U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-254/82-10(DPRP); 50-265/82-11(DPRP)

Docket No. 50-254; 50-265 License No. DPR-29; DPR-30

Licensee: Commonwealth Edison Company
Post Office Box 767
Chicago, IL 60690

Facility Name: Quad-Cities Nuclear Power Station, Units 1 & 2

Inspection At: Quad-Cities Site, Cordova, IL

Inspection Conducted: June 30, through September 7, 1982

R. D. Walker for
Inspectors: N. J. Chrissotimos 10-18-82

R. D. Walker for
S. G. DuPont 10-18-82

Roger D. Walker
Approved By: Roger D. Walker, Chief 10-18-82
Reactor Projects Section 2C

Inspection Summary

Inspection on June 30 through September 7, 1982 (Report No. 50-254/82-10(DPRP), 50-265/82-11(DPRP)

Areas Inspected: Licensee Action on Previous Inspection Findings; Operational Safety Verification; Monthly Surveillance Observation; Preparation for Refueling; Onsite Review Committee; Inservice Inspection Program; Followup on Regional Requests; Meeting with the Public; Monthly Maintenance Observation; Review of Licensee's Monthly Performance Report; Licensee Event Reports Followup; Drywell Entries; Significant Event Followup; and Exit Interview. The inspection involved a total of 250 inspector-hours onsite by two NRC inspectors including 50 inspector-hours onsite during off-shifts.

Results: No items of noncompliance were identified.

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DETAILS

1. Persons Contacted

*N. Kalivianakis, Superintendent
T. Tamlyn, Assistant Superintendent Operations
D. Bax, Assistant Superintendent Maintenance
L. Gerner, Assistant Superintendent for Administration
*J. Heilman, Quality Assurance, Operations
*G. Tietz, Technical Staff Supervisor

The inspector also interviewed several other licensee employees, including shift engineers and foremen, reactor operators, technical staff personnel and quality control personnel.

*Denotes those present at the exit interview on September 7, 1982.

2. Licensee Action on Previous Inspection Findings

(Closed) Noncompliances (254/265; 81-04-02; 254/265 81-04-05; 254/265 81-04-06): The NRC in a letter dated June 1, 1981, accepted your response letter of April 28, 1981, describing the actions that you have taken to correct the noncompliances. The inspector has reviewed the actions described and has no further concerns. The items of noncompliance are closed.

(Closed) Unresolved Item (254/265; 79-20-01): Conflict of Regulations and Technical Specifications concerning Operation of the Economic Generation Control. The Office of Nuclear Reactor Regulation has been provided with all information and will provide the required actions.

(Closed) Noncompliance (254/265; 82-07-01/82-08-01): QA Records Retained in Active Files Longer Than Allowed by Master Retention Schedule. The inspector verified that the actions described in the licensee's response letter of May 27, 1982, have been accomplished. The inspector has no further concerns and this item is closed.

(Closed) Unresolved Item (254; 79-03-01): Technical Specification Change 4.5.D.1, Simulated Auto-Initiation of ADS, Auto Pilot Valves Surveillance Frequency. The change has been submitted and the interpretation of the Technical Specification is clearly understood among the licensee, the NRR project manager, and the senior resident inspector.

(Closed) Open Item (254/81-07-08; 265/81-07-03): Lack of Uniform or Standard Criteria for Determining the Technical Acceptability of a Vendor or Supplier. The licensee has developed SNED Procedure Q.41, Technical Evaluation of Vendors, to establish the criteria for technical review of vendors. An audit of vendor reviews showed that the procedure was being followed and the records were being retained. The inspector has no further concerns in this area.

3. Operational Safety Verification

The inspector observed control room operations, reviewed applicable logs and conducted discussions with control room operators during the months of July and August 1982. The inspector verified the operability of selected emergency systems, reviewed tagout records and verified proper return to service of affected components. Tours of Unit 1 and 2 reactor buildings 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 inspector by observation and direct interview verified that the physical security plan was being implemented in accordance with the station security plan.

The inspector observed plant housekeeping/cleanliness conditions and verified implementation of radiation protection controls. During the months of July and August, the inspector walked down the accessible portions of the Unit 1, 2 and the 1/2 diesel generator cooling water systems to verify operability. The inspector also witnessed portions of the radioactive waste system controls associated with radwaste shipments and barreling.

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.

