U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Report Nos. 50-295/90003(DRP); 50-304/90003(DRP)

Docket Nos. 50-295; 50-304 License Nos. DPR-39; DPR-48

Licensee: Commonwealth Edison Company
P. O. Box 767
Chicago, IL 60690

Facility Name: Zion Nuclear Power Station, Units 1 and 2

Inspection At: Zion, IL

Inspection Conducted: January 16 through March 10, 1990

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3/28/90
Date

Inspection Summary

Inspection from January 16 through March 10, 1990 (Report Nos. 50-295/90003 (DRP); 50-304/90003(DRP))

Areas Inspected: Routine, unannounced resident inspection of licensee action on previous inspection findings, operational safety verification and engineered safety features (ESF) system walkdown, surveillance observation, maintenance observation, engineering and technical support, new fuel inspection, licensee event reports (LERs), training, and quality program effectiveness. A number of events and other items of interest occurred at the Zion Station during this report period. The summary of operations, paragraph 3, describes cavitation of the 1A auxiliary feedwater (AFW) pump, valve misalignment for the 1B AFW pump, Unit 1 trip due to high steam generator (SG) level, inadvertent start of the 1B AFW pump, shutdown of both units due to 'O' emergency diesel generator (EDG) inoperability, Unit 2 manual trip due to electro-hydraulic control problems, Unit 2 circulating water discharge pipe problems, 2C SG primary to secondary leakage, Unit 2 turbine oil leak in afterbay, and liquid in solidified low level radwaste barrels. The maintenance observations (paragraph 6) include a Unit 2 unplanned power increase during maintenance, the Unit 1 refueling outage, failure of the 1B EDG, loss of DC power to the 2B EDG, 2A EDG failures to meet start time, and failures of the 'O' EDG. Paragraph 7.c describes failures of the 2A AFW pump. Paragraph 11 describes meetings held by licensee management for

station staff in order to emphasize the importance of eliminating personnel errors and a waiver of compliance and enforcement discretion related to an inoperable EDG.

Results: Of the 9 areas inspected, no violations or deviations were identified in 7 areas, and 1 violation with four examples was identified in the remaining 2 areas. The examples were the failure to provide an adequate and appropriate procedure for testing of the 1A AFW pump which resulted in the cavitation and damage of the pump, failure to properly align and properly verify valve position which resulted in the inoperability of the 1B AFW system, failure to follow a surveillance test which resulted in the inadvertent start of the 1B AFW pump, and failure to follow out-of-service guidance which resulted in the inoperability of the 2B EDG (paragraphs 4a, 4b, 4c and 6e). There were three Open Items identified: the Unit 2 unplanned power increase, the 2A EDG failures to meet its start time requirement, and the 2A AFW pump failures due to overspeed trips (paragraphs 6.b, 6.f, and 7.c, respectively).

Other significant findings of this inspection include both units being required to be taken to cold shutdown due to the inoperability of a single EDG, Unit 2 steam generator primary-to-secondary leakage of approximately 200 gallons per day just prior to the shutdown for the refueling outage, and low-level radwaste barrels from Zion that arrived at a burial site with free-standing liquid in them.

DETAILS

1. Persons Contacted

*T. Joyce, Station Manager
*T. Rieck, Superintendent, Services
W. Kurth, Superintendent, Production
*P. LeBlond, Assistant Station Superintendent, Operations
*R. Johnson, Assistant Station Superintendent, Maintenance
J. LaFontaine, Assistant Station Superintendent, Planning
R. Budowle, Assistant Station Superintendent, Technical Services
N. Valos, Unit 2 Operating Engineer
W. Demo, Unit 1 Operating Engineer
M. Carnahan, Unit 1 Operating Engineer
E. Broccolo, Jr., Director of Performance Improvement
E. Fuerst, Project Manager, ENC
T. Vandevoort, Quality Assurance Supervisor
C. Schultz, Quality Control Supervisor
*W. Stone, Regulatory Assurance Supervisor
*W. T'Niemi, Technical Staff Supervisor
R. Smith, Security Administrator
T. Saksefski, Regulatory Assurance
W. Mammoser, PWR Projects

*Indicates persons present at the exit interview.

The inspectors also contacted other licensee personnel including members of the operating, maintenance, security, and engineering staff.

2. Licensee Actions on Previous Inspection Findings (92701, 92702)

(Open) Violation (295/89018-01d; 304/89017-01d): Failure to take adequate and timely corrective action to maintain and test the auxiliary feedwater (AFW) pump turbine overspeed mechanisms. In a letter to Mr. A. Bert Davis from R. A. Chrzanowski dated December 12, 1989, the licensee committed to perform the overspeed test on the Unit 1 AFW within two weeks following the outage and on the Unit 2 AFW before March 31, 1990. On February 10, 1990, the licensee performed three unsuccessful overspeed tests for the 1A AFW pump. The pump was manually tripped each time to prevent exceeding the caution statement of the procedure. The overspeed trip mechanism was disassembled to determine the cause of the failures. Investigations indicated that the clearance between the overspeed weight and the tappet spring assembly was incorrect. Also, an adjustment to the adjustment screw which controls the force against the overspeed weight was needed. On February 12, the overspeed test was successfully completed for the 1A AFW pump.

Due to the problems experienced with the 1A AFW pump, the licensee tested the 2A AFW pump. On February 13, the 2A AFW pump failed to trip on overspeed and was manually tripped. Similar to the 1A AFW pump, the clearance between the overspeed weight and the tappet spring assembly was incorrect and was adjusted. However, when the pump was retested, it again failed to trip. Investigations indicated that the overspeed spring was of the incorrect length. The spring was replaced and the 2A AFW pump was retested successfully on February 16 and declared operable on February 17. This issue remains open for further investigation by regional inspectors.

