U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Report Nos.	95-81 95-81
Docket Nos.	50-352 50-353
License Nos.	NPF-39 NPF-85
Licensee:	PECO Energy Correspondence Control Desk P.O. Box 195 Wayne, Pa 19087-0195
Facility Name:	Limerick Generating Station, Units 1 and 2
Inspection Period:	September 12, through September 21, 1995
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EXECUTIVE SUMMARY
Limerick Generating Station
Report No. 95-81 & 95-81

On September 11, 1995, at 1247, with Unit 1 operating at 100% of rated power, a main steam line safety relief valve (SRV) lifted. Attempts to close the SRV were unsuccessful, and the operators initiated a manual reactor scram. An uncontrolled cooldown of the reactor occurred, which exceeded technical specification limits. All other plant equipment acted normally with the exception of one residual heat removal (RHR) pump. Approximately 30 minutes into the event, the operators observed indications of cavitation on the A RHR pump, removed it from service and vented the pump. It was returned to service at a reduced flow rate and ramped up to 8500 gpm. At 0227, on September 12, 1995, reactor pressure had been reduced to below 75 psig and one loop of shutdown cooling was placed in service. At 0430, Unit 1 was in cold shutdown with a reactor coolant temperature of 194 degrees F. No unusual radiological conditions were noted during the event and no unusual releases of radioactive material were detected.

The Special Inspection started at the site at 1820, on September 11, 1995, to assess the effectiveness of Limerick line management actions, to assess root causes for the SRV lift and the RHR cavitation, to assess whether the existence of generic industry information, and to determine if any operational restart issues existed.

The licensee determined the root cause of the SRV lift was pilot valve corrosion and that the RHR pump cavitated because of suction strainer clogging. The licensee further determined that the pilot valve corrosion resulted from pilot valve leakage and that the RHR pump suction strainer clogging resulted from a combination of a large amount of corrosion products in the suppression pool (SP) and the existence of foreign material in the SP.

The inspectors determined that the processes and practices used by Limerick line management in response to the event were exceptional in that they were logical, carefully contemplated, based on sound principles of industrial and nuclear safety, and effectively managed.

The inspectors identified several issues with respect to adequate LGS management corrective action prior to the September 11, 1995 event concerning SP cleanliness/ECCS operability, and SRV operability. These questions are identified as unresolved item (URI) 352,353/95-81-01.

The inspectors identified no issues which would affect the restart of Unit 1 or the continued operations of Unit 2.

<u>Engineering</u>

The inspectors observed and evaluated a large number of Limerick and corporate engineering activities associated with the event. Engineering evaluations were determined to be conservative and based on good engineering principles. Engineering services supplied to the unit were aggressive and responsive to operational and safety aspects of event resolution.

EXECUTIVE SUMMARY CONTINUED

Plant Support

The inspectors observed and evaluated support services supplied by Health Physics, Chemistry, Radiological Waste, and Contract Management (diving services, General Electric (GE), Wyle). The services effectively contributed to the licensee event response activities.

Safety Assessment and Quality Verification

The inspectors observed the activities of the site QA and ISEG organizations associated with the event. The Independent Safety Engineering Group (ISEG) members were knowledgeable of the technical issues, aggressive in their review activities, and demonstrated a high level of individually expressed professional independence. However, prior to the event the ISEG had undergone a number of organizational changes, which affected its participation in the event review. It had previously been reduced in number, the level of ISEG offsite organizational access appeared to have been limited and the practice of issuing draft reports to line management prior to the issuance of final reports held the potential for a loss of independence. The activities of the site QA organization were observed at several working levels and determined to be adequate.

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DETAILS

1.0 PLANT OPERATIONS

1.1 Stuck Open Safety Relief Valve (SRV) Event

On September 11, 1995, at 1247, with Unit 1 operating at 100% of rated power, main control room personnel received alarms and plant indications that the M main steam system safety relief valve (SRV) was open. The operators implemented Limerick emergency operating procedures. Attempts to close the SRV were unsuccessful, and the operators initiated a manual reactor scram as required by technical specifications (TS) 3/4.4.2. At 1250, the Shift Manager declared an Unusual Event (UE) based on a suspected failure of an SRV to close. The operators closed the main steam isolation valves to reduce the depressurization rate of the reactor vessel. The SRV appeared to have closed at 1307 when reactor pressure had decreased to 410 psig but this could not be verified because RCS pressure continued to decrease. The maximum reactor coolant system (RCS) cooldown rate observed was approximately 157° F per hour, exceeding the TS limit of 100 degrees F per hour. Suppression pool temperature reached a maximum of 124°F during the event. Prior to the event, residual heat removal (RHR) train A was in service for routine suppression pool (SP) cooling. The B train of RHR was placed in service for SP cooling immediately after the M SRV opened. Approximately 30 minutes into the event, the operators observed indications of cavitation on the A RHR pump, removed it from service and vented the pump. It was returned to service at a reduced flow rate and ramped up to 8500 gpm. At 0227, on September 12, 1995, reactor pressure had been reduced to below 75 psig and one loop of shutdown cooling was placed in service. The UE was terminated at 0227. At 0430, Unit 1 was in cold shutdown with a reactor coolant temperature of 194 degrees F. No unusual radiological conditions were noted during the event and no unusual releases of radioactive material were detected.

The Inspectors did not perform a detailed review of operator response, operator training, or emergency operating procedures. A detailed review of these issues was conducted in inspection report 352,353/95-12.

1.2 Cooldown rate

As a result of the stuck open M SRV, the RCS experienced a cooldown in excess of technical specification (TS) 3.4.6.1 requirements. TS 3.4.6.1 states that the RCS temperature and pressure shall be limited in accordance with temperature curves attached to the TS, with a maximum cooldown rate of 100°F in any one hour.

TS 3.4.6.1 requires that with the maximum cooldown rate of 100 degrees F in any one hour exceeded, restore the temperature to within the limits within 30 minutes; perform an engineering evaluation to determine the effects of the out-of-limit condition on the structural integrity of the RCS; and determine that the RCS remains acceptable for continued operations or be in at least hot shutdown within 1 hour and cold shutdown within the following 24 hours.

The licensee performed an engineering evaluation to determine the effects of the excessive cooldown event on the RCS, as required by TS. The Inspectors reviewed the engineering evaluation, discussed its findings with Limerick engineering representatives, reviewed licensee conclusions with respect to operator actions in the control room, and observed the licensee's resolution of the issue at a September 20, 1995, plant operation review committee (PORC) meeting. As a result of the PORC meeting the licensee dispositioned this event as the first of eight allowed cooldown events.

The Inspectors determined that the cooldown event was bounded by the plant design and that it represented no immediate safety concern with respect to the restart of Limerick Unit 1.

1.3 Sequence of Events

09/11/95 Unit 1 was operating at 100% of rated power with the A RHR pump operating for suppression pool cooling.

1246 SRV leak annunciator alarmed and acoustic identification of an open "M" SRV.

1248 House loads were transferred.

1249 The mode switch was placed in shutdown.

1250 The C feedwater pump was manually tripped.

1250 The main turbine was tripped manually.

1250 Reactor vessel level increased to 54.5 inches (A and B feedwater pumps tripped).

1250 An unusual event was declared.

1251 The B RHR pump was started for suppression pool cooling.

1307 The M SRV indicated closed at 410 psig.

1330 The A RHR pump was secured due to fluctuating motor current and decrease in differential pressure across the pump.

1345 The A RHR pump was restarted at a reduced flow and monitored until 1500.

09/12/95

0230 The B RHR loop was placed in the shutdown cooling mode with a flow rate of 10,000 gpm.

0330 The A RHR loop was placed in the shutdown cooling mode with a flow rate of 9,700 gpm.

0630 The B RHR pump is secured from shutdown cooling.

1.4 Independent Barrier/Weakness Assessment

The inspectors performed an independent barrier analysis of the September 11, 1995 event. The inspectors determined that there were no significant operations barriers/weaknesses that contributed to the initiation of this event.

