U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Report Nos. 85-36; 85-09

Docket Nos. 50-352; 50-353

License Nos. NPF-39; CPPR-107 Priority -- Category C;A

Licensee: Philadelphia Electric Company
2301 Market Street
Philadelphia, Pennsylvania 19101

Facility Name: Limerick Generating Station, Unit 1 & 2

Inspection Conducted: September 23 - November 30, 1985

Inspectors:

E. M. Kelly, Senior Resident Inspector, Limerick
J. Rogers, Reactor Engineer
R. Jacobs, Senior Resident Inspector, Susquehanna
T. Johnson, Senior Resident Inspector, Peach Bottom
S. Reynolds, Lead Reactor Engineer

Reviewed by: J E Beall 1/17/86
J. E. Beall, Project Engineer

Approved by: Robert M. Gallo 1/21/86
R. M. Gallo, Chief, Reactor Projects Section 2A

Inspection Summary: Combined Inspection Report for Inspection Conducted September 23 - November 30, 1985 (Report Nos. 50-352/85-36; 50-353/85-09)

Areas Inspected: Routine and backshift inspections consisting of: followup on NUREG-0737 Item II.K.3.2.8 (ADS Accumulators), and License Condition 2.C.7 (ISI); plant tours; observation of TC-3 startup testing and review of test procedures and results; maintenance and surveillance observations; and review of LERs and periodic reports. The inspection addressed the licensee's corrective action for unfinished Unit 2 grading and construction which could affect equipment in the Control Structure under design basis flood conditions (Detail 6). Also addressed are events (Detail 5) which include: loss of 220 kV power; ECCS Division 4 logic actuation, SLCS initiation, and a reactor scram on October 15, 1985.

Results: Four unresolved items were identified involving: consideration of procedures for off-normal ESW system alignments (Detail 2.1); Control Structure flood barrier modifications (Detail 6); administrative controls applied to SDV drain valve troubleshooting (Detail 8.1); and, surveillance procedures for HPCI isolation testing (Detail 9.4). No violations were identified.

A total of 278 hours of onsite inspection were accounted for by the Limerick resident inspector, regional specialists, and senior resident inspectors from Susquehanna and Peach Bottom. Ten hours were applied to Unit 2 activities.

DETAILS

1.0 Persons Contacted

Philadelphia Electric Company

J. Basilio, Administrative Engineer
J. Doering, Operations Engineer
P. Duca, Technical Engineer
J. Franz, Superintendent of Operations
A. Jenkins, GE Startup Manager
G. Lauderbach, Quality Assurance Engineer
G. Leitch, Station Superintendent

Also during this inspection period, the inspectors discussed plant status and operations with other supervisors and engineers in the PECo, Bechtel and General Electric organizations.

2.0 Followup on Unresolved Items

2.1 (Open) BNL Review of Off-Normal Procedures for ESW

During a technical review of the Emergency Service Water (ESW) system, the availability of off-normal procedures was identified as a concern described in the Brookhaven National Laboratory (BNL) Technical Review Report dated October 4, 1984. In a letter dated November 7, 1984, the licensee responded by stating that restrictions were placed in ESW operating procedures for system alignments which had not been preoperationally tested.

The BNL report noted that there are no procedures for the realignment of the ESW system on the loss of an ESW loop, or for use of the normal service water system on failure of the ESW system. The inspector noted that the procedures in question are recommended by Regulatory Guide 1.33, Rev. 2 (Appendix A, Item 6g). The inspector reviewed ESW alignment procedures S11.1.A, S11.2.A, S11.8.C, S11.8.B, and confirmed that there are no off-normal operating procedures for ESW. Since each diesel generator can be supplied from either of two ESW loops, the inspector questioned the licensee on the need for a procedure to realign ESW cooling water from the alternate loop in case one loop is inoperable. The licensee agreed to consider a procedure (or procedures) to include ESW-diesel loop realignment and other abnormal ESW alignments deemed necessary. Pending further action by the licensee and subsequent NRC review, this item is unresolved (50-352/85-36-01).

2.2 (Closed) TMI Action Item II.K.3.28 Qualification of Accumulators on ADS Valves

This item required demonstration that the accumulators for the ADS valves provide sufficient capacity and enable cycling the ADS valves twice at 70% drywell design pressure. SSER 2 Section 3.10 indicated that the licensee had provided an analysis which shows that 5 actuations of the ADS valves at atmospheric pressure was equivalent to two actuations at 70% of design pressure. The inspector reviewed preoperational test results 1P-83.1, "Main Steam (NSSS) Startup Systems 83A and 83C", and verified that the ADS accumulators were sufficient to provide five valve actuations. In the SSER, NRR indicated that the licensee committed to monitor ADS bottle pressure daily and that accumulators leakage would be monitored periodically. The inspector verified that the licensee had included these requirements in surveillance test procedures. The inspector had no further questions, and considers this item closed.

2.3 License Condition 2.c.7

This license condition required submittal of an Inservice Inspection Program by October 26, 1985, for NRC staff review and approval. The inspector reviewed PECo letter dated October 23, 1985 (Kemper to Butler) which provided the Unit 1 First 10-year Interval ISI Programs in accordance with Section XI of the ASME Code. Discussions with the NRC Licensing Project Manager for Limerick indicated that this license condition would be satisfied after staff review and subsequent approval in a safety evaluation.

3.0 Review of Plant Operations

3.1 Summary of Events

The plant operated at 50 - 75% power through most of this inspection period. Startup testing in Test Condition (TC)-3 was begun on September 23, and was ended on November 15, 1985 following a planned turbine trip and reactor scram from 75% power. TC-3 testing involved several successful major evolutions, described in Detail 4, and was conducted at power levels between 30 - 75%.

Two planned reactor scrams and one unplanned scram occurred during this period. The unplanned scram (addressed in Detail 5.4) occurred on October 15 from 2% power during a startup following a turbine trip test. The two planned scrams followed turbine trips at 50 and 75% power and were part of the startup test program.

Special preparations were made by the licensee during the last week of September for Hurricane Gloria, the effects of which were felt onsite on September 26 and 27, 1985. No plant or major site damage was experienced.

The unit operated at about 50% power between October 2 - 29, except for a shutdown during October 8 - 15 following a turbine trip startup test to clean out main condenser water boxes to alleviate high zinc concentrations experienced in condensate and feedwater. Conductivity continued to be higher than normal throughout this inspection period, averaging about 0.4 microhmo/cm. The licensee initiated a program of more frequent condensate resin replacements, and successfully reduced reactor water conductivity to values on the order of 0.2 micromho/cm near the end of November.

Startup testing was performed from October 29 through November 14 at power levels of 70 - 75%. Following a scheduled turbine trip on November 14, the plant remained shutdown until November 25 to replace IRMs and repair a main turbine combined intermediate valve. Natural circulation testing in TC-4 was conducted on November 30 at about 42% power with both recirculation pumps tripped for twelve hours.

