time, the licensee was not aware of the consequences of staying in hot shutdown. However, they were later found to be minimal.

-- The Scram Action Item List did not specifically require an engineering evaluation for the DW temperature excursion. The inspector found that the requirements for these types of evaluations are addressed in a general nature in AD-QA-327 Step 6.3.2 which lists the requirement for evaluations prior to restart. However, the guidance for the conditions under which evaluations are needed requires amplification. In this case, the average DW temperature of 165 °F exceeds the TS 3.6.1.7 limit by 30 °F. Yet, no specific evaluation was required even though this is a limiting assumption for the accident analysis. After inspector interaction, a detailed engineering evaluation was performed. However, the scope and depth of the evaluation was influenced by NRC involvement. The licensee has agreed to review and modify the necessary procedures.

The following last two conclusions may have generic implications. They are related to the lack of diversity in electrical distribution system design and a procedural weakness in coping with a long-term loss of an ESS bus.

-- The inspector found that the basic design of the 2C ESS bus lacked sufficient separation. Specifically, that CIVs for all four DW coolers were supplied by an MCC powered from the 2C ESS bus. Thus, a loss of this bus resulted in the inability to cool the DW. In this case, DW temperature continued to increase unabated until cooling was reestablished about nine hours after the loss of the 2C bus. The inability to provide at least one train

of DW cooling during an anticipated operational occurrence is of concern. The licensee has agreed to review the need for design changes for this lack of separation. This will be completed by 12/31/92.

-- The inspector also noted that procedures did not address a sustained loss of the "2C" ESS bus. The procedures were written to identify the lost loads, and short-term corrective actions. The procedures did not identify the need for temporary power supplies. The licensee has agreed to develop or revise existing procedures to address a sustained loss of any ESS bus. This will be completed by December 31, 1992.

2.2.2 Reactor Water Cleanup System Isolations

On March 7, while performing deep backshift inspection, the inspector noted electricians repairing the position indication for a butterfly valve on the 719 foot elevation of the Unit 1 Reactor Building. At 11:40 a.m., it had been unintentionally struck by a shield block for the drywell equipment access. . Apparently, workers were rigging the blocks out of the area when one of them jerked while being suspended by an overhead chain fall. This caused the block to impact a limit switch for the Reactor Building Closed Cooling Water (RBCCW) to the drywell return valve (FV-18771C) which damaged the position indicating limit switch and caused a short circuit. The short circuit that resulted caused a fuse to blow which interrupted power to the control circuit. As a result, the drywell cooling and recirc pump motor cooling supply realigned from Reactor Building Chilled Water (RBCW) to Reactor Building Closed Cooling Water (RBCCW) system when the solenoids associated with valves FV-18771A-D were deenergized. The low flow condition in the RBCW loop led to the trip of the operating reactor building chiller. When RBCCW realigned to the drywell, the RWCU non-regenerative heat exchanger load was isolated, which led to a RWCU system isolation on high inlet temperature to the heat exchanger. During the time that RBCCW was cooling the drywell, average drywell temperature increased from 123°F to 132°F.

Licensee management responded to the area and the inspector noted that the licensee took the following actions:

-- Movement of the shield blocks was halted until Reactor Operational Condition 4 was established.

-- The Duty Manager was notified.

-- The affected limit switch assembly was isolated from the circuit to allow for circuit reenergization.

-- The affected valve failed open and the manual isolation valve (187123) associated with it was closed and yellow-tagged to allow for RBCW system restoration.

-- The reactor building chiller was successfully restarted.

The inspector considered these actions prudent for the circumstances. There was a second and third RWCU isolation during system restoration attempts made at 1:30 p.m., March 7 and at 6:04 a.m., March 8. Between 11:40 a.m. and 1:30 p.m., Operators restored cooling water to the non-regenerative heat exchanger (NRHX) and were also in the process of restoring the RWCU System. RWCU Operating Procedure provides two criteria for determining if the system is required to be filled and vented as part of restoration following an automatic isolation. The first criterion that allows restoration is less than two hours has elapsed since the isolation occurred. The second criteria is that RWCU temperature must be less than saturation temperature for actual RWCU Pressure. Both of these conditions were satisfied, and thus, the licensee decided not to fill and vent RWCU as part of the restoration process. When the outboard isolation valve was opened per procedure, a RWCU System high flow signal was initiated resulting in an ESF actuation. The licensee postulated a rapid inflow of water into the RWCU System piping because the system was not completely filled. In Licensee Event Report (LER) 92-003-00 (Section 8.1 also pertains), the licensee concluded the root cause of the second isolation was due to the existing RWCU pump design. The inspector noted that the rapid inflow was due to voiding between the outboard CIV and the RWCU pump discharge check valves. The procedure directed monitoring for saturation conditions outside this sub-system boundary. The licensee has recognized this as a Unit 2 RWCU procedure weakness and has corrected this by now requiring filling and venting after system isolation. The inspector initially had concerns regarding the adequacy of the procedure that have been addressed by the recent revision.

The third isolation occurred during system restoration on March 8 as a result of a high differential flow signal. This isolation occurred because of a failed Rosemount differential flow transmitter which was replaced and recalibrated. The inspector had no further questions on the third isolation.

2.2.3 Confined Space Entry Procedure Performance Deficiency

On April 7, the inspector observed operations personnel performing Residual Heat Removal Service Water System Remote Position Indicator checks in the Emergency Service Water (ESW) valve vault. The ESW valve vault is considered a confined space. The inspector questioned the operators on Safety Procedure 13, Confined Space Entry, which was being utilized during the indicator checks.

The inspector determined that Safety Procedure 13 was not properly implemented. Specifically, the operators failed to post a confined space entry procedure sign at the entrance to the confined space; and did not post and properly complete the entry log card. The placement of the sign indicates that a confined space entry is in progress and outlines the steps to be taken in the event of an emergency. The entry log card identifies the responsible/qualified individual at the entry point to the confined space. It also provides space to record the actions taken to support the entry and the recording of sampling data obtained. The inspector determined that a responsible individual was present and required atmospheric sampling was performed prior to and during entry. The inspector had no further questions.

The inspector notified the licensee's Industrial Safety Group and shift supervision. The individuals involved were instructed on the proper use of the procedure. Operations Training was conducted on proper confined space posting and entry controls. The inspector had no further questions.

3. RADIOLOGICAL CONTROLS

3.1 Inspection Activities

PP&L's compliance with the radiological protection program was verified on a periodic basis. These inspection activities were conducted in accordance with NRC inspection procedure 71707.

3.2 Inspection Findings

3.2.1 Unit 1 Drywell Tour

The inspector toured the Unit 1 drywell, with a region based health physics inspector, on March 25. Unit 1 outage activities were well underway at the time of the tour. The inspector identified deficiencies relative to radiological postings in work areas within the drywell, ineffective use of temporary shielding, and insufficient knowledge of workers inside the drywell relative to radiation levels in the work areas. These findings are detailed in NRC Inspection Report 50-387/92-12.

Housekeeping and cleanliness controls were observed and found to be effective throughout the drywell. The inspector determined that combustible material and fire prevention controls were properly implemented. Additional strengths noted were well-lighted working conditions and use of a roving health physics technician to monitor ongoing activities within the drywell.

The inspector identified potential industrial safety hazards on the 738' and 779' elevations. These potential hazards included unattended loose tools on incomplete scaffolding and scaffolding without proper protective padding on protruding edges. The inspector informed the industrial safety group of these deficiencies. These industrial safety conditions were promptly corrected by the licensee.

4. MAINTENANCE/SURVEILLANCE

4.1 Maintenance and Surveillance Inspection Activity

On a sampling basis, the inspector observed and/or reviewed selected surveillance and maintenance activities to ensure that specific programmatic elements described below were being met. Details of this review are documented in the following sections.

4.2 Maintenance Observations

The inspector observed and/or reviewed selected maintenance activities to determine that the work was conducted in accordance with approved procedures, regulatory guides, Technical Specifications, and industry codes or standards. The following items were considered, as applicable, during this review: Limiting Conditions for Operation were met while components or systems were removed from service; required administrative approvals were obtained prior to initiating the work; activities were accomplished using approved procedures and quality control hold points were established where required; functional testing was performed prior to declaring the involved component(s) operable; activities were accomplished by qualified personnel; radiological controls were implemented; fire protection controls were implemented; and the equipment was verified to be properly returned to service.

These observations and/or reviews included:

-- WA 14085 and 14086, Reactor Water Cleanup Pump Removal and Replacement, dated March 18, 1992.

-- WA 12827, 4.16kv Engineered Safeguards Bus Outage, dated March 27,1992.

-- PMR 91-3022, Jet Pump Sensing Line Clamp Modification, dated April 1, 1992.

-- WA 13303, Inspect Unit 1 RCIC Turbine Overspeed Trip Mechanism and Install New Tappet Ball, dated April 14, 1992.

4.3 Surveillance Observations

The inspector observed and/or reviewed the following surveillance tests to determine that the following criteria, if applicable to the specific test, were met: the test conformed to Technical Specification requirements; administrative approvals and tagouts were obtained before initiating the surveillance; testing was accomplished by qualified personnel in accordance with an approved procedure; test instrumentation was calibrated; Limiting Conditions for Operations were met; test data was accurate and complete; removal and restoration of the affected components was properly accomplished; test results met Technical Specification and procedural requirements; deficiencies noted were reviewed and appropriately resolved; and the surveillance was completed at the required frequency.

These observations and/or reviews included:

-- NMTWD-1 Inservice Inspection Magnetic Particle Inspection for the "A" Core Spray Pump Discharge Flange, dated March 3, 1992.

-- SI-180-416, Reactor Water Level Switches - Time Response Testing, dated March 30, 1992.

-- SO-116-113, Residual Heat Removal Service Water (RHRSW) Quarterly Flow Verification, dated April 7, 1992.

4.4 Inspection Findings

The inspector reviewed the listed maintenance and surveillance activities. The review noted that work was properly released before its commencement; that systems and components were properly tested before being returned to service and that surveillance and maintenance activities were conducted properly by qualified personnel. Where questionable issues arose, the inspector verified that the licensee took the appropriate action before system/component operability was declared. Except as noted below, the inspectors had no further questions on the listed activities.

4.4.1 Reactor Water Cleanup Pump Removal and Replacement

During a plant maintenance inspection, the inspector noted a potential design problem with the cart that supported the new seal-less RWCU pumps. The weight of the pump was transmitted to the wheel assembly through a steel support plate. This plate was configured in such a way that appeared to impact on a cooling water flange for the pump. Since the inspector was concerned with gouging or marring of the seating surface, he contacted the Modifications Installation Group (MIG) engineer. The engineer agreed with the finding and added a QC hold point to WA 14089 that required QC to verify flange face cleanliness and the absence of damage prior to installing any interconnecting piping. This inspection was conducted on April 3 with no adverse findings. The licensee also agreed to evaluate the need to modify the cart design for the Unit 2 Fall 1992 outage. The inspector had no additional questions.

4.4.2 Inservice Inspection Magnetic Particle Test

The inspector observed a magnetic particle test (MT) pre-outage inservice inspection (ISI) that was performed on the Unit 1 "A" Core Spray pump discharge flange. The inspector questioned the two ISI contractor technicians on the exam and the procedure. The two individuals appeared to be knowledgeable in performance of their activities and were properly qualified. The individuals were specifically questioned on when NDE data is required to be recorded. The individuals responded that unless there is an indication, the data is required to be recorded by close of business that day prior to leaving the site.

The inspector determined that the MT procedure did not provide clear guidance on when data required by the procedure is to be recorded. Procedure MI-II-003 ISI Data Review and Approval provides instructions on review and approval of ISI NDE data reports generated during ISI. This procedure requires written notification within 12 hours of discovery of an indication. For instances where there are no indications there is no specific guidance on when to record data. This lack of written guidance presents a potential problem with the accuracy of data recording since there is no limit on the amount of NDE exams conducted by an ISI NDE technician in a given day.

The inspector reviewed this matter with the Supervisor Quality Control and the Nuclear Department NDE Level III. Subsequently the licensee issued written guidance on when to record NDE data. Additionally, the licensee agreed to revise NDE procedures and training to include guidance on when to record NDE data prior to September 1, 1992 which is before the scheduled Unit 2 Refueling Outage.

4.5 ESF Actuations During Bus Outage Work

Two ESF actuations occurred during 4.16kv ESS Bus Outage work on separate occasions during the current inspection period.

On March 28, the "A" train of SGTS auto-started along with the "A" train of CREOASS during planned restoration of the "1A" ESS Bus following outage work. Electrical maintenance workers were in the process of restoring normal power supply to the logic circuits for HVAC LOCA and radiation trip signals in accordance with (IAW) OP-105-002 (ESS Bus "1A" schedule outage). The power supply to that circuit was previously swapped from its normal source to a temporary source. During the first step of restoration the temporary power leads are lifted. When a temporary power lead was lifted the SGTS and CREOASS systems auto-started, and normal Zone III ventilation isolated per design.

On March 31, an inadvertent Zone III isolation and auto start of the "B" train of SGTS and CREOASS systems occurred. In preparation for removing ESS Bus "1B" from service for outage work, the power supply was deenergized to the HVAC LOCA and radiation trip logic to allow installation of temporary power. At this point the electrical maintenance workers determined they needed to install banana jacks prior to continuing with the procedure. Since a Technical Specification Limiting Condition for Operation was entered when the power supply was deenergized, operators reclosed the normal power supply breaker to prevent exceeding the LCO action statement time limit. When the breaker was reclosed, Zone III ventilation isolated, and the "B" train of SGTS and CREOASS auto-started.

The licensee formed an event review team to investigate these two events. One LER will document both ESF actuations. The inspector will determine the adequacy of licensee assessment and corrective actions during review of the LER.

5. EMERGENCY PREPAREDNESS

5.1 Inspection Activity

The inspector reviewed licensee event notifications and reporting requirements for events that could have required entry into the emergency plan.

5.2 Inspection Findings

No events were identified that required emergency plan entry. No significant issues were identified.

6. SECURITY

6.1 Inspection Activity

PP&L's implementation of the physical security program was verified on a periodic basis, including the adequacy of staffing, entry control, alarm stations, and physical boundaries. These inspection activities were conducted in accordance with NRC inspection procedure 71707.

6.2 Inspection Findings

The inspector reviewed access and egress controls throughout the period. No significant observations were made.

7. ENGINEERING/TECHNICAL SUPPORT

7.1 Inspection Activity

The inspector periodically reviewed engineering and technical support activities during this inspection period. The on-site Nuclear Systems Engineering (NSE) organization, along with Nuclear Technology in Allentown, provided engineering resolution for problems during the inspection period. NSE generally addressed the short term resolution of problems, and scheduled modifications and design changes, are addressed by the Nuclear Modifications organization, to provide long term problem correction. The inspector verified that problem resolutions were generally thorough and directed at preventing recurrences. In addition, the inspector reviewed short term actions and concluded that they provided reasonable assurance that safe operation could be maintained.

7.2 Inspection Findings

7.2.1 Poor Reliability of the Reactor Protection System Power Supplies

On a continuing basis, the inspector has monitored the frequency and type of Reactor Protection System (RPS) problems. The recent increase of problems appears excessive considering the overall importance of the system. Thus, the inspector conducted a review of historical information to assess its significance. Station Operational Occurrence Reports (SOORs) have documented at least 138 problems with the RPS of both units since 1982. The majority of problems were attributed to known causes. However, some problems had no known cause. The inspector was concerned that these problems have existed without effective corrective action for an extended period of time.

Thus, the inspector met with licensee engineering personnel on March 6 to discuss this concern. Prior to the meeting, the inspector independently reviewed the master listing for RPS SOORs. This listing provided a one line description of each SOOR. The majority of the problems with the RPS power supplies were attributable to Electrical Protection Assembly (EPA) breaker tripping. Spurious EPA breaker tripping has been a long-standing licensee problem. Three major causes have dominated the problem history:

-- The first problem involved EPA breaker tripping caused by large motor starts in the 1982 to 1985 time frame. This problem was remedied by the installation of isolating-regulating (Isoreg) transformers.

-- The second problem involved a poor design in an RPS power distribution (breaker) panel that distributed power to various RPS loads. The cable routing inside the panel caused excessive strain and frequent cracking of a protective insulator on a key circuit breaker. The licensee repeatedly replaced this breaker after it grounded the RPS bus on numerous occasions. The failure to consider this long-standing problem as a design weakness led to a loss of shutdown cooling and the declaration of an Alert in February 1990. This design weakness existed in excess of five years and was corrected by a new breaker panel that was designed and installed on both units within a two week period immediately following the loss of shutdown cooling event.