1.5 Conclusion

The Inspectors did not perform a detailed review of operator response, operator training, or emergency operating procedures. A detailed review of these issues was conducted in inspection report 352,353/95-12. Based on a general review of the operations aspects of the event, discussions with operations personnel, an independent barrier analysis of the event and a discussion with the inspectors that performed inspection 352,535/95-12, the inspectors determined that there were no concerns related to the restart of Unit 1 or the continued operation of Unit 2.

2.0 SAFETY RELIEF VALVES

2.1 Description of Two Stage Target Rock Safety Relief Valves

The ASME Boiler and Pressure Vessel Code, Section III Rules for Construction of Nuclear Power Plant Components, requires overpressure protection of the RCS in accordance with the Code. The Limerick Generating Station (LGS) units each have 14 main steam safety relief valves (SRVs) which provide the Code required overpressure protection of the RCS. In addition to the overpressure protection function, several of the SRVs provide an automatic depressurization system (ADS) function as part of the emergency core cooling system (ECCS). The 14 SRVs have letter designations (A, B, C, D, E, F, G, H, J, K, L, M, N and S). The ADS uses selected SRVs (S, H, M, E, K) for depressurization of the reactor in response to certain design transients.

The 14 SRVs at each Limerick unit are two stage (pilot disc stage and main disc stage) 6 inch by 10 inch valves, manufactured by the Target Rock Corporation (TRC). The SRVs are self actuating (will actuate when the RCS pressure reaches the SRV setpoint) and can also be remotely operated (actuated by an electro-pneumatic external power source). The pilot disc is held in the closed position by a spring force. The main disc, a reverse seated disc (flow over the disc), has an attached piston. The main disc is maintained in the closed position by system pressure over the disc.

The self actuating mode responds to RCS pressure. When RCS system pressure reaches the pilot disc setpoint, the pilot disc will open, the stabilizer disc will follow the pilot disc and close and the main disc piston chamber will be vented. Venting of the piston chamber causes the main disc forces to become biased in the open direction and the main disc will move to the full open position.

In the remote operating mode, a switch in the control room actuates a solenoid valve and a pneumatic system removes the spring load from the pilot disc. RCS pressure will move the pilot disc open and then the sequence of opening the main disc is the same as described in the self actuation mode.

The Limerick 2-stage TRC, SRVs are configured differently from the standard industry 2-stage TRC design. The difference is in the orientation of the body inlet and discharge. In the Limerick SRVs the inlet is horizontal and the discharge is vertically downward (the main disc assembly is vertical with the main seat in a horizontal plane). In the standard industry design the inlet is vertically upward and the discharge is horizontal (the main disc assembly is horizontal with the main seat in a vertical plane). The vertical orientation of the pilot assembly and the air actuator assembly in the Limerick SRV and in the standard industry SRV are the same.

2.2 Unit 1 Operating Experience

Since the startup of Unit 1 in 1985 and the startup of Unit 2 in 1990, Limerick has experienced SRV leakage problems. Based on inspectors discussions with engineering personnel and reviews of photographs of worn main discs, main seat leakage due to the unique main disc orientation was the predominant past problem (not pilot disc wear). Because of continuing main seat leaks (identified by high tailpipe temperatures during operation and by repairs required at the test facility), PECO initiated a meeting on October 6, 1987, at which PECO, Bechtel, TRC and GE discussed the possible leakage problem causes and potential resolutions. The main seat leakage problem cause was thought to be the result of condensate collecting at the main seat due to the valve orientation. This phenomenon was referred to as puddling and created disc distortion. After this meeting GE was contracted to do a study and perform tests comparing the leakage of the Limerick SRVs with the standard industry oriented SRVs.

The subsequent GE study provided main seat leakage test result comparisons of: 1) the standard industry oriented two stage SRV, 2) the Limerick two stage SRV with its unique orientation, and 3) a modified Limerick design SRV prototype. The modified Limerick SRV prototype was designed to reduce the collection of condensate (puddling) at the main disc. Test results verified higher main seat leakage in the Limerick SRV and that the modified Limerick SRV prototype showed improvement over the standard vertical discharge valve. The result of these efforts led to major Limerick SRV modifications implemented in the 1990-1993 time period when new valve bodies and valve parts, incorporated main seat/disc drainage improvements (an elevated main seat, the inlet port sloped 3° away from the main seat, and the hub drain relocated toward the sloped inlet port). The new modified valves were installed on Unit 2 in the 1993, 2RO2 outage and on Unit 1 in the 1992, 1RO4 outage. The modification was also carried out on the licensee's 14 spare valves.

The M SRV, serial number 527, with a setpoint of 1140±1% psig, opened at approximately 1000 psig and initiated the UE on September 11, 1995. The M SRV was installed in the 1RO5 outage (during the normal periodic changeout of SRVs) and had been in service 18 months. The inspectors reviewed the M SRV prior-to-installation test report to verify that there were no unusual test findings that could cause the valve to open during operation. The M valve was last tested and refurbished at the Westinghouse Western Service Center Safety Valve Test Facility on September 2 through September 27, 1993. (This was Limerick's first use of this facility for SRV testing.)

The inspectors reviewed Westinghouse test report 93-125, which provided details of the as-found, intermediate, and as-left testing. The leakage test was a cold bar test at 1010 psig with no droplets to be observed. The as-found testing listed a failed pretest leakage (noted as pilot/main), and a failed setpoint test, with the as-found lift of 1238 psig (+8.5% over nominal). Three subsequent lifts were at 1161, 1129, and 1122 psig. The test sheet notation was, pilot and main leaked on initial pressurization and stopped during heat-up and soak. A failed post setpoint leakage (noted as pilot leakage) was the last as-found test performed and the SRV was then repaired. Retest #1 after the repair listed a failed pretest leakage (noted as pilot) and the setpoint was satisfactory but the reseat percentage of 74% was too high. The SRV failed the post setpoint leakage and was then repaired and readjusted. Retest #2 listed a failed pretest leakage (noted as pilot). The as-left setpoint of 1135 psig and 70% reseat were satisfactory. The test sheet notation indicated that the pilot had slight leakage before the test. The post setpoint leakage was found satisfactory. The inspectors concluded that the above test results were representative industry SRV test results. However, there was no evidence that the licensee had pursued the cause of the test notations that indicated pilot valve leakage or had designated any special monitoring process to evaluate the in plant performance of the valve.

The inspectors also reviewed the system engineer's SRV tailpipe temperature data for Units 1 and 2. There were no licensee requirements to trend this information and no documented guidance or defined limits for acceptable or unacceptable leakage conditions. There was a control room tailpipe temperature alarm setpoint of 250°F. The Unit 1, M, S, D, F, and L SRVs were known to have high tailpipe temperatures (as high as 295°F on the M, and 285°F on the S) prior to the September 11, 1995, event.