No violations or deviations were identified.

3. Summary of Operations

Unit 1

The unit entered this reporting period in mode 7, physics testing, in preparation for leaving the refueling outage which had started in September 1989. On January 17, 1990, at approximately 4:15 a.m., the licensee completed low power physics testing and entered Mode 2, Hot Standby. On January 25 at 6:10 p.m., the unit was synchronized to the grid. On January 27, at 8:16 a.m., the unit tripped due to a turbine trip/feedwater isolation caused by a high-high 1D steam generator level. The unit was taken critical on January 28 and placed on-line at approximately 9:30 p.m. The unit operated at power levels up to 100% power during the month of February. On March 1 at 6:48 p.m., the licensee commenced a shutdown due to the inoperability of the '0' emergency diesel generator (EDG) for allowed outage time stipulated in the Confirmatory Order dated February 29, 1980. On March 7 at approximately 4:58 a.m., the unit was placed in cold shutdown due to the inoperability of the '0' EDG and the inability to make the EDG operable within the time granted by the March 2 regional temporary waiver of compliance (see paragraph 12). The unit remained in cold shutdown for the remainder of the report period.

Unit 2

On January 15, in accordance with abnormal operating procedures, power was reduced to 40% to bring the sulfate concentration within vendor specifications limits for steam generator (SG) secondary chemistry. On January 18 at approximately 2:41 a.m., the unit was manually tripped due to electro-hydraulic control system problems. On January 19 at 7:37 a.m., the unit was placed on-line. The unit operated at power levels up to 100% power during the month of February. At 8:25 p.m. on March 1, the licensee commenced a unit shutdown due to the inoperability of the '0' EDG. On March 2, the Regional Administrator granted a temporary waiver of compliance to allow Unit 2 to stay in hot shutdown during further testing of the EDG. On March 6, a 144-hour extension to the waiver was granted to allow time for required testing prior to proceeding to a refueling outage. The outage was scheduled to begin March 22 but was entered early due to the failure of the '0' EDG.

4. <u>Operational Safety Verification and Engineered Safety Features System Walkdown (71707 & 71710)</u>

The inspectors observed control room operations, reviewed applicable logs and conducted discussions with control room operators from January 15 through March 10, 1990. During these discussions and observations, the inspectors ascertained that the operators were alert, cognizant of plant conditions, attentive to changes in those conditions, and took prompt action when appropriate except as noted. On January 25, Unit 1 tripped from a turbine trip due to a high-high steam generator level which resulted from operator inattentiveness. On the positive side, on January 18, an operator manually tripped the Unit 2 turbine as required by plant conditions. The inspectors verified the operability of selected emergency systems, reviewed tagout records and verified proper return to service of affected components. Tours of the auxiliary and turbine buildings were conducted to observe plant equipment conditions, including potential fire hazards, fluid leaks, and excessive vibrations and to verify that maintenance requests had been initiated for equipment in need of maintenance.

The inspectors by observation and direct interview verified that selected physical security activities were being implemented in accordance with the station security plan. The ingress routine was modified consistent with the other Commonwealth Edison sites.

The inspectors observed plant housekeeping/cleanliness conditions and verified implementation of radiation protection controls. From January 16, 1990 to March 10, 1990, the inspectors walked down the accessible portions of the AC electrical power systems; DC electrical power systems; residual heat removal systems; service water systems; component cooling water system, main and auxiliary steam systems; condensate and feedwater systems; circulating water systems; diesel generator and auxiliaries systems; make-up demineralizers; fuel handling systems; control room; safety injection systems; containment spray systems; and auxiliary feedwater systems to verify operability.

These reviews and observations were conducted to verify that facility operations were in conformance with the requirements established under Technical Specifications, 10 CFR, and administrative procedures.

The following observations were made:

<u>Unit 1</u>

a <u>1A Auxiliary Feedwater Pump Cavitation</u>

On January 16, 1990, the 1A turbine driven auxiliary feedwater (AFW) pump was manually tripped during a routine surveillance test. The unit was in Mode 7, Physics Testing, at the time.

The 1B and 1C AFW pumps were in service, each supplying different headers to control the steam generator (SG) levels. In preparation for the surveillance test, the operator unloaded the 1B pump by slowly throttling the 1A and 1B header discharge valves. This was done to maintain constant reactor coolant temperature and control rod position due to the possibility of creating a slightly positive moderator temperature coefficient. After securing the 1B pump, the operator reviewed the test procedure for the 1A turbine driven pump. The operator noted that the surveillance procedure required the pump's recirculation valve to be closed which would result in no discharge path for the pump since the A/B header discharge valves were also closed. The operator communicated the concern to the shift management. The shift supervisor did not understand the full extent of the operator's concern about the valve lineup for the pump.

The 1A AFW pump was started and was operated on recirculation for approximately 15 minutes as per the test procedure. During this period, the operator once again questioned shift supervisors about the closing of the recirculation flow path that would be performed in upcoming steps. The shift supervisor consulted with the shift engineer and determined that the procedure should be followed as written. This determination was based on knowledge of the procedure and review of the station piping and instrumentation drawings, instead of actual plant conditions that existed at the time. The operator asked the shift supervisor why the AFW system flows were being recorded, because in the current valve alignment, the SGs were only being supplied by the 1C AFW pump. The procedure was reviewed by the shift engineer and it was decided to proceed with the test as written. The operator then directed the local operator to close the pump's recirculation valve. Approximately seven minutes later, the local operator noted an abnormal temperature rise on the pump's thrust bearing, a water hammer sound, and the oil cooling water relief valve had lifted. The control room operator then tripped the 1A AFW pump. Subsequent examination revealed extensive damage to the rotating elements of the pump (paragraph 6.a).

