U.S. NUCLEAR REGULATORY COMMISSION

REGION I

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| Report No. | 89-18<br>89-26 |
| Docket No. | 50-352<br>50-353 |
| License No. | NPF-39<br>NPF-85 |
| Licensee: | Philadelphia Electric Company<br>Correspondence Control Desk<br>P.O. Box 7520<br>Philadelphia, Pa 19101 |
| Facility Name: | Limerick Generating Station, Unit 1 and 2 |
| Inspection Period: | July 31, 1989 - September 11, 1989 |
| Inspectors: | T. J. Kenny, Senior Resident Inspector<br>L. L. Scholl, Resident Inspector<br>R. L. Fuhrmeister, Resident Inspector<br>M. G. Evans, Resident Inspector<br>J. E. Beall, Senior Resident Inspector, Beaver Valley |

Approved by: Lawrence T. Doerflein 10/23/89
Lawrence T. Doerflein, Chief, Date
Reactor Projects Section 2B

Summary: Routine daytime (319 hours) and backshift/holiday (101 hours) inspections by the resident inspectors consisting of (a) plant tours, (b) observations of maintenance and surveillance testing, (c) review of LERs and periodic reports, (d) review of operational events, (e) system walkdowns, and (f) power ascension activities on Unit 2.

During this inspection period:
Results:

Unit 1. There were very few events on Unit 1 this report period. The event involving three workers being overcome by heat stress and requiring offsite medical attention was due to a failure to follow an administrative procedure. (section 2.1.1).

<u>Unit 2</u>. There were site visits by a Commissioner, the Director of NRR and the Region I Administrator in preparation for a full power license (section 2.2.1) which was issued on August 25, 1989. The startup test program is progressing smoothly and ahead of schedule. (section 6.0).

# DETAILS

## 1.0 Persons Contacted

Within this report period, interviews and discussions were conducted with members of licensee management and staff as necessary to support inspection activity.

## 2.0 Operational Safety Verification

The inspectors conducted routine entries into the protected areas of the plant, including the control room, reactor enclosure, fuel floor, and drywell (when access is possible). During the inspection, discussions were held with operators, technicians (HP & I&C), mechanics, security personnel, supervisors and plant management. The inspections were conducted in accordance with NRC Inspection Procedure 71707 and affirmed the licensee's commitments and compliance with 10 CFR, Technical Specifications, License Conditions and Administrative Procedures.

### 2.1 Unit 1 (71707, 93702)

#### 2.1.1 Inspector Comment and Findings

This report begins with Unit 1 at 100% reactor power. On August 1, 1989 channel "D" radiation monitor caused a trip of refueling floor ventilation. The event occurred when an I&C technician incorrectly tested "D" Refuel Area Ventilation Exhaust Duct Radiation Monitoring instead of "D" Reactor Enclosure Ventilation Exhaust Duct Radiation Monitor during the performance of a surveillance test. The technician was counseled regarding proper work practices and attention to detail. The technician acted responsibly after the discovery of the mistake and restored the system to normal. The action taken by the licensee was appropriate.

On August 29, 1989, three of six workers were overcome with heat exhaustion while flushing and cleaning control rod drives that had been removed during the last refueling outage. The workers were working in an area designed for the decontamination work. After exiting the work area the workers experienced sickness and were sent to Pottstown Memorial Medical Center where they were treated and released. The workers were not contaminated. In accordance with procedure A-66, "Heat Stress Management," a stay time had been computed for the room, which was at 92° Fahrenheit (F) ambient temperature. The calculation considered two sets of protective clothing, with an outer plastic covering and filter respirators. The resultant stay time was recorded on the A-66 form (Attachment 2 to the procedure used to determine stay times in hot areas) as twenty-five minutes. The pre-planning for the job recognized the potential for heat stress and the planning was appropriate; however, the workers did not obey the twenty-five minute stay time and were in the room for a period of one hour. An investigation by the licensee showed that the A-66 form was also used on preceding days and was also not followed for stay times. This specific procedure is not required by Technical Specifications and, therefore, not cited as a violation. However, this is the third such incident involving heat exhaustion over the last two years and it appears this area requires increased management attention.

In addition to the workers failure to adhere to the stay times on the A-66 form, supervision was remiss in not monitoring the job properly nor providing proper cooling for the individuals on the job. The air conditioning to the area was out of service and no real attempt to return it to service was made. Fans were not provided for the workers which may have provided a cooling medium. The inspector also questioned the supervisory oversite of this job and discussed, with plant management, the need for tighter controls while working in heat stress areas. The inspector noted that licensee counseled the individuals involved on the need to follow procedures.

The licensee is also performing a Human Performance Evaluation System (HPES) review in order to better understand the reasons behind the incident. The inspector will review the results when available. The licensee is also monitoring all work in heat stress locations with the Industrial Safety Group.

The Unit was at 100% power at the end of this report period.

## 2.2 Unit 2 (71707, 93702)

### 2.2.1 Inspector Comments and Findings

This report begins with the fuel loaded and preparations being made to achieve initial criticality.

On August 10, 1989, Dr. Thomas Murley, Director, Office of Nuclear Reactor Regulation and Mr. William Russell, Region I Administrator toured the site in preparation for the Commission full power briefing on August 17, 1989.

On August 12, 1989 the reactor was made critical at step 77 of the withdrawal sequence. Criticality had been predicted at step 75. This difference in steps was within acceptable tolerances in accordance with startup procedures.