Three unusual events were declared during the period: on September 26 - 27 for Hurricane Gloria; on October 15 because of the unplanned scram; and on November 23 following a bomb threat received by telephone which was evaluated and determined to be not credible. Operator license examinations were conducted for 14 license candidates, including 9 PECo staff engineers, on November 11 - 18, 1985.

3.2 Operational Safety Verification

The inspector toured the control room daily to verify proper manning, access control, adherence to approved procedures, and compliance with LCOs. The status of control room annunciators was reviewed, operators were found to be cognizant of and responsive to all alarms. The licensee has maintained good control over annunciator status by highlighting and discussing existing alarms in daily planning meetings. The inspectors periodically attended these meetings. Nuclear instrument panels and other reactor protective systems were examined, and effluent monitors were reviewed for indications of releases. Panel indications for onsite/offsite emergency power sources were also examined for automatic operability. No unacceptable conditions were noted.

During entry to and egress from the protected area and vital island, the inspector observed proper access control, security boundary integrity, search activities, escorting and badging, and availability of radiation monitoring equipment including portal monitors.

The inspector reviewed shift superintendent and control room logs covering the entire inspection period. Log keeping was found to be clear, accurate and informative. Sampling reviews were made of equipment trouble tags, night orders, and the temporary circuit alteration and LCO tracking logs. The inspector also observed several shift turnovers during the period, and found these to be well-organized and professionally conducted. Operations activities were observed to be performed in accordance with the applicable procedures and requirements. Control room noise and occupancy were kept at reasonable levels necessary to support startup test activities, and were significantly improved from the previous inspection period.

3.3 Station Tours

The inspectors toured accessible areas of the plant throughout this inspection period, including: the Unit 1 reactor and turbine-auxiliary enclosures; the main control and auxiliary equipment rooms; emergency switchgear and cable spreading rooms; diesel generator and radwaste enclosures; the spray pond and pumphouse, and the plant site perimeter. During these tours, observations were made relative to equipment condition, fire hazards, fire protection, adherence to procedures, radiological controls and conditions, housekeeping, security, tagging of equipment, ongoing maintenance and surveillance, and availability of redundant equipment. Overall plant housekeeping and cleanliness, and equipment tagging and labelling were observed to be excellent. This observation was made by the senior resident, as well as two visiting resident inspectors and NRC Region I license examiners who toured the plant during this period.

3.4 ESF System Walkdown

The inspector independently verified the operability of the High Pressure Coolant Injection (HPCI) system by performing a walkdown of the accessible portions of the system, and confirmation of the following items:

-- The system check-off list and operating procedure are consistent with the plant drawings and as-built configuration.

-- Identification of equipment conditions and items that might degrade performance.

-- Valves and breakers were properly aligned, necessary instrumentation is functional, and appropriate valves were locked.

-- Control room witches, indications, and controls are satisfactory.

-- Surveillance procedures adequately implement technical specification requirements.

The following references were reviewed:

-- Technical Specification Section 3.5.1

-- P & ID M-55 and 56

-- FSAR Section 6.3.2.2.1

-- HPCI Operating Procedure S55.1.A

No unacceptable conditions were identified.

4.0 Startup Test Activities

4.1 Summary

Test Condition 3 startup testing was begun on September 23, performed at progressively higher power levels of from 30 to 75%, and was completed on November 15, 1985. TC-5 testing was performed at 50 - 75% power between November 15 - 30, 1985. TC-4 natural circulation testing was conducted on November 30, 1985, after tripping both recirculation pumps from 40% power. Inspection coverage of major test evolutions is described below, as well as in Limerick Inspection Report Numbers 50-352/85-38 and 44.

4.2 Onsite Meeting

On September 25, 1985 a management meeting was held onsite between NRC and licensee personnel and GE test representatives to discuss the Limerick Generating Station Startup test program. The licensee presented the status of the program as of that date, described the overall program including significant test results, and discussed the principal problems encountered and the resolution of those problems. The licensee then described his future plans to conduct the program as described in the FSAR. No unacceptable items resulted from this management review.

The following personnel were present:

NRC Representatives

L. Bettenhausen, Chief, Operations Branch
R. Gallo, Chief, Projects Section 2A
P. Eselgroth, Chief, Test Programs Section
E. Kelly, Senior Resident Inspector
J. Beall, Project Engineer
D. Florek, Lead Test Engineer

PECo Representatives

G. Leitch, Station Superintendent
J. Franz, Superintendent - Operations
P. Duca, Technical Engineer
A. Jenkins, General Electric Startup Manager

4.3 Test Observations

4.3.1 Turbine Trip, STP-27.2

On October 8, 1985, the licensee successfully conducted planned turbine trip test STP-27.2 from 51% power. The unit responded normally to the turbine trip and consequent scram transient. The reactor was then taken to a cold shutdown condition in preparation for hotwell inspections. The test was witnessed by an NRC regional project engineer. Adequate preparations and shift briefings were held prior to the test, and operators were observed to properly use trip procedures.

On the morning of, but prior to the test, with the unit at about 49% power, a standby liquid control pump inadvertently started during restoration of the normal electrical lineup following pump maintenance. The pump start caused a RWCU system isolation, and an injection of sodium pentaborate solution into the reactor vessel. The pump was secured, RWCU was restored and the reactor was monitored for response to the injection. Power decreased by a small amount (less than 1%), main steam line radiation levels decreased, and conductivity increased from 0.4 to about 2.0 micromho/cm. This event is further discussed in Detail 5.5. Following licensee evaluation of plant conditions, the STP-27.2 test was initiated.

4.3.2 HPCI Cold Quick Injections, STP-15.5

The inspector observed the conduct of Startup Test STP-15.5 involving a HPCI cold quick start and injection into the reactor vessel performed on November 5 at 65% power. The time from initiation to achieve 5600 gpm rated flow was 31 seconds, which failed the test criterion of 25 seconds and exceeded the technical specification limit of 30 seconds. HPCI was declared inoperable and troubleshooting was conducted to determine the cause of the failure. Reactor power was reduced to approximately 20% after the test to conduct STP-30.5 recirculation and jet pump cavitation testing. Upon completion of the tests, the plant was returned to 69%

power on November 6. The licensee then imposed a hold on testing in Test Condition 3, pending resolution of HPCI inoperability.

HPCI remained inoperable for four days while repairs to various oil leaks, valves and the turbine control valve circuitry were performed. Ramp time reduction and controller gain adjustments were made to increase stability. STP 15.5 was re-performed successfully from 65% power on November 9th. HPCI rated flow of 5600 gpm was achieved 21 seconds after initiation, and the HPCI turbine speed transient was acceptable. The inspector observed the initial testing, portions of the repair work, and the licensee's PORC evaluation of the HPCI test results. No unacceptable conditions were noted.

4.3.3 Single Recirculation Pump Trip, STP-30.1

Startup test STP-30.1 was performed on November 7, by tripping the "A" recirculation pump from 74% power and 95% core flow. Reactor vessel level swelled to 10 inches above normal level, as expected, but 9 inches below the high level trip setpoint. The feedwater control system properly restored level, with 2 of the 3 feed pumps running. Power decreased to 43% as a result of the recirculation pump trip. The "A" recirculation pump was successfully restarted, recirculation pump speeds and flows were equalized, and power was stabilized at 54%, within 30 minutes. The test was witnessed by the resident inspector and a regional inspector. The Level I test criterion of not scramming while restoring the tripped recirculation pump was successfully achieved, as well as Level II test criteria related to level swell and scram margin. No unacceptable conditions were noted.