A few moments later, the 1C motor driven AFW pump tripped on low suction pressure. The low pressure in the common suction header was momentary, resulting from steam which was generated at the 1A AFW pump collapsing. The 1B AFW pump was started to maintain SG levels. On January 17, the 1C AFW pump was vented, tested, and returned to service. It is believed that the 1C pump could have been restarted immediately after it tripped had it been needed.

The root cause of this event was procedural deficiency compounded by personnel error on the part of shift supervision. The surveillance procedure was normally used during mode 1 testing; however, it was applicable for use during modes 1, 2, and 3. Although the unit was in mode 7, the plant conditions were similar to that for mode 3. The procedure directs the operator to stop the 1B AFW pump prior to conducting the test on the 1A AFW pump. The operator maintained constant flow to the SGs by increasing flow from the 1C pump and closing the discharge valves to the A/B header due to plant conditions and a concern with the moderator temperature coefficient that existed at the time. The procedure assumed that the A/B header discharge valves would be opened, the normal at-power valve position. The procedure did not have a precaution or guidance to ensure that a flow path existed prior to closing the recirculation valves. The shift supervisors were involved to varying degrees in responding to the operator's concerns about cavitating the pump. The procedure was not adequately reviewed for the plant conditions and the shift supervisors relied on the fact that the surveillance had been successfully completed many times in the past.

Failure to maintain and implement procedures for adequately testing the AFW pump is contrary to Technical Specifications 6.2.1 and is considered a violation (295/90003-01a(DRP)).

b. <u>Valve Misalignment for the 1B Auxiliary Feedwater Pump</u>

On January 23, 1990, the licensee discovered a manually locked AFW valve misaligned (closed when it should have been open) during a performance test on the 1B AFW pump. The unit was in mode 2 at 2% power, in the process of starting up from a refueling outage. The pump's recirculation line was operable and prevented damage to the pump. The misalignment would have prevented flow from the 1B AFW pump to any steam generator had the AFW system been required. It is believed that the valve misalignment had existed for approximately five hours. The error occurred when the system was realigned to return the 1A AFW pump to service following maintenance for damage caused by pump cavitation.

The root cause of this event was personnel error. The equipment operator (non-licensed B-man) and the independent verifier (shift foreman, reactor operator-licensed) both assumed that the valve was open based on its stem position and did not physically turn the valve to verify its position as taught in the operator training program. Discussions with the personnel involved indicated that the B-man noted that one of the valves which he was to open appeared to have been already opened as observed by its stem length. The B-man did not unlock and physically verify the valve position as he was trained to do. The remaining three valves were then properly aligned; however, it was not communicated to the operations staff that only three of the four valves were manipulated. The shift foreman who performed the independent verification relied on the valve stem lengths to verify the valve positions also.

A contributing factor was that the procedure used was confusing. The steps to split the headers had an asterisk placed after them. The asterisk statement at the bottom of the page directed the operator to perform these steps in the reverse order to unsplit the header.

The licensee's immediate corrective actions included performing walkdowns of selected systems to verify the position of the valves and the operability of the associated system. The inspectors also conducted independent verifications for the following systems: auxiliary feedwater, residual heat removal, safety injection, component cooling, containment spray, and diesel generator subsystems and supports. No other discrepancies were noted.

Zion administrative procedure, ZAP 5-51-3A, requires that valves be checked by attempting to move them in the closed direction. Failure to follow ZAP 5-51-3A and general practices for valve verification as discussed in training is contrary to Technical Specification 6.2.1. This is considered a violation (295/90003-01b(DRP)).

c. <u>Unit Tripped due to High Steam Generator Level</u>

On January 27, 1990, at 8:16 a.m., Unit 1 tripped from 39% power due to a turbine trip/feedwater isolation. Instrument Mechanics (IMs) were investigating the 1D steam generator (SG) level deviation alarm. The feedwater regulator valve controller was placed in manual and the level deviation and the high-high level annunciators for the 1D SG were taken out of service. After verifying stable indications, the operator continued normal functions including a boration of the reactor coolant system (RCS) and control rod manipulation to raise the RCS temperature one degree. This temperature increase caused plant efficiency to also increase which resulted in reduced steam demands and a slight mismatch between steam flow and feed flow. The level in the 1D steam generator gradually increased to the 70% level setpoint which caused the turbine trip and the subsequent reactor trip. The root cause of the incident was operator error, in that the steam generator levels were not monitored often enough during manual operation of the feedwater regulator valve. Three operable SG level indicators were available for the operator's use with the feedwater regulator valve controller in manual and the annunciators out of service.

All systems responded to the trip as expected with the exception of three rod position indicators (RPIs) which showed more than 12 steps out although their associated rod bottom light was lit. The licensee emergency borated the RCS per procedure. The RPIs indicated full in approximately 30 minutes later. The indications of rods being not fully inserted were attributed to a rod position indication system problem. The unit was taken critical on January 28 at 4:40 a.m. and was placed back on-line at approximately 9:30 p.m.