-- The third, and current, problem involves the failure of the RPS power supplies to be reliable as a result of the effect of high area temperatures on the EPA logic cards. The EPA logic cards and breaker assemblies are installed in both unit's reactor building. The enclosures are sealed shut and not ventilated. As a result, the electronic components on the EPA Logic Cards are subject to accelerated aging.

The inspector noted that resolution of the first problem was performed in a timely manner. The problem was indicative of a design weakness that was addressed in a time frame commensurate with its safety significance. The second problem was strictly addressed on a repair/replacement basis. The licensee failed to immediately view the repetitive failures as a weakness in the basic design. This problem was corrected after a breaker panel of a different design was installed in February 1990. The resultion of the latter problem is continuing.

One of the latest unexpected occurrences of breaker tripping occurred on February 23, 1992. The inspector reviewed Licensee Event Report (LER) 1-92-001 and Significant Operating Occurrence Report (SOOR) 1-92-064 which documented loss of normal power to the "B" RPS bus and the accompanying half scram with isolations. The licensee found the EPA breakers open, and an investigation ensued with no cause found. The EPA breakers were closed, the scram was reset, and systems were restored to their normal configuration. During this review, the inspector noted the LER and SOOR referenced 11 and 16 past similar events, respectively. In the case of SOOR 1-92-064, the inspector noted that the licensee searched the SOOR database for past similar SOORs and identified none. However, a search of the database, by the inspector, under "cause unknown" yielded the 16 SOORs mentioned above. Specifically, a partial listing included one 1986, no 1987, and two 1988 SOORs (1-86-079, 1-88-082, 1-88-177). The inspector found that this search yielded incomplete results.

The inspector independently reviewed past SOORs since 1982 and for the years of interest to assess the adequacy of the licensee's investigation. The inspector found that there were at least 34 distinct EPA breaker trips documented in SOORs since 1984 where the cause was: 1) unknown, 2) from a postulated problem, or 3) attributable to a direct failure of an EPA logic card or related component. These results were compared to the PP&L results in a tabular format:

YEAR	PP&L EPA FAILURES	NRC IDENTIFIED TRIPS
1984	1	2
1985	0	1
1986	1	4
1987	2	6
1988	2	5
1989	6	2
1990	5	6
1991	3	6

This data shows that the licensee did not consider EPA breaker trips where no known cause was found. The inability to identify a specific cause for these earlier trips and the failure to include these in overall data base indicates a lack of licensee attention to a significant condition adverse to quality and resulted in failure to effectively correct the condition. The omission of trips from unknown or postulated causes resulted in a delay in escalating corrective action implementation to its current level.

The inspector also monitored the performance of the licensee's task team that was formed in May 1991 to address the excessive number of EPA breaker trips. The inspector noted the formation of a task team was a good licensee initiative. However, considering the frequency of these events in previous years its formation was untimely. Additionally, the team did not have a written charter or clear direction on its specific scope. When the team members were questioned regarding its activities, the inspector found that there were meetings. However, they were not regularly scheduled, and there were differences in expectations with respect to the team's activity.

The inspector has noted that the licensee began many new initiatives to increase the focus of engineers on plant systems. Specifically, numerous changes in the licensee's engineering organization were made as a result of the Organizational Effectiveness Review (OER). The OER has increased the total number of Nuclear Systems Engineering (NSE) staff from approximately

70 to 100 people. In addition, the number of systems that each engineer was responsible for has decreased from four to six down to one or two systems. This has been done to increase the focus of each engineer on a limited number of systems.

Notwithstanding the above positive aspects, the inspector considers the lack of effective corrective action for the RPS power supply problem significant. Four specific factors have contributed on the licensee's inability to permanently correct the problem:

-- The licensee does not always consider the existence of recurring problems indicative of a weak design. The typical licensee approach of modifying procedures, improving preventative maintenance, and replacing defective components was ineffective at preventing recurrence for the current EPA breaker tripping problem. This should have indicated a weakness in the basic design.

-- The responsibilities and accountabilities of the engineer in the old "Tech" organization were significantly diluted because of the number of systems each engineer was expected to oversee. The burdensome work load on each engineer minimized the likelihood of effective problem resolution. The new NSE organization minimizes the number of system responsibilities to increase engineer accountability.

-- The use of feedback from trending programs for system problems was weak. Information from many sources is being gathered. However, it is not being used effectively to understand and resolve long-standing system problems. Engineers were not always aware that many NCRs, EDRs and SOORs indicated the existence of recurring problems on their systems. The feedback provided by these systems appears under utilized.

-- In general, engineers have stated that management expects system problem resolution to be performed with a minimum number of modifications, and that solutions involving major modifications should be avoided or delayed. This belief appeared to be evident relative to the amount of time it took to install seal-less Reactor Water Cleanup (RWCU) pumps for a long-standing leaking seal problem. From the inspector's review it is apparent that management expected the engineering staff to fully develop modification proposals in terms of cost-effectiveness and justification; and if sufficient basis was not determined, the proposed modification could be delayed or not accepted. Communication and understanding of expectations in this area needs improvement.

Because of the long standing nature of this recurring problem, the inspector considers this a significant condition adverse to quality. For significant conditions adverse to quality, 10 CFR 50 Appendix B Criterion XVI requires that actions be taken to preclude repetition. Since the licensee has not taken effective actions to preclude EPA breaker trips due to spurious causes or from no known cause, this is an apparent violation of 10 CFR 50 Appendix B Criterion XVI. (VIO 50-387/92-06-01)

7.2.2 Reactor Coolant Pressure Boundary Erosion/Corrosion

In the course of executing their Erosion/Corrosion assessment program during the current Unit 2 outage, the licensee found excessive wall thinning at certain locations within three distinct systems, i.e., Main Steam (MS), Main Feedwater (FW), and Extraction Steam (ES). Of particular interest was the wall thinning seen in the MS and FW systems since these locations are unisolable. Listed below is the actual data found:

SYSTEM	LOCATION	NOM. WALL	MIN. WALL	ACTUAL
MS	90° Elbow - Prior to SRV's	1.158"	0.893"	1.086"
FW	12" Middle Riser to RPV	0.688"	0.438"	0.482"
ES	90° Tee's - Inside Condenser	0.375"	0.250"	0.118"

The licensee evaluated the wall thinning discovered at these locations on April 4 and 5. Actions were initiated to repair and/or replace affected portions of the ES system. Expanded inspections were conducted in all these systems and the need for additional repairs was evaluated. The ES system was satisfactorily tested prior to its full restoration to unrestricted operation.

The E/C detected in the FW system was of critical concern to the licensee. The particular area of interest was in the base metal portion of the 12" middle riser that attached to the reactor pressure vessel (RPV). The affected piping section was immediately downstream of a weld that connected the 12" riser to a 20" to 12" tee from the "B" FW supply line inside containment. This piping is unisolable from the RPV. The licensee evaluated the inspection results and concluded that continued reactor operation was not justified until replacement or repair was accomplished. The maximum expected wear rate due to E/C was projected to be 0.040"/fuel cycle, but actual E/C wear rate was between 0.060"/fuel cycle and 0.170"/fuel cycle. The licensee reviewed the three E/C models published in NUREG-5007, KWU, and EPRI-3944 used for this location and determined that the models did accurately predict this tee as requiring inspection. However, the magnitude of wall thinning detected greatly exceeded the projections. The licensee qualified an ASME Section XI weld overlay procedure to repair the piping. The weld overlay was subsequently completed. The licensee is evaluating the need for E/C program revision.

In the case of the "C" MS line, the licensee determined that sufficient margin existed to justify reactor operation for another cycle. This conclusion was based on a worst case wear rate of 0.100"/fuel cycle which conservatively considered UT measurement inaccuracies, as well as, significant allowances for uncertainties in E/C model predictions. Expanded inspections of sister locations showed normal wear. Additional inspections are planned in this area during the Unit 1 7th refueling outage.

The licensee discussed the inspection results with the inspector on April 6 and 7. To promptly consider generic concerns, a conference call was conducted on April 7 where the licensee results and evaluations were discussed between technical experts at NRC Region I and at NRC headquarters. These results confirmed the need for a previously scheduled team inspection on May 4 - 8. A detailed review of the licensee's E/C program and the adequacy of their specific repair/replacement/evaluation activities will be reviewed during this inspection.

Notwithstanding the planned team inspection, the inspector determined that the excessive thinning of the FW piping had generic implications. Contract inspection personnel were questioned on operational experience at other BWRs. These personnel stated there was little being done for locations inside containment. Using this information, the inspector concluded that generic communication would be prudent. At the conclusion of the inspection period, an NRC Information Notice was in preparation.

8. SAFETY ASSESSMENT/QUALITY VERIFICATION

8.1 Licensee Event Reports (LER), Significant Operating Occurrence Report (SOORs), and Open Item (OI) Followup

8.1.1 Licensee Event Reports

The inspector reviewed the following Licensee Event Reports (LERs) submitted to the NRC as part of an ongoing review.

Unit 1

91-014-00 RPS alternate power supply EPA breaker overvoltage setpoints declared inoperable. On November 4, 1991, the Unit 1 alternate power supply EPA breakers for "A" RPS were found in the tripped condition. Licensee investigation revealed the overvoltage trip setpoints of the EPA breakers for both units were greater than allowed by Technical Specifications. This was due to a "shift" of the EPA overvoltage setpoints. This event was reviewed in inspection report 50-387/91-21.

The setpoints of the alternate power supply EPA were adjusted to within TS Limits. The calibration procedure for the alternate supply EPA setpoints will be updated to ensure alternate power supply transformers are utilized as a calibration source.

The licensee determined that the event was reportable per 10 CFR 50.73 (a)(2)(i)(B) in that an operation prohibited by the plant's Technical Specifications (TSs) occurred due to all station alternate RPS power supply electrical protection assemblies being declared inoperable. Technical Specification 3.8.4.3 action b. requires that if both RPS electrical power monitoring assemblies for an inservice power supply are inoperable, restore at least one electric power monitoring assembly to operable status within 30 minutes or remove the associated power supply from service. No alternate RPS power supplies were in service at the time of discovery, however, the alternate RPS power supplies of both units have been in service for greater than 30 minutes in the past. This licensee identified violation is not being cited because the criteria specified in Section VII.B.2 of the Enforcement Policy were satisfied.

91-015-00 High Pressure Coolant Injection System inoperable due to broken steam control pilot valve. On November 7, 1991, with Unit 1 at 100% power, the HPCI quarterly flow surveillance failed to meet the TS acceptance criteria by a small margin. Inspection of the turbine steam chest revealed that the head of the #1 poppet (pilot valve) had broken off. This event was determined to be reportable as a condition that alone could have prevented fulfillment of the safety function of the system. However, sufficient safety margin exists in the design such that HPCI could have performed its intended safety function in any accident or operating scenarios even with the poppet broken off. The broken poppet was replaced and the other poppets were inspected. The surveillance was then satisfactorily completed.

An engineering failure analysis will be performed to determine the failure mode, and will include metallurgical evaluation, and procurement/manufacturing data. Any additional corrective actions will be determined at a future date depending on the results of the failure analysis. The licensee will submit an update to this LER to identify any additional actions taken to prevent recurrence.

91-016-00 Postulated Appendix R fire in the control room could place the plant outside of its analyzed design basis. On November 20, 1991, PP&L determined that the fire could result in a hot short in the control circuit of one of a number of components required to shutdown the unit from the remote shutdown panel. Safety significance was considered minimal because backup systems exist that are able to bring the plant to a successful safe shutdown, fire detection and suppression systems are operable in the control room, and operations control room personnel are qualified in fire protection and have acess to portable fire fighting equipment. Further licensee assessment regarding corrective actions to eliminate the postulated scenario is continuing. This event was reviewed in NRC Inspection Report 50-387/91-21.

91-017-00 Unplanned ESF actuation when radiation monitor power was interrupted. On November 25, 1991 an unplanned ESF actuation occurred when a fuse blew in the power supply to radiation monitors serving the Zone III ventilation, SGTS and CREOASS systems. The loss of power caused a Zone III isolation and auto-start of SGTS and CREOASS systems. No adverse consequences occurred as a result of this event. This event was reviewed in NRC Inspection Report 50-387/91-21.

92-001-00 ESF actuations due to an RPS EPA breaker trip. On February 23, the primary power supply to the "B" RPS power distribution panel was lost when both of its electrical protection assembly (EPA) breakers tripped. Plant systems functioned as designed in response to the event. Primary containment isolations and initiations of "A" and "B" SGTS and "A" CREOASS systems occurred, as designed. Section 7.2.1 pertains.

92-002-00 Opening found through fire rated barrier. On February 10, the licensee commenced an 18 month inspection of the Common Building Fire Barriers. During performance of the inspection the licensee observed a one inch diameter opening in a cable chase that passed through a fire rated barrier on elevation 689 of the control structure which resulted in a condition prohibited by Technical Specifications. This barrier is required to meet Technical Specification (TS) 3.7.7. The required compensatory measures were implemented per TS 3.7.7. This consisted of an hourly firewatch and operable fire detectors in place. The cause of the event could not be determined, however, the licensee assumed that this condition existed from construction. The licensee plans to seal the penetration.

The licensee determined that the event was reportable per 10 CFR 50.73 (a)(2)(i)(B) in that an opening was discovered through a fire rated barrier with no compensatory measures in place per T.S. 3.7.7. This licensee identified violation is not being cited because the criteria specified in Section V.G. of the Enforcement Policy were satisfied.

92-003-00 RWCU actuations due to high flow and high differential flow signals. On March 7, at 1% power during plant shutdown, an ESF actuation occurred when RWCU system inboard and outboard containment isolation valves automatically closed. On March 8, while in cold shutdown, a second ESF actuation occurred when the same valves automatically closed again while operations was in the process of restoring the RWCU system from the previous isolation. A RWCU system high flow signal initiated the first RWCU unplanned ESF actuation. A high differential flow signal initiated the second unplanned ESF actuation. Section 2.2.2 pertains.

92-004-00 Unplanned ESF actuation when the relay circuit board failed. On February 20, operators were preparing to add nitrogen to the Unit 2 drywell. The operator was unable to open the Unit 2 drywell nitrogen make-up outboard isolation valve. Further investigation revealed that the corresponding Unit 1 isolation valve nor the drywell vent bypass outboard isolation valves on either unit could be opened. The licensee determined that the root cause of the event was a failed relay circuit board in the SGTS exhaust radiation monitoring circuit. Although the valves were already in the closed position, failure of the circuit board resulted in actuation of

ESF logic, thus constituting an unplanned ESF actuation. The circuit board was replaced and retested. There were no adverse safety consequences as a result of the event.

Unit 2

91-014-00 Main Steam Isolation Valve (MSIV) closure time exceeded Technical Specification Limit. On December 12, 1991, with Unit 2 at 100% power, an instrumentation and control (I&C) engineer discovered that a MSIV closure channel response time exceeded the TS required valve of 60 milliseconds (msec) by 2 msec. This was caused by an omission of a 10 msec trip channel sensor response time in I&C procedures. The Unit 2 "B1" channel was 2 msec over Technical Specification limits. The MSIV closure response channels operate on a one-out-of-two taken twice logic. Three of the four channels were within TS required limit and the system would have performed its intended safety function in the required time. The licensee reviewed "Response Time Procedures" of both units to ensure no other response time tests were affected. No other response times exceeded TS limits. Changes were initiated for I&C response time testing procedures to ensure that the 10 msec for channel sensor response is included. This event was reviewed in NRC Inspection Report 50-387/91-21.

91-015-00 High pressure coolant injection system inoperable when steam supply isolated due to leak. On December 16, 1991, with Unit 2 at 100%, a small leak was discovered in a drain line for the HPCI system steam supply line. The HPCI steam supply valve was closed during the repair, which rendered the system inoperable. The licensee determined that erosion/corrosion of the carbon steel HPCI drain line to be the cause. The piping is included in the erosion/corrosion control program and had been identified as experiencing some degradation. The licensee had generated work documents to replace the subject piping with upgraded material during the next refueling outage in each unit. There were no significant safety consequences as a result of this event.