4.3.4 Trip of Both Recirculation Pumps, STP-30.2

The inspector observed the performance of Startup test STP-30.2 on November 7 involving a manual trip of the pump motor breakers on both recirculation pumps from 70% power at 96% core flow. Reactor level swelled approximately 14 inches, as expected, and was properly controlled by the feedwater system with two feed pumps on-line. Power decreased to about 35% and, following data collection to ascertain pump-motor coastdown rate, both pumps were successfully restarted within 22 minutes. The drive flow coastdown transient was calculated to be within the acceptable pump-motor inertia time constant necessary to limit a reactor power spike associated with an end-of-cycle turbine or generator trip. Power was restored to about 70% on November 8, 1985.

An unplanned trip of both recirculation pumps occurred about 2 hours prior to the conduct of STP 30.2 on November 7 as a result of connecting test leads to the wrong relay points. The resident inspector was present during the transient and observed proper design performance of the recirculation and feedwater flow control systems. Reactor power decreased from 69 to 35%, with the expected level swell and proper feedwater control system response. Both pumps were successfully restarted within 15 minutes. The main turbine remained on-line and operators were observed to be experienced and adept at restarting the recirculation pumps within loop temperature constraints and without causing a plant scram. Operators were well-briefed and prepared on implementation of procedure OT-112, Recirculation Pump Trip. No unacceptable conditions were identified.

4.3.5 Turbine Trip from 75% Power, STP-27.3

A main turbine trip in accordance with STP-27.3 was manually initiated from 74.6% power on November 14, 1985. A reactor scram occurred, from turbine control valve/stop valve closure. Reactor vessel level reached a minimum of +11 inches and then increased to a maximum of +68 inches. The level transient caused all three feedwater pump turbines to trip on high level about 55 seconds after the scram. The feed pump trip on high level was later attributed to a failure of the feedwater level control system level setpoint setdown function to operate properly, and was later corrected. The setpoint setdown function lowers the level set to 17 inches, instead of 34 inches, if level drops to 12 inches or below. The MSIVs, as expected, did not isolate. Both recirculation pumps tripped as designed, and were restarted successfully within 15 - 20 minutes. Reactor pressure peaked at 1028 psig. The inspector reviewed the GP-18 Scram Review Procedure, including computerized sequence of events and alarm printouts, and had no further questions. The inspector observed the turbine trip, plant recovery, and subsequent plant startup. Plant management involvement and presence were noted. Shifts were well-prepared, with added complements of operators and test engineers available during the test.

Plateau review of TC-3 data was completed November 16.

4.3.6 Test Condition 4, Natural Circulation Testing

The inspector observed the initiation of TC-4 natural circulation testing on November 30, 1985. Recirculation pump M-G set "A" was tripped from 47.7% power and 45% total core flow (at an 80% rod pattern) with both pumps at minimum speed. Power was reduced to 45% and, 5 minutes later, the "B" recirculation pump was tripped. Power was further reduced to about 42% and core flow to about 39%. Test data were accumulated over the remainder of the day, and both pumps were re-started by 11:53 p.m. that night.

The inspector attended the pre-test control room staff briefing which was supplemented by a GE test memorandum outlining recommendations and precautions for reactor operation in natural circulation testing. The briefing addressed the special test exception in technical specifications allowing for up to 24 hours in natural circulation operation, as well as temperature restrictions placed upon drive loop and steam dome conditions at pump recovery. Operators were observed to be cognizant of these restrictions and periodically monitored loop temperatures and power/flow conditions during the testing. The inspector had no further questions. Exit from TC-4 involved driving in deep rods to achieve a 75% rod pattern and establishment of sufficient scram margin. Testing was satisfactorily completed, recirculation pumps restarted, and power was restored to 70% by 7 a.m. on December 1, 1985. No unacceptable conditions were identified.

5.0 Event Followup

5.1 Loss of 220 kv Power

At 2:38 p.m. on September 24, 1985, five circuit breakers tripped open in the 220 kV switchyard, one of the two required independent offsite power sources. The plant, which was operating at 38% power with site loads powered off the unit auxiliary transformer via the main generator, remained on-line. The breaker trips caused a loss of voltage on the associated 13.2 kV station auxiliary bus which de-energized the number 101 safeguard transformer normally aligned to two of the four 4160 volt safeguard buses (D11 and D13). An automatic fast transfer (within 0.25 seconds) of the safeguards buses to the other offsite power circuit (500 kV substation) via the number 201 safeguard transformer occurred as designed.

Non-vital loads which were lost during the fast transfer of the D11 and D13 buses included both reactor water cleanup pumps, the "A" drywell chiller and instrument air compressor, and the first-stage air ejector -- all were successfully restarted. The momentary loss of safeguards bus power, until the fast transfers occurred, caused upscale indications on the chlorine and high radiation monitors associated with the control room emergency fresh air supply (CREFAS) system, which isolated the control room ventilation and initiated CREFAS fans. Normal ventilation system operation was restored at approximately 4:30 p.m., and an ENS call to report the CREFAS initiation was made at 6:15 p.m. on September 24, 1985.

Initial licensee investigation had found no protective relay actuations, leading to the suspicion of a fault or spurious signal in the breaker supervisory logic. The breaker supervisory logic is a two way remote control system using a high frequency telephone tone to position substation breakers. All 220 kV yard breakers were reclosed less than one hour after they had tripped, and the telephone "pairs" to these breakers were disabled until an AT&T representative could arrive onsite to troubleshoot the supervisory logic. An operator was stationed in the 220 kV yard until the problem was resolved. The licensee's investigation and corrective action, described in LER 85-076 dated October 31, 1985, consisted of replacement of defective programmable memory chips in the breaker supervisory remote panel. No further problems have been experienced. The resident inspector observed operator response to this event, verified proper system design responses and reviewed LER 85-076. No unacceptable conditions were identified.

5.2 Division 4 Logic Actuation

On September 26, 1985, a spurious ECCS actuation signal was received on Division 4 logic during HPCI surveillance testing. The reactor was at 41% power at the time, and startup testing was in progress on the recirculation system. Reactor level, and all other primary system parameters, were unaffected by the event. Safeguards loads were shed off of D14 bus, and the D14 diesel generator started along with the "D" RHR and Core Spray pumps associated with that logic division. No ECCS injections occurred. HPCI received an initiation signal but did not start because it was out of service at the time as part of the surveillance test. The performance of the surveillance test is further discussed in Detail 9.4.