As the result of this and other events involving personnel error, the licensee assigned supervisory licensed personnel for continuous control room overview. The primary responsibilities were to ensure the operators were at the controls, ensure a maximum conservative approach to operations, and that actions were in accordance with station policy. The licensee later changed this to require management supervision for one hour per shift. The licensee is currently requiring the supervision once per day. It appears that the involvement of management in the control room has been effective.

d. Inadvertent Start of the 1B AFW Pump

On February 13, 1990, the 1B AFW pump was inadvertently started during a routine surveillance test. The procedure involved transferring control of the AFW pump from the control room to the remote shutdown panel and then starting the lube oil pump locally from the panel. Prior to the test, the indications at the local panel were as follows: the green light for the lube oil pump was illuminated indicating the oil pump was off and the red and green lights above the 1B AFW pump switch were not illuminated. Upon closing of the transfer switch, the green light above the 1B AFW pump illuminated. At this time, the local operator inadvertently started the AFW pump instead of the lube oil pump as directed in the procedure. The local operator immediately recognized the error and stopped the pump.

The root cause of this event was personnel error. Discussions with the local operator indicated that several factors contributed to this error. The operator had limited experience and it was the first time the operator performed this surveillance without direct supervision. The location of the start/stop control switches for the AFW pump and the associated lube oil pump were close together and of similar design. The switches were clearly labeled. A similar event occurred in June 1989, (LER 295/89008), when the same AFW pump was inadvertently started. The corrective actions included a modification to the local control panel which was completed prior to this recent event. The modification changed the location of the AFW control switches to make all of the local panels consistent.

This event constituted the third one involving personnel errors on the auxiliary feedwater system within a month. The licensee initiated a standing order which required a licensed shift supervisor to accompany an operator during any local operator activities involving manipulation of the system. Other corrective actions included placing covers over the AFW pump switches and shading the background of the lube oil pump switches.

Failure to follow PT-7a, "Starting Procedure for Auxiliary Feedwater Pump Lube Oil Pumps," which caused the subsequent inadvertent start of the 1B AFW pump is contrary to Technical Specification 6.2.1 and is considered a violation (295/90003-01c(DRP)).

Unit 2

e. Unit 2 Manual Trip due to Electro-Hydraulic Control (EHC) Problems

On January 15, 1990, in accordance with abnormal operating procedures, power was reduced to 40% to bring the sulfate concentration within vendor specification limits for steam generator secondary chemistry. The chemistry problem was caused by leakage from the circulating water system into the main condenser. The technical staff performed helium testing of the condenser waterboxes and tubes to identify the location of the leak. It was determined that the southwest waterbox had a tube-to-tube sheet interface leak.

The licensee isolated the waterbox and repaired the leak.

On January 18, while unisolating the southwest waterbox, an expected vacuum transient occurred in the main condenser. During the recovery from this vacuum perturbation, a steam flow/feed flow deviation alarm was received for the 2A steam generator and the control rods began to cycle. The rod control system was operating in automatic at the time. The operator took manual control of the rods and the turbine control system when it was noted that the main turbine governor valves were also cycling. The operator returned the valves to the expected position and placed the control system back in automatic. The valves began to cycle again. The operator manually tripped the unit because EHC system control was unstable.

Investigations determined that the linear variable differential transmitter (LVDT) which provided governor valve position indication to the main control board and to the turbine control system had broken and separated from the valve mounting bracket. The LVDT was replaced and tested. On January 19 at approximately 11:30 p.m., the unit was placed back on-line.

Upon returning the unit to service the high sulfate concentration in the steam generators returned at high power levels. A leak was later identified in the inlet side of the southeast waterbox. Further investigations indicated that the leak was minimized with increased circulating water inlet temperature. Long-term actions are being pursued.

f. <u>Unit 2 Circulating Water System Discharge Pipe</u>

On January 23, 1990, a section of the Unit 2 discharge pipe lifted from the lakebed, broke at least three pipe joints and resettled higher than it was originally installed. The licensee installed clamps on the pipe to prevent further deterioration and had divers swim the length of the Unit 1 and 2 discharge piping to inspect for further damage. The cause of the upbedding of the pipe is unknown; however, the licensee intends to inspect the discharge valves, ice-melt valves and discharge piping during the refueling Unit 2 outage. The resident staff will monitor their evaluation.

g. <u>2C Steam Generator Primary-to-Secondary Leakage</u>

In late January 1990, the licensee identified a slowly increasing trend in primary-to-secondary leakage in the 2C steam generator (SG). At the time, the leakage was approximately 25 gallons per day (gpd) and increasing at approximately 8 gpd per week. The licensee issued a standing order to take samples twice per shift unless a change of 25 gpd was noted in the analysis. Samples would then be required hourly. By late February, the leakage increased to approximately 190 gpd with a upward trend of 50 gpd per week. The licensee plans to perform eddy current testing on the SGs during the refueling outage which started on March 13, 1990.

h. Unit 2 Turbine Oil Leak into the Afterbay

On March 5, 1990, the licensee noted a loss of main turbine oil from the Unit 2 turbine oil reservoir and observed an oil slick in the screenhouse afterbay. The leak was identified to be from the upper oil cooler of the turbine lube oil system into the service water system. The leak was isolated and the oil was cleaned from the afterbay. The United States Environmental Protection Agency and State of Illinois were properly notified. On March 6, sand and water samples were analyzed for oil content and were found acceptable.

Common

i. Shutdown of Both Units Due to 'O' EDG Inoperability

On March 1, the licensee commenced a two-unit shutdown from full power due to the inoperability of the 'O' EDG. The licensee was unable to return the EDG to service within the time limitations of the temporary waiver of compliance. Unit 1 proceeded to cold shutdown. An extension of 144 hours to the temporary waiver of compliance was granted by the Regional Administrator on March 7 to allow time to perform testing on Unit 2 prior to a refueling outage. The outage was originally scheduled to begin on March 22. This issue is discussed in paragraph 11b.

j. Liquid in Solidified Low-level Radwaste Barrels

On January 17, the licensee notified the resident that US Ecology identified free standing liquid in drums of solidified low-level radwaste that had been shipped to the Richland, Washington radwaste burial site from the Zion Station. The problem was detected during off-loading of the drums from the shipment truck when movement of liquid within some of the drums could be heard. The lids of some of the drums were deformed, possibly from freezing and thawing of the drum contents during outside storage and transportation. There were no releases to the environment. A regional specialist investigated the event (see inspection report 295/89037(DRSS); 304/89033(DRSS)).