The inspectors selected a representative sample from the system engineer's file of SRV tailpipe temperatures for review. The inspectors concluded that the system engineer test data had been trended adequately and indicated a long history of valve leakage on the M and S valves. In addition, the inspectors determined that there was no operability acceptance criteria established for acceptable leakage by system engineering and that as the set point temperatures were successively raised for the tailpipe alarm there did not appear to be a justifiable engineering evaluation based basis for continued operations. Resolution of this issue is considered question 1 of unresolved item (URI) 352,353/95-81-01.

2.3 Post Event SRV Activities, M SRV Testing, and Problem Cause(s)

Post Event SRV Activities

After the inadvertent opening of the M SRV valve on September 11, 1995, site engineering contacted GE and TRC to determine if any events similar to this had occurred. No similar events could be found of a 2-stage TRC SRV inadvertent opening at operating pressure, whether caused by pilot disc erosion, leakage or any other failure reason. PECO management tasked a licensee SRV team effort led by Limerick component engineering and assisted by systems engineering to provide a plan to find the problem cause(s) and to recommend subsequent required actions. The licensee's SRV team reviewed past SRV history and formulated possible causes of the M SRV lift with TRC and GE. The licensee's SRV team recommended removal of the M SRV (the event initiator) and also the S, F, L, and D valves since the common tie to these SRVs was high tailpipe temperatures. Limerick SRV component engineering formulated a preliminary test plan based on 5 postulated failure scenarios and discussed this plan in a September 13, 1995, conference call with TRC and Wyle lead personnel. After the conference call, site component engineering prepared a formal M SRV test sequence and the parties involved in the phone conference agreed with this test sequence. The M SRV had already been shipped and arrived at Wyle Laboratories on September 14, 1995. Two PECO engineers (a corporate engineer who is also on the BWROG SRV task group and a metallurgical engineer), a lead GE SRV engineer, the lead Wyle test engineer and two TRC technicians were involved with the testing of the valve. The S SRV was also transported to Wyle Laboratories to be used for verification testing as required.

M SRV Testing

Prior to the M SRV shipment, its electrical circuitry and logic was checked and no abnormal behavior was found. The inspectors inspected/reviewed/discussed the electrical circuitry and logic testing and had no questions. At Wyle the M SRV test sequence developed by PECO, TRC, GE and Wyle, began with a visual inspection of the main disc/seat and body through the outlet bore. Visual inspections showed extensive discoloration evidence of pilot leakage and minimal evidence of main disc/seat leakage. The inspectors made independent visual observations of some of the affected SRVs, reviewed photographs of the affected component areas, and discussed/reviewed the observations of licensee and contractor technicians. The inspectors had no comments.

The as-received M SRV was then placed on the test stand and a steam pressure test to 300 psig was attempted; however, at 15 psig there was excessive leakage that appeared to be from the pilot (flows from the partial flow test gag, a part of the test configuration, provided indication of the leak source). The valve was then removed from the test stand and a pilot rod depth measurement was taken. The pilot rod depth was 0.075 inches deeper than when installed at the start of the Limerick operating cycle, which indicated possible pilot disc or pilot seat erosion. The pilot cartridge assembly was removed and no debris was found. The pilot cartridge assembly was then installed in the standard oriented Wyle slave body that had a known good main seat and a steam pressure test was started. At 50 psig there was severe pilot leakage that was quantified as 150#/hr. This was extrapolated to a 3000#/hr flow for a 1000 psig inlet pressure. Wyle, GE, and TRC noted that the M SRV being tested had the highest pilot leakage they had seen in a 2-stage TRC SRV. Inlet pressure was then increased and at 870 psig, there was an indication that the pilot rod had moved up 0.020 inches and then back down. The initial rod motion was accompanied by an audible steam noise. On the next test, it was easier to maintain pressure, indicating some parts may have shifted during the 0.020 inch pilot rod movement. From a qualitative comparison, the leakage was less than that observed prior to the 0.020 rod movement. The inlet pressure was increased and reached 1250 psig and there was no valve actuation (pilot or main disc).

The disassembly inspection found the clearance at the air actuator to pilot rod connection was gone. Gasket 128 (a potential bypass of the pilot) was intact, and the stabilizer disc and seat had little indications of wear. The pilot disc was severely eroded and in two pieces, and also had its side wall eroded through in two areas (160° apart) at a location right above the lower guide ring. Steam wire drawing erosion was also evident in the pilot seat. The pilot rod end that transmits the spring load to the pilot disc was also severely eroded and bent, and the pilot rod bellows were eroded in several areas (the erosion of these parts was caused by the steam flow path created by the eroded pilot disc). The main disc was removed from the SRV body and was found in good condition.

Problem Cause(s)

The licensee's evaluation of the test results and observations of disassembled parts was that the severe pilot disc erosion (that had occurred over a long time) was the prime problem contributor. (The photographs returned from Wyle that the Inspectors reviewed showed the pilot disc to be severely eroded. Based on prior Limerick in-plant experience and the use of industry and Limerick leakage temperature profiles, pilot leakage generally occurred after the ADS exercising test that is performed at 500 psig during startup. The licensee identified the ADS test as a problem initiating cause.

Two M SRV failure hypotheses were postulated by the licensee based on the severe erosion of the pilot disc and pilot rod: 1) the pilot rod drop of 0.075 inches caused engagement of the actuator lift collar and relieved some spring load which caused the main disc to lift, and/or 2) the pilot rod, disc nose piece and stabilizer disc lifted, cutting off the feed to the main disc piston upper chamber, which caused the main disc to lift. The inability to replenish the main disc piston chamber due to the severe pilot leakage caused the long blowdown. The licensee's conclusion was that the exact failure mechanism was undeterminable.

A verification of the pilot disc material specified as Stellite 6B, was made by the licensee by: tracking the receipt inspection records, obtaining the disc serial numbers off the failed M SRV disc and verification with TRC, and verifying the hardness of the failed disc that was returned to the PECO Valley Forge Metallurgical laboratory. The inspectors determined that LGS had adequately characterized the model and material content of the failed pilot disc.

The inspectors concluded that: the licensee's planning for the M SRV testing involved the appropriate resources; the Limerick and PECO component engineers were highly knowledgeable of the Limerick SRVs and the test plan; the implementation of the testing was comprehensive and well thought out; the testing and disassembly inspection at Wyle had the correct level of observer expertise; the licensee's decision to replace the S, D, F, and L SRVs was conservative; and Limerick line management and high level PECO corporate management were fully involved with the post September 11, 1995, event activity.

The inspectors also concluded that: the licensee's failure hypotheses were plausible; the precise failure mechanism could not be determined; and that the prime problem contributor was severe pilot disc erosion. Because the testing did not duplicate the plant event (a main disc lift), the inspectors pursued the issue of what pilot leakage could cause a main disc lift. The Wyle M SRV tests provided some leakage information (150#/hr leak at 50 psig inlet pressure extrapolated to 3000#/hr at 1000 psi inlet pressure). The inspectors were also able to obtain some leakage data from the licensee based on GE SIL and other industry information. The licensee had received and analyzed specific industry data concerning main and pilot disc leakage. As a part of the licensee's industry review, LGS system engineering conducted tailpipe temperature monitoring, which is discussed below. The inspectors determined following a review of industry data provided by GE and Wyle, that uninsulated tailpipe temperatures of 212 degrees F indicated some small amount of SRV leakage.

Additional information from TRC was obtained and provided to the Inspectors (TRC letter dated September 21, 1995). A TRC stated that there was a high degree of confidence that the main disc would not lift with a pilot leakage of 1000#/hr, and could lift with a pilot leakage of 3000#/hr. The 1000#/hr leakage rate compares to a tailpipe temperature (measured at the standard distance from the SRV) of approximately 250 F. Field observations of the valves, thermocouples and insulation are discussed in section 2.8 of this report.