The spurious ECCS actuation signal was apparently caused by disturbance of a fuse in the Division 4 logic as an I & C technician was attempting to connect a test lead for 24 VDC power. The momentary disturbance of the fuse created a high drywell pressure signal, coincident with a low reactor pressure signal, which resulted in the logic actuation. Loss of reactor enclosure cooling water caused CRD and RWCU pump trips, however, these were restored immediately. Also lost was power to a reactor enclosure supply fan which necessitated a manual isolation of secondary containment ventilation and a corresponding SGTS start. Control room isolation and an emergency ventilation system start also occurred, as designed. All equipment was restored to normal status, including reset of the ECCS signal and related isolations, within one hour.

The event was witnessed by the senior resident inspector. Operator actions to assess the event, including its cause and subsequent system restorations, were observed to be organized and in accordance with procedures. The event was later described in LER 85-077.

No violations were identified.

5.3 Recirculation Pump Trip

On September 27, 1985, with the plant at about 35% power and 60% total core flow, the "A" recirculation pump tripped, reducing power to about 28%. The recirculation pump tripped as a result of the loss of its lube oil pump due to a failure of a transformer which feeds the number 114B 440 volt load center bus.

Loads fed from the de-energized 114B bus were manually transferred by operators to another 440 volt load center, including the "A" recirculation pump lube oil pump. However, technical specification restrictions on a 50 degree farenheit temperature differential between the idle and operating recirculation loops could not be attained for approximately 1 3/4 hours. The pump was restarted at 3:04 p.m., after loop temperatures were equalized, and power was restored to 33%. The transformer failed due to a small rain water leak which had developed following the storm experienced on September 27. The transformer was subsequently replaced.

The inspector reviewed the circumstances surrounding this event, and observed operator actions to restart the "A" pump. Loop and vessel temperatures were observed to be within technical specification limits, and no violations were identified.

5.4 Reactor Scram on Low Water Level

At 12:15 a.m. on October 15, 1985, the unit experienced a scram due to low reactor water level during a reactor startup. The cause of the low level was a reactor pressure increase above the discharge pressure capability of the on-line condensate pumps before a reactor feed pump was placed in-service to supply high pressure feedwater to the reactor vessel. The plant responded normally to the transient. The licensee declared an Unusual Event at 12:30 a.m. which was terminated at 1:05 a.m.

The inspector reviewed Limerick Upset Report (UR)-014 issued on October 30, 1985, and LER 85-083 issued on November 15, 1985, both of which described the event. Details presented in these reports were confirmed by the inspector as accurate, attributing the cause to both personnel error and a procedural deficiency. Plant operators were involved with turbine shell and chest warming, and were withdrawing relatively high worth rods at the time that reactor pressure began to increase more quickly. The main turbine EHC pressure set was at 600 psig, and reactor pressure had increased from 450 to 640 psig in approximately 20 minutes, with no indication of bypass valve opening.

With only one condensate pump in service at the time, and the reactor feedwater pumps being warmed-up but not yet running, the increasing reactor pressure quickly approached the 700 psig shutoff head of the condensate pump and reactor vessel level began to decrease, with a low level alarm received at 550 psig. Operator efforts to recover level were hampered by the feedwater pump minimum flow recirculation valve, which was open while attempting to bring the "B" feed pump on-line. As a result of the open recirculation valve, condensate header pressure decreased to 480 psig, and further hampered efforts to recover the decreasing vessel water level. The feed pump bypass valve HVC-06-120 was out of service at the time of the event, and could have provided another path to offset the level decrease experienced in placing the feed pump in-service with its recirculation valve open.

The inspector reviewed reactor pressure and level recorder traces, and the sequence of events log. The inspector confirmed that the scram occurred approximately seven minutes following receipt of the low level alarm annunciator, leaving little time for level recovery in spite of operator attempts to insert control rods to reverse the pressure rise. The reactor scram occurred at the +12.5 inch level setpoint, and minimum level reached was +7.0 inches. The scram signal was reset in approximately 21 minutes, and rod withdrawals for startup were continued at 3:00 a.m. on October 15, 1985. Criticality was reached at 6:02 a.m. that morning, and the reactor was successfully brought to rated conditions later that same day. Power ascension continued to 50% power by October 17 whereupon startup testing was performed.

The licensee revised General Procedure (GP)-2, Normal Plant Startup, step 3.3.18, by lowering the prescribed EHC pressure set from 600 to 450 psig. The lowered EHC set pressure allows for operational flexibility in placing a second condensate pump in service and the first feedwater pump on-line. Reactor pressure is thereby restricted to a value within the condensate pump's capacity, by causing turbine bypass valve opening at 450 psi header pressure. The lowered EHC set pressure also allows for inherent EHC pressure set inaccuracy, which is also approximately 50 psi below vessel pressure. The inspector reviewed the revised version of GP-2, observed the successful plant startup later in the day on October 15, and had no further questions. No violations were identified, and plant heatup was observed to be within the 100° F per hour rate limit.

5.5 Standby Liquid Control Actuation

On October 8, 1985 standby liquid control (SLC) pump "A" started and injected approximately 5 - 7 gallons of sodium pentaborate solution into the reactor vessel. The actuation was caused by closing the pump breaker for return to service following maintenance. The unit was at 48% power at the time, and the estimated power reduction associated with the injection was less than one percent based on reactor water samples taken afterwards. The SLC system was secured after it was determined that the actuation was unnecessary, and had been caused by a transient pulse in the solid state electronic circuitry in the automatic start logic. The pulse was of sufficient duration to energize auxiliary relays which started the pump, isolated the RWCU inboard isolation valve, and actuated the pump discharge squib valve -- all as designed. Following the licensee's evaluation of this event, a planned turbine trip startup test (discussed in Detail 4.3.1) was performed approximately 3 hours later, and the plant was then shut down for several days for condenser hotwell inspections and cleaning.

The licensee performed the following corrective actions associated with the SLC actuation:

-- Reverse flushing of all affected core spray and SLC system piping, followed by a forward flush to remove residual sodium pentaborate solution from the piping and the core spray sparger injection lines. This reduced reactor water conductivity to an acceptable value below the 1.0 micromho/cm technical specification limit, and well below the 6.5 micromho/cm value initially experienced after the SLC injection.

-- Operation aids were posted in the main control room on the SLC pump hand switches instructing operators to remove squib valve fuses and place the pump control switches in STOP position, prior to closing the pump breaker.

-- Subsequent troubleshooting and testing found Division 2 Redundant Reactivity Control System (RRCS) high power output isolator (HPOI) cards, which are powered via the pump breaker and are part of the auto start logic, to be subject to an internal pulse when a pump breaker is initially closed. The pulse causes the card output circuit to momentarily function as a "closed contact" which, if not opened prior to the energization of two auxiliary relays, will actuate the SLC pump and its discharge squib valve. Therefore, the startup transient experienced on October 8 lasted long enough (approximately 0.08 seconds or 5 cycles) to energize the auto start relays, which then remained sealed in and caused the actuation of SLC pump "A".

-- The SLC injection lasted for approximately one minute and SLC tank level dropped by about 1.75 inches which corresponds to 70 gallons. The 2 ppm boron concentration found by licensee chemistry samples was back-calculated to an estimated 5 - 7 gallons which actually entered the reactor vessel. The boron addition represented an insignificant effect upon core reactivity, or less than 1% power reduction. Boron concentrations measured following the flushing were less than 10 ppb, and were attributed to filtration and demineralization by RWCU as well as some precipitation.