One violation with three examples was identified.

5. Monthly Surveillance Observation (61726)

The inspector observed Technical Specifications required surveillance testing and verified that testing was performed in accordance with adequate procedures, that test instrumentation was calibrated, that limiting conditions for operation were met, that removal and restoration of the affected components were accomplished, that test results conformed with technical specifications and procedure requirements and were reviewed by personnel other than the individual directing the test, and that any deficiencies identified during the testing were properly reviewed and resolved by appropriate management personnel.

The inspector witnessed portions of the following test activities:

PT-6	Containment Spray System Test and Checks
PT-7	Auxiliary Feedwater Systems Checks and Tests
PT-7A	Starting Procedure for Auxiliary Feedwater Pump Lube Oil Pumps
PT-10	Safeguards Actuation Unit 1
PT-10	Safeguards Actuation Unit 2
PT-11	Diesel Generator Loading Test
PT-100	Main Turbine Overspeed Tests
PT-101	Main Turbine Protection Devices Trip Tests
TSS 15.6.5.2	Initial Criticality after Refueling and Nuclear Heating Level

No violations or deviations were identified.

6. Monthly Maintenance Observation (62703)

Station maintenance activities on safety related systems and components were observed or reviewed to ascertain whether they were conducted in accordance with approved procedures, regulatory guides, industry codes or standards, and in conformance with Technical Specifications. Consideration was given to: the limiting conditions for operation while components or systems were removed from service; approvals prior to initiating the work; use of approved procedures; functional testing and/or calibrations prior to returning components or systems to service; quality control records; personnel qualifications and training; certification of parts and materials; and radiological and fire prevention controls. In addition, work requests were reviewed to determine status of outstanding jobs and to assure that priority was assigned to safety related equipment maintenance which may affect system performance.

Technical Specifications required surveillance testing on the reactor ventilation and containment isolation systems were reviewed or observed. Consideration was given to procedures, calibration of test instrumentation, limiting conditions for operation during testing, removal and restoration of the affected components, whether test results conformed with technical specifications and procedure requirements, review of test results by personnel other than the individual directing the test, and correction of any deficiencies identified during the testing. PT-21, "Reactor Coolant System Leakage Surveillance," was reviewed. In late February, the licensee experienced problems with the computer program for calculating the reactor coolant system leak rate and performed manual calculations during the remainder of the inspection period. The licensee was investigating the root cause for the computer discrepancies. The residents are monitoring the leak rate calculations.

The following maintenance activities were observed or reviewed:

Z89015	1C AFW Pump Suction Pressure Gauge
Z89803	Unit 1 Reactor Coolant Filter Change Out

The inspectors had the following observations:

a. 1A AFW Pump Cavitation Event

On January 16, 1990, the 1A Turbine Driven Auxiliary Feedwater pump was manually tripped during a routine surveillance test due to cavitation. The licensee investigated and assessed the damage to the pump. The cavitation caused metal to be removed from the edge of the driven inboard end suction eye wear ring. The pump end of the rotating assembly had cavitation pitting damage for approximately 120 degrees of its circumference. The pump end of the rotating assembly wear ring had rubbed against the casing and was blue in color (blush). The heat had cause the wear ring to freeze to the shaft. The entire impeller assembly was replaced. There was no apparent damage to the non-rotating pump components.

b. Unit 2 Unplanned Power Increase During Maintenance

On January 18, during the stroking of the unit 2 main turbine governor valves by the instrument maintenance (IM) personnel while the unit was at hot, zero power, the main turbine speed increased to 650 rpm before the turbine was manually tripped by the control room operator. During this transient, reactor power increased to approximately 1.5% power for a few seconds. Prior to the event, the IMs had isolated the EHC oil to the turbine stop valves to prevent them from opening and admitting steam to the turbine. However, steam leaked through the stop valves which admitted steam to the turbine when the governor valves were stroked causing the power increase. This is an Open Item (304/90003-02(DRP)) pending review of the licensee's corrective actions to prevent reoccurrence.

c. Unit 1 Refueling Outage

On January 25, 1990 at 6:09 p.m., Unit 1 was synchronized to the grid. The refueling outage that started on September 7, 1989, took a total of 141 days to complete, about twice as long as planned. Major activities completed during this outage included environmental qualification inspections, fuel moves, detailed control room design review (DCRDR), snubber overhauls, containment spray riser testing, overhaul of the '0' emergency diesel generator (EDG) and auxiliary feedwater (AFW) motor operated valves (MOV) modifications. Several significant problems were encountered which caused the extension including diesel generator repairs, AFW MOV repairs, reactor conoseal repairs, 1 MOV RH8702 repack, rod position indication system and physics testing, steam generator girth welds indications and repair, 1A AFW pump cavitation and the repairs to the electro-hydraulic control for the main turbine generator. A significant list of "lessons learned" was developed by the licensee which are planned to be incorporated into the scheduling and execution of the Unit 2 outage.

d. Failure of the 1B Emergency Diesel Generator

On January 29, 1990 at 12:37 p.m., Unit 1 was operating at 50% power when the 1B emergency diesel generator (EDG) was declared inoperable due to failure of the air start distributor shaft which caused incorrect timing of the starting air being sent to the EDG's cylinders. The key-ways which hold the distributor shaft in a fixed position were chipped off which caused the shaft to rotate and changed the timing of starting air to the cylinders.