No items of noncompliance or deviations were identified in this area.

4. Monthly Surveillance Observation

The inspector observed technical specifications required surveillance testing on the Unit 1 main steam line isolation valves and Unit 2 core spray valve operability 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 also witnessed portions of the following test activities:

Unit 1

QIS 20	Main steam line low pressure isolation function test
QIS 21	Main steam line high flow isolation function test

QIS 31	Main steam line high radiation scram and isolation function test
QOS 6600-1	Diesel generator load test

Unit 2

QOS 1400-3	Core spray differential pressure
QOS 1400-2	Core spray valve operability
QOS 1400-4	Core spray pump operability

No items of noncompliance or deviations were identified in this area.

5. Preparation for Refueling

The inspector verified that the approved refueling procedures were technically adequate in the areas of fuel handling operations, fuel and control rod transfer operations, core verification, inspection and receiving of new fuel, fuel inspection prior to reuse, and handling and inspection of other core internals. The inspectors verified that the procedures contained provisions to ensure monitoring of the source range instrumentation during core alteration, to maintain proper decay heat removal systems, to inspect cladding for bowing, distortion, swelling and crud buildup.

The inspector verified by direct observation that the receipt inspection and storage of five new fuel elements was performed by the licensee in accordance with approved procedures.

No items of noncompliance or deviations were identified in this area.

6. Onsite Review Committee

On June 22 and 23, 1982, the inspectors attended onsite review committee meetings. The inspectors observed the conduct of the meetings and ascertained that provisions of the Technical Specifications dealing with membership, review process, and qualifications were satisfied.

The June 22 meeting pertained to the review and identification of equipment requiring repairs and testing after the reactor scram and loss of electrical power to Unit 2 on June 22, 1982.

The June 23 meeting involved reviewing the need for the diesel generator underexcitation relay (140-DG 1/2/CEH) on the 1/2 diesel generator. The relay had actuated on June 22, tripping the diesel during a recovery from a loss of electrical power and Unit 2 scram. The committee's conclusion was to remove the relay. The relay's removal was proven not to affect the auto-starting of the diesel generator during emergency conditions. The station nuclear engineering department (SNED) concurred with the decision.

No items of noncompliance or deviations were identified in this area.

7. Inservice Inspection Program

During a review of the inservice inspection program, the inspector had a concern regarding the feasibility of performing a volumetric examination on the vessel support skirt's circumferential weld joint and the BK1 welds on cast stainless steel.

Concerning the Unit 1 vessel support skirt's circumferential weld joint under the present ASME code (1971), volumetric examination will be performed on 8 feet of the circumferential weld joint every 10 years. Because of the difficulty of the angle and physical accessibility involved with this type of examination, the licensee believes that a surface examination, as recommended by ASME XI (Winter, 1980, Addenda) Fig. IWB-2500-14, would be more conservative and present a more informative examination.

In regards to the BK1 welds volumetric examinations, Technical Specifications 3.6.F. requires 100 percent cumulative inspection in the first 10 years of operation. For Unit 1, the licensee has submitted a relief request, number CR-8, dated July, 1979, to perform a surface examination on ten (10) BK1 integrally-welded external support attachments on the recirculation pumps and valves. These external support attachments are welded to cast stainless steel pump and valve bodies. Due to the nature of cast stainless steel, a volumetric examination would not yield sufficent data. The licensee has stated that the examination of these 10 welds, as documented in relief request CR-8, and the vessel support skirt circumferential weld joint will be performed in accordance with the more conservative 1980 Addenda to Section XI.

The inspector discussed this situation with the Office of Nuclear Reactor Regulation and NRR found the approach taken by the licensee to be acceptable.

No items of noncompliance or deviations were identified in this area.

8. Followup on Regional Requests

a. Check valve failures in diesel generator cooling systems have been identified at both Quad-Cities and Dresden stations.

   Quad-Cities recently replaced the affected check valves with new design-type valves. The inspector verified that the new valves were ordered in compliance with the design specifications of the system.

   The inspector has no further concerns in this area.

b. In regards to the potential generic issue involving leakage of one instrument equalizing valve which may render HPCI or RCIC flow pressure switches inoperable, the inspector verified that this potential also exists at Quad-Cities station.