The licensee has planned a modification which will install a 1 - 2 second time delay relay in the SLC pump start logic which should preclude the transient pulse effect in the HPOI cards from energizing the initiation relays when bus voltage is lost or a pump breaker is closed. The inspector reviewed the above actions, discussed their implementation with licensee representatives, and verified that the problem does not affect the ability of the SLC system to perform its design function. The inspector noted that the operation aids were posted on the SLC pump hand control switches in the main control room, and that licensed operators were cognizant of and understood the problem. The inspector also reviewed LER 85-079 issued on November 6, 1985, which described the event cause and corrective actions. The LER was found to be thoroughly prepared and well-detailed, with complete information regarding the effects of this event on power, reactor water chemistry, and SLC system design. The inspector had no further questions, and will review the modifications to the SLC start circuitry in a future inspection.

6.0 Unit 2 Flood Barriers

The licensee's engineering staff identified a condition not covered by the plant's operating and emergency procedures, as reported to the NRC on October 8, 1985 in accordance with 10 CFR 50.72, and in LER 85-080 dated October 31, 1985.

Analysis by the licensee indicated that, given the present status of Unit 2 under Probable Maximum Precipitation (PMP) conditions, the two chiller units serving the common Control Structure could be flooded. The control structure includes the common control room, the remote shutdown panel, the emergency auxiliary switchgear rooms, the battery rooms, the cable spreading room, and the auxiliary equipment room (which houses the plant computer for both units). Loss of both chiller units could impact personnel habitability and electronic equipment throughout the control structure.

The identified flooding pathway involves flooding of the Unit 2 Turbine Auxiliary Enclosure due to presently incomplete walls and barriers. The control room chillers are located below-grade, in the control structure, and could be affected by the flooding of Unit 2. The licensee began the construction of temporary Unit 2 flood barriers on October 4 when the flood potential was discovered and prior to the October 8, 1985 notification which was made to NRC when the effects on Unit 1 were identified. The licensee completed the barrier construction by October 10, and prepared Off-Normal Procedure ON-115, Loss of Control Enclosure Cooling, to be implemented in case of control structure flooding or loss of both chiller units.

The inspector reviewed the installation of the flood barriers installed at various Unit 2 Turbine Enclosure doorways and walls, and implemented under Modification Design Change Package (MDCP) No. 0524 and a Construction Job Memorandum issued on October 8, 1985. The MDCP was approved in July 1985 and required flood protection curbs at the Unit 1 and 2 Turbine Enclosures. The curbs were intended to protect against potential flood paths because of incomplete site grading and temporary building locations. However, the larger effect of incomplete interior and exterior Unit 2 Turbine Enclosure walls was not recognized in July 1985. Further, the modification, while approved in July 1985, was not finished until September 1985. In September 1985, because of an unrelated modification which was proposed but never installed to increase the Unit 2 cooling tower basin storage capacity, the adequacy of the MDCP-0542 changes was questioned by the licensee site staff who subsequently concluded that additional flood barriers would be required. These were proposed and implemented via the October 8, 1985 memorandum (document #107), with work finished by October 10, 1985. The work consisted of installed structural steel and wood barriers to prevent flood water from flowing into the power block in the event of either a Unit 2 cooling tower basin rupture or a PMP event. The work was performed under MRF-85-7950 and was depicted on Bechtel Drawing No. C-303, Sheet 2, Turbine Building Flood Protection Barriers, Elevation 217'-0", Unit 2. Also, to protect against flooding of the Division 1 through 4 Battery Room Numbers 321 - 324, drain plugs were installed to prevent back-flow through the drain system from outside storm drains.

The inspector observed the installed battery room drain plugs, which were appropriately affixed with unit isolation tags. All flood barriers described in MDCP-0524 and Drawing No. C-303 were observed during a walk-down by the inspector to be installed as depicted. All barriers were noted as being controlled by a posting which directed opening only upon Operations shift supervision authorization. The inspector also reviewed the ON-115 procedure approved on October 10, 1985, which provides for alternate cooling methods to the Control Enclosure by placing control room ventilation in the purge (outside air) mode and by propping open various doors to the invertor, battery and switchgear rooms. The procedure also addresses the determination of an effective temperature (considering relative humidity and personnel habitability) which, would require initiation of a plant shutdown. The inspector observed no unacceptable conditions.

Upon discovery of the flood potential by the licensee, the Unit 2 cooling tower basin was drained on September 21 - 22 to a minimum level (for fire protection water supply) until the licensee's evaluation of a basin rupture on plant operating systems was completed.

Finally, the inspector reviewed the licensee's QA review of project documentation, which confirmed that no additional instances of potential impact on Unit 1 structures or equipment were overlooked as was the flooding event due to incompleted site grading and construction. No violations were identified. Pending completion of permanent modifications to the Control Enclosure north wall to preclude flood water entry, and the implementation of administrative controls for opening of Unit 2 temporary flood barriers, this item is unresolved (50-352/85-36-02).

7.0 Licensee Reports

7.1 In-Office Review of Licensee Event Reports

The inspector reviewed Unit 1 LERs submitted to the NRC Region I office to verify that details of the event were clearly reported, including the accuracy of description of the cause and adequacy of corrective action. The inspector determined whether further information was required from the licensee, whether generic implications were involved, and whether the event warranted onsite followup. The following LERs were reviewed:

	LER Number (NOTE)	Title
*	85-039	Engineered Safety Feature Actuation Caused by Valving Error
	85-071	Engineered Safety Feature Actuation RWCU Isolation
	85-072	Reactor Water Cleanup System Isolation on High Differential Flow
	85-073(a)	Reactor Scram and Low Condenser Vacuum Isolation
	85-074	Actuation of an Engineered Safety Feature (SGTS)
	85-075	Failure to Verify Operability of Fire Door
	85-076(b)	Automatic Initiation of Control Room Emergency Fresh Air System (CREFAS)
	85-077(c)	Engineered Safety Feature Actuation of Core Spray, RHR, HPCI & Diesel Generator

	85-078	Failure to Perform a Technical Specification surveillance requirement
	85-079(d)	Standby Liquid Control System Actuation
	85-080(e)	Operation in a Condition not covered by Operating or Emergency Procedures
*	85-081	Main Control Room Chlorine Isolation and Emergency Fresh Air System Initiation
	85-082	Reactor Water Cleanup System Isolation on High Differential Flow
	85-083(f)	Full Reactor Scram on Reactor Low Level
	85-084	Failure to Initiate a Manual Rod Block as Prescribed in Technical Specifications

*Further discussed in Detail 7.2.
(a) Previously addressed in Limerick Inspection Report 50-352/85-30.
(b) Addressed in Detail 5.1
(c) Addressed in Detail 5.2
(d) Addressed in Detail 5.5
(e) Addressed in Detail 6.0
(f) Addressed in Detail 5.4

7.2 Onsite Followup of Licensee Event Reports

For those LERs selected for onsite followup (denoted by asterisks in Detail 7.1), the inspector verified the reporting requirements of 10 CFR 50.73 and Technical Specifications had been met, that appropriate corrective action had been taken, that the event was reviewed by the licensee, and that continued operation of the facility was conducted in accordance with Technical Specification limits.