The parts in the air start distributor were replaced and tested. On February 1 at 11:40 a.m., the 1B EDG successfully completed the one hour operability test run and was declared operable. Enforcement discretion was granted to allow enough time to complete the repair and testing of the EDG (paragraph 11.b).

e. Loss of DC Power to the 2B Emergency Diesel Generator

On February 13, 1990 while performing a walkdown in preparation for maintenance on the 2B emergency diesel generator (EDG) starting air compressor, a mechanic found the DC power key switch in the ON position. The switch was not tagged out on the out-of-service list; however, the mechanic assumed it should have been, turned the DC power switch to the OFF position and removed the key. The control room received a loss of DC control power annunciator. An operator was dispatched to investigate the cause of the trip annunciator. The operator located the mechanic and obtained the key and restored the DC power to the EDG within approximately seven minutes. Normal station power supplies were available during this event.

The root cause of this event was personnel error. Discussions with the mechanic indicated that the several factors contributed to the error. Maintenance on the EDG in the past was performed with the DC power switch in the OFF position. The mechanic noticed this discrepancy and attempted to determine the required switch position by phoning the control room; however, the phone system was not functioning properly. The mechanic changed the switch to the OFF position even though it involved manipulating a switch on the local control panel which was contrary to station practices. Zion administrative procedure, ZAP 14-51-2, "Inspection, Test and Operating Status - Tagging of Equipment," directs that operations personnel take equipment out service and provides guidance for the supervisors of the work . ivity on performing out-of-service system verification.

Failure to follow ZAP 14-51-2 and general practices on manipulating equipment located on panels is contrary to Technical Specification 6.2.1 and is considered a violation (304/90003-01(DRP)).

f. 2A Emergency Diesel Generator Failures To Meet Start Time

During this reporting period, the 2A EDG failed to meet the starting time of 12 seconds on several occasions. Subsequent starts after the failures were within the time limitation. This is considered an Open Item (304/90003-03(DRP)) pending a review of the root cause evaluation for the excessive starting times.

g. Failures of the 'O' Emergency Diesel Generator

On February 20, 1990, the 'O' EDG failed to start from a manual start signal during a routine surveillance. The licensee conducted subsequent successful tests and was unable to repeat the failure. At that time, the failure was attributed to dirt in the local annunciator first out panel. The EDG was tested and returned to service. The EDG was again successfully tested on February 23.

On February 25, the O EDG failed to start from a simulated signal during a routine surveillance test. This failure constituted the fifth EDG failure for both units. The local annunciator first out panel indicated an overspeed trip had occurred. Troubleshooting and retesting of the EDG did not reproduce the failure and the EDG was declared operable on February 26. Further investigation by the licensee indicated that a possible root cause of the failure could be due to the master trip valve malfunctioning. On March 1, at approximately 4:40 a.m., the licensee placed the EDG out of service for maintenance including replacement of the master trip valve and further testing. This placed both units on an eight-hour clock with an additional twelve hours to hot shutdown as required by the February 29, 1980 Confirmatory Order. The licensee was unable to return the EDG to service within the required time due to problems including the incorrect installation of a solenoid valve and an unsuccessful maintenance test.

Other possible root causes for the failures were investigated. The technical staff noted that air trapped in the lube oil system filter housing, acted as a surge tank and prevented pressure from reaching the required level before the timing mechanism for the trip timed out. It was determined that during a maintenance activity in December 1989, the lube oil system was not vented due to an inadequate maintenance procedure. The licensee vented the system and completed a successful maintenance run. However, during the operability test, the EDG experienced a high main connecting rod bearing temperature trip. At the end of this inspection period, the licensee was investigating the root cause and examining the remaining diesels for excessive bearing wear. A regional inspector followed the licensee's progress during the evaluation; this issue will be documented in inspection reports 295/90006 and 304/90006.

One violation was identified.

7. Engineering and Technical Support (37828, 73756)

a. Modifications Review

The inspector reviewed selected modification packages to assess the conduct of modification activities at the plant. This review included interviews with personnel responsible for tracking and assembling the packages; assessment of the adequacy and thoroughness of completed modifications; and analysis of the backlog of open modification packages. The following completed modification packages were reviewed:

- M22-2-88-064 Replace Containment Hydrogen Monitors
- M22-2-86-037 Reposition Safety Injection Accumulator Relief Valves
- M22-2-86-038 Replace Reactor Coolant Pressure Transmitters with Rosemount Transmitters
- M22-2-85-037 Replace Pressurizer Level Cold Calibration Transmitter
- M22-1-89-004 Install Timers in Source Range Hi Flux at Shutdown Annunciator Alarms.

The following incomplete modification packages were reviewed:

- M22-0-77-017 Install Load Cell and Mechanical Stops on Fuel Crane
- M22-0-85-042 Replace Station Battery Chargers and Batteries.

The modification packages included reviews for training requirements, Quality Control, Quality Assurance, and Technical Staff approval. Assessment were made regarding the determination of whether or not a 10 CFR 50.59 safety evaluation was required. Reviews of the Technical Specifications and FSAR documentation appeared adequate for the scope of each modification. Quality Assurance (Quality Performance) reviewed all modification packages and selective additional hold points to the installation portions. The inspector had no concerns.

b. Inservice Testing (IST) of Pumps and Valves

The inspector reviewed the licensee's program for the inservice testing of pumps and valves. This review included interviews with personnel within the inservice inspection (ISI) department, which has responsibility for the IST program at the site, and a review of procedures and documentation that implemented the scheduling and acceptance criteria in accordance with ASME Section XI 1980, Winter 1981 addenda. The licensee submitted its IST program to the NRC for approval and is awaiting final approval. In addition, the licensee responded to Generic Letter 89-04, Guidance on Developing Acceptable Inservice Testing Programs," with a submittal dated October 2, 1989.