92-001-00 Unit 2 manual scram following loss of engineered safeguards 4.16kv bus. On March 18, with Unit 2 at 100% power the "B" emergency diesel generator tripped on "Generator Loss of Field." While in the process of substituting in the "E" EDG for the "B" EDG, the operator reset a relay target on Engineered Safeguard System (ESS) 4.16kv bus 2C. When the relay target was reset, the bus locked out. The loss of ESS bus 2C resulted in several ESF actuations. Due to degraded plant conditions caused by the bus lockout, operators manually scrammed the Unit 2 reactor. Section 2.2.1 pertains.

The inspector reviewed the above LERs to verify: the details of the event were clearly and accurately reported, the cause is properly identified, and adequacy of corrective actions taken or planned. The inspector determined whether: additional information was required from the

licensee, generic implications were involved, reporting requirements were met, and the event warranted onsite followup. Unless otherwise noted, no significant observations were made.

8.1.2 Significant Operating Occurrence Reports

SOORs are provided for problem identification and tracking, short and long term corrective actions, and reportability evaluations. The licensee uses SOORs to document and bring to closure problems identified that may not warrant an LER.

The inspectors reviewed the following SOORs during the period to ascertain whether: additional followup inspection effort or other NRC response was warranted; corrective action discussed in the licensee's report appears appropriate; generic issues are assessed; and, prompt notification was made, if required:

Unit 1

72 SOORs, inclusive of 1-91-330 through 1-92-130.

Unit 2

27 SOORs, inclusive of 2-92-001 through 2-92-038.

The following SOORs required inspector followup:

1-92-019 Documented Unusual Event that was declared following localized hydrogen ignition and contaminated injured man. This was documented in NRC Region I Combined Inspection Report 50-387/92-02; 50-388/92-02.

1-92-030 Documented the failure of isolation logic to initiate as expected while transferring "B" RPS Bus to the alternate power supply. Section 7.2.1 pertains.

1-92-031 Documented normal supply EPA breaker trip function failure during testing. Section 7.2.1 pertains.

1-92-033 Documented "B" RPS alternate power supply Isoreg transformer output voltage valve being too low. Section 7.2.1 pertains.

1-92-064 Documented "B" RPS normal power supply EPA breaker trip. Section 7.2.1 pertains.

1-92-082 Documented RWCU system ESF actuations that occurred during system restoration following a system isolation that occurred during drywell equipment hatch shield block removal. Section 2.2.2 pertains.

1-92-123 Documented ESF actuation that occurred during 4.16kv ESS Bus outage work. Section 4.5 pertains.

1-92-129 Documented ESF actuation that occurred during 4.16kv ESS Bus outage work. Section 4.5 pertains.

2-92-024 Documented 2C ESS Bus walkout and manual scram due to degraded plant conditions. Section 2.2.1 pertains.

8.1.3 Open Items

8.1.3.1 (Closed) UNR 50-387/89-01-03(Common), Operator Inattentiveness and Procedural Weakness

During the period of January 4 to February 3,1989 the inspector identified several instances of operator inattention to detail and procedural weakness that resulted in three scrams. The first scram resulted when operators performed an abnormal line-up of instrument air valves without a procedure. The following operating shift, which was unaware of the system status, altered the alignment causing loss of air to cooling tower basin level instruments. The second scram occurred as the plant was returning to power. It was caused by limited procedural guidance and operator inattention while transferring feedwater level control to the master controller. The third scram occurred during a separate shutdown, when an operator did not follow procedures correctly and failed to bypass the scram discharge volume high level trip while resetting the scram resulting in a scram signal. Each of these indicates weaknesses in establishing or implementing written procedures.

In response to the scram caused by loss of instrument air, the licensee added explicit directions to the Instrument Air procedure (OP-118/218-001) governing valve manipulations and requirements for Shift Supervisor permission and Power Control Center notification when performing this lineup. In response to the operator inattentiveness factor in this event, administrative procedure AD-QA-302 "System Status and Equipment Control" was revised to specify approved authorization for system evolutions and requirements for logging them to provide effective equipment status control.

The licensee's response to operator inattentiveness during the feedwater transient induced scram was to provide extensive training to all operating shifts. The operator involved in the event developed and conducted pertinent training for operating personnel. The Supervisor of Operations and Nuclear Training Group developed and conducted specific training that focused on supervisor involvement in critical evolutions, adhering to procedures, and additional practice with feedwater controls.

Enhancements were also made to the applicable procedure (GO-100/200-003) concerning the establishment of automatic feedwater level control which directs the operator to watch for expected water levels during the transient.

In response to an operator's failure to properly reset a scram, the licensee revised procedures GO-100/2000-004 and 005 to explicitly direct the operator to bypass the scram discharge volume high level trip prior to resetting a scram. Training on this procedural change and the procedures mentioned above, was conducted for all Operations shifts.

The procedure revisions were reviewed and appear to adequately address the weaknesses that resulted in operator errors. The training provided to operators and management emphasis on procedural adherence appear to have been effective based on the fact that no scrams due to operator error have occurred since February of 1989. Based on the above this item is closed.

8.1.3.2 (Closed) UNR 50-387/89-01-04(Common), Operability Determination of Diesel Generator Starting Air Systems

During a routine inspection of the Emergency Diesel Generators, the inspector questioned whether the licensee considered a diesel generator inoperable when only one of its two air start receivers was available. The inspector had found that the Final Safety Analysis Report (FSAR) could be interpreted to imply that only one of the air start systems is required to start the diesel while, in practice, use of one air start receiver would result in a starting time of 10 seconds plus/minus half a second compared to the maximum allowed time of 10 seconds.

In discussions with system engineers, the inspector found that, although tests had been conducted to show that one air start receiver is capable of starting the diesel, the licensee had always considered the diesel generator to be inoperable when only one air start receiver was available. This policy is stated in Technical Safety Assessment EDMG00032 and is implemented in the monthly diesel generator operability surveillance procedure SO-024-001. Section 6.1 of this procedure requires confirmation that both air start solenoids are properly aligned, that the pressure in both receivers is greater than 240 psig, and that the pressures in both receivers are within 10 psig of each other. The procedure steps and checkoff lists are written to convey that the air start system, and hence the diesel, is operable only if both air start receivers meet the criteria. Routine shift rounds (Plant Instruction OI-PL-0161) also require operators to verify that all air start receivers are at a pressure of 240-250 psig. These surveillances are based on Technical Specification 4.8.1.1.2.a.7 which requires that all air start receivers be at greater than or equal to 240 psig to declare the diesel operable. Section 9.5.6.2 of the FSAR specifies that the system is designed to crank the engine using air from both of the air receiver tanks for diesel generators A,B,C, and D and from all four air receivers for diesel generator E. Therefore, the FSAR is consistent with plant policy and surveillance testing.

The inspector reviewed Significant Operating Occurrence Reports for the time period of November 1989 to January 1992 which described events in which diesels were declared inoperable and noted that LCO 3.8.1.1 was entered due to inoperability of one of the two air start receivers. A sample of completed shift round sheets were reviewed and found to contain no instances of inoperable air start receivers which were not responded to by entering LCO 3.8.1.1. The licensee's practice of declaring the diesel generator inoperable when either air start system is inoperable is acceptable. Therefore, this item is closed.

8.1.3.3 (Closed) UNR 50-387/89-10-02 (Common), Adequacy of Appendix R Fire Protection Program

On May 11, 1989, an individual approached an NRC inspector with concerns about the licensee's compliance to appropriate Appendix R requirements for fire penetration seals. Specifically, he raised four concerns, including the inadequacy of Control Structure fire barrier and seal inspection program criteria and requirements for establishing fire watches due to seal damage. (The allegation is discussed in greater detail in inspection report 50-387/89-35 and 50-388/89-34.) On May 15, 1989, the alleger contacted the licensee's site fire protection engineer, and the concerns were documented in Significant Operating Occurrence Report No. 1-89-184. The licensee determined that surveillance procedure criteria failed to identify the inoperability of some damaged seals. By May 19, 1989, the licensee considered all damaged seals to be inoperable and established fire watches for the affected areas, maintaining them until all rework was complete. In the aforementioned NRC allegation follow-up inspection, the inspector reviewed the licensee's response to the concerns and concluded that the allegation was generally unsubstantiated except for one item. This item resulted in a non-cited violation; the licensee had violated the Technical Specification Section 3.7-7 action statement regarding fire watches for inoperable fire barriers (50-387/89-35-01 and 50-388/89-34-01). The allegation was closed based on the licensee's programmatic corrective actions, but the unresolved item remained open until performance of these actions could be demonstrated.

The licensee's actions to prevent recurrence of these events follow:

(1) An appropriate fire watch is established when penetration damage is discovered.
(2) Specification C-1072, Design and Installation of Penetration Seals, was revised to include inspection acceptance and operability determination criteria.
(3) The following procedures were generated/revised to clarify the surveillance and operability determination processes:

AD-QA-902	Penetration Sealing
AD-QA-905	Penetration Seal Repair Evaluation Procedure
AD-QA-906	Fire Rated Penetration Seal Surveillance Program
SM-013-010	18 Month Inspection of Common Penetration Seals
SM-113-010	18 Month Inspection of Unit 1 Penetration Seals
SM-213-010	18 Month Inspection of Unit 2 Penetration Seals

The inspector reviewed the above documentation and determined that the licensee had developed a comprehensive program to improve its control of fire rated penetration seals. The licensee's corrective actions fully addressed the concerns and demonstrated a strong commitment to effective penetration sealing as it relates to plant safety. In fact, the average number of fire zones requiring hourly fire watches in 1990 was improved from about 190 per month to about 40 per month. The average number of these fire zones remained low at about 42 per month in 1991 and has dropped to about 26 per month so far in 1992. The reduction in affected fire zones reflects excellent progress toward recovering from previous weaknesses in fire protection performance. This item is closed.

8.1.3.4 (Closed) UNR 50-387/89-15-01 (Common), Reactor Protection System (RPS) Logic Functional Testing

A 1985 inspection report documented concerns about the licensee's RPS channel and logic system functional surveillance requirements (UNR 50-388/85-23-01). A majority of the inspector's concerns were resolved, and the item was closed in 1989. However, the inspector opened a new item to track the more specific concern that each series contact in the RPS multiple contact trip system logic was not checked independently (UNR 50-387/89-15-01). The trip system logic consists of many relay contacts which open to de-energize relays and cause a trip. Each relay has two redundant series contacts in the logic string. Opening either contact trips the trip system, and the licensee's continuity test only verified that one or the other contact opened, rather than both. Technical Specification (TS) 1.21 defines a Logical System Functional Test (LSFT) to be "a test of all logic components, i.e. all relays and contacts, all trip units, solid state logic elements, etc., of a logic circuit from sensor through and including the actuated device, to verify OPERABILITY." This definition appears to require that all contacts be tested, but the licensee maintained that the redundant contacts should not be required to be tested individually. They argued that a failure of a redundant contact would not have caused the RPS to be inoperable as a result of a single failure, and the additional contacts merely enhanced reliability. This item remained open pending appropriate resolution, either a TS amendment on the definition of LSFT or a change in the actual test procedure.

The licensee revised their earlier position and concluded that, although General Electric (GE) does not specifically address multiple contacts in series, optimum reliability is a stated design criterion. Since multiple contacts in series increase reliability, the licensee has taken the position that both series contacts shall be tested independently during scheduled refuel and inspection outages. Procedure MT-GE-025 *GE HFA Relay Contact Maintenance* was revised to include the independent testing of the individual contacts; the revision has been in effect since October 28, 1991.

The inspector reviewed GE Design Specification 22A3056 *Reactor Protection System*, Procedure MT-158-A01 *RPS "A" Channel HFA Relay Contact Inspection*, and Procedure MT-GE-025 *GE HFA Relay Contact Maintenance*. MT-158-A01 supports the periodic maintenance of the RPS relays for Channel A1 by removing the relays from service so that MT-GE-025 can be performed. The inspector concluded that by committing to test the contacts independently, the licensee conservatively met the intent of the original definition of LSFT. This item is closed.

8.1.3.5 (Closed) DEV 50-387/89-18-01 (Common), Diesel Generator Day Tank Fuel Supply

During a routine inspection, an NRC inspector noted a deviation from the Final Safety Analysis (FSAR) commitment for fuel levels in the diesel generator day tanks. At that time, the updated FSAR, Revision 40 of page 9.5-39 indicated that each day tank contains fuel oil sufficient for over two hours of full load continuous diesel generator operation and that fuel requirements for diesel generators A,B,C,and D were 272 gallons per hour and diesel generator E was 550 gallons. However, the inspector found that the plant operator daily rounds log specified a minimum day tank fuel requirement of 60% and 48% for day tanks A through D, and E, respectively, which was less than the volume committed to in the FSAR. Another issue involving diesel generator day tank supply was raised in an Electrical Distribution System Functional Inspection (EDSFI) (Inspection Report 50-387/90-200). The inspector questioned whether the day tank level required by Technical Specifications, operating and surveillance procedures were in accordance with ANSI N195 Standard which requires the day tank to contain enough fuel to operate for.a minimum of one hour at 110% of its rated capacity. The inspector found that the licensee had calculated the tank capacities using nonconservative values of specific gravity for the fuel and typical operating room temperatures which could result in less fuel in the tank than believed due to thermal expansion.

In response to the concerns raised by the EDSFI, the licensee conducted a review of its day tank level setpoints. The results of the study were documented in report SEA-ME-332 which concluded that the most conservative volumes necessary to meet the ANSI requirement are 461 gallons for diesels A through D and 528 for E. The tank levels corresponding to these volumes are greater than the setpoints at which the transfer pump would automatically turn on to fill the tank. However, the licensee has stated that since the accident analysis is only based on the capacity of the 7 day storage tanks, the amount of fuel in the day tanks does not enter into the design basis analysis and therefore does not affect the margin of safety. NCR 90-01 stated that this condition does not affect the operability of the system since the fuel oil transfer system will perform its function and will not prevent the fulfillment of the diesel generators' safety function. The licensee has decided to use a 45 minute operating time as a basis for day tank minimum volume Technical Specification limits and automatic transfer pump initiation. This corresponds to 322 gallons for A through D and 378 gallons for E. A Technical Specification change is in progress to incorporate these limits and change the bases to state that the day tank volumes do not conform with the one hour supply requirement of Regulatory Guide 1.137 which endorses American National Standards Institute (ANSI) N195. The licensing department will pursue an exception to the ANSI standard if it is determined that the tanks are not in compliance with its intent.

In response to the concern that an insufficient amount of fuel was being maintained in the day tanks, the licensee revised procedures to require the tanks to be topped off after each run and to be filled to a level of 63 inches for tanks A through D and 58 inches for tank E as verified by daily surveillances. These levels correspond to volumes of 485 and 580 gallons, respectively, which can supply fuel for at least 66 minutes of full load operation. The following procedures

were revised by adding the new "top off" requirement: SO-024-001 "Monthly diesel Generator Operability", SO-024-014 "Monthly Diesel Generator E Operability", OP-024-004 "Transfer and Test Mode Operations of Diesel Generator E", OP-024-001 "Diesel Generators", and OP-023-001· "Diesel Fuel Oil System". The inspector reviewed the procedures listed above for inclusion of the new requirements, reviewed a sample of the operators' daily surveillance checkoff sheets (OI-PL-0161) for sufficient levels in the tanks, and verified the current tank levels by direct observation.

In response to the original concern regarding the deviation from FSAR commitments, the FSAR was revised to read " The day tank contains fuel oil sufficient for over one hour continuous diesel generator operation at its continuous rated load". The licensee has planned to revise this section again, as well as the Technical Specification interpretation, upon approval of the Technical Specification change to reflect the 45 minute supply.

Based on the fact that the licensee appears to be administratively maintaining a sufficient volume in the day tanks and satisfy ANSI requirements and has adequately addressed the effect of the change on the safety analysis and operability of the diesel generators, this item is closed.

8.1.3.6 (Closed) UNR 387/89-21-01 (Common), Nuclear Safety Assessment Group (NSAG) Evaluation of Loss of Water from Spent Fuel Pool Events

This unresolved item was opened to address 28 open items documented in a licensee NSAG audit report (84-13) conducted in response to IE Bulletin 84-03, "Refueling Cavity Water Seal". The report reviewed the licensee's evaluation of the potential for failure of the refueling cavity water seals and recommended several corrective actions. The inspector noted that the corrective action recommendations were thorough and comprehensive and that the review would be complete when all 28 items were completed. The three remaining items are addressed here.

1. Item 841304, *Train personnel on loss of Spent Fuel Pool level*, was closed by the licensee based on a verbal commitment that training would be provided in the future. However, the inspector did not have reasonable assurance that the scope and content of training was adequate at that time.