7.2.1 LER 85-072, RWCU System Isolation and Reactor Coolant Spill

On September 7, 1985, with Unit 1 at 22% power, the Reactor Water Cleanup (RWCU) system isolated due to high differential flow while placing the 'A' filter/demineralizer (F/D) into service. The high differential flow developed when the F/D outlet vent valve, HV-45-1-07A, did not fully close. The partially open valve allowed high pressure water to reach low pressure portions of the F/D vent to the backwash receiving tank line. Seals on two flow glasses in this line ruptured and pressure relief valve PSV-45-1-67 opened as a result of the high pressure and discharged water and resin at elevation 313 of the Unit 1 Reactor Enclosure. The radiological consequences of the spill were reviewed in Inspection Report 50-352/85-28.

The cause of the spill was binding in vent valve HV-45-1-07A, preventing the valve from closing. The spill occurred when the F/D vessel was unisolated and pressurized. To prevent recurrence, the licensee revised procedure S45.8.A, "Regeneration of a RWCU Filter Demineralizer", to require shutting manual isolation valves, 45-1-29A(B) and 45-1-39A(B), prior to unisolating the vessel. These valves provide additional isolation to the F/D vent path.

The inspector discussed another concern with the licensee concerning the potential for overpressurizing the low pressure piping in the precoat piping to the F/D vessel. The licensee is preparing a modification to the regeneration timer cycle which will prevent pressurizing the F/D vessel until the precoat cycle is complete and the low pressure precoat piping is isolated from the F/D. The licensee intends to perform this modification under Field Deviation Disposition Request (FDDR) HH1-3489 during the next extended shutdown. The inspector had no further concerns.

7.2.2 <u>LER 85-039, ESF Actuation of Containment Atmosphere Sampling Valves</u>

On March 30, 1985, with Unit 1 in Cold Shutdown, three isolation valves associated with containment atmosphere sampling were closed as a result of licensee test engineers apparently incorrectly opening an instrument drain valve. The valve which was opened, momentarily, was drain valve 1F044A-39 which connected to the variable impulse leg of level transmitter LT-42-1N081A. The test engineers were performing a check-off list of instrumentation valving located throughout the Reactor Enclosure, in preparation for a reactor startup. In the process of verifying the correct (closed) position of drain valve 39, the engineer apparently began to open the valve in a counter clockwise fashion.

Opening valve 39 caused the high pressure variable leg for LT-81A to decrease in pressure and the transmitter to sense a lower differential pressure corresponding to a reactor vessel level decrease. The spurious low level signal caused the isolation of three small (1/2 to 2 inches) containment atmosphere sampling valves, SV57-133, 183 and 191, as designed. The isolations were reset and the valves re-opened within 5 minutes, although containment sampling was not required with the plant shut down.

The inspector reviewed procedure RT-2-000-630, Instrument Valve Check-Off List, which was prepared subsequent to this event and which details a method to verify the proper position of instrument valves. This procedure formalizes the conduct of instrumentation valve checks, and cautions the personnel performing such checks to attempt to close the valves first, slowly - one-quarter turn. The inspector discussed this event with the I&C supervisor, who stated that it had been addressed in an I&C group "all- hands" meeting on April 16, 1985. The inspector noted that no similar occurences of mistakenly checking instrumentation root valve positions, initially attempting to turn in the open direction, have been experienced since April 1985. The information presented in LER 85-39 was found to be accurate and of sufficient detail to understand the event and effectively follow-up on corrective actions. The inspector had no further questions.

7.2.3 LER 85-081, Actuation of CREFAS

Normal control room ventilation isolated on October 13, 1985, and the emergency fresh air system (CREFAS) initiated as a result of failure of the "D" chlorine detector. This instance was the fourth which occurred during this inspection period, and has been a frequently experienced failure since initial fuel load. The present chlorine detector design utilizes a chlorine sensitive cassette tape which responds optically to isolate normal control room ventilation and initiate CREFAS, an engineered safety feature. The CREFAS isolation requires a 4-hour ENS call to the NRC and preparation of an LER, when either the "C" or "D" detector is actuated.

The inspector discussed the frequent chlorine detector tape failures with a licensee test engineer, and a proposed modification design change package (MDCP) No. 85-611. The change will replace the detectors with a different type, utilizing an electrochemical probe in the ventilation duct intake plenum. Work associated with this modification is scheduled to begin in December 1985 and will be addressed further in Limerick Inspection Report 50-352/85-46.

7.3 Review of Periodic and Special Reports

Upon receipt, periodic and special reports submitted by the licensee were reviewed by the inspector. The reports were reviewed to determine that the report included the required information, that test results and/or supporting information were consistent with design predictions and performance specifications, that planned corrective action was adequate for resolution of identified problems, and whether any information in the report should be classified as an abnormal occurrence.

The following periodic and special reports were reviewed:

-- Initial Plant Startup Report - December 1984; dated September 23, 1985

-- Monthly Operating Reports - September, October, November 1985

-- Annual Plant Modification Report, October 22, 1985

-- Annual Fire Protection Modification Report, dated October 29, 1985

-- Special Report - RCIC Actuations and Injections, dated November 14, 1985

-- Revisions and Corrections to Semi-Annual Effluent Releases Report No. 2 - January through June 1985; dated November 13 and 22, 1985

No violations were identified.

8.0 Scram Discharge Volume (SDV) Vent and Drain Valves

8.1 SDV Drain Valve Misalignment

During normal operations, the scram discharge volume inboard drain valve XV-47-1F011 and outboard drain valve XV-47-1F181 are normally held open by air pressure, which allows draining of the scram discharge volume (SDV). Upon initiation of a scram, both valves are closed after air pressure is relieved from the diaphragm on the valve actuators, thus preventing the discharge of reactor water from the SDV to the radwaste system. Both valves have manual handwheels which may be used to "jack" the valves open or closed, and both are primary containment isolation valves.

On November 3, 1985, at 6:32 p.m., with the reactor at 71% power, the diaphragm of SDV drain valve SV-47-1F181 ruptured and the valve failed closed. This condition was discovered at approximately 1:00 a.m. on November 4, 1985, during normal operator panel rounds and, at 1:35 a.m., a shift engineer and a shift technical advisor observed that both SDV drain valve handwheels were in the neutral position. At 2:19 a.m., November 4, a plant operator and a maintenance worker manually opened outboard valve XV-47-1F181 by turning the handwheel off its neutral position to drain the SDV on orders from shift supervision. At 3:24 a.m., the same personnel manually closed the valve. The plant operator and the maintenance worker involved stated that they did not touch valve XV-47-1F011.