2.4 Inspection and Test of the S, D, F, and L SRVs

Based on the findings from the M valve testing, the outlets of the other four removed SRVs were visually inspected to determine if there were main disc leaks or pilot disc leaks. The inspection of the S valve was performed at Wyle, and inspections of the D, F, and L valves were performed at Limerick. The visual inspections all showed indications of main disc leakage. A minimal discoloration evidence of pilot leakage was found on the D SRV.

The test plan for the S valve involved installing the S pilot cartridge assembly in the standard Wyle slave body and performing a pressure test to confirm the visual inspection findings that the S SRV problem was main disc leakage, and not pilot disc leakage. Wyle performed the pressure test on the S SRV pilot cartridge assembly at 1000 psig for several hours and there was no leakage. This confirmed that the S SRV problem was main disc leakage.

2.5 Licensee's In Plant Post Installation SRV Surveillance Tests

Nine surveillance tests are performed by LGS at varying frequencies to determine SRV operability. Some of these tests are only performed on the ADS SRVs. Subsequent to the replacement of the five leaking SRVs (M, S, D, F, L), the following four tests were performed prior to or during the startup of Unit

1 following the September 11, 1995, UE:

1. ADS Leak Test: This test was performed satisfactorily on the M and S valves on September 15, 1995. It verifies the integrity of a portion of the ADS accumulator system supply.

2. SRV Cyclic Test: This test was performed satisfactorily on all five replaced valves. It verifies proper mechanical operation of the SRV air operator assembly and verifies proper electrical and mechanical operation of the solenoid valve assembly by cyclic test.

3. ADS Valve Exercising: The test was performed subsequent to this report, during reactor startup on the M and S valves, at 500 pounds reactor pressure. This test demonstrates the operability of the ADS valves with manual initiation from the control room.

4. Accident Monitoring, SRV Position Indicating: This test was satisfactorily performed for all five replaced valves on September 17, 1995. This test is performed to verify operability of the acoustic monitoring system. The acoustic monitoring system is used to determine safety relief valve position, particularly during post accident plant conditions.

The inspectors reviewed/discussed the adequacy and the performance of the above listed tests and had no comments.

Five of the nine SRV surveillance tests were not performed subsequent to the replacement of the leaking SRVs. PECO did not perform two of these tests, the ADS Logic System Functional test and the ADS timer test. These tests involve actuation of the ADS system and were not affected by the replacement of the five leaking valves. Two of these tests, the Reactor Vessel Valve test and the SRV Position Indicator Functional test are covered by other tests that were performed (the ADS leak test and the Accident Monitoring, SRV Position Indicating Instrumentation Channel Calibration test). The SRV setpoint verification test is required by TS and IST, to be performed on at least seven SRVs at a 24 month frequency or if required by an initiating event. Since this test was performed at the previous refueling outage 1R05, in February 1994, and since the five replacement valves were laboratory certified, the licensee met the TS and IST requirements. The inspectors reviewed/discussed the licensee's decision not to repeat the above five tests and determined that the decision was conservative.

2.6 Licensee Corrective Actions to Unit 1 Unusual Event

For Unit 1, the licensee's corrective actions were:

1. The licensee formulated a comprehensive test plan for the M SRV (the event valve). Tests were conducted and the material conditions of the M SRV was determined. Testing provided information for the SRV failure hypothesis and which SRV parts were the major contributors.

2. The licensee installed 5 qualified (pretested) SRVs (M, S, D, F, L), and replaced the five problem valves.

3. The licensee has performed the required in-plant, post installation testing on the installed replacement SRVs.

4. An SRV tailpipe temperature monitoring and trending program with acceptance criteria for leakage temperature limits was established. Ongoing reviews and investigation of additional sensing devices to determine the leak source are planned.

The inspectors concluded that the corrective actions taken by the licensee were adequate for the restart and operation of LGS Unit 1. However, the inspectors was unable to conclude that operation of Unit 1 with a leaking tailpipe temperature, measured at the standard position, of greater that 250 degrees F was conservative and would ensure that another SRV would not occur. The licensee committed to prepare an engineering evaluation to justify operation between 250 degrees F and some elevated temperature.

For Unit 2, the operating experience and licensee's corrective actions were:

1. During the current operating cycle, two SRVs have shown signs of leakage, E with a tailpipe temperature of 214°F and F with a tailpipe temperature of 187°F. These temperatures are below the control room 250°F alarm setpoint and below the 295°F temperature of the M Unit 1 SRV that self-actuated.

2. Similar to the Unit 1 action, an SRV tailpipe temperature monitoring and trending program, with acceptance criteria for leakage temperature limits, was established. Ongoing reviews and investigation of additional sensing devices to determine the leak source are planned by the licensee.

The inspectors concluded the current E and H tailpipe temperatures represent relatively low leakages and not in the leakage range necessary to self actuate an SRV based on the Unit 1 evaluation data. The inspectors further concluded that the corrective actions taken were adequate for continued operation of LGS Unit 2. However, the inspectors was unable to conclude that operation of Unit 2 with a leaking tailpipe temperature, measured at the standard position, of greater that 250 degrees F was conservative and would ensure that another SRV would not occur. The licensee committed to prepare an engineering evaluation to justify operation between 250 degrees F and some elevated temperature.

2.7 Generic Implications

In the early 1980s, the 2-stage TRC SRV design replaced the 3-stage TRC SRVs design on BWR plants because of inadvertent lifts of the 3-stage SRVs at power. The 2-stage SRV design was developed because the inadvertent lifts of the 3-stage at power were undesirable challenges to the RCS and operators. Since the 2-stage SRVs were installed, the SRVs have experienced setpoint drift problems (difficulty in SRV setpoint repeatability) where high setpoints were caused by the pilot disc sticking to its seat. This problem resulted in

SRVs that did not lift until the system pressure was significantly higher than the SRV setpoint. The prior 2-stage SRV concern had been directed to the possibility that pilot disc sticking could prevent an SRV main disc lift. Until the September 11, 1995, Limerick event, there had been no industry event of a 2-stage SRV inadvertent lift at power. The Limerick September 11, 1995, event was industry unique and not the expected behavior of a 2-stage SRV.

While there was factual evidence that the Limerick SRV did lift at power, the post event testing of the failed M SRV did not duplicate the main disc lift of the event. The inspectors concluded there was generic implication to the event because: 1) the orientation of the pilot stage in the Limerick SRVs are the same as in the general industry design, 2) the potential exists that severe pilot disc erosion and severe leakage (the largest contributor to the M SRV main disc lift) could also occur in the general industry design.

The inspectors further concluded that: tracking and trending of SRV tailpipe temperatures should be accomplished by system engineering; appropriate acceptance for operability should be established based on sound engineering data; qualified SRV testing history should be reviewed in detail by licensees on receipt to determine if qualification testing indicated any valve specific leakage characteristics and the ADS exercise testing during startup noted as a Limerick pilot disc leakage initiator should be reviewed to determine if there is a causal relationship to ADS SRV valve leakage.