During the current inspection period, the inspector verified that the training is now complete, and pertinent information has been added to the initial operator training course. Lesson plan (SY017) L2 "Fuel Pool Cooling and Cleanup" was changed by adding a figure of the seal rings and a listing of the NSAG reports and a related administrative procedure as references and suggested reading materials.

2. Item 841310, *Add SFP Instrumentation*, proposed adding additional instrumentation to improve monitoring capability for level, temperature, and radiation. Upon further review, the licensee concluded that adequate instrumentation exists. The inspector in 1989 reviewed the

availability of accessible instrumentation on 818' elevation of the reactor building. The inspector noted that on a loss of Unit 1 SFP level the direct radiation shine would not allow monitoring at the local panels adjacent to the SFP.

During the current inspection period, the licensee has been evaluating enhancements to control room instrumentation that would provide operators with more information concerning fuel pools and fuel pool cooling system.

3. Item 841314, *Replacement of reactor cavity seals*, proposed changeout of the Presray cavity seals based on their five year service life. The licensee believed that the seals should be replaced on an interval greater than five years. At the time of the 1989 inspection, the seals were greater than nine years old for Unit 1 and less for Unit 2. The inspector questioned the continued use of the seals beyond Presray's recommendation unless sound technical justification to the contrary existed.

The licensee evaluated seal service lives of 12 years for upper seal rings and 24 years for lower seal rings in calculation FC-C-WPG-011. The evaluation concluded that the seals are not susceptible to any common mode failures induced by changes in material properties resulting from exposure to the service environment during a 40 year life. The environmental conditions used in the analysis were taken from vendor design specifications. The analyses determined that thermal aging (based on an environment of 150 °F compared to the actual maximum temperature of 125 °F) had no effect on the strength of the seal material and that radiation exposure is the limiting factor with respect to material response. A Presray aging study determined the effects of a 40-year radiation dose of $1/10^7$ R which is 50 times greater than the actual dose. The study found that, after being exposed to this dose, the tensile strength of the material was still four times greater than the minimum required by design, there was no change in the hardness, and elongation passed design requirements. The 12 and 24 year replacement schedule is therefore based not on material property degradation resulting from exposure but on the potential for failures due to unidentified mechanisms. The different service life recommendations reflect the fact that the upper seals are more directly exposed to the environment and assure that the seals will age at different times.

Based on the inspector's review of the changes to the "Fuel Pool Cooling and Cleanup" Unit of Instruction (UI) the completion of training in March, 1985, and that this UI is part of the biennial requalification program, Item 1 is closed. Item 2 is closed based on the licensee's evaluation (EWR M70818) and planned modifications per Design Change Package (DCP) 91-9044 and 91-9045. The licensee has committed to track this item internally and to notify the NRC of any planned deviation from this commitment. The inspector reviewed the calculations and NCRs pertaining to Item 3, and it appears that the licensee has conducted a thorough evaluation of the seals' design and expected life. The inspector verified that the licensee is committed to the new replacement schedule as evidenced by the generation of work packages with scheduled replacement dates; item 3 is closed.

Based on the above, this item is closed.

TI 2515/66 also addressed refueling water cavity seal failure. The closure of this Open Item satisfies the TI requirements. Therefore, as a result of closing this item, TI 2515/66 is also closed.

8.1.3.7 Closed) UNR 387/89-24-02, NCR and SOOR Resolution Procedures Do Not Require Engineering Review When Needed

During the period of July 30 to September 9, 1989, the inspector identified inadequacies in the licensee's procedures for the engineering review of Nonconformance Reports (NCRs) and Significant Operating Occurrence Reports (SOORs). Specifically, the licensee failed to incorporate adequate guidance for engineering review into the administrative programs for these deficiency tracking mechanisms (procedures AD-QA-120 (NCRs) and AD-QA-424 (SOORs)).

In response to this concern, the licensee revised procedures AD-QA-120 and AD-QA-424 to incorporate formal procedural controls in an effort to ensure that NCRs and SOORs receive the appropriate level of engineering review required to evaluate and disposition deficient conditions at Susquehanna.

The procedural revisions were reviewed and appeared to adequately address the weaknesses that generated this concern. A number of NCRs and SOORs were also reviewed to evaluate the implementation of the procedural revisions. The sample of NCRs and SOORs were found to be prepared in accordance with the procedural guidance and contained adequate engineering involvement and review. Based on the above, this item is closed.

8.1.3.8 (Closed) UNR 50-387/89-27-01, 50-388/89-24-01 Qualified Life of Target Rock Solenoids

During an inspection of the environmental qualification for Target Rock solenoid valves, the inspector found that the qualified life of normally energized solenoid valves had been extended from 8 years to 60 years over the course of several qualification tests. These results were considered generally unacceptable since life extension was primarily based upon an analysis which took into account the Class H rating of the solenoid coil insulation and field temperature measurements which appear not to have considered worst environmental and process conditions. In response to these concerns and to changes in the qualification process, the licensee revised the Environmental Qualification Assessment Report for Target Rock solenoid operated valves, EQDF-46, which addresses all concerns of the unresolved item. Each of the inspector's concerns, along with the licensee's response are listed below.

1. Concern - Use of analysis based upon the NEMA Class rating of insulation to establish the solenoid coil's qualified life is not an acceptable substitute for accelerated aging in the case of equipment located in harsh environments, unless it can be unquestionably demonstrated that the insulation is not age sensitive during the installed life of the coil.

Response - The most recent qualification testing analyzed in EQDF-46 did not base the solenoid coils' qualified life on the NEMA Class rating of the insulation but rather on calculations which determined the insulation's qualified life since it was determined that the insulation is age sensitive. Arrhenius methodology was used to determine the expected life of the coil wire insulation using the following values which were based on testing of heat rise within a continuously energized valve: 120 °F ambient temperature, 400 °F process flow, a coil wire insulation operating temperature of 240 °F, LOCA and post accident insulation temperature of 259 °F, and a post accident period of 100 days. The result was an expected qualified life of 16 years for the coil wire insulation making it the limiting component of the coil assembly.

2. Concern - The calculation of the temperature rise of the energized coil by means of resistance measurements should allow for hot spot temperature since resistance measurements provide only average temperature rise.

Response - The licensee calculation of maximum coil temperature was based on resistance measurements and the coil housing temperature determined by averaging thermocouple readings at nine different locations. A 5 degree margin was added to the results to account for non-measurable heat sources, one of which is hot spot temperatures.

3. Concern - The calculation for the temperature rise of the coil should take into account environmental conditions(normal, abnormal and accident), installation requirements(heat tracing, heat buildup inside solenoid enclosure,) and process conditions.

Response - Qualification Test Reports 4207 and 4501 documented the temperature rise of various areas and components of continuously energized valves. These tests demonstrated the heat rise in normal conditions (ambient temperature of 73 F with no flow) and abnormal and accident conditions (ambient of 150 and 120 with 400, 500, and 600 process flow through the valve). Heat trace temperatures (set at 150) and internal heat rise were accounted for.

4. Concern - Measurements whether taken in a laboratory or in the plant should be controlled and must meet all of the IEEE 323-1974 requirements.

Response - The qualification test procedures used to determine qualification life (TRP 1901, TRP 2192, and TRP 3764) were prepared in accordance with IEEE 323-1974 "Qualifying Class 1E Equipment for Nuclear Power Generating Stations". The procedures control measurements by requiring measuring equipment to be in calibration and have known accuracies which are acceptable. The dates of calibration and accuracies were recorded in each of the test reports.

5. Concern - Self heating of other components (e.g., rectifiers and relays) should be equally addressed.

Response - The Environmental Qualification Assessment Report (EQAR) recognized the fact that valves which are continuously energized greater than one hour will be subjected to the internal heat rise of their electronic components and listed this type of heat as one of the four thermal

aging stresses to which the valves are subjected. Test reports 4501 and 4207 which analyzed thermal aging of continuously energized solenoid valves accounted for this heat rise in its calculations of qualified valve life.

6. Concern - All nonmetallic materials and relative activation energies should abe addressed by the calculation.

Response - The revised EQAR listed the non-metallic subcomponents of each component with the activation energy that was used in the qualified life calculations as well as the basis for the activation energy used. The activation energies were used as a variable in the Arrhenius equation to determine the qualified life of the solenoid components.

7. Concern - To take advantage of the NEMA rating of the insulation, the analysis should equally demonstrate that all materials are not sensitive to other aging elements, such as radiation, relative humidity, cyclic aging, normal and seismic vibration, etc.

Response - The qualified life analyses did not use the NEMA rating of the insulation as the basis of the solenoid coil life but instead independently calculated the expected qualification life of the insulation and factored the result into the qualified life of the solenoid.

8. Concern - Bases for calculations and assumptions should be appropriately justified.

Response - The calculations analyzed in the EQAR used Arrhenius methodology to determine the qualified life of solenoid components. Variables in this equation include ambient temperature, process fluid temperature, internal temperature, and activation energy. Ambient and process fluid temperatures were obtained from operating experience based on the valves location and function. Values greater than the actual maximum expected temperature were used for conservatism. Temperature rise within valves was based on test reports 4207 and 4501 and compared to maximum solenoid housing temperatures documented in field measurement reports. The methodology and basis for determining these coil temperatures were described in the EQAR. The source and basis for the activation energies used for each material was given for every component.

9. Concern - The calculation should clearly identify the solenoid valves within the scope of the analysis.

Response - Table 1 of the EQAR clearly identified the analysis or report number which was used to qualify each component of each model of valve. The model number of every Target Rock solenoid valve which was qualified in this report is listed in table 9.

Based on review of the EQAR and discussions with the licensee's Environmental Qualification group, the inspector determined that the responses adequately address these concerns and this item is closed.

8.1.3.9 (Closed) Violation 50-388/89-31-01, Failure to Determine Cause of Test Quantity Being in Required Action Range

As a result of an inspection conducted on November 6-9, 1989, the licensee was cited for violation of Technical Specification 4.0.5. Technical Specification 4.0.5 specifies that inservice testing of pumps shall be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code. Section XI of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Article IWP-3000, Inservice Test Program paragraph IWP-3230(b) specifies that if test quantities fall within the required action range, the pump shall be declared inoperative and not returned to service until the cause of the deviation has been determined and the condition corrected.

During the performance of surveillance testing, conducted on March 28, 1989, of the residual heat removal service water pump 2P506B, results gave a differential pressure test quantity of 77.6 pounds per square inch differential (PSID). Although this fell within the required action range (above the acceptance range of 65-71 PSID) the pump was returned to service without the cause of the deviation being determined.

In its response to this violation, dated February 5, 1990, the licensee stated that the high values of the performance test quantities are not indicative of pump degradation. Rather, that they are indicative of instrumentation or system changes, and as such, warrant prompt investigation and resolution; but in no way justify any declaration of pump inoperability. Based on this philosophy the licensee proposed a relief request, which was submitted to NRR for review on March 11, 1991, from the requirement that a pump must be declared inoperative and not returned to service when conditions cause an excursion of the pump flowrate or differential pressure test quantities beyond the "High Value" limits of the required action range.

By letter dated June 28, 1991, the NRC documented a conference call held with the licensee to discuss this issue on April 16, 1991, during which the licensee was advised that the NRC staff was in agreement with this position and that the requested relief was not needed. This guidance was based on information presented in the June 1989 public minutes discussing Generic Letter 89-04, distributed by letter dated October 25, 1989, which provided updated positions on the topic in question. Based on the information presented above and the licensee's corrective actions, this item is closed.

8.1.3.10 (Closed) UNR 50-387/89-81-01 (Common), Bypass Control Program

During the period of October 16 to October 20, 1989, the inspector identified programmatic and procedural weaknesses related to the licensee's implementation of the temporary modifications (bypasses) program under the Electrical and Mechanical Bypass Control procedure AD-QA-484, Rev. 3. At the time of the concern, there were in excess of 130 open bypasses installed at Susquehanna with a significant number being long-standing. The inspector also found that many open bypasses had not received the required quarterly status or justification updates. In addition,

he noted that the bypass procedure did not include requirements to ensure that bypasses were resolved and closed in a timely manner, or that affected drawings and procedures were annotated to reflect these temporary design changes.

NRC Inspection Report Nos. 50-387/91-06 and 50-388/91-06 dated August 13, 1991 documented a review of bypasses (temporary modifications) to assure that such modifications were completed in accordance with requirements. This review determined that the selected bypasses had been reviewed and approved in accordance with the bypass control procedure, installed in accordance with the installation package, properly documented, and that periodic reviews of the bypasses were being performed in accordance with the administrative procedures.

Presently, under AD-QA-484, Rev. 5, the total number of open bypasses for both units is fifteen for non-outage items, and fifteen for items related to the ongoing Unit 1 6th Refueling and Inspection Outage. Furthermore, the licensee has maintained its open bypasses total in the low twenties over the past year. This demonstrated control of active bypasses indicates a strong management and staff involvement in the control and close-out of bypasses at Susquehanna and adequately addresses the inspector's concerns. Based on the above, this item is closed.

8.1.3.11 (Closed) UNR 50-387/90-06-01 (Common), Specific Identification of Regulatory Guide (RG) 1.97 Instruments

An NRC inspector discovered during a March 1990 inspection that the Category 1 instruments of both Unit 1 and Unit 2 had not been specifically identified as recommended by RG 1.97. The licensee's Final Safety Analysis Report (FSAR), paragraph 3.13.1, discussed this deviation, but no justification was provided. The FSAR indicated that the instrumentation for accident monitoring is not specifically identified on the control panel and that the licensee's position on RG 1.97, Revision 2 was transmitted to the NRC in PLA-965 on November 13, 1981. Further, NUREG 0737, Supplement 1 and NRC Generic Letter 86-33 (12/17/1982) asked the licensee to document any deviation from RG 1.97. However, this deviation was not documented in the licensee's 6/31/1984 submittal to the NRC.

The licensee addressed this concern by adding a justification to the July 1992 FSAR submittal that supports the decision to deviate from the RG 1.97 recommendation. The FSAR update includes a short justification which states that the control panel layouts and instrument identifications are based on good human factors engineering, as validated by the Detailed Control Room Design Review (DCRDR).

In addition, a licensee human factors engineer provided two general justifications for deviating from the RG 1.97 guidance: (1) The accident monitoring instrument needs vary with each type of accident. (2) The extra identification scheme would only provide redundant or unnecessary information to the operator, since the existing system has been proven effective in reviews and evaluations. The inspector accepted this reasoning, based on a thorough review of the human factors evaluations which support the control room design.

The inspector reviewed the licensee's DCRDR, the Susquehanna Safety Evaluation Report, and the licensee's System 1 Validation, which evaluated the changes made in response to NUREG 0737, Supplement 1. These studies document the use of proven human factors engineering techniques to evaluate the chosen instrument identification scheme. Additionally, a review of the correspondence between the licensee and NRR staff indicated that the human factors methodologies and techniques used were approved by the NRC.

The inspector also walked down the control panels in the control room and interviewed several operators. The labelling scheme in the control room implements color-coded instruments, where violet instruments are DC powered and orange instruments reflect level or pressure indications. The inspector concluded that this system is a viable option to separately labelling all accident monitoring instruments, since the existing system allows the operators to refer to the same labelling scheme in normal operations as they would during accidents. This familiarity could benefit the operator-instrument interface during high stress situations, whereas a shift to a different identification scheme used solely for accident monitoring could serve to confuse the operator.

The inspector concluded that the licensee's deviation from RG 1.97 does not hinder the operator's abilities to respond to an accident. This item is closed.

8.2 Major On-Line Plant Modifications Which May Reduce Safety

The NRC noted that in the spring of 1991, the licensee for Wolf Creek Generating Station (WCGS) replaced its plant computer while operating at 100% power. The NRC staff reviewed this activity and concluded that the loss of Safety Parameter Display System (SPDS), sequence-of-events logging and other monitoring resulted in a negative safety impact and should have dictated a cold shutdown replacement. To consider generic implications of doing major modifications on-line, the inspector reviewed licensee plans to ensure major safety impacting modifications are not done on-line.

Currently, the inspectors are not aware of any major modifications that will be performed on-line. However, without adequate licensee controls, the installation of major modifications without proper assessment is possible. To ensure adequate controls are in place to address this concern, the inspector discussed this concern with the plant scheduling group. They provided the following feedback.