At 10:36 a.m. that morning, valve XV-47-1F181 was again manually opened to drain the SDV. At 11:09 a.m., an operator closed XV-47-1F181 and noticed that the handwheel of inboard valve XV-47-1F011 was off its neutral position and therefore the valve was jacked open. The operator reported his findings to shift supervision. An attempt was made to remotely operate valve XV-47-1F011 from the control room but the valve was jacked-open and therefore inoperable for closing as a containment isolation valve. The operator then placed the handwheel of valve XV-47-1F011 in the neutral position, returning the valve back to operability. At 10:47 p.m. November 4, outboard valve XV-47-1F181 (which had the ruptured diaphragm) was placed back into service in its normally open position after repairs had been completed under MRF No. 8508622.

On October 28, 1985, a quarterly surveillance test (ST-6-47-200-1) had been satisfactorily completed on all SDV drain and vent valves. Both SDV drain valves were stroke-tested and left in the as-found (open) position, but no verification was made that the handwheels were in the neutral position.

As an immediate corrective action, at approximately 2:00 p.m. on November 4, the licensee chained and locked all four SDV drain and vent valves and the NRC inspector verified that the drain valves were chained and locked open, and the handwheels were in the neutral position. The licensee determined that the SDV drain valve handwheels require ten turns off of neutral before manual engagement occurs in the open position. It appears that between the hours of 3:24 a.m. and 11:09 a.m. on November 4, the handwheel of valve XV-47-1F011 was turned approximately 10 turns jacking open the valve thus preventing the valve from isolating the SDV if a scram had occurred during this time period.

The inspector reviewed Limerick Upset Report 017 which described the results of the licensee's investigation of the mispositioning of the inboard SDV drain valve, including: (1) interviews or statements from personnel involved in administratively opening the drain valves; (2) process computer alarm typer printout verifying when the outboard valve failed closed; and (3) a sequence of events from the time the valve failed until it was repaired.

The inspector reviewed Technical Specification 3.6.3 for primary containment isolation valves and determined that the licensee did not violate the Technical Specification at the time of the SDV drain valve failure since the affected penetration was not open (XV-47-1F181 failed closed). At least one deactivated automatic valve was therefore secured in the isolated condition. Pending further review by the licensee to determine how the XV-47-1F011 SDV drain valve was manually jacked open, and the apparent lack of administrative controls applied to the opening of the SDV drain valves this item is unresolved (50-352/85-36-03).

8.2 SDV Vent Valve - Bent Stems

Bent stems on both scram discharge volume vent valves XV-47-IF010 and XV-47-1F180, were identified during an independent walk-down of the system on October 24 by a licensee reactor test engineer. An equipment trouble tag was initiated and subsequently brought to the attention of plant management on October 28, whereupon the valves were successfully exercised and found to stroke open and closed within their maximum allowable times. Both valves had previously been surveilled, successfully, on July 13 and October 13, 1985. The valves are ITT Hammel-Dahl Type V502, 1 inch globe valves, with a 3/4 inch actuator stem coupled to a 3/8 inch valve stem. The smaller diameter valve stems were observed to be bent, above the engaged threads, at a location which does not affect the ability of the valve to stroke open or closed as verified by previous surveillance, as well as the test performed on October 28. The valves are in series and held open (normal position) by instrument air, and close on spring pressure when the air is vented off their diaphragm during a scram.

The inspector observed the condition of the valve stems, reviewed the surveillance test results, and discussed the problem with plant management. The inspector had no further questions, although surveillance testing of these valves will be observed in future inspections, in order to assure that the bent stems do not affect valve operation.

No violations were identified.

9.0 Surveillance Activities

The inspector observed the performance of selected surveillance tests to determine that: The test procedure conformed to technical specification requirements; administrative approvals and tagouts were obtained before initiating the test; testing was accomplished by qualified personnel in accordance with an approved procedure; test instrumentation was calibrated; limiting conditions for operations were met; test data were accurate and complete; restoration of 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.

9.1 Scram Relay Auxiliary Contacts

During the conduct of ST-2-041-618-1 on October 17, 1985, an indicating light DS2 at reactor protection system (RPS) logic panel 10C609 in the auxiliary equipment room was observed not to return to the "On" condition following completion of the test. ST-2-041-618 is a monthly channel functional test of RPS Division II A logic for MSIV closure. The light is actuated by auxiliary contacts of the K14 scram relays, and was determined not to affect proper RPS actuation. The ST was approved, and the light failure was noted with an equipment trouble tag.

Another surveillance, ST-2-041-622-1, was conducted on October 19, 1985, for monthly channel functional test of RPS Division IIA logic for main steam line high radiation logic, and a similar DS2 light failure was noted. That failure was noted by shift supervision and plant management was promptly contacted and briefed, whereupon field engineers were called in to troubleshoot the circuitry.

The cause of the light failures was determined to be a binding of the auxiliary contacts off the K14 scram relay. The auxiliary contacts affect non-safety related process computer input and indicating lights, and were determined to not affect proper RPS actuation and scram functions. The K14 relay is normally energized, and a scram signal will de-energize the coil and operate three main contacts which affect a scram. The four auxiliary contacts are operated off the K14 relay by mechanical arms which are re-positioned by the main contactor. One of the two arms pulled-in by the main contactor was found to be slightly cocked, bound-up, and thus unavailable to properly reposition when the K14 coil was re-energized. That failure prevented the DS2 indicating light and process computer input contacts from properly resetting to their normal positions. These conclusions were presented to the PORC in a meeting attended by the senior resident inspector on October 21.

The K-14 relay is a General Electric type CR105D relay, used only in the RPS scram logic. All eight K14 relays were inspected by the licensee, and some looseness (gaps varying from 1/8 to 1/16 inch) in the plunger posts or operating linkage arms of 4 relays was found and tightened. The following maintenance actions were completed by October 23, 1985:

MRF#	K14 Relays	RPS Channel
85-8226	C & G	A2
85-8274	D & H	B2
85-8273	B & F	B1
85-8270	A & E	A1

Retesting, which was witnessed by the senior resident inspector, verified that the affected auxiliary contacts repositioned properly. The work was dispositioned by GE FDDR No. HH1-3493, approved on October 21, 1985. The probable cause of the loose linkage arms was a modification performed for all K14 relays in February 1983 which changed auxiliary contacts 7 and 8 from normally-closed to normally-open. No similar failures have been observed since October 19, and an estimated 30 surveillance tests observe proper response of indicating light DS2 as part of RPS logic testing. The senior resident inspector noted a good questioning attitude adopted by shift supervision which successfully identified and raised this problem to the level of plant senior management, who promptly evaluated and resolved the problem. The inspector reviewed GE elementary diagram 1020-E-10-25 and discussed RPS logic operation with respect to this problem, and had no further questions.

No violations were identified.

9.2 Wetwell/Drywell Vacuum Breakers

The inspector noted a difference in drywell air suppression chamber pressures of nearly 0.9 psi on October 27, 1985, which required manually opening drywell-suppression chamber vacuum breakers 57-137A-1 and 2 to equalize pressures. In response to the resident inspector's questioning of proper vacuum breaker response, and the source of the suspected leak in the suppression pool of instrument air due to faulty compressor operation, the licensee's test engineers set up pressure gauges to determine the actual pressure conditions inside of the suppression pool.