The inspector reviewed the following implementing procedures:

- ZAP 10-51-1, Inservice Testing of Pumps and Valves, Rev. 6
- TSS 15.6.20-P, IST Pump Surveillance, Rev. 5
- TSS 15.6.20V-P, Power Operated Valve Testing, Rev. 4
- TSS-15.6.20V-8, Valve Leak Testing, Rev. 6.

The program consisted of adequate measures for ensuring that the licensee performed its IST surveillances using proper acceptance criteria with provisions for increasing the frequency of testing when a pump entered an alert range as well as taking appropriate action when a pump entered the action range. Pump head acceptance criteria was determined by pump curves with alert and action ranges contained in each procedure. Vibration data acquisition was location specific as per drawings contained in each applicable procedure and was based on velocity. The separate areas of the IST program (MOV testing, vibration, etc.) had an engineer assigned to them with clearly defined responsibilities and lines of communications.

The following pump test procedures were reviewed:

- PT-2I Centrifugal Charging Pump Tests, Rev. 26
- PT-2A Safety Injection System Tests, Rev. 32
- PT-2J Residual Heat Removal Pump Tests, Rev. 30.

The inspector had no concerns.

c. Failures of the 2A Auxiliary Feedwater Pump

On March 6, 1990, the 2A auxiliary feedwater (AFW) pump tripped on overspeed during a surveillance test which involved the simultaneous start of all three AFW pumps. Investigation by the technical staff indicated that water was trapped in the steam line which caused erratic operation of the governor control system. The discharge pressure fluctuated which caused the turbine speed to oscillate until the overspeed mechanism tripped. The steam line was drained. On March 7, the licensee retested the pump for further trouble shooting activities. During the startup of the pump, the back pressure relief valve lifted and the governor began to swing. The governor regained control after the water slug had passed. The operator established required flow to the AFW supply headers and secured the pump. A second start was attempted with no additional water or instability of the governor observed. Based on their evaluation, the technical staff recommended that the steam line should be drained prior to running the 2A AFW pump. On March 8, prior to implementing the technical staff's recommendation, the pump was started and tripped on overspeed. It appears that the trip was a premature trip due to the misalignment of the overspeed trip mechanism. This is considered an Open Item (304/90003-04(DRF)) pending review of the licensee's evaluation and corrective actions.

d. Accumulator Fill Line Integrity Inspection

On February 6, 1990, at the Byron station, while equalizing the 1C safety injection accumulator with the 1D accumulator, water was observed leaking from the 1C accumulator fill line at the nozzle pipe-to-tank weld. In response to this event, the technical staff at the Zion station investigated to determine if a similar problem existed. All fill, sample, drain, and test lines at the tank nozzle welds on the Unit 1 and Unit 2 accumulators were inspected for any indication of cracking or abnormal vibration. No problems were identified. The supports associated with these lines were inspected for misalignment or looseness and no deviations were noted.

e. Technical Staff Morning Meeting

The inspectors observed several technical staff morning meetings to assess their effectiveness. The meetings included discussions of the previous day's work, problems encountered by each system engineer, work planned and assignments for the day. The status of work and concerns of interest throughout the station were also discussed. The inspectors found these meetings thorough, well-organized, and beneficial to the attendees.

8. New Fuel Receipt (60705)

The inspectors observed the receipt of new fuel, reviewed applicable logs and instructions, and conducted discussions with fuel handling personnel. During these discussions and observations, the inspectors ascertained that the removal of new fuel assemblies from their shipping containers and their subsequent inspection and storage in the new fuel storage racks were in conformance with approved instructions. The personnel handling the fuel were knowledgeable, qualified, and appropriately supervised. All activities observed were conducted in a satisfactory manner.

No violations or deviations were identified.

9. Licensee Event Reports (LERs) Followup (92700)

Through direct observations, discussions with licensee personnel, and review of records, the following event reports were reviewed to determine that reportability requirements were fulfilled, immediate corrective action was accomplished, and corrective action to prevent recurrence was accomplished in accordance with Technical Specifications. The following Unit 1 LERs are considered closed:

LER NO.	DESCRIPTION
89022	0BN Service Water Area Vent Fan Aircraft Crash Damper Found Open due to Solenoid Valve Failure
90002	1A AFW pump Cavitation (This event is discussed in paragraph 4.a)
90004	Unit 1 trip due to High Level in 'D' Steam Generator (This event is discussed in paragraph 4.c)

The inspectors made the following observations:

LER 295/89022: On November 22, 1989, the OBN service water area vent fan aircraft crash damper located in the crib house was found open with its fan off. Technical Specification 3.1.7.2 requires that the damper be closed unless its fan is operating. Investigation revealed that the damper control air solenoid valve had failed closed which caused the damper to fail open. Discussions with the licensee indicated that although not included in the LER write-up, the licensee planned to include the crash dampers on the B-man crib house equipment checklist. This LER is considered closed.

LER 295/90004: This event is discussed in paragraph 4.c. To prevent recurrence, the licensee issued a standing order which required an operator to be stationed continuously at the steam generator control panel whenever the main feedwater control valves were in manual control mode. This LER is considered closed.

No violations or deviations were identified.