Pennsylvania Power and Light (PP&L) uses a "defense-in-depth" or "multiple barrier" approach when scheduling work for either nuclear unit. There are multiple checkpoints to ensure that modification installation is done under the most prudent conditions possible. The following highlights PP&L modification scheduling philosophy:

-- During the initial scoping of a Design Change Package (DCP), a corporate, systems, and modification engineer perform a simultaneous walkdown of any modification to be installed in-plant. One aspect of this walkdown is to understand the safety impact of the

modification during its installation. Specifically, what, if any, plant conditions are required. Any restrictions on plant conditions are also discussed at this point.

-- As an adjunct to the walkdown, one of the maintenance functional area coordinators and a plant scheduler review the desired modification installation time window to determine its feasibility from a plant safety standpoint. Modification installation is scheduled to minimize plant safety impact.

-- Later in the process, after the DCP is reviewed and approved by engineering, and before the Plant Operations Review Committee (PORC) reviews the DCP, an installation "kick-off" meeting is conducted. During the meeting, the safety impact of the installation is considered. The installation time window is planned based on its prudency.

-- During the installation phase of the DCP, there are three independent safety checks on any planned modification. To install the modification, the affected system must be released to the installing work group. Typically, the release of systems to the Modifications Installations Group (MIG) is controlled by an Equipment Release Form (ERF). The ERF is used as the controlling document by Operations for any work that affects in-plant systems. Before Operations releases the ERF, plant scheduling and the Operations Outage group must signify that plant conditions support the installation. This three tiered review provides a "multiple barrier" approach in ensuring that modification installations performed on-line do not have a negative safety impact.

The inspector considers the licensee plans in preventing negative safety impacts that might result from on-line major modifications prudent and consistent with the NRC "net safety benefit" philosophy espoused in the Statements of Consideration for 10 CFR 50.65, Monitoring the Effectiveness of Maintenance at Nuclear Power Plants. This "net safety benefit" philosophy requires that the increased risk of having safety related equipment out-of-service (OOS) be weighed against the benefit of doing preventative or corrective maintenance to improve reliability or correct existing problems. Modifications, although not maintenance activities, receive the same scrutiny as maintenance activities. PP&L's use of "net safety benefit" principles when considering plant conditions to install modifications is good.

9. MANAGEMENT AND EXIT MEETINGS

9.1 Resident Exit and Periodic Meetings

The inspector discussed the findings of this inspection with station management throughout and at the conclusion of the inspection period. Based on NRC Region I review of this report and discussions held with licensee representatives, it was determined that this report does not contain information subject to 10 CFR 2.790 restrictions.

9.2 Inspections Conducted By Region Based Inspectors

Date	Subject	Inspection Report No.	Reporting Inspector
2/18-21	Emergency Preparedness	92-04	L. Eckert
3/2-6	Fire Protection Program	92-07	A. Finkel
3/2-6	Radioactive Effluents	92-08	L. Peluso
3/3-5	Security and Safeguards	92-09	G. Smith
3/9-13	Welding/Inservice Inspection	92-11	H. Kaplan/ R. McBrearty
3/23-27	Health Physics-Outage	92-12	J. Noggle
3/16-27	Maintenance Team Inspection Followup	92-13	D. Caphton
3/29-4/3	Design Changes and Modifications	92-14	R. Bhatia

9.3 Management Meeting - Mid-term SALP

The NRC and PP&L management met on February 25 for the licensee's presentation on their mid-term SALP period self assessment. PP&L management discussed their self assessment in all SALP functional areas. The presentation was informative and there was a good exchange of information between NRC and PP&L management.

The list of meeting attendees is included in Attachment 3. The licensee's presentation is enclosed in Attachment 4.

ATTACHMENT 1

Abbreviation List

ADS - Automatic Depressurization System
ASME - American Society of Mechanical Engineers
CFR - Code of Federal Regulations
CIG - Containment Instrument Gas
CREOASS - Control Room Emergency Outside Air Supply System
DG - Diesel Generator
ECCS - Emergency Core Cooling System
EDR - Engineering Discrepancy Report
EP - Emergency Preparedness
EPA - Electrical Protection Assembly
ERT - Event Review Team
ESF - Engineered Safety Features
ESW - Emergency Service Water
EWR - Engineering Work Request
FSAR - Final Safety Analysis Report
HVAC - Heating, Ventilation, and Air Conditioning
I&C - Instrumentation and Control
LCO - Limiting Condition for Operation
LER - Licensee Event Report
LOCA - Loss of Coolant Accident
LOOP - Loss of Offsite Power
MSIV - Main Steam Isolation Valve
NCR - Non Conformance Report
NQA - Nuclear Quality Assurance
NRC - Nuclear Regulatory Commission
OI - Open Item
PCIS - Primary Containment Isolation System
PMR - Plant Modification Request
PORC - Plant Operations Review Committee
PSID - Pounds Per Square Inch Differential
QA - Quality Assurance
RCIC - Reactor Core Isolation Cooling
RHR - Residual Heat Removal
RHRSW - Residual Heat Removal Service Water
RPS - Reactor Protection System
RWCU - Reactor Water Cleanup
SGTS - Standby Gas Treatment System
SI - Surveillance Procedure, Instrumentation and Control
SO - Surveillance Procedure, Operations
SOOR - Significant Operating Occurrence Report
TS - Technical Specifications
WA - Work Authorization

ATTACHMENT 2

Manual RX Scram Due to Loss of the "2C" ESS Bus

Sequence of Events

3/18/92

0949	A Reactor Building Nuclear Plant Operator (NPO) was resetting the flag for relay No. 87A1B on the "2C" Engineer Safety Systems (ESS) bus when it tripped and locked out all supplies. The following relays tripped when the bus was lost: 86A2, 86A, 86A1, 2A302-02, and 27B1-4. The sense faulted condition prevented breaker reclosure from the preferred, alternate, or standby power sources.
0951	The Reactor Water Cleanup (RWCU) system isolated.
0952	The "C" diesel generator (DG) was verified to be running.
0956	Drywell (DW) temperature was verified to be acceptable.
0956	The "B" Instrument Air (IA) compressor tripped on low oil pressure and could not be restarted. The Plant Control Operator (PCO) told the Turbine Building NPO it was probably related to the "C" bus outage. The "A" instrument air (IA) compressor continued to operate to supply IA loads.
0957	The operations supervisor promptly encouraged the use of offnormal procedures, a walkdown of the control boards, and thoughtful actions.
1002	Operations personnel discussed the potential for main steam isolation valves (MSIVs) closure due to a loss of containment instrument gas (CIG) to the drywell. The 90 psig supply to the drywell (SV-22651) closed on a loss of the "2C" bus.
1003	After weighing the potential effects of continuing to operate without CIG to the MSIVs, the operations supervisor conservatively directed the shift supervisor to initiate a manual scram.
1003-1004	Operators announced that a reactor scram was imminent and actions were taken per the Scram Imminent Operating Procedure (OP).

-- The power control center was called (Load Dispatcher) and informed of the imminent scram.

-- Reactor Recirculation (RR) flow (both pumps) was lowered to minimum.

-- Auxiliary bus power was transferred to the startup transformers.

1005 A manual reactor (Rx) scram was ordered. The mode switch was taken to shutdown. The reactor scram emergency procedure (EO-200-101) was already out and being followed at the time of the scram.

1006 The main generator tripped, as expected, and no safety relief valves (SRVs) lifted.

-- Reactor water level was 40 inches.

-- All control rods were verified to be fully inserted .

1007 Operators tripped the "C" reactor feed pump (RFP) due to excessive feed to the vessel per EO-101.

1007 Reactor Water level was 47 inches.

1009 Operators noted that drywell temperatures were continuing to increase due to a loss of drywell cooling.

1009 The reactor scram was reset.

1009 Reactor level was continuing to increase. The operator had difficulty controlling reactor water level. Level peaked at 53 inches which was one inch below the level that would have tripped off all running feed pumps.

1012 The feedwater level control system was placed in the startup mode of operation per OP-245-001 Section 3.18.

1014 The inspector verified that one turbine bypass valve (TBV) was open. A normal heat sink was established with the "A" reactor feed pump running, and the "B" reactor feed pump was on operating at minimum flow conditions. In addition to the steam loads being supplied by the open TBV, the air ejectors and steam seals were in service. The plant was relatively stable at this time. Reactor water level was under control.

1014-1025 Review the E-plan entry. No entry was required.

1030 Confirmed that reactor building ventilation zone 2 was out of service (00S) and that the "A" Loop of the Residual Heat Removal (RHR) was 00S due to power loss to various dampers and valves.

1035 Drywell temperature exceeds 150° F. Operators enter Primary Containment Control (EO-200-103).

1038 Residual heat removal service water (RHRSW) flow was initiated. Started the "D" RHR pump and placed the "B" loop of RHR in the suppression pool cooling mode.

1044 Opened the cooling tower cold water bypass valves (OP-242-001 Attachment A).

1100 Inspector reverified certain key parameters:

Rx level = 35 inches	Suppression pool temperature 66°F
Rx press = 589 psig	Suppression pool temperature 22'8"
DW pressure = 1.0 psig	DW temperature = 149°F

1125 Reset the main generator "first-out" panel.

1125 The inspector reverified certain key parameters:

Rx level = 36 inches	DW temperature = 153°F (TS=135°F)
Rx press = 560 psig	DW press = 1.1 psig
Rx temp = 480°F	

Both reactor recirculation pumps were running
The "B" loop of the residual heat removal was operating in the suppression pool cooling mode
Feed and condensate in service - "A" reactor feed pump through the low load valve
Stm loads - #1 BPV (throttled), SJAE, main turbine steam seals.
Main steam isolation valves open.

1125 - 1245 Various BOP equipment shutdown.

1254 Temporary power applied to SV-22651, Instrument gas supply to the DW. The MSIVs are no longer isolated from their respective containment instrument gas (CIG) supply.

1320 Temporary power (pneumatic supply) applied to HD-27508A, Drywell/Wetwell Vent and Purge damper. This damper must be open to vent the drywell (due to high pressure through the Standby Gas Treatment (SGTS) system. This was needed to depressurize the containment.

ATTACHMENT 3

PP&L/NRC Management Meeting

Mid-term SALP

Pennsylvania Power & Light Company (PP&L)

R.G. Byram, Vice President, Nuclear Operations
H.G. Stanley, Superintendent of Plant
C.A. Myers, Manager, Nuclear Regulatory Affairs
J.R. Miltenberger, Manager, Nuclear Safety Assessment
T.C. Dalpiaz, Manager, Plant Services
E.W. Figard, Manager, Nuclear Maintenance
M.W. Simpson, Manager, Nuclear Technology
H.D. Woodeshick, Special Assistant to the President
R.M. Peal, Compliance Supervisor
J.M. Kenny, Licensing Group Supervisor
C.R. Whirl, Supervisor, Quality Verification
T.G. Bannon, Licensing
R.R. Wehry, Compliance Engineer

Nuclear Regulatory Commission (NRC)

C.W. Hehl, Director, Division of Reactor Projects
A.R. Blough, Chief, Projects Branch 2
J.R. White, Chief, Projects Branch 2
D.J. Mannai, Resident Inspector, SSES
R.W. Cooper, Deputy Devision Director, DRSS
J.D. Noggle, Radiation Specialist, DRSS
J.J. Raleigh, Project Manager, NRR
C.L. Miller, NRR, PD 1-2
D.L. Caphton, Senior Technical Inspector, DRS

Others

D. Ney, Nuclear Engineer, PA DER

MID-TERM SALP

An Assessment of the Susquehanna SES

PP&L - SUSQUEHANNA

Attachment 4

A SUCCESSFUL YEAR

Susquehanna surpassed expectations in 1991 in safe, efficient operation. This was achieved during a time of rapid change in the department.

- Safe Operation
- Improved Discrepancy Management
- Enhanced Responsiveness
- Excellent Outage Performance
- Excellent Generating Performance
- Restructured Organization

MANAGEMENT PERSPECTIVES

- Our Mission, Vision, and Values support our commitment to be the best.
- We have a strong nuclear safety culture and are improving our integrity of design.
- Assessment and change are essential to meet our rising expectations.
- Our integrated planning process provides focus and balance to our work.
- We are focussed on discrepancy management and responsiveness.
- We are committed to providing our people with the "tools" to succeed.
- Our people are the foundation for success.

ASSESSMENT

Corporate Management

- Nuclear Department Senior Management
- Corporate Management Committee (CMC)
- Board of Directors

External Industry Experts

- Environmental Advisory Committee (EAC)
- Radiation Advisory Committee (RAC)
- Nuclear Training Advisory Committee
- Susquehanna Review Committee (SRC)

Internal Nuclear Department Groups

- Nuclear Quality Assurance (NQA)
- Nuclear Safety Assessment Group (NSAG)
- Engineering Review Committee (ERC)
- Plant Operations Review Committee (PORC)

SUSQUEHANNA STEAM ELECTRIC STATION

PP&L

State Agencies

- Public Utility Commission (PUC)
- Pennsylvania Emergency Management Agency (PEMA)
- Department of Environmental Resources (DER)

Federal Agencies

- Nuclear Regulatory Commission (NRC)
- Federal Emergency Management Agency (FEMA)

Industry Groups

- Institute of Nuclear Power Operations (INPO)
- Nuclear Management and Resources Council (NUMARC)

WHY WE'RE HERE

Our independent and internal assessments have given us a picture of our strengths and weaknesses - we'd like to understand your view of Susquehanna.

- Independent Assessment
- Provide Our Perspective
- Understand Your Perspective

ORGANIZATION EFFECTIVENESS REVIEW UPDATE

Our largest assessment. We've implemented the structure of the OER and continue to focus on our people.

• Leadership / Supervision:	Essential to Success
• Role of Engineering:	Separate Day-to-Day from Long Term
• Functional Alignment:	Long Term Productivity Gains

MID-TERM SALP REVIEW

We are committed to be the best. With emphasis on Nuclear Safety, we are continuing to improve in all SALP areas.

GENE STANLEY	Plant Superintendent's Perspective
ED FIGARD	Maintenance / Surveillance
TED DALPIAZ	Radiological Protection
GENE STANLEY	Operations, Security, Emergency Preparedness, Engineering / Technical Support, Safety Assessment / Quality Verification, Future Challenges

SUPERINTENDENT's PERSPECTIVE

- STATION PERFORMANCE IN 1991

  - INDUSTRIAL SAFETY
  - RADIOLOGICAL SAFETY
  - DEFICIENCY MANAGEMENT
  - STATION OPERATING SUMMARY
  - SALP AREA ASSESSMENTS

INDUSTRIAL SAFETY

- ALTHOUGH TOTAL NUMBER OF INJURIES INCREASED SLIGHTLY IN 1991, THE LEVEL OF SEVERITY OF INJURIES DECREASED.

- NO INJURIES DURING UNIT 2 4TH REFUEL/INSPECTION OUTAGE.

- GOAL IS TO ACHIEVE AND MAINTAIN AN "ACCIDENT FREE" WORKPLACE.

- THIS GOAL IS ATTAINABLE BY INCORPORATING SAFE WORK BEHAVIORS INTO ALL TASKS.

RADIOLOGICAL SAFETY

- GOES HAND-IN-HAND WITH INDUSTRIAL SAFETY.

- BEHAVIOR-BASED APPROACH

- IN 1991, THE NUMBER OF PERSONNEL CONTAMINATIONS PER 1,000 RADIATION WORK PERMIT EMPLOYEE HOURS DECREASED.