2.8 SRV Walkdown Observations

The inspectors observed the replaced M, S, and L SRVs and the J, K, and N SRVs, located in the Unit 1 drywell at the 277 ft. elevation. Observations were also made of the acoustic monitors. The acoustic sensors were attached to the vertical discharge pipe by metal banding on the pipe exterior. The acoustic sensors were all mounted on the vertical discharge piping at approximately 18 inches below the SRV discharge flange. Observations were also made of the location of the tailpipe temperature sensors. These sensors appeared to be in thermowells mounted on the surface of the vertical discharge pipe at varied distances from the SRV discharge flange. The distances were estimated to be: 10 feet on the M, 8 feet on the S, 4 feet on the L, 10 feet on the K, 6 feet on the N, and 7 feet on the J. The SRV were insulated with custom fitted insulation and the SRV discharge piping was not insulated. The inspectors concluded that the licensee's monitoring program should consider the sensor location.

The inspectors also observed the pilot cartridge assembly that could not be inserted into the D replacement body during this inspection. This assembly was chucked in a lathe in order to determine its axial runout. The runout was found to be 0.007 inches and a likely cause of the inability to insert this assembly into the body. This pilot cartridge assembly was not used and another cartridge was inserted in the replacement D SRV. The inspectors concluded that the licensee's actions were correct and that an out-of-alignment pilot cartridge was not a contributor to the M SRV event since out-of-alignment cartridges cannot readily be installed in the close tolerance body bores of an SRV.

2.9 Sequence of Events for Unit 1 9/11/95 Transient

2/94 - 3/94 Unit 1 refueling, 1R05, was conducted.

All 14 SRVs were replaced (pilots & main bodies) with refurbished units from Westinghouse. This was the first time that the SRVs were refurbished by Westinghouse versus Wyle Laboratory.

3/94 — Unit 1 1R05 was completed. Prior to startup all pre-startup testing was completed, which included:

ST-1-041-470-1, SRV Cyclic Test
ST-4-LLR-005, 006, 007, 008, 009-1, ADS Leak Test
ST-2-041-474,475-1, Acoustic Monitor
ST-1-050-101, 102-1, ADS LSF

3/10/94 — Unit 1 Startup

3/11/94 — ADS valve exercise test ST-6-050-760-1 performed at 500 psig reactor pressure. All valves operated satisfactorily.

3/12/94 — Unit 1 S SRV has high tailpipe temperature.

3/14/94 — System Manager investigated the Unit 1 SRV tailpipe temperatures. It appeared that the Unit 1, S SRV tailpipe temp did not return to its original temperature prior to stroking under ST-6-050-760-1. In addition it was noted. Tailpipe temps were as follows:

S = 220°F
M = 220°F
F = 170-180°F

3/94 — LGS discussed leaking SRVs with the GE Site Services Representative. Various options were reviewed including living with the leakage and/or lifting the SRVs in an effort to reseat them. The options were reviewed with Engineering Director.

3/94 — The leaking SRV issue was reviewed at a Director's meeting. Senior Management determined that leakage did not warrant immediate corrective maintenance.

7/94 — The Unit 1 L SRV started showing signs of leakage. Tailpipe temperatures were around 170°F.

7/25/94 — Unit 1 M SRV tailpipe temperature had increased to 265°F. A/R A0865809 was generated to raise SRV tailpipe alarm setpoint from 260°F (normal Unit 2 setpoint) to 280°F. The A/R was processed and dispositioned through a normal work coordination process.

10/7/94	Unit 1 load drop to 5% for offgas after condenser cleaning resulting in a thermal cycle on the SRVs.
1/95 - 2/95	Unit 2 refueling 2R03
2/21/95	Dual unit scram resulting in a thermal cycle on the SRVs.
3/3/95	Unit 1 SRV temperatures were: F - 220°F L - 217°F M - 273°F S - 277°F All others at 120 - 150°F
4/17/95	A benefit to cost (B/C) evaluation was performed to provide a basis for S and M SRV replacements. The B/C was about 2 in favor of replacing and was based on economic factors only. The primary benefit was the avoidance of multiple operator actions going into suppression pool cooling during the summer months.
4/17/95	Sponsorship is given to gather a multi-discipline team together to evaluate possible M and S SRV replacement.
4/19/95	System Manager and Branch Head held a meeting with Maintenance Foremen, Operations Supervision, Maintenance Technical Staff, GE Outage Planning, Maintenance Planning, Component Engineering and Outage Management to discuss SRV replacement. Many concerns surfaced regarding ECCS blocking, heat stress, flange fit up and repair and Maintenance manpower. The meeting concluded that valve replacement was physically possible but had significant risks.
4/19/95	The Branch Head reviewed the results of the above meeting with the Maintenance Director and Craft Manager, the Engineering Director, and the Plant Manager.From the discussion with these individuals the additional concern was raised. SRV replacement was viewed as a significant activity which could be problematic without more time to prepare. The Branch Head recommended against SRV replacement during the "work week 9519" outage. Recommendation was supported by VP and Directors.
4/21/95	A0930284 was generated for S leakage. A0930287 was generated for F leakage.

5/9 - 5/12 Unit 1 "work week 9519" outage was conducted resulting in a thermal cycle on SRVs. The leaking SRVs were not replaced.

5/24/95 Unit 1 SRV Tailpipe Temperatures

F - 240°F
L - 235°F
M - 280°F
S - 280°F

6/5/95 A/R A0939210 was generated to raise SRV tailpipe alarm setpoints from 280°F to 290°F.

7/26/95 Unit 1 SRV tailpipe temperatures were:

F - 245°F
L - 230°F
M - 280°F
S - 285°F

8/95 An outage was planned to replace a failed fuel bundle on Unit 1 (1E06). Any other potential outage scope was reviewed by System Managers. The System Manager recommended that the Unit 1 M and S SRVs be replaced during 1E06.

The Branch Head and Engineering Director discuss replacing SRVs. Much of the original benefit (avoiding multiple suppression pool cooling operations during the summer) going into 1E06 had been reduced, the risks were the same, and the M and S SRV leak rates had been relatively constant. Accordingly, no further effort was expended to obtain sponsorship for SRV replacement.

8/20/95 Unit 1 outage 1E06 was started resulting in a thermal cycle on SRVs.

8/29/95 On Unit 1 startup from 1E06 the head vent flange leaked which required a return to cold shutdown to repair. This resulted in a thermal cycle on SRVs.

8/31/95 Outage 1E06 hydrostatic test was performed. The RCS pressure could not be placed at the required hydrostatic pressure due to leaking SRVs. The plant operations review committee (PORC) reviewed and dispositioned the failed test. The LGS PORC disposition was reviewed PECO senior management.

9/1/95 Unit 1 commenced a startup following head vent flange repair resulting in a thermal cycle on SRVs.