The inspector discussed the situation with the licensee and the licensee will inform the instrument department of this potential problem. Also, it will be re-emphasized to the technicians to look for problems in this area by sensing differential temperatures on the lines during routine surveillance.

c. The resident inspector was requested by Region III to specifically confirm that the bullet-resistant and fire resistant doors had been tested and approved for fire resistance by a nationally recognized laboratory.

It was determined that the doors were manufactured by the following suppliers:

Bullet-Resistant Fire Doors - Chicago Bullet Proof Equipment Company, Park Forest, IL

Fire Resistant Doors - Phillipp Manufacturing Company, East Hampton, WA
F. L. Saino Manufacturing Company, Memphis, TN
Steelcraft Manufacturing Company, Cincinnati, OH

The licensee's documentation was reviewed and it confirmed that both the fire resistant and dual function bullet/fire resistant doors were tested and approved by Underwriters Laboratories, Inc., Northbrook, IL.

Codes and Standards: "Standard for Safety UL10B, Fire Tests of Door Assemblies," Fifth Edition and "Standard for Safety UL752, Bullet-Resisting Equipment," Fifth Edition for the Chicago Bullet Proof manufactured bullet resistant fire doors.

The inspector has no further concerns in this area.

No items of noncompliance or deviations were identified in this area.

9. Meeting With Public

On Sunday evening, August 29, 1982, the Senior Resident Inspector appeared live on a 90-minute television program titled "At Issue." Other participants on the show included representatives from Commonwealth Edison, Iowa Disaster Services and Citizens for Safe Energy. The show featured call-in questions from the viewers.

The topics discussed were general in nature and no specific questions were asked about the Quad-Cities facility. Questions involved nuclear power safety and Commonwealth Edison's nuclear power program.

Although a basic difference in philosophies exists among the groups represented, the inspector believes that the program benefitted the viewing public on nuclear power issues and concerns.

10. Monthly Maintenance Observation

Station maintenance activities of safety related systems and components listed below were observed/reviewed to ascertain that they were conducted in accordance with approved procedures, regulatory guides and industry codes or standards and in conformance with Technical Specifications.

The following items were considered during this review: the limiting conditions for operation were met while components or systems were removed from service, approvals were obtained prior to initiating the work, activities were accomplished using approved procedures and were inspected as applicable, functional testing and/or calibrations were performed prior to returning components or systems to service, quality control records were maintained, activities were accomplished by qualified personnel, parts and materials used were properly certified, and radiological controls and fire prevention controls were implemented.

Work requests were reviewed to determine status of outstanding jobs and to assure that priority is assigned to safety-related equipment maintenance which may affect system performance.

The following maintenance activities were reviewed:

Unit 1

WR 20473 'B' train SBGT system, replacement of auxiliary contacts in the opening circuit of the inlet damper.

WR 20494 HPCI motor gear unit, replacement of an amplifier circuit board in the flow controller.

Unit 2

WR 20128 Electromatic relief valve 2-203-3C, replacement of the valve rings and guide.

WR 20195 HPCI pump discharge valve torque switch.

Following completion of maintenance on the Unit 1 HPCI motor gear unit and the Unit 2 electromatic relief valve, the inspector verified that these systems had been returned to service properly.

No items of noncompliance or deviations were identified in this area.

11. Review of Licensee's Monthly Performance Report

The inspector reviewed the licensee's monthly performance reports of Units 1 and 2 for the months of June and July, 1982.

Areas covered by the report were amendments to Technical Specifications, summary of corrective maintenance performed on safety-related equipment, Licensee Event Reports, operating data tabulations, and refueling information. The report was reviewed for compliance with Technical Specification 6.6.A.3.

No items of noncompliance or deviations were identified in this area.

12. Licensee Event Reports Followup

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 had been accomplished in accordance with technical specifications.

Unit 1

RO 82-08/03L, dated April 20, 1982, steam line high flow RCIC isolation differential pressure cell failed to trip.

The occurrence was attributed to personnel error. On April 5, 1982, an instrument mechanic inadvertently bent the needle to the differential pressure switch during re-assembly of the switch, which resulted in the actuating needle preventing the operation of the switch. Redundancy of the system would have ensured a RCIC isolation if necessary. The switch was replaced and the system proven operable on April 20, 1982.

RO 82-09/03L, dated April 30, 1982, the 'C' RHR service water pump was taken out of service due to water in the RHR service water booster pump outboard bearing oil reservoir.