While each vacuum breaker is required to be set to lift at a differential pressure of 0.5 psi ±5%, each assembly actually consists of two valves in series which, as described in FSAR Section 9.4.5, provides measurable flow only when differential pressure across the assembly (both valves) reaches about 1 psid. Both valves reach fully-open position when pressure reaches 2.9 psid across the valves. The inspector had questioned whether the valves were operating properly, since differential pressure between the drywell and suppression pool had approached 1 psid. The inspector reviewed calibration data sheets which had documented the last as-left lift settings of all eight vacuum breakers on October 25 - November 1, 1984 as within ±5% of 0.5 psid. Those settings are required to be calibrated at 18 month intervals. The inspector also reviewed the results of 18 monthly surveillances of the vacuum breakers conducted since January 1985, which, successfully exercised the valves for operability in accordance with Surveillance Test ST-6-060-760-1. The ST-6-060-760-1 procedure was verified to be last performed and completed on November 12, 1985.

Each valve is a 24 inch Anderson-Greenwood type CVI-L which is designed to be capable of opening in 0.2 seconds and passing 36,780 scfm of air flow at 0.7-0.8 psid. The inspector concluded that the vacuum breakers were operating properly, and that pressure equalization between the pool and drywell air spaces would not be expected to occur at differential pressures less than 1.0 but greater than 0.5 psid. The inspector considered the licensee's test engineering group to be responsive and technically knowledgeable with respect to his concern for operability. No unacceptable conditions were noted.

9.3 HPCI and RCIC Pump Tests

The inspector reviewed the results of ST-6-055-230 conducted on November 10, 1985 involving a quarterly pump and check valve flow test of HPCI at rated steam conditions using the full flow test line from and to the condensate storage tank. The pump was verified to develop required flow of 5650 gpm with a system test head corresponding to a differential pressure of 1020 psi with reactor steam supplied at 955 psig to the HPCI pump turbine. All check valves functioned properly to open and permit flow, and equipment essential to HPCI operability were independently verified as returned to their required as-found condition.

The inspector observed the conduct of ST-6-049-230-1 on November 12, 1985, involving a quarterly pump and check valve flow test of RCIC at rated steam conditions using the CST test lines. The pump developed the required 600 gpm flow at a differential pressure of 884 psid with 960 psig reactor steam supplied to the turbine. Test results were properly entered, evaluated and approved, and the test was observed to be conductd in accordance with the procedure. All RCIC equipment was verified by the inspector as being returned to required as-found conditions necessary for system operability.

The inspector had no further questions, and no unacceptable conditions or violations were identified.

9.4 HPCI Isolation Timer

While performing a HPCI system steam supply line differential pressure timer surveillance test ST-2-055-634-1 on September 26, 1985, a spurious Division 4 ECCS trip signal was received. That event, described in LER 85-077 issued on October 24, 1985, is addressed in Detail 5.2.

The inspector observed the event and noted the HPCI system was inoperable at the time and that, while a valid initiation signal was received, no injection occurred. The HPCI system had been removed from service to perform ST-2-055-634. The cause of the Division 4 spurious signal was traced to a loose connection to the power supply of a fuse for 24 VDC Division 4 trip units and Rosemount transmitters located at auxiliary equipment room panel C618. While making a test connection to perform the surveillance, an allegator clip was landed on a terminal strip connection in this panel which apparently momentarily disturbed the fuse and caused the actuation. The inspector observed the licensee's inspection and tightening of the suspected loose connection. The licensee plans to revise the method of procedurally obtaining test box power from this fuse connection, by adjustment of the trip unit rather than applying an external voltage signal.

The inspector discussed this event and the surveillance procedure with licensee I & C test engineers, and had the following concerns related to the ST:

-- The surveillance procedure contains a precaution and an initialled acknowledgement by the control room operator that HPCI will be inoperable. However, HPCI had not been logged inoperable and, further, intentions were to block out an RHR pump during this test. The RHR pump had been logged inoperable but the permits had not yet actually been applied, so that it was technically still operable.

-- Because ST-2-055-634 is a monthly simulation of HPCI steam line high differential pressure in Division 4 logic, it affects isolation of the steam line inboard turbine isolation valve. It is not desirable to close this valve since failure to reopen would involve HPCI inoperability and shutdown for a drywell entry. Therefore, the procedure requires the valve be deactivated open.

-- The surveillance procedure closes the outboard isolation valve, making HPCI inoperable, by manually closing a valve which would not reopen on a valid HPCI initiation signal as occurred on October 24, 1985. Further, while closing the outboard valve is apparently done to satisfy containment isolation technical specifications (for a penetration with an isolation valve incapable of automatic closure), the valve is not secured or deactivated closed and is not logged as being in an action statement for Technical Specification 3.6.3.

The inspector observed the conduct of this surveillance test on October 3, 1985, which created a similar spurious Division 4 activation signal. Revision of ST-2-055-634-1 to consider: (1) logging HPCI inoperable; (2) not closing the outboard isolation valve, or closing, deactivating and entering the action statement; and (3) obtaining test box power differently to prevent use of alligator clip, are collectively unresolved pending future inspection of this and other similar channel test (50-352/85-36-04).

10.0 Review of AWS D1.1 Visual Weld Acceptance Criteria (VWAC)

On August 28, 1985 Regional welding and NDE Specialist Inspectors attended and reviewed the licensee's VWAC Training Program conducted to meet the requirements of the J. P. Knight (NRC) to D. Dutton (Nuclear Construction Issues Group (NCIG)) June 26, 1985 VWAC acceptance letter. The attendees represented construction, engineering, and QC organizations. The three hour session was one of four identical sessions scheduled for August 27 and 28, 1985. The training was conducted by Bechtel Materials and Quality Services (M&QS) welding specialists who were involved in the preparation of the VWAC NCIG-01 document. The attendees were given copies of the NCIG-03 training document. The presentation utilized the slides developed for the NCIG presentation to the NRC in June 1985.

Bechtel personnel indicated that there is currently no practical training scheduled and this program would essentially complete the VWAC training. They indicated that the VWAC document is also being presented to design engineering personnel for their cognizance. Discussions with the licensee's site QA Group indicated that they were in the process of requesting an FSAR change relative to commitments to codes and standards for VWAC, and will indicate on the Bechtel G-20 document where the VWAC document can be applied. The areas in which the VWAC document will be applied will then be given the standard Project Engineering approval. The licensee committed to provide explicit guidance regarding the control of "Engineers" (as defined in AWS D1.1) application of the VWAC document and the "Engineers" approval for re-inspection of painted surfaces.

No violations were identified.

11.0 Unresolved Items

Unresolved items are items about which more information is required to ascertain whether they are acceptable or constitute a deviation or a violation. Unresolved items are discussed in details 2.1, 6, 8.1 and 9.4.

12.0 Exit Meeting

The NRC resident inspector discussed the issues and findings in this report throughout the inspection period and at an exit meeting held with Mr. G. Leitch on December 16, 1985.

At this meeting, the representatives of the licensee indicated that the items discussed in this report did not involve proprietary information. No written material was provided to the licensee during this period.