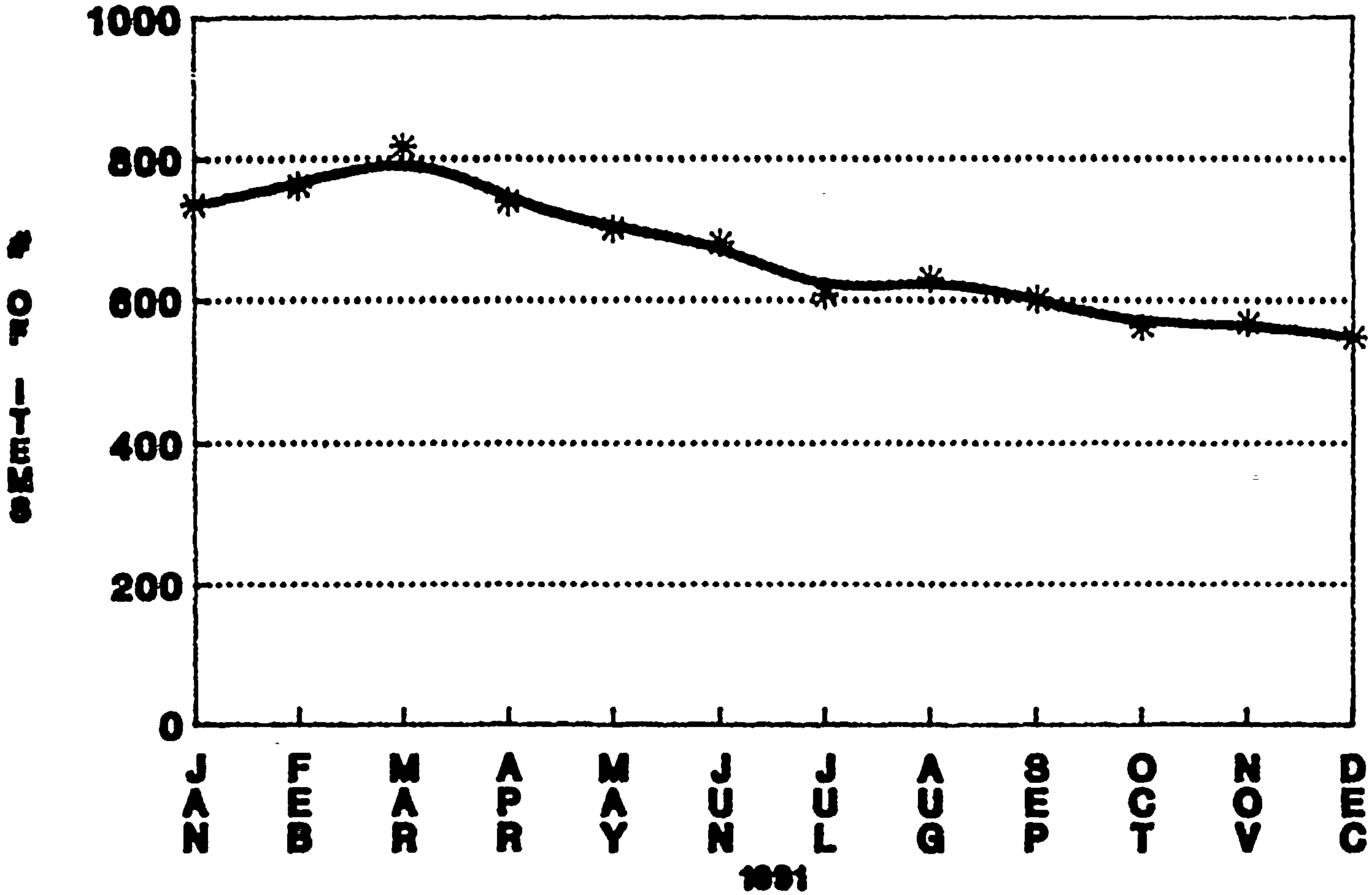
- THE SPENT FUEL POOL CLEANOUT PROJECT POSED SIGNIFICANT RADIOLOGICAL SAFETY CHALLENGES - TOTAL EXPOSURE WAS LOW.

- WE CONTINUE TO IMPROVE PERFORMANCE TO KEEP PACE WITH RISING STANDARDS.

DEFICIENCY MANAGEMENT

- o PURSUED AND CONTINUE TO PURSUE RESOLUTION TO DEFICIENCIES IDENTIFIED BY OURSELVES AND OTHERS
  - EVENT REVIEW TEAMS
  - ASSESSMENTS
- o SEVERAL EFFORTS IN 1991 TO IMPROVE IN THIS AREA
  - DEFICIENCY MANAGEMENT TASK FORCE
  - CYCLE CLOSURE CONCEPT
  - CENTRALIZING OF TRACKING AND REPORTING
- o REDUCTION IN OPEN DEFICIENCIES DURING 1991 FROM 810 TO 547 AT YEAR's END

DEPT DEFICIENCY PERFORMANCE INDICATOR
NCRS-SOORS-NRC-AUDITS-EDRS-QSF



DATA AS OF JAN 7, 1992

SUSQUEHANNA OPERATING SUMMARY

CAPACITY FACTOR

(1991)

UNIT 1 95%

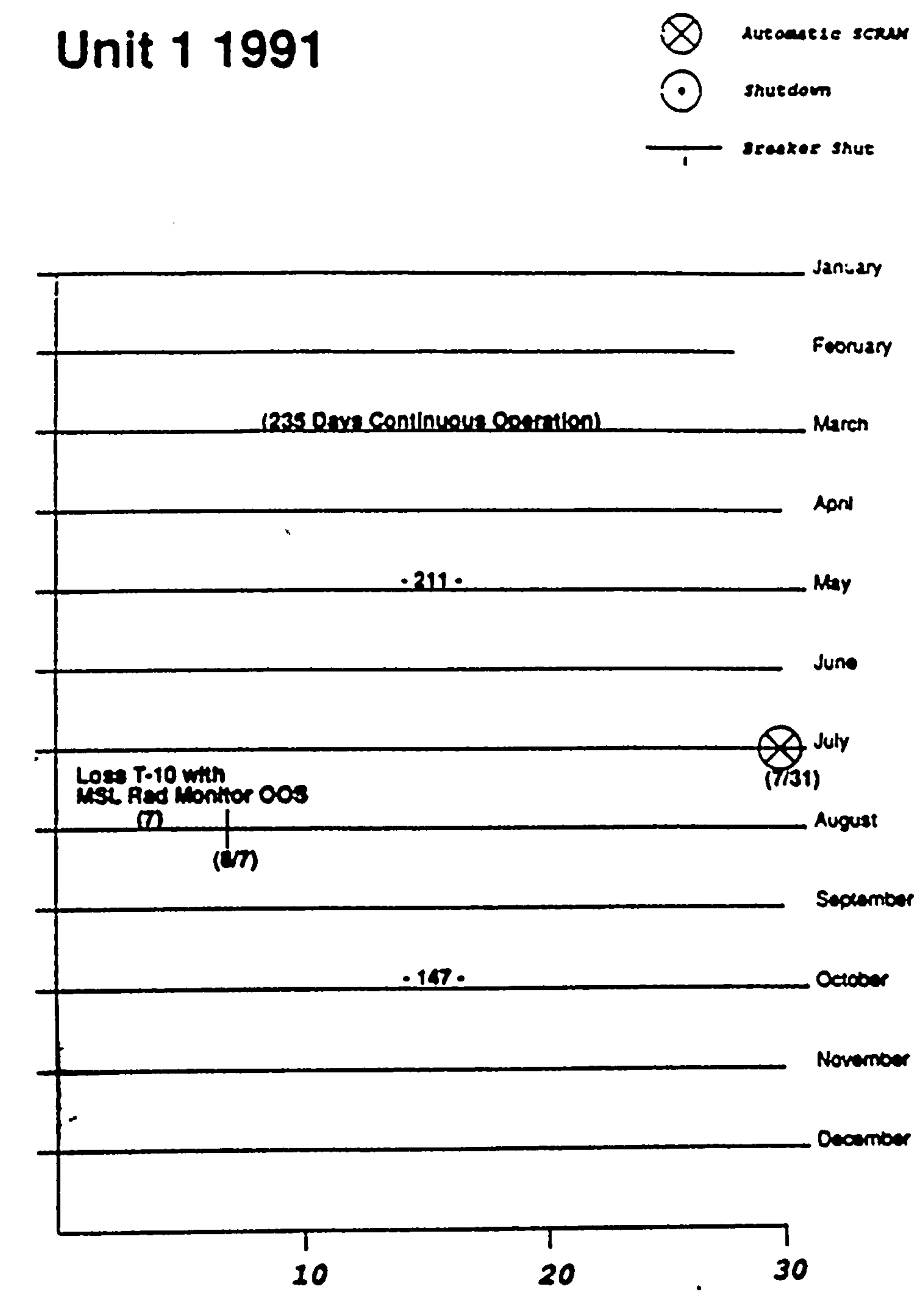
(HIGHEST OF ANY GE PLANT)

UNIT 2 76%

(INCLUDES 60 DAY OUTAGE)

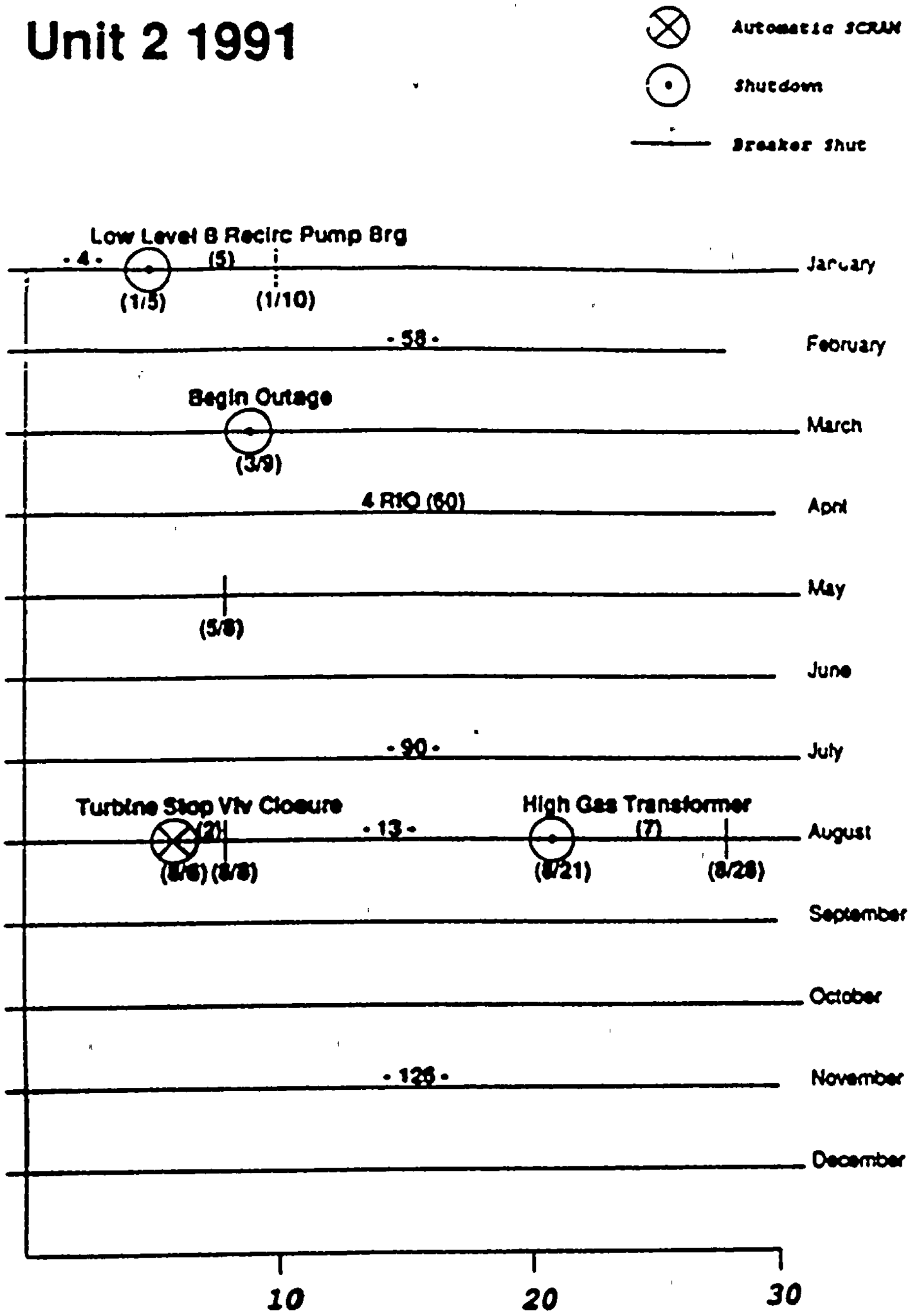
o NEW RECORD FOR POWER GENERATION IN 1991: 15,857 GWH PRODUCED

Unit 1 1991

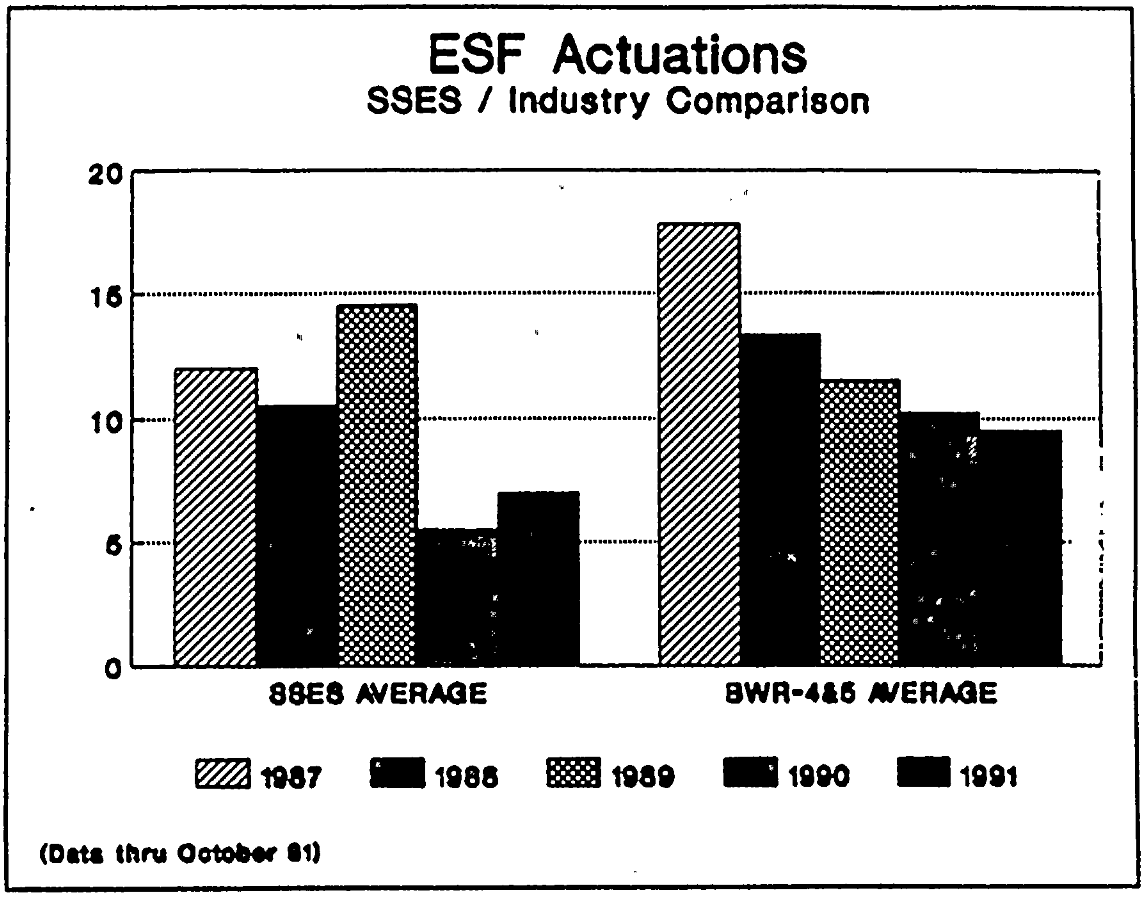


358 Days of Operation

Unit 2 1991



291 Days of Operation



ESF Actuations
SSES / Industry Comparison
20
15
10
5
0
SSES AVERAGE
BWR-4&5 AVERAGE
1987
1988
1989
1990
1991
(Data thru October 91)

MAINTENANCE

STRENGTHS / ACCOMPLISHMENTS

POSITIVE INITIATIVES

RESULTS

PLANT EQUIPMENT IS WELL MAINTAINED

- o PLANT PERFORMANCE
- o HIGH AVAILABILITY OF EQUIPMENT

REASON:

- o TRAINED, STABLE MAINTENANCE WORK FORCE
- o STRONG MAINTENANCE PROGRAM
- o TEAMWORK AND COOPERATION

RESULT:

- o SAFE AND RELIABLE OPERATION

1991 OUTAGE - UNIT 2 FOURTH RIO

MARCH 9 THROUGH MAY 8
60 DAYS
PLANT STARTED UP AND RAN WELL

MODIFICATIONS / WORK ACCOMPLISHED:

- o RHRSW VALVES IN RHR Hx LINES
- o ROOM COOLERS IN RHR, CS, & TUNNEL
- o PARTIAL ARC ADMISSION
- o GENERATOR REWIND
- o HPCI OVERHAUL
- o 500 KV SWITCHYARD
- o CIRC WATER EXPANSION JOINTS
- o COMPLETED INSTRUMENT AIR UPGRADE
- o CLOSED 17 BYPASSES & 56 NCR's