Concerning RO 82-09/03L, the water in the bearing oil reservoir had apparently seeped in from an adjacent leaking pump packing. The packing was replaced and the bearing oil was changed by the licensee as immediate corrective action. Similar events are documented in inspection reports 50-254/82-08(DPRP), Paragraph 5, and 50-265/82-09(DPRP), Paragraph 5. The licensee has initiated a modification to install a different design bearing seal that will prevent recurrence.

RO 82-10/03L, dated May 19, 1982, the 1/2 emergency diesel generator cooling water pump overheated during surveillance.

RO 82-11/01T, dated June 5, 1982, No. 4 turbine control valve failed to fast close during surveillance. Details of occurrence are documented in inspection reports 50-254/82-08(DPRP) and 50-265/82-09(DPRP), Paragraph 11.

RO 82-14/03L, dated July 8, 1982, the 'B' standby gas treatment train discharge damper failed to open during surveillance.

RO 82-16/03L, dated July 11, 1982, during routine panel checks, HPCI motor gear unit failed to maintain the high speed stop setting.

Concerning RO 82-16/03L, the HPCI motor gear unit (MGU) set was found on the low speed stop (LSS) during a routine panel check. It was raised manually to the high speed stop (HSS) which is the normal setting; however, when the control switch was released (spring return to normal), the MGU returned to the LSS. The licensee determined that an amplifier circuit board internal to the signal converter speed control circuit of the MGU had failed. The defective circuit produced a false signal which prevented the MGU from maintaining the HSS. The licensee declared HPCI inoperable and proposed bypassing the signal converter. NRC (Region III staff and the senior resident inspector) discussed with the licensee the ability of HPCI to perform its design function. It was determined that the required injection flow rate would be achieved with the automatic flow controller bypassed, and the MGU set at the HSS. An auto-initiation would accelerate the HPCI turbine to the HSS and an injection flow rate of 5600 gpm or greater would be achieved. The licensee bypassed the signal converter and manually set the MGU to the HSS. The HPCI pump and valve operability surveillance was then successfully performed. HPCI was declared operable on July 11, 1982. The defective circuit board was replaced, tested and the HPCI MGU was returned to automatic flow control on July 13, 1982.

RO 82-18/03L, dated June 25, 1982, diesel generator cooling water pump was taken out-of-service for preventative maintenance.

RO 82-19/03L, dated July 13, 1982, reactor automatic relief valves (1-203-3B, 3D and 3E) drifted in excess of Technical Specification limits during surveillance.

Concerning RO 82-19/03L, the licensee had previously recognized that the Barksdale dual control Bourdon tube instruments have a tendency to drift.

Thus the licensee increased the calibration cycle to a quarterly frequency as a preventative measure. This action is more conservative than the requirements in the Technical Specifications. The establishment of these measures and the practice of trending Barksdale instrument drift appears to be adequate action in attempting to resolve instrument drift problems.

Unit 2

RO 82-06/03L, dated May 14, 1982, suppression chamber to drywell vacuum breaker (AO-2-1601-32C) failed to fully reclose during surveillance.

Concerning RO 82-06/03L, the cause was attributed to be the counterweight being slightly beyond the pivot point of the valve disc. The unit was placed into cold shutdown and the counterweight was adjusted. The valve was successfully re-tested on May 15, 1982, and the unit was returned to service.

RO 82-07/03L, dated May 15, 1982, the '3C' electromatic relief valve failed to consistently operate manually during surveillance.

Concerning RO 82-07/03L, the failure of the 3C electromatic relief valve to consistently operate by manual control was attributed to loose wiring on the relief valve control switch. The connections were tightened and the valve successfully tested on May 16, 1982. During this occurrence, the automatic depressurization system and the manual close function of the relief valve were always operable.

RO 82-08/03L, dated May 15, 1982, Acoustic monitors for electromatic relief valves 3A, 3D and 3C failed during surveillance.

RO 82-10/03L, dated June 24, 1982, HPCI pump discharge valve failed to open during surveillance.

Concerning RO 82-10/03L, the cause of the occurrence appears to be the actuating arm on the torque switch failing as a result of fatigue. The torque switch was replaced and the HPCI pump was tested successfully on June 25, 1982.

RO 82-12/03L, dated July 14, 1982, reactor automatic relief valves (2-203-3A, 3B, 3C and 3E) pressure setpoint drifted during surveillance.