10. Training (41400)

During the inspection period, the inspectors reviewed abnormal events and unusual occurrences which may have resulted, in part, from training deficiencies. Selected events were evaluated to determine whether the classroom, simulator, or on-the-job training received before the event was sufficient to have either prevented the occurrence or to have mitigated its effects by recognition and proper operator action. Personnel qualifications were also evaluated. In addition, the inspectors determined whether lessons learned from the events were incorporated into the training program.

Events reviewed included the events discussed in this report. In addition, LERs were routinely evaluated for training impact. No events reviewed this period were found to have significant training deficiencies as contributors.

No violations or deviations were identified.

11. Quality Program Effectiveness (40500)

a. Plant Standdown

Due to the recent events involving personnel errors and lack of attention to details, (as discussed in paragraphs 4.a, 4.b, and 4.c), the licensee management organized a plant standdown. On January 30, 1990, all personnel met by department for four hours. All nonessential work was stopped and contract personnel left the site. Each department reviewed their past performance and discussed actions to take to improve their performance. Mr. T. Maiman, Vice President, PWR Operations or Mr. K. Graesser, General Manager, PWR Operations, addressed each department, explaining to them that personnel errors were no longer acceptable at the Zion Station. The department heads discussed recent personnel errors associated with the department. The causal factors which contributed to the personnel error were also considered.

The inspectors attended sessions for the following departments: Instrument Maintenance; Health Physics; Planning; Engineering; Mechanical Maintenance; Electrical Maintenance; Quality Control; Quality Assurance, and Operations. The discussions appeared to be open and a beneficial means of communications.

Several concerns were raised during these sessions. One concern was the lack of effective and timely communication between departments and staff. As a result, the licensee restructured the daily meetings and changed the requirements for who was to attend these meetings in order to improve the flow of information at the station. A general meeting is held daily to discuss major plant evolutions and activities scheduled for the day. Departmental meetings are held weekly to promote better communication with the staff. These changes appear to be effective in improving the daily operation of the station.

b. Enforcement Discretion and Regional Temporary Waivers of Compliance

The Zion Station Confirmatory Order of February 29, 1980, Appendix A, item B.6, states requirements for the emergency diesel generator (EDG) testing frequency and allowable outage time for inoperable EDGs which are dependent on the number of accumulated EDG failures per unit. The licensee experienced several EDG failures during this report period for which waivers of compliance with requirements of the Confirmatory Order was requested.

(1) Unit 1 1B Emergency Diesel Generator

On January 29, 1990, at approximately 12:37 p.m., the 1B EDG was declared inoperable. Due to Unit 1 experiencing four EDG test failures in the past 100 tests, the Confirmatory Order stipulated an allowable outage time of 32 hours or be in hot shutdown within the next 12 hours and in cold shutdown in the following 30 hours. Repairs to the 1B EDG were not be completed within the allowed outage time; therefore, the licensee requested enforcement discretion. The enforcement discretion was granted by the Regional Administrator at approximately 6:00 p.m. on January 30, 1990 to allow an extension of 40 hours to complete the repairs and testing. The diesel was returned to service on February 1. The maintenance performed on the EDG is discussed in paragraph 7d.

(2) Unit 1 and Unit 2 - 'O' Emergency Diesel Generator

On March 1 at approximately 4:40 a.m., the licensee placed the EDG out of service for maintenance including replacement of the master trip valve and further testing. This placed both units on an eight-hour clock with an additional twelve hours to be in hot shutdown as required by Confirmatory Order since both units had experienced five EDG failures within the last 100 tests. The licensee was unable to return the diesel to service within the required time. A temporary waiver of compliance had been granted by the Regional Administrator on March 2, 1990, which required the 'O' EDG to be operable by 12:00 p.m. (noon), March 6, 1990. If not operable by this time, both units were required to be in cold shutdown by 6:00 a.m., March 7, 1990. On March 5, 1990, at approximately 8:30 p.m., the 'O' EDG failed an operability surveillance due to a main connecting rod bearing high temperature trip. As a result of the EDG trip, the licensee was unable to meet the commitments of the temporary waiver of compliance. On March 6, 1990, the Regional Administrator, with NRR concurrence, extended the waiver of compliance for Unit 2 for 144-hours to allow performance of required tests on Unit 2 prior to proceeding to a refueling outage. Unit 1 entered cold shutdown at 4:58 a.m. on March 7 and Unit 2 was allowed to remain in hot standby until noon on March 12, 1990.

12. Enforcement Discretion and Waiver of Compliance

Regional waiver of compliance is a vehicle for the Regional Administrator to grant relief from technical specification (TS) limiting conditions of operations or other requirements in certain limited circumstances in which a license amendment would not be appropriate. The intent of such discretion is to promote safety by not imposing unnecessary transients on an operating plant or not delaying reactor startup due to literal reading of TS under certain circumstances where there is no safety reduction. Prior to mid-February 1990, regional waiver of compliance was termed "enforcement discretion."

13. Open Items

Open Items are matters which have been discussed with the licensee which will be reviewed further by the inspector and which involve some action on the part of the NRC or licensee or both. Three Open Items disclosed during this inspection are discussed in paragraphs 6.b, 6.f, and 7.c.

14. Exit Interview (30703)

The inspectors met with licensee representatives (denoted in paragraph 1) throughout the inspection period and at the conclusion of the inspection on March 9, 1990, to summarize the scope and findings of the inspection activities. The licensee acknowledged the inspectors' comments. The inspectors also discussed the likely informational content of the inspection report with regard to documents or processes reviewed by the inspectors during the inspection. The licensee did not identify any such documents or processes as proprietary.