9/1/95	Unit 1 M and S SRV Tailpipe temperatures were approximately 295°F. This is approximately 15°F higher than before 1E06 was commenced. A/R A095567 generated to raise alarm setpoint to 300°F.
9/2/95	Unit 1 conducted a down power maneuver due to INOP Post-LOCA recombiners. Slight thermal cycle on SRVs.
9/8/95	Unit 1 SRV tailpipe temperatures were: D - 215°F F - 247°F L - 230°F M - 285°F S - 285°F The D SRV started leaking after 1E06 activities. Unit 1 M and S SRVs returned to their pre- 1E06 tailpipe temperatures.
9/11/95	The Unit 1 M SRV lifted spuriously and a reactor pressure blowdown resulted.
9/12/95	The Unit 1 M SRV was removed and shipped to Wyle Laboratory for failure analysis. Unit 1 S MSRV was shipped shortly thereafter.
9/12/95	The Unit 1 M, S, L, F, D SRVs were replaced (pilots and main bodies).
9/15/95	Failure analysis from Wyle Laboratory indicated that all leakage on M SRV was due to pilot seat leakage. This leakage eventually led to the catastrophic failure of the pilot stage assembly which caused the main disk to lift.
9/15/95	Failure analysis of the S SRV indicated that all leakage from this valve was from the main seat.
9/15/95	The F, L, and D SRVs were visually inspected at LGS. The leakage appeared to be from main disk.
9/16/95	LGS Engineering provided operational guidance for Unit 2 operation with leaking SRVs. Tailpipe temperatures on Unit 2 were: E - 210°F H - 200°F

2.10 Independent Barrier/Weakness Assessment

The inspectors performed an independent barrier/weakness analysis of the September 11, 1995 event. The inspectors determined that there were barriers/weaknesses related to the SRVs that contributed to this event. The barriers/weaknesses are listed below:

a. The unique orientation of the Limerick SRVs.

b. The practice of raising the SRV leakage alarm setpoint through its calibration range without a full understanding of the leakage mechanism, or valid, verifiable engineering basis. The failure to establish a operability based, verified acceptance criteria for SRV leakage rate. The resolution of this issue is considered question 2 of URI 352,353/95-81-01.

c. The failure to correct the Unit 1 leaking SRVs either immediately after the April 1994 startup or in two subsequent maintenance outages. The resolution of this issue is considered question 3 URI 352,353/95-81-01.

2.11 Conclusions

The inspectors concluded that the licensee's post event corrective actions and monitoring activities were excellent, in that they were aggressive, routinely incorporated quality considerations into the line decision making practices, based on sound engineering principles and focused on safety. The inspectors concluded that because the present temperatures are at less than the alarm setpoint, that is representative of a 1000#/hr leak flow, there is reasonable assurance that a main disc won't lift, which proved an acceptable basis for continued operation of LGS U-2, and startup of Unit 1.

The inspectors identified a number of questions which were outside the charter of this inspection and are identified as URI 352,353/95-81-01. The inspectors requested at the exit for this inspection, that the licensee docket its SRV operability justification and its SRV monitoring process. No issues that would prevent the restart of Unit 1 or the continued operations of Unit 2 were identified.

3.0 RESIDUAL HEAT REMOVAL (RHR) PUMP SUCTION STRAINER/SUPPRESSION POOL

3.1 RHR Suction strainer/Suppression Pool Description

The RHR system provides five basic functions: 1) shutdown cooling, 2) low pressure coolant injection (LPCI) for the emergency core cooling system (ECCS), 3) suppression pool cooling, 4) containment spray, and 5) infrequent special operations such as assisting with fuel pool cooling. The RHR system is comprised of four independent loops. During suppression pool (SP) cooling and LPCI modes of operation, each RHR pump draws suction from the suppression pool through its associated suction strainers. Each RHR pump suppression pool suction consists of a horizontally mounted, T-shaped pipe connection. The RHR pump suction strainers are located at the foot of the T, with one suction strainer mounted at each end of the T. Loops A and B have heat exchangers that are cooled by RHR service water and can be used for SP cooling. Loops C and D have crossover connections that would allow them to be used as a backup for SP cooling. Until recently, the station practice was to use the A loop for suppression pool cooling. The reason for this is that the A loop was the only RHR loop with the capability to letdown water directly to the radwaste system. The station changed this practice approximately two to three months prior to this inspection, in order to allow operation of the B loop for SP cooling. When using the B loop for suppression pool cooling, level reduction of the SP is accomplished through a separate SP cleanup system.

The SP acts as a heat sink for the main steam system SRVs and as a water volume for the ECCS. The suppression pool serves as the primary source of cooling water to the low pressure ECCS (RHR in LPCI mode and core spray systems). It also serves as the alternate source of water for the high pressure coolant injection (HPCI) and the reactor core isolation cooling (RCIC) system. The high pressure systems draw suction preferentially from the condensate storage tank (CST). Each ECCS loop has the ability to take a suction from the suppression pool through a suction line fitted with a suction strainer similar to that described above. The configuration for the high pressure strainers is slightly different in that the suction is mounted in a vertical T, and the strainers are slightly different in size.

The inspectors determined that each suppression pool suction strainer for the ECCS is a truncated cone type. The construction of the suction strainers for this plant is somewhat different than is typical for most domestic BWRs. Each ECCS suction strainer is made of 3/8 inch thick perforated 304L stainless steel plate. The strainers are perforated with 5/8 inch diameter holes on 7/8 inch centers. In addition, each strainer is covered by a 12 x 12 316L stainless steel mesh. The wire diameter on the mesh is .023 inches. The total surface area of each RHR suction strainer is 13.7 ft^2 with 23% free area. The total of each core spray (CS) strainer is 6.6 ft^2 with 25% free area. The CS systems have the lowest NPSH margin of the low pressure ECCS. However, the RHR strainers have higher flow velocities through the strainer. Therefore, it is not clear as to which strainers are the limiting component in the SP with respect to post accident strainer clogging.

As a heat sink for the SRVs, the suppression pool services 9 SRVs that function to protect the RCS from overpressure and 5 SRVs that have a dual function. Each of the SRVs discharge into a tailpipe which in turn discharges into a quencher within the suppression pool.

There is physical separation between the locations of the quencher for the M SRV (the SRV that stuck open during the event) and the RHR 1A strainer which clogged during the event. While both components are located in the same quadrant of the pool, they are separated by a minimum distance of approximately 12 feet horizontally and 6.5 feet vertically. There is a steel column located approximately midway between the closest points of the strainer and the quencher. The centerline of the RHR strainers are located a maximum of 23 inches from the suppression pool wall.

The suppression pool is a cylindrical in shape, 88 feet in inside diameter and 52 feet 6 inches high. The water volume ranges from a minimum vclume 122,120 ft^3 to a maximum volume of 134,600 ft^3. There are 87 downcomers connecting the drywell and the suppression pool. Each downcomer is 24 inches in outside diameter. In addition, there are 14 quenchers in the pool which allow the pool to act as a heat sink for the SRVs when they open.

3.2 Operating Experience

Neither unit has previously experienced any problems related to clogging of ECCS strainers. The station previously monitored ECCS pump suction pressure during quarterly pump, valve and flow testing. Trending of this data led the licensee to conclude in March of 1994 that strainer clogging was not occurring in either unit. They discontinued ECCS strainer suction monitoring based on inservice testing relief received from the NRC. However, based on the ongoing efforts to resolve the generic BWR ECCS strainer clogging issue, highlighted in NRC Bulletin 93-02 and its supplement, the licensee decided to clean the suppression pool and ECCS suction strainers of both units during the next available refueling outage for each unit. Unit 2 was cleaned during 2R03 in February, 1994. Unit 1 was scheduled for cleaning during its upcoming refueling outage, 1R06, currently scheduled for February, 1996.

3.3 Licensee Corrective Actions/Root Cause Analysis

In response to the September 11, 1995 event, the licensee first began a process of investigation to determine the root cause of the event. Samples were taken of the material on the RHR strainer surface, on the floor of the SP (sludge), and in suspension in the water. The licensee also used portable filtering systems to clarify the pool water so that videotape could be used to record the as found and as left conditions of the SP and ECCS strainers. The material samples were analyzed with the following results:

1. The material on the 1A RHR strainer was analyzed by General Electric and determined to be a fibrous polypropylene material. The licensee was unable to determine the specific source of the material, but was able to determine that the material was not fiberglass such as would be found in piping insulation or ventilation filters. The licensee was able to determine that the fibrous material did not originate from material or components designed to be within the SP. In addition, the material on the strainer surface included a significant amount of sludge which appeared to have been filtered out of the suppression pool water by the fibrous material entrained on the strainer surface. The material found on the 1B strainer appeared to have been of a similar nature as that found on the 1A.