OUTAGE SAFETY RECORD

- NO PERSONNEL INJURIES
- DECAY HEAT REMOVAL ALWAYS CONTROLLED NO LOSS OF SDC
- CORE REACTIVITY AND CONTAINMENT WERE WELL MANAGED
- EXPOSURE OF 329 MANREM
- 2 ESF ACTUATIONS

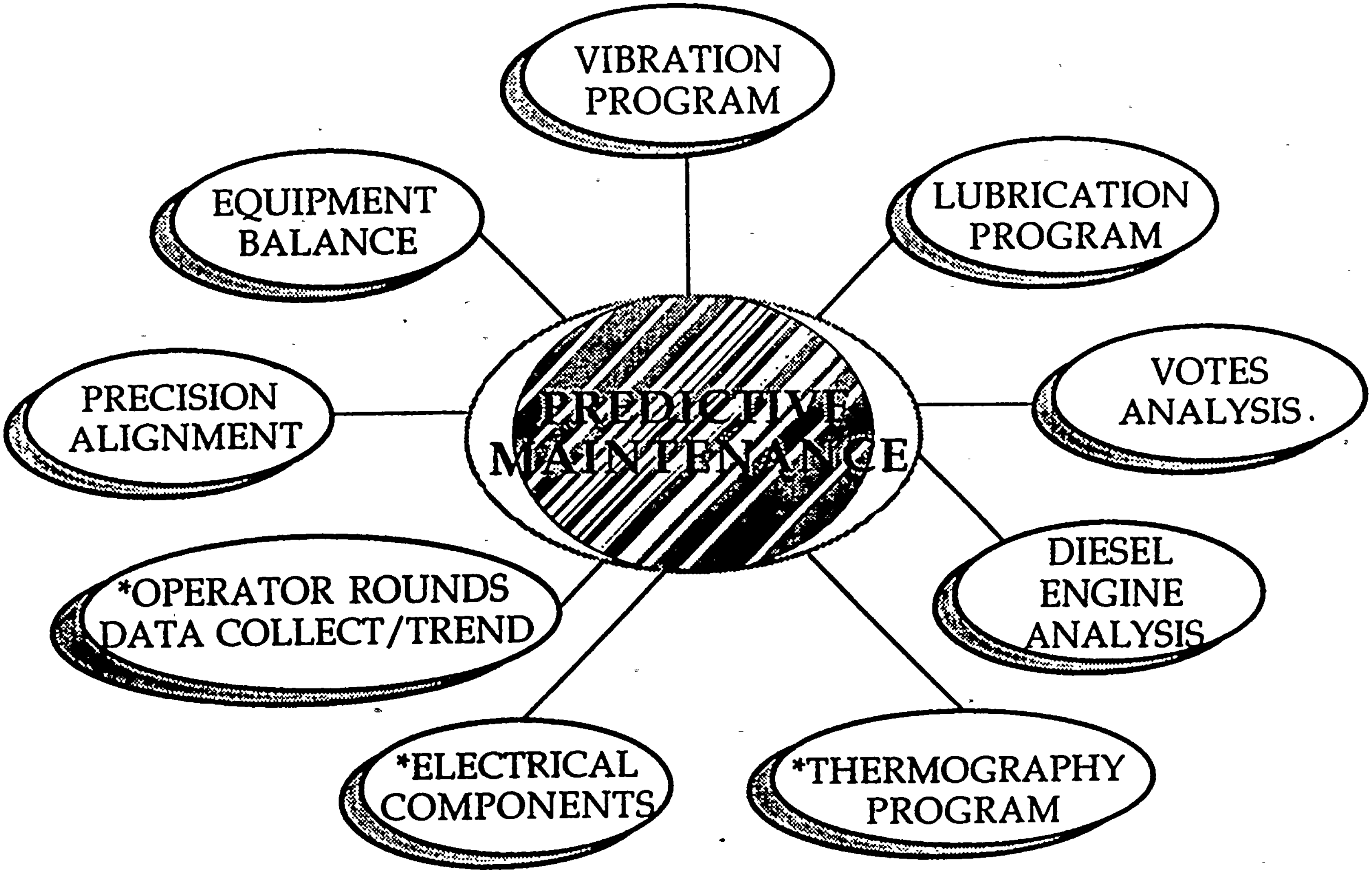
PREDICTIVE MAINTENANCE

PEOPLE:

- o SUPERVISOR ASSIGNED IN 1991
- o EXPERIENCED ASSISTANT FOREMAN
- o 6 MECHANICS
- o 2 ELECTRICIANS TO BE ASSIGNED

ACCOMPLISHMENTS:

- o UNIT 2 "C" PHASE MAIN TRANSFORMER COMBUSTIBLE GAS SAMPLE (HAZLETON TRANSFORMER ORGANIZATION)
- o "C" ESW PUMP MOTOR
- o TURBINE BUILDING FANS 1V104B & 1V101A



* TO BE DEVELOPED

MOTOR OPERATED VALVES
NRC INSPECTION IN SEPTEMBER 1991

RESULTS CONCLUDED THAT MOV PROGRAM IS:

- o THOROUGH
- o WELL MANAGED
- o ON SCHEDULE

ALL MOV's WILL BE TESTED BY AUGUST 1994.

DIESEL GENERATOR RELIABILITY
1989 CRANKCASE OVERPRESSURIZATIONS

- o ROOT CAUSE IDENTIFICATION
- o INSPECTIONS/REFURBISHMENT
- o MODIFICATIONS
- o PERFORMANCE ANALYSIS/TRENDING
- o INSPECTIONS

NO TIN SMEARING

NRC MAINTENANCE TEAM INSPECTION

- LENGTHY, THOROUGH REVIEW OF MAINTENANCE

- MANY POSITIVE ASPECTS AND STRENGTHS CITED.

- ALL VIOLATIONS HAVE BEEN ADDRESSED AND ARE READY FOR CLOSURE (PLA-3548)

MAINTENANCE RULE

NRC OFFICE OF NUCLEAR REGULATORY RESEARCH
VISIT TO SSES - DECEMBER 1991

- PP&L IS MONITORING MAINTENANCE EFFECTIVENESS

- WE BELIEVE WE MEET THE INTENT OF THE MAINTENANCE RULE

POSITIVE INITIATIVES

PROCEDURES AND PROCEDURAL ADHERENCE

WORK PLANNING

WORK PRACTICES

SUPERVISORY OVERSIGHT

PROCEDURES AND PROCEDURAL ADHERENCE

- o PROCEDURES

- o WORK PLANS

- o STANDARDS

- o PERFORMANCE

WORK PLANNING

- o INTEGRATED CONSTRUCTION AND PLANT STAFF PLANNING ORGANIZATION

- o COMPUTER NETWORK OPERATING

- o MAINTENANCE FACILITIES

WORK PRACTICES

- "CONDUCT OF MAINTENANCE" SPECIFIES EXPECTATIONS

- BACK-TO-BASICS TRAINING FOR CREW

- SUPERVISORY COACHING

- SELF ASSESSMENTS

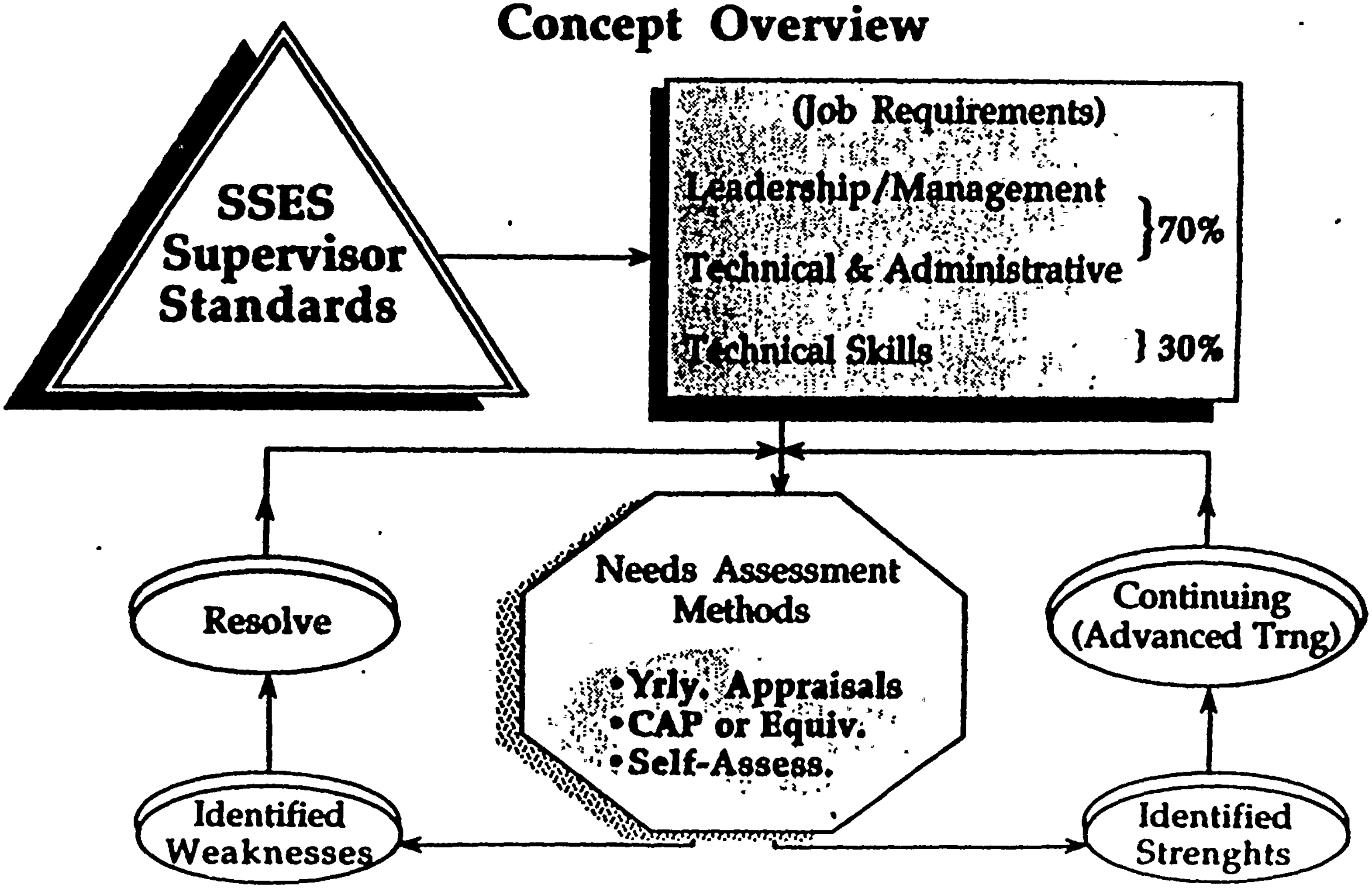
SUPERVISORY OVERSIGHT

- o CONTINUING TRAINING THROUGH SUPERVISORY TRAINING AND CERTIFICATION PROGRAM

- o MAINTENANCE SELF ASSESSMENT PROGRAM
  - PILOT PROGRAM UNDERWAY
  - FULL IMPLEMENTATION BY JUNE 1992

Susquehanna S.E.S. Supervisor Certification Program

Concept Overview



CONCLUSIONS

SAFETY:

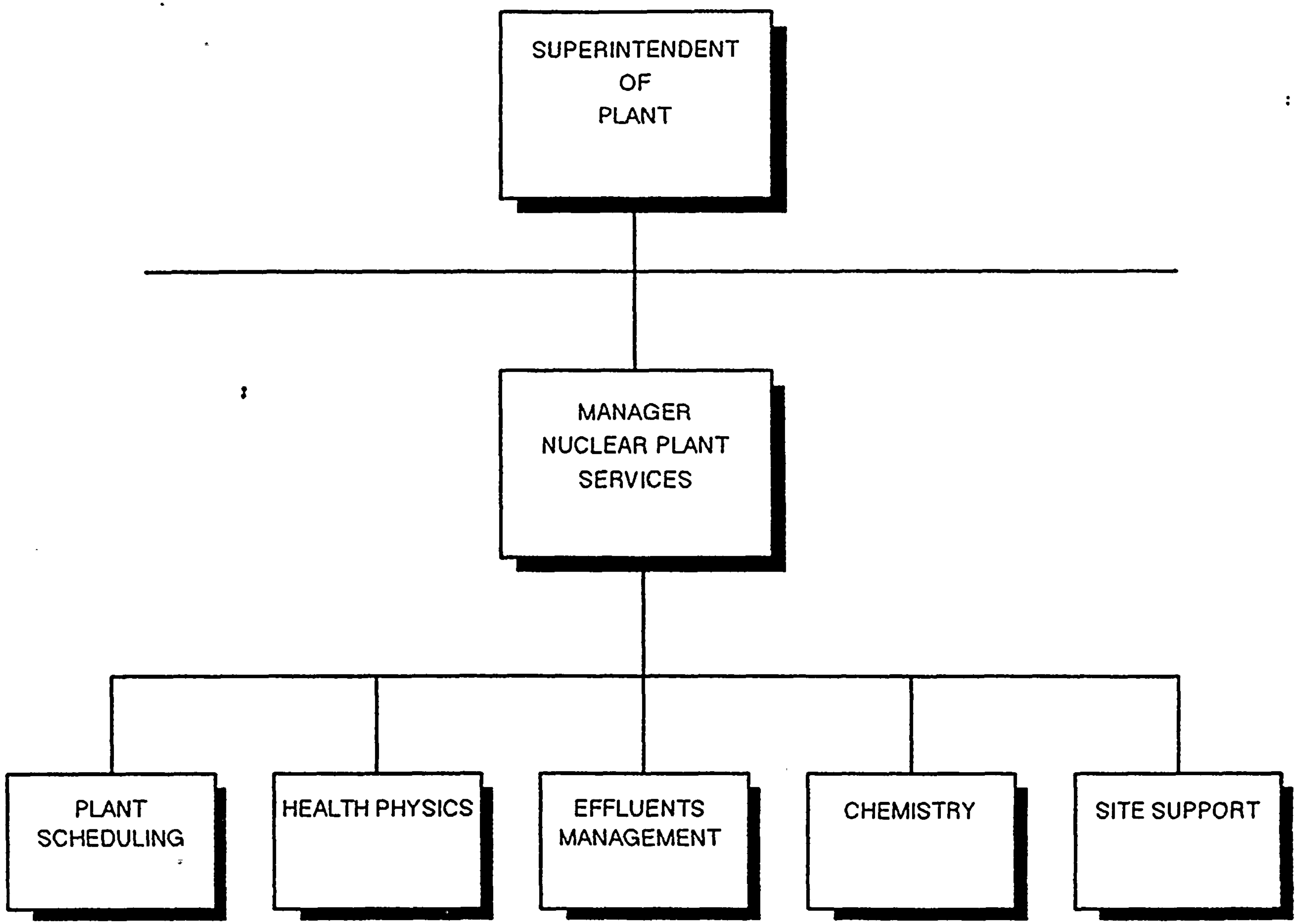
- o MAINTENANCE WORKS SAFELY
- o PLANT IS KEPT SAFE
    - FEW SCRAMS/ESF ACTUATIONS

IMPROVEMENTS:

- o INITIATIVES IN PROGRESS
- o SELF ASSESSMENTS UNDERWAY

PERFORMANCE:

- o INDUSTRY COMPARISONS
- o PAST SSES COMPARISONS


SUPERINTENDENT OF PLANT
MANAGER NUCLEAR PLANT SERVICES
PLANT SCHEDULING
HEALTH PHYSICS
EFFLUENTS MANAGEMENT
CHEMISTRY
SITE SUPPORT

RADIOLOGICAL CONTROLS

STRENGTHS

HEALTH PHYSICS

- ALARA PROGRAM AND IMPLEMENTATION
- STRONG PEOPLE INVOLVEMENT
- STRONG PROGRAMS AND IMPLEMENTATION
- PERSONNEL ROTATIONS

EFFLUENTS

- CONTROL OF EFFLUENTS SHIPMENTS/VENDORS
- VOLUME REDUCTION TECHNIQUES

PREVIOUS ISSUES RESOLVED

- CONTROL OF CONTRACTORS
- QUALIFICATION OF PERSONNEL
- WORKER PERFORMANCE

HEALTH PHYSICS

- o ALARA PERFORMANCE

- o CONTAMINATION CONTROL

SYSTEM ALARA INITIATIVES

- o RWCU PUMP CHANGEOUT
- o SNUBBER REDUCTION
- o CONDENSATE DEMINERALIZER MODS
- o USE OF POCKET ALARMING DOSIMETERS
- o ADDITIONAL AREA RAD MONITORS

PERSONNEL ALARA INITIATIVES

- RESPONSIVE TO EMPLOYEE ALARA CONCERNS
- WORK GROUP INVOLVEMENT IN ALARA GOALS
- ALARA GOALS BY FUNCTIONAL AREA
- EMPLOYEE RECOGNITION
- MAINTENANCE SUPERVISOR HEADS STATION ALARA COMMITTEE

CONTAMINATION CONTROL INITIATIVES

- BACK TO BASICS TRAINING
- FIRST LINE SUPERVISORY TRAINING
- ADDITIONAL PCM'S
- UPGRADED PROTECTIVE CLOTHING
- COMMUNICATION OF JOB DETAILS
- IMPROVED WORK PRACTICES
- REDUCE CLEAN AREA CONTAMINATIONS

FUEL POOL CLEANOUT PROJECT

PROCESS, SHIP, AND DISPOSE OF IRRADIATED HARDWARE & SPECIAL NUCLEAR MATERIALS STORED AT SSES.