Concerning RO 82-12/03L, the licensee has recognized the tendency of Barksdale instruments to drift and has increased the calibration frequency as documented in this report in the discussion pertaining to RO 82-19 of Unit 1.

No items of noncompliance or deviations were identified in this area.

13. Drywell Entry

On July 6, 1982, the licensee made a drywell entry while operating at 75 percent power to investigate a 2 gpm unidentified leak. This action is required by the Confirmation of Action Letter dated January 22, 1982. The leak was identified and stopped by backseating the recirculation header crosstie valve.

No items of noncompliance or deviations were identified in this area.

14. Significant Event Followup (June 22, 1982)

During May and June 1982, the licensee planned to perform corrective maintenance on the reserve auxiliary transformer (T22) to repair an oil leak. The licensee had postponed the maintenance on numerous occasions because of severe weather but decided that it would be done on June 22, 1982.

The site staff, Station Nuclear Engineering Department and General Electric Company evaluated the possibility of performing maintenance on the reserve auxiliary transformer (T22) during a unit shutdown. It would require offsite power being supplied to the unit from the reserve transformer (T21) via the unit main power transformer (T2). The evolution would require the removal of the generator output copper links, and the installation of numerous jumpers bypassing interlocks between the generator, switchyard components, and transformer.

The licensee concluded that such an evolution was possible; however, it was felt that the planned 10-hour maintenance work did not warrant a unit shutdown because of the complexity involved in re-routing the offsite power.

As a result of the possible consequences associated with the removal of the reserve auxiliary transformer during unit operation, the NRC (Regional Section Chief and the Senior Resident Inspector) decided that it was essential to have an inspector onsite throughout the scheduled maintenance.

On June 21, 1982, the Unit 1 diesel generator had been declared inoperable and was under a 7-day Action Statement permitted by the Technical Specification LCO. The inoperability was due to repairs being made on the cooling water pump motor.

The inspector discussed this situation with the Assistant Superintendent of Operations and Operating Engineer and expressed his concern that, even though Technical Specifications allowed maintenance to be performed on TR 22 (TR 22 out-of-service) concurrent with the Unit 1 diesel generator out-of-service, the decision to proceed was not as conservative as may be expected of the licensee.

Preparations for removal of the transformer from service began at approximately 3:30 a.m. on June 22, 1982. Observations were made from the control room by the resident inspector of the performance of Procedure QOP 6100-3, "Removing Reserve Auxiliary Transformer 22 from Service with Unit 2 Operating," which included operability surveillances of the Unit 2 and shared diesel generators.

At 5:25 a.m., while Unit 2 was operating at 760 MWe, bus 22 was inadvertently tripped by the equipment operator. The equipment operator had mistakenly pulled the 4 kv bus 22 potential fuses instead of the 4 kv transformer 22 potential fuses. When bus 22 tripped, the 2 "B" reactor feed pump also tripped causing a reactor low water level scram. (Bus 22 is the 2B reactor feed pump power supply.) Approximately one minute later, the Unit 2 generator tripped, resulting in a loss of all normal AC power to the unit. During the first minute of the event, the unit operator decreased the 2 "A" reactor recirculation MG set speed and increased feedwater flow by opening a feedwater regulating valve. This action coupled with the rapid decrease in reactor power and continued availability of 2 "A" reactor feed pump returned reactor water level from a negative 12 inches to a positive 58 inches.

After the unit generator had tripped, both the Unit 2 and shared (1/2) diesel generators auto-started on undervoltage signals from their respective buses (24-1 and 23-1). Ten seconds later, the Unit 2 and 1/2 diesel generators were at speed and automatically closed onto the 4 kv emergency buses 24-1 and 23-1. During this time period, reactor pressure increased to the Target Rock (203-3A) relief valve setpoint of 1105 psig. The 203-3A valve auto-actuated four times between 5:28 and 5:40 a.m. To minimize the challenges made to the 203-3A valve, the operator attempted to manually open the 203-3C Electromatic relief valve. Even though the 203-3C valve position indication and acoustic monitor indicated that the 203-3C valve had opened, it had not and the reactor pressure continued to increase until the operator manually opened the 203-3E Electromatic relief valve.

At 5:30 a.m. the resident inspector notified the senior resident inspector of the reactor scram and loss of AC power.