2. The sludge material found on the floor of the pool was a combination of corrosion products (80%), organics (12%), and dirt (8%). The suspended material was similar to that on the floor of the pool, and consisted of 80% corrosion products, 3% organics, and 17% dirt. The licensee determined that the corrosion products consisted primarily of iron oxides (90%) and a smaller percentage of zinc (10%). These materials are considered by the licensee to be consistent with the materials and

coatings that are located in the SP. The licensee stated that the organics were primarily made up of wood and plastics. These materials were clearly foreign materials originating from outside the suppression pool.

The inspectors observed suppression pool cleaning operations and reviewed the licensee's videotapes of the strainers and suppression pool. The videotapes revealed that the majority of the debris found on the strainer surfaces were found on the 1A and 1B strainers. The other ECCS strainers were essentially clean with a light coating of corrosion products on the surface of the strainer. In addition, close up footage of the 1A strainer indicated that there were small pieces of debris entrained on the strainer surface that appeared to be small pieces of wood. A review of the videotape of the suppression pool floor showed a general covering of the floor with sludge and other foreign materials, such as nails, wood, hose, and tape. The licensee concluded that the root cause of the materials being left in the suppression pool was a failure to implement an effective foreign material exclusion program in the suppression pool.

The licensee took the following corrective actions:

1. The licensee inspected and cleaned all Unit 1 ECCS suction strainers. Unit 2 ECCS strainers were cleaned during 2R03.

2. The licensee inspected and cleaned the entire Unit 1 suppression pool. The Unit 2 SP was cleaned during 2R03.

3. Following the completion of cleaning and inspection activities in Unit 1, the licensee conducted an endurance test using three low pressure ECCS pumps to demonstrate the effectiveness of their suppression pool cleaning efforts. The pumps were run in parallel for 6 hours. During the test, the licensee monitored pump suction pressure on 15 minute intervals. Test results demonstrated that pump suction pressure did not degrade significantly (no change on the 1A strainer and a maximum of 0.2 psi on the 1D) over the period of time during which the test was conducted. Following the test, the licensee sent divers into the pool to inspect and videotape the strainers to demonstrate that no unacceptable debris buildup occurred during the test. However, upon review of the videotape of the strainers, the licensee's engineering staff determined that there was unacceptable buildup of material on the 1A strainer and some minor buildup on the 1D strainer. The licensee cleaned the strainers again and reran the test. The second test suction pressure trends were the same as for the first test; however, videotape of the strainers taken post-test determined that there was again a buildup of debris on the 1D strainer which the licensee considered unacceptable. The test was run a third time. The test results for the third test were determined by the licensee to be acceptable. The inspectors observed/reviewed portions of the testing and reviewed portions of the videotape of the post-test inspection. The licensee established a set of criteria for the cleanliness of the SP and operability of the ECCS strainers. The inspectors reviewed the criteria and determined that it was conservative.

4. The licensee performed an evaluation to determine if any degradation of ECCS equipment and heat exchangers occurred as a result of the event, or as a result of debris passing through the strainer. To assist making this determination, the licensee took samples from low points in the A RHR piping for the RHR suction and the RHR heat exchanger discharge piping. A sample was also taken from one CS suction. The samples were analyzed by the licensee to see if there were any fibrous materials in the water. No fibrous materials were found in the samples. The licensee concluded that corrosion products in the water do not represent a potential threat to the ECCS pumps since this material has been present in the pool for a long period of time and has not previously impacted ECCS pump or heat exchanger performance. This conclusion was based on a review of pump and heat exchanger performance data.

5. The licensee prepared an engineering evaluation of the operability of the ECCS and SP prior to the September 11, 1995 event. The evaluation determined that the ECCS system, although degraded could have performed its intended purpose. The inspectors reviewed this engineering evaluation and concluded that the SP and ECCS systems were impacted, that the RHR system was degraded and that there was reasonable assurance that sufficient flow could have been supplied to the core following a design basis accident. Resolution of the TS operability of the ECCS systems is question 4 of URI 95-28-01.

3.4 NRC Bulletin 93-02, Debris Plugging of Emergency Core Cooling Suction Strainers

As part of this inspection, the inspectors reviewed the licensee's responses to NRC Bulletin 93-02 (NRCB 93-02), "Debris Plugging of Emergency Core Cooling Suction Strainers," and NRCB 93-02 Supplement 1,"Debris Plugging of Emergency Core Cooling Suction Strainers." The inspectors also reviewed the Independent Safety Engineering Group's (ISEG's) assessment of the licensee's actions in response to the bulletin and its supplement. The inspectors concluded that the licensee's responses to the bulletin and its supplement were adequate. The inspectors also evaluated the training materials used for informing operators and other appropriate plant personnel about the issues related to the potential clogging of ECCS strainers including indications of strainer clogging, and determined that they were adequate.

The licensee did not commit to cleaning their suppression pools in either of their responses to NRCB 93-02 or its supplement; however, the licensee independently decided to clean their SPs and ECCS suction strainers, based on ongoing industry and NRC work on this issue.

3.5 Generic Implications

There are two generic aspects to the strainer clogging issue. The first aspect deals with the root cause of this event. The root cause of this event appears to stem from a failure at sometime to prevent foreign material from being introduced into the suppression pool. It is not clear whether or not this material may have been in the pool since construction because the suppression pool and the ECCS strainers have not previously been inspected.

The second aspect is the existence of a large amount of corrosion products in the pool. The inspectors has concluded that the materials found in both the suppression pools at Limerick station appear to be consistent with those found in other plants who have recently cleaned or inspected their pools.

3.6 Independent Barrier/Weakness Assessment

The inspectors performed an independent barrier/weakness analysis of the September 11, 1995 event with respect to the functionality of the ECCS system and the cleanliness of the SP. The inspectors determined that there were barriers/weaknesses related to the SP and ECCS functionality that contributed to this event. The barriers/weaknesses are listed below.

a. The routine and extended operation of suppression pool cooling as a result of SRV leakage into the pool.

b. The apparently unique strainer design and hole size.

c. The lifting of the M SRV.

d. The apparent failure to perform an aggressive Unit 1 SP and ECCS operability analysis, based on the Unit 2 SP cleanliness data. Resolution of this issue is considered question 5 of URI 352,353/95-81-01.

e. The failure to perform monitoring or cleaning of the Unit 1 suppression pool during two Unit 1 maintenance outages that followed the Unit 2 cleaning. Resolution of this issue is considered question 6 of URI 352,352/95-81-01.

f. The failure to control the entrance of foreign material into the suppression pool. Resolution of this issue is considered question 7 of URI 352,352/95-81-01.

3.7 Conclusions

The inspectors concluded that the licensee's corrective actions and monitoring activities with respect to the SP cleanliness/ECCS operability, following the event were excellent. LGS management employed multitasked resolution schemes built on leading edge industry knowledge and techniques. The corrective actions were aggressive, routinely incorporated quality considerations into the line decision making practices, based on sound engineering principles and focused on safety. Based on the licensee's engineering evaluation, the SP and ECCS systems were impacted, and the RHR system was degraded, but there was reasonable assurance that sufficient flow could have been supplied to the core following a design basis accident. The inspectors identified a number of questions which were outside the charter of this inspection and are identified as parts of URI 352,353/95-81-01.
The inspectors requested at the exit for this inspection, that the licensee docket its ECCS suction strainer operability justification and it suppression pool monitoring process. No issues that would prevent the restart of Unit 1 or the continued operations of Unit 2, were identified.