CHALLENGES:

- o HEAVY LOADS
- o HIGH ACTIVITY/HIGH RADIATION LEVELS
- o HOT PARTICLE CONTROL
- o PERSONNEL EXPOSURE CONTROL
- o RADWASTE SHIPPING ISSUES

KEY ELEMENTS TO SUCCESS

PROGRAMMATIC

- WORK PLANNING
- USE OF INDUSTRY EXPERIENCE
- MULTI-DISCIPLINE TEAM
- SAFETY EVALUATION/PROCEDURES

IMPLEMENTATION

- OVERSIGHT

RESULTS

WASTE:

- 15 CLASS C SHIPMENTS IN 5 MONTHS
- TOTAL OF 242,540 CURIES
- VOLUMES: 1005 CU FT (BURIAL)
92 CU FT (WASTE)

EXPOSURE:

- TOTAL EXPOSURE 23.581 MAN-REM
- 52 PERSONNEL CONTAMINATIONS
(7 RESULTED IN ASSIGNED EXPOSURE)
- MAX INDIVIDUAL EXPOSURES
WHOLE BODY 1.715 REM
SKIN 5.873 REM

ASSESSMENTS:

- 3 NRC INSPECTIONS: NO VIOLATIONS OR FINDINGS
- 7 NQA SURVEILLANCES: NO MAJOR FINDINGS
- 4 SOOR'S
- 12 MINOR NCR'S

EFFLUENTS ACTIVITIES

- METHANE GAS MITIGATION
- 10CFR61 SAMPLING PROGRAM UPGRADES
- REMOTE PROCESSING HIGH ACTIVITY RWCU WASTE
- 142 RADIOACTIVE SHIPMENTS

CASK SHIPMENTS CLASS A	65
CASK SHIPMENTS CLASS B	8
SEG SHIPMENTS	14
ALARON SHIPMENTS	2
LAUNDRY SHIPMENTS	30
RADIOACTIVE MATERIAL (OTHER)	23

- 15,692 CUBIC FEET DISPOSED
- 14,236 CURIES DISPOSED

ASSESSMENTS

EXTERNAL

RESPIRATORY PROTECTION

HP RECORDS

INSTRUMENTATION

RADWASTE CONTROL ROOM

INTERNAL

ALARA

RADIATION ADVISORY COMMITTEE

CONTAMINATION CONTROL

REGULATORY

ALARA

RADIOLOGICAL CONTROL

SPENT FUEL POOL CLEANOUT

RADWASTE SHIPMENTS

RADIOLOGICAL CHEMISTRY CONTROL

EMERGING ISSUES

- o LLRWHF

- o 10CFR20

KEYS TO SUCCESS

- o INNOVATIVE IDEAS
- o IMPROVED WORKER PERFORMANCE
- o WORKER INVOLVEMENT IN SOLUTIONS

RESULTS

- o PERFORMANCE CONTINUES TO IMPROVE

- o ASSESSMENTS/EVALUATIONS

- o NEW ISSUES QUICKLY ADDRESSED

OPERATIONS

- OPERATIONS CONTINUES TO BE A STRENGTH AND A PRIORITY FOR SUSQUEHANNA

- STRONG MANAGEMENT INVOLVEMENT AND A CONSERVATIVE APPROACH TO NUCLEAR SAFETY

- REQUAL STATUS - WHERE WE ARE GOING

INITIATIVES

- o ORGANIZATION CHANGES
  - SHIFT TECHNICAL ADVISORS AND REACTOR ENGINEERING REPORT TO MANAGER-NUCLEAR OPERATIONS
- o STRONG REACTIVITY CONTROL PROGRAM
- o IMPROVED CONTROL OF TRANSIENT EQUIPMENT IN THE PLANT
- o EOP IMPLEMENTATION

INITIATIVES (CONT'D)

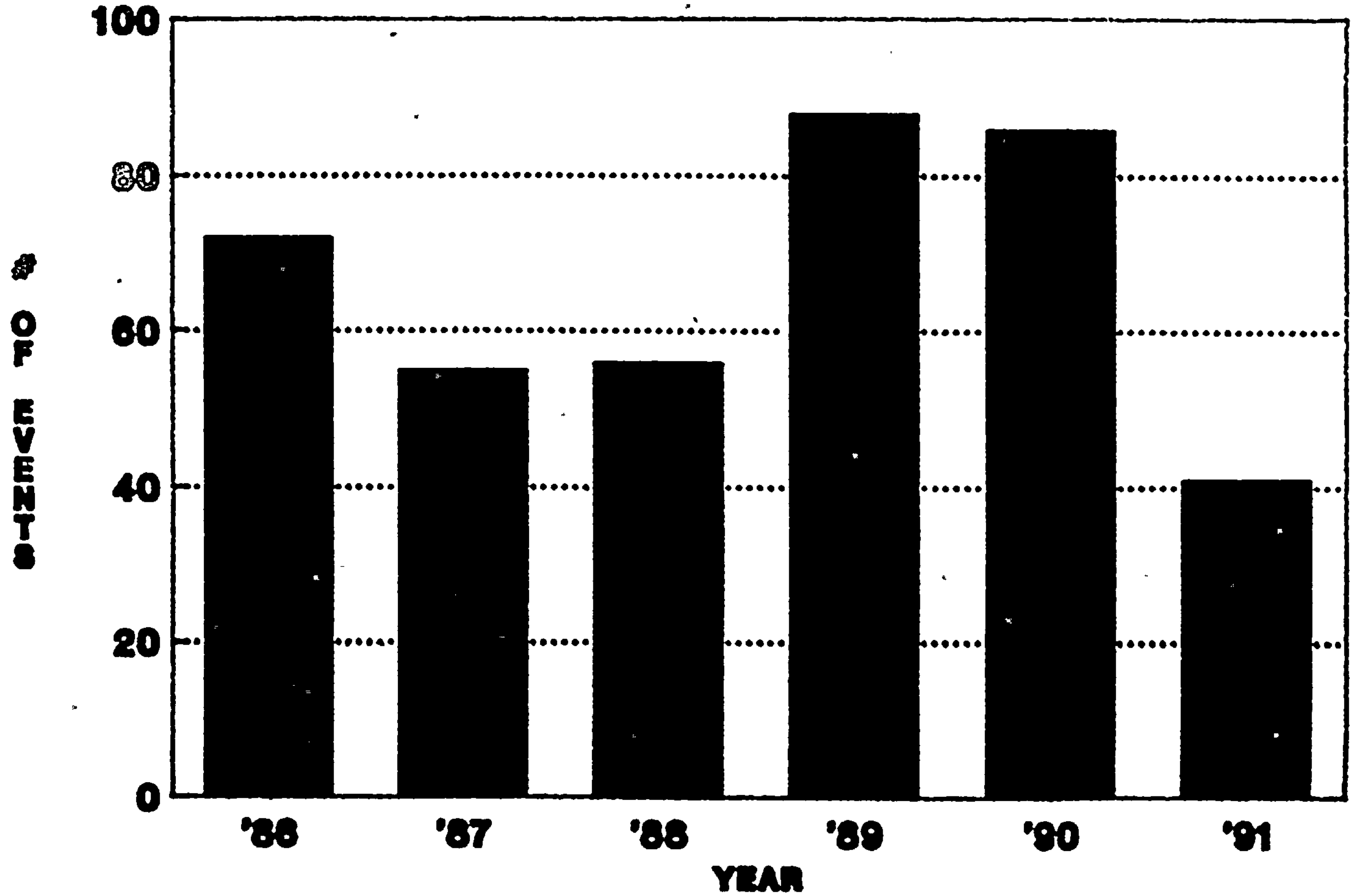
- INCREASED ATTENTION TO CONTROL OF PLANT PARAMETERS

- SIMULATOR UPGRADE

- IMPROVEMENTS IN NON-LICENSED OPERATOR AREA
  - OPERATOR ROUNDS
  - TRAINING

- 12-HOUR SHIFT POSITIVE FEEDBACK

STATUS CONTROL SOOR'S
SIGNIFICANT OPERATING OCCURRENCE REPORTS



ASSESSMENTS

- o NSAG ANNUAL ASSESSMENT OF OPERATIONS

- o SELF ASSESSMENTS
  - BACK TO BASICS
  - PERMIT & TAG
  - STATUS CONTROL

SECURITY AND SAFEGUARDS

- PROFESSIONAL, DEDICATED SECURITY ORGANIZATION
- EXCEPTIONALLY LOW TURNOVER OF SECURITY PERSONNEL
- 12-HOUR SHIFT POSITIVE FEEDBACK
- SELF ASSESSMENT IS KEY STRENGTH
  - MINIMUM OF 12 CONTINGENCY EXERCISES PER MONTH DURING NON-OUTAGE PERIODS (TRAINING EFFECTIVENESS MEASUREMENT)
  - QUARTERLY SELF-ASSESSMENTS CHALLENGE SYSTEMS/EQUIPMENT TO IDENTIFY ANY WEAKNESSES
  - OPERATIONAL READINESS CHECKS CONDUCTED BY CORPORATE SECURITY ASSESS PROCEDURAL SUFFICIENCY AND EFFICIENCY AND MEASURE ABILITY TO RESPOND TO EVENTS

EMERGENCY PREPAREDNESS

- STRONG ORGANIZATIONAL STRUCTURE INCLUDING EX-SRO/SHIFT SUPERVISOR AND ONE PROJECT MANAGER FULL TIME FOR FFE-3 COORDINATION.

- POSITION SPECIFIC PROCEDURES ARE IN PLACE AND FUNCTIONING WELL.

- CONTINUING TO REFINE COMMUNICATIONS AND EFFECTIVE TRAINING OF RESPONSE PERSONNEL.

- LEAD BWR FOR DEVELOPMENT OF EAL's IN CONJUNCTION WITH NUMARC.

- HOST UTILITY FOR FFE-3.

EMERGENCY PREPAREDNESS (CONT'D)

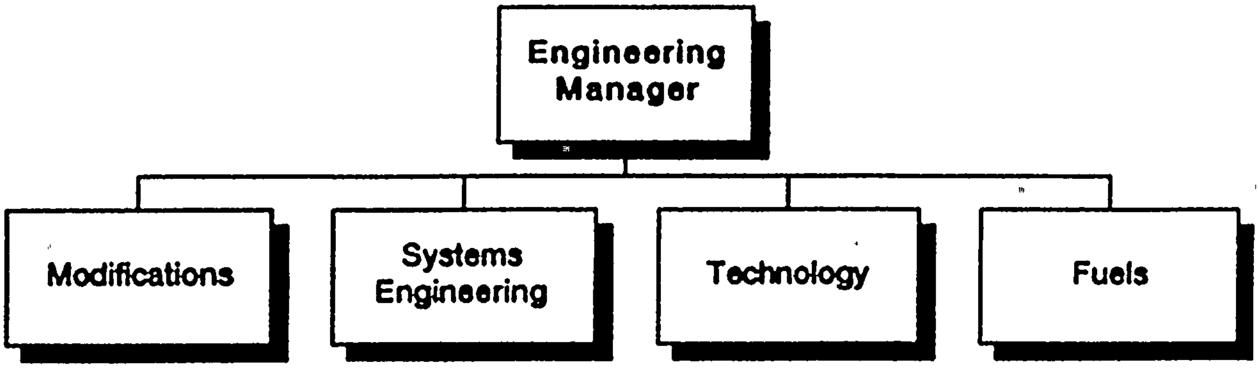
ASSESSMENTS

- NQA (SRC) ANNUAL PURSUANT TO 10CFR50.57
- DRILL PERFORMANCE ASSESSMENTS BY OUTSIDERS (UTILITIES, ETC.)
- EP ACTIVATION FOLLOW-UP ASSESSMENTS
- REGULATORY

ENGINEERING PERFORMANCE

- o MANAGEMENT INVOLVEMENT
- o RESPONSIVENESS
- o INTEGRATED APPROACH TO ENGINEERING

ORGANIZATION CHANGES



CONTINUING MANAGEMENT ATTENTION

- ELECTRICAL ISSUES
- RESPONSIVENESS
- STATION BLACKOUT COMPLIANCE
- EQ PROGRAM
- DESIGN BASIS DOCUMENTATION
- ORGANIZATION

INITIATIVES

- CORE RELOAD LICENSING METHODOLOGY
- DIESEL GENERATOR ROOT CAUSE
- RISK MANAGEMENT INITIATIVES
- COMPONENT MODELING
- EDR PROCESS ENHANCEMENTS
- ENGINEERING REVIEW COMMITTEE
- SAFETY EVALUATION IMPROVEMENTS
- FUNCTIONAL ORGANIZATION

ENGINEERING VISION

IMPROVE PLANT RELIABILITY AND MARGINS OF SAFETY

- o DEFINE AND EXECUTE AN INTEGRATED DBD PROGRAM
- o CONTINUE DEVELOPMENT OF ERC AND REFINE INTERFACES WITH PORC AND SRC
- o IMPROVE ENGINEERING QA PROCESSES
- o COMPLETE INTEGRATION OF IPE/PRA INTO DECISION MAKING AND PRIORITIES
- o MAINTAIN OPEN DISCREPANCIES TO A MANAGEABLE LEVEL
- o UPGRADE AND EXECUTE ENGINEERING AND TECHNICAL TRAINING PROGRAMS

SAFETY ASSESSMENT / QUALITY VERIFICATION

- o CONSERVATIVE APPROACH TO NUCLEAR SAFETY
- o COMPREHENSIVE SELF ASSESSMENT PROGRAMS
- o ASSESSMENT GROUP ESTABLISHED IN NQA
- o ENGINEERING REVIEW COMMITTEE ESTABLISHED
- o FOCUS ON SHUTDOWN RISK REDUCTION
- o EVENT REVIEW TEAMS PROVIDE ROOT CAUSE ANALYSIS
- o STRENGTHENING DOCUMENTATION ON DISCREPANCIES
- o CONTINUING TO IMPROVE MEETING COMMITMENTS

CHALLENGES FOR 1992 - 93

WE KNOW THAT THE ONLY WAY TO MAINTAIN IS TO IMPROVE, AND SUBSTANTIAL IMPROVEMENT MEANS CHANGE.

- OPERATE SAFELY AND RELIABLY
- PERFORM OUTAGE WORK SAFELY AND EFFICIENTLY
- CONTINUE IMPLEMENTING OER PRINCIPLES
- CONTINUE PERSONNEL DEVELOPMENT EFFORTS
- INCREASE FOCUS ON LEARNING FROM INDUSTRY
- MAKE "ASSESSMENT & CHANGE" A WAY OF LIFE

MANAGEMENT PERSPECTIVES

- OUR MISSION, VISION, AND VALUES SUPPORT OUR COMMITMENT TO BE THE BEST.
- WE HAVE A STRONG NUCLEAR SAFETY CULTURE AND WE DEFEND THE DESIGN OF THE PLANT.
- ASSESSMENT AND CHANGE ARE ESSENTIAL TO MEET OUR RISING EXPECTATIONS.
- OUR INTEGRATED PLANNING PROCESS PROVIDES FOCUS AND BALANCE TO OUR WORK.
- WE ARE FOCUSSED ON DISCREPANCY MANAGEMENT AND RESPONSIVENESS.
- WE ARE COMMITTED TO PROVIDING OUR PEOPLE WITH THE "TOOLS" TO SUCCEED.
- OUR PEOPLE ARE THE FOUNDATION FOR SUCCESS.