Concurrently, the unit operator had attempted to start the HPCI system, but was unsuccessful due to the reactor water level being greater than the HPCI turbine trip setpoint. At this point in the event, the only ECCS to be challenged was the Target-Rock relief valve.

At 5:40 a.m., the reactor was stable and under control with sufficient reactor pressure being controlled by manual operation of the Electromatic relief valves. The next step in procedure QGA-12, "Loss of Auxiliary Electrical Power," was to initiate suppression pool cooling by starting an RHR service water pump (900 HP motors supplied by buses 23 and 24) and an RHR pump (supplied by buses 23-1 and 24-1). The operator had already back-fed buses 23 and 24 from their respective emergency buses, 23-1 and 24-1.

"B" loop of the suppression pool cooling mode of RHR was successfully initiated on buses 24 and 24-1 which were being supplied by the Unit 2 diesel generator. At 5:47 a.m., the operator started 2 "A" RHR service water pump on bus 23 for "A" loop of suppression pool cooling. The 1/2 diesel generator had an approximate load of 500 KW prior to starting the RHR service water pump (per procedure). The diesel generator immediately tripped when attempting this evolution causing loss of power to 4 kv buses 23-1 and 23 and 480 v bus 28. These buses are the ultimate sources to the instrument bus, the 2A reactor protection bus, and the essential service bus static inverter.

Initially, the essential service bus was erroneously postulated as tripped during the event because of the vast number of instruments and alarm indications that were lost when the instrument bus and the 2A reactor protection bus was de-energized. Instrumentation that was lost included the narrow range (0 to 60") GEMAC level indicator and the reactor pressure indicators (0 to 1200 psi) 25A and 25B. With many of the control room indications not working, personnel were dispatched to the local 2202-5 instrument rack (located in the reactor building) to relay indications to the control room from the mechanical indicators as backup information.

At 5:50 a.m., the sernior resident inspector arrived in the control room. At this time the licensee declared a GSEP unusual event, although the conditions of an unusual event were not met. In declaring this, the licensee was taking a conservative position.

At 5:55 a.m., the primary containment pressure reached 2 psig. Inspection of the drywell after the event revealed that the main steam relief valves discharge line flange's gaskets had leaked. Also, the blind flanges that had been installed awaiting the completion of the discharge line vacuum relief valve installation were loose which caused steam leakage into the drywell.

The 2 psig drywell pressure is an ECCS initiation signal at which the HPCI system will inject water automatically into the vessel. The personnel at the local mechanical indications reported the rise in vessel level, thus verifying HPCI injection.

Following the 1/2 diesel generator trip, the shift engineer informed both the resident and senior resident inspectors that Unit 1 was also in an unusual event because it had no operable diesel generators. The shift engineer also stated his intentions of first returning Unit 2 to a stable condition before attempting to return a diesel generator back into operation or begin a shutdown. Unit 1 was stable and operating at 50 percent power at this time.

Concurrently, the senior resident inspector established communications with the NRC regional duty officer (Glen Ellyn) through the NRC Headquarters duty officer (Washington, D.C.). Information communicated by the senior resident inspector included the GSEP unusual event of Unit 1 which was now operating without any diesel generators.

Also, the 2 psig drywell pressure signal auto-started the 2 "B" core spray pump (the pump did not inject because reactor pressure was greater than the 325 psig injection permissive setpoint) and the following equipment was automatically tripped - the running RHR service water pump, drywell coolers, and reactor building closed cooling water pumps (RBCCW).

Throughout the event, operating personnel were returning T22 back to service, which was accomplished at approximately 5:56 a.m. By 6:05 a.m., all 4 kv buses were fed by T22 and offsite power. By 6:25 a.m., the instrument bus was restored and normal scram recovery was intiated. The liensee terminated the GSEP Unusual Event at 6:45 a.m. for Unit 2.

An inspection of the 1/2 diesel generator revealed that it had tripped on under-excitation. The licensee successfully restarted the diesel at 8:20 a.m. after the lockout relay was manually reset. The Unit 1 unusual event was then terminated by the licensee.

Concurrently, suppression pool cooling was re-established to reduce the drywell pressure below 2 psig and to lower the suppression pool temperature that had risen to approximately 109°F.

The senior resident inspector attended the onsite review committee meeting that was held to identify the equipment requiring repairs prior to the unit startup.