4.0 SAFETY ASSESSMENT/QUALITY VERIFICATION

4.1 Problem Identification, Event Corrective actions, and Root Cause Analysis

The inspectors inspected the Limerick Performance Enhancement Program, the Limerick Nonconformance process, and the PECO engineering request process with respect to the licensee's response to the transient that occurred on September 11, 1995. In each of the aspects examined by the inspectors, the licensee adequately identified the aspect, established a time table for resolution of the aspect, and tracked the aspect in a site tracking system.

4.2 Quality Assessment Organization involvement in the Event Response Activities

The inspectors observed the activities of the site Quality Assessment (QA) Organization associated with the September 11, 1995, event at several different management working levels in the plant. The management levels included site outage director meetings, department working groups, supervisor working groups, and scene work crews. The inspectors observed, reviewed and/or discussed a full range of safety issues, quality issues and QA involvement in site activities associated with the root cause evaluation and corrective actions for the September 11, 1995 event. The Inspectors determined that the QA organization concentrated its efforts at the working group, project group and work scene levels, and that QA efforts were adequate.

The licensee recently implemented its "Quality to the Line" process outlined in FSAR Chapter 17. The Inspectors observed LGS line management routinely and aggressively pursuing the inclusion of quality into all phases of the post event resolution activities.

4.2.2 Site Independent Safety Engineering Group (ISEG)

The inspectors observed the activities of the site ISEG associated with the September 11, 1995. The ISEG performed an independent historical evaluation of the event following the completion of many of the licensee activities. The Inspectors observed, reviewed and/or discussed with the licensee, a full range of safety issues, quality issues and ISEG involvement in activities associated with the root cause evaluation and corrective actions for the September 11, 1995 event.

The ISEG's involvement and responsibilities during the September 11, 1995, event were reviewed, and the Inspectors determined that within fifteen minutes following the event, an ISEG staff member was in the control room evaluating operations and operator response to the event. The ISEG subsequently assigned a staff member, who was in training and would not return until the following week, to follow the event. On September 12 through September 14, other ISEG staff members followed the event by attending morning meetings, outage directors meetings, and observing forced outage activities. They also discussed issues regarding the event with component engineers, regulatory engineers, and system managers. ISEG assigned event issues relating exclusively to the SRVs to another ISEG staff member. From September 18 through September 20, ISEG staff members attended morning meetings, SRV meetings, suction strainer/suppression pool cleaning meetings, overview PORC meetings, and special PORC meetings. Due to the substantial scope of the issues in the September 11 event, ISEG further divided followup of the event into three separate categories, SRV issues, suction strainer/suppression pool issues, and overall operations response to the event.

The ISEG augmented their group with two additional ISEG staff members to assist during the increased work load following the event. Although they recognized the need for additional ISEG staff involvement and supplemented their group, previous ISEG review assignments and training commitments impacted on ISEG's ability to be fully involved in the initial activities involving the SRV and SP.

On September 1, 1995, PECO began implementation of an amendment to FSAR section 13.4.5 and section 6.0, Administrative Controls, of their TS. This amendment involved changes to the Limerick independent engineering review organization. Prior to the amendment, the independent engineering review organization was described in FSAR section 13.4.5, entitled the Independent Safety Engineering Group (ISEG). Although the group is still referred to as ISEG, the amendment changed the title of section 13.4.5 to the Independent Technical Review Program.

Prior to the TS change the ISEG was composed of five, dedicated, full time engineers. The amendment allowed the independent technical review function to be performed by a minimum of three individuals. These individuals were required to have at least eight years of relevant experience but are no longer required to have an engineering or related degree.

Prior to the TS change the ISEG reported directly to the Director, Nuclear Quality Assurance. Following the TS change the three full time engineers report to the LGS Site Quality Division Manager.

Prior to the TS change the ISEG issued its reports directly to the Director, Nuclear Quality Assurance. At some intermediate time the ISEG started a practice of issuing draft reports to the line for its comments prior the issuance of a final product. Following the TS change the practice of issuing draft reports to the line was continued. Final ISEG reports are now issued to the Site QA manager who approves and distributes the report. The inspectors determined that the issuance of draft reports to the line prior the issuance of a final reports held the potential for a loss of independence.

Two years prior to the September 11, 1995, event, the ISEG reviewed LGS activities concerning suppression pool housekeeping, monitoring of suction strainer performance, inspections of suction strainers, and suppression pool water quality control activities. ISEG reported results of their review in ISEG-93-065, issued on June 11, 1993. In their report, ISEG stated that they believed that monitoring pump suction pressure, as an indicator of ECCS strainer performance, had limited benefit alone. ISEG recommended that an evaluation be conducted to determine whether a periodic inspection of ECCS suction strainers should be performed to more accurately determine ECCS suction strainer performance. The inspectors determined that this report was reviewed by PORC and was used by LGS as a partial basis for cleaning Unit 2 SP and scheduling Unit 1 SP for cleaning. The inspectors determined that ISEG activities, with respect to SP cleaning, were aggressive and LGS line management responded adequately.

The inspectors concluded that ISEG members were knowledgeable of the technical issues related to the event, technically aggressive in their review activities, and demonstrated a high level of individually expressed professional independence.

4.3 Line Management Involvement in the Event Resolution

The Inspectors assessed the effectiveness of Limerick line management to prioritize, plan, schedule, and safely control activities in response to the September 11, 1995 event. Inherent in these activities was root cause identification and corrective action implementation in response to the event. The inspectors determined that the processes and practices used by Limerick line management to schedule, prioritize, evaluate, coordinate, implement, self check, test, and accept plant activities associated with this event were logical, carefully contemplated, based on sound principles of industrial and nuclear safety, and effectively managed.

Site management effectively augmented the operating staff to respond to the September 11, 1995 event. The augmenting personnel included industry representatives, owner's group representatives, and additional PECO personnel. Site management effort, talent, and attention were redistributed in response to the changing developments in the field. The inspectors noted that the site management was flexible, open to the free exchange of views with respect to problem resolution, and established multiple, parallel resolution paths for each objective.

The Inspectors noted that line management took an active role in the resolution of safety issues including rescheduling, amending and/or enhancing plant activities to account for safety considerations. The Inspectors determined for the activities associated with the September 11, 1995 event that management effectively demonstrated the principles described in the "Limerick quality to the line process."

4.4 Conclusion

The Inspectors concluded that line management oversite was highly effective, incorporated QA into all observed aspects of plant operations and maintained a strong focus on industrial and nuclear safety. Management aggressively pursued corrective actions and root causes associated with the operability of Unit 1 and 2. QA participation in the post event activities was determined to be adequate with a potential weakness identified in the independence and access of the ISEG process.

5.0 Exit Meeting

The inspectors discussed the issues in this report with PECO Energy representatives throughout the inspection period, and summarized the findings at an exit meeting with the Site Vice President Mr. McFarlin, the Plant Manager, Mr. R. Boyce, and other members of their staff on July 21, 1995. PECO Energy personnel expressed disagreement with the inspection findings concerning the staffing, independence and organizational reporting of the ISEG. In addition, the licensee committed to provide the NRC a written description of; (1) SRV operability criteria and monitoring; and (2) ECCS/SP operability and monitoring prior to October 6, 1995. No written inspection material was provided to licensee representatives during the inspection period.