This included the 203-3C Electromatic relief valve which failed to open when actuated manually during the event. The valve was replaced with a spare and tested satisfactorily during the startup.

The licensee conducted a systematic examination into the cause of the 1/2 diesel generator trip. The examination revealed that the under-excitation relay (140-DG 1/2 CEH) actuated. The licensee conducted a test on June 23, 1982, which duplicated the conditions during the event, with the resident and senior resident inspectors witnessing the test. The diesel was auto-started, loaded to 300 kw and a RHR service water pump was manually started. The under-excitation relay actuated,confirming the cause of the diesel trip.

As a result of the examination, the onsite review committee recommended that the under-excitation relays be removed from the diesel generators. Station Nuclear Engineering (SNED) concurred with the decision to remove the relays and that the removal of these relays did not affect the auto-starting of the diesels during emergency conditions.

All repairs and testing were completed and reviewed by June 24, 1982, at 1:20 p.m., at which time a normal control rod withdrawal was commenced for reactor startup on Unit 2.

Throughout the event and recovery, the resident and senior resident inspectors were present onsite.

The inspectors' review of the inadvertent trip of the bus by the equipment operator revealed that supervision was requested and neither the shift engineer or the shift foreman were available to directly supervise that portion of the procedure. The shift foreman was performing his required yard inspection and the shift engineer was involved with the portion of the procedure pertaining to the control room.

Following onsite review, the senior operating engineer recommended that there should be direct supervision of the performance of this procedure by a qualified second person in the future.

The licensee was requested by NRC to document details of the event in a special report (dated July 8, 1982). As a result of this report, the licensee has made the following commitments:

a. Procedure revisions will be made to clarify steps and add information which may prevent inadvertent actions by personnel.

b. Station Nuclear Engineering (SNED) is to evaluate a proposed change to the diesel generator's auto-start circuitry which will provide a seal-in circuit to allow all of the protective trips to be blocked until normal power is restored.

c. Station Nuclear Engineering (SNED) is to evaluate a proposed change to the instrument and ESS bus to provide more reliable backup feeds.

d. Modifications (M-4-1(2)-80-31) are to be installed during the next refuel outages. These modifications will alter the core spray logic so that drywell coolers and reactor building closed cooling water pumps do not trip on 2 psig drywell pressure initiation of core spray if normal electrical power is available to the emergency buses.

e. The NRC will be notified prior to removal of the reserve auxiliary transformer from service to discuss details of the work involved.

The inspector believes that if direct supervision had been provided by a qualified individual, the chances of an inadvertent trip of Bus 22 may have been significantly reduced.

The decision to remove the auxiliary transformer from service concurrently with the Unit 1 diesel generator and Unit 2 "C" reactor feed pump out-of-service was nonconservative.

This nonconservative management decision is not typical of this station, which had been rated by the Systematic Assessment of Licensee Performance Board Report (SALP) as demonstrating a high level of performance with respect to operational safety.

The NRC wants the licensee to be aware of the significance of the event and realize that performance in this manner does not constitute a high level of safety performance.

As a result of the circumstances surrounding the event, the senior resident inspector submitted a proposed Technical Specification change to the Offices of Nuclear Reactor Regulation dated June 29, 1982.

The proposal would require that whenever the reactor is in the run mode, the reserve auxiliary transformer may be unavailable, provided that:

a. All diesel generators are operable.

b. Repairs are necessary to prevent immediate degradation or failure.

c. The NRC is notified of the situation prior to removal of the transformer from service.

At no time during the event was the reactor core in jeopardy of being uncovered. It is recognized by the inspector that the actions taken by the operators and their supervisors were both timely and correct with respect to the adverse situation that was present. Emergency and abnormal procedures were followed and the performance of the people involved demonstrated a high level of knowledge of their duties and responsibilities.

Neither the resident inspector nor Region III have any further concerns with the report submitted on July 8, 1982, or the licensee's actions.

The circumstances surrounding the failure of Electromatic relief valve 203-3C will be discussed in Report No. 254/82-16; 265/82-18; 237/82-20; and 249/82-21.

15. Exit Interview

The inspector met with licensee representatives (denoted in Paragraph 1) throughout the month and at the conclusion of the inspection on September 7, 1982, and summarized the scope and findings of the inspection activities. The licensee acknowledged the inspectors comments.