On August 14, 1989 Commissioner Curtiss toured the site. Accompanying the Commissioner was Mr. David Stone of Limerick Ecology Action.

On August 17, 1989 while raising pressure from the 800 psig plateau to the 900 psi plateau it was noted that one of the Average Power Range Monitor (APRM) channels was indicating slightly above the level corresponding to 5% power level. The reactor operator and the shift supervisor were observing indications at the reactor console during the evolution, while the Shift Technical Assistant (STA) was observing indications on the Cathode Ray Tube (CRT) display from the plant computer. In order to raise reactor pressure, the Electrohydraulic Control system (EHC) pressure setpoint was raised, causing the turbine bypass valves to close and allowing reactor pressure to increase slowly. As the bypass valves closed, their position reached the minimum setting allowed by the bypass valve jack. The operator then lowered the setting of the bypass valve jack per procedure to permit pressure to increase further. Approximately one minute later, the STA noted that the digital readouts on the CRT screen showed approximately a 20 psi pressure increase, and approximately 1/2% power increase. When he alerted the shift supervisor, the bypass valve jack setpoint was immediately returned to its initial setting. Pressure and power were stabilized at their original values and the pressure increase was terminated while the transient was evaluated.

Data from the process computer showed that 2 of the 6 APRM channels went slightly above the level corresponding to 5%. Channel "B" indicated a level equal to 5.41%, while channel "E" indicated a level equal to 5.37%. All other APRM channels indicated below the levels corresponding to 5%. When the readings of all APRM channels were averaged, it was determined that total core power had reached 4.67%. The average of all channels is more representative of total core power due to the individual channels showing the effects of local power peaking resulting from rod pattern changes as the reactor is heated up and pressurized. After review of the event by the onsite safety review committee, pressure was raised to the 900 psi plateau for commencement of Reactor Core Isolation Cooling (RCIC) system testing. On August 23, 1989, power ascension testing for test condition heatup (0-5% power) was completed.

On August 25, 1989 the Commission issued a full power license to Limerick Unit 2. Reactor power was raised to 6% on August 26. Test condition 1 (5-20% power) was entered at 3:30 a.m. on August 27, 1989 and at 8:32 p.m. the mode switch was placed in the run mode.

This report period ended with the licensee conducting testing in test condition 2 with the reactor at approximately 30% power.

2.2.2 Reactor Enclosure Area Radiation Monitor Annunciator

During a tour of the control room, the inspector noted that the common annunciator for the reactor enclosure area radiation monitors was alarming. The alarm was due to recent transversing incore probe (TIP) operation and is expected to stay in for approximately one day until the gamma radiation levels (due to TIP activation) decay to a level which is below the instrument setpoint. The inspector was concerend that when the TIP radiation levels cause the annunciator to alarm all other reactor enclosure area radiation monitor alarms (19 channels) are masked. The licensee is evaluating and considering ways to isolate the TIP room area monitor from the common annunciator. This item will be addressed in more detail in inspection report 50-353/89-27.

The inspectors concluded that the licensee responded properly in all of the events identified above and had no further questions at this time.

## 3.0 Update/Closeout of Open Items

### 3.1 Unit 1

3.1.1 (Closed) Unresolved Item (50-352/87-31-03) Potential Loss of Isolation Capability Due to Breaker Trip on Instantaneous Reversal of Motor Operated Valves. A concern existed that, if a motor operated containment isolation valve received a close signal while it was being opened, its supply circuit breaker may trip on overcurrent thus rendering the valve inoperable. If this condition occurred simultaneously on two valves the containment isolation capability would be lost for that penetration. Based on the fact that only one valve is normally operated at a time, the tripping of the circuit breakers for both the inboard and outboard isolation valves is unlikely. Additionally, the licensee has revised procedure A-7, "Conduct of Operations," to include a precaution to operate only one penetration isolation valve at a time which further minimizes the potential for such an event. This item is closed.

3.1.2 (Closed) Unresolved Item (50-352/87-19-03) Weakness in Liberal Use of Temporary Circuit Alterations. The number of temporary circuit alterations (TCAs) has been reduced significantly. There are currently less than 10 TCAs in place per unit and most are on non-safety systems. A procedure for interim plant modifications has also been implemented. This procedure provides a mechanism for updating plant procedures and critical drawings for any long term temporary plant modifications. Thus, the interim modification process eliminates the potential safety concerns associated with the TCA process. This item is closed.

3.2 <u>Unit 2</u>

3.2.1 (Closed) Construction Deficiency Report (50-353/89-00-12) Non-ASME Nupro valves were installed in ASME designated instrumentation lines to facilitate the testing of the excess flow check valves. The licensee subsequently discovered that the O-ring pressure boundary within the valves could fail due to radiation effects during a design basis accident. All of the Nupro valves were replaced in Unit 2 prior to initial criticality. Based on this action this item is closed.

3.2.2 (Closed) TMI Action Plan Item III.D.1.1, Primary Coolant Outside Containment. This item was last updated in inspection report 50-353/89-24. The inspector reviewed the results of six surveillance tests required to be completed prior to exceeding 5% power operation for Unit 2. The results were determined to be satisfactory. This item is closed.

3.2.3 (Closed) TMI Action Plant Item II.F.1, Additional Accident Monitoring Instrumentation. The inspector reviewed the licensee's actions and installation of accident monitoring instrumentation including; noble gas effluent radiological monitor, containment high-range radiation monitor, containment pressure monitor, containment water level monitor, and containment hydrogen concentration monitor. The inspector concluded that procedures are in place to operate the above systems and the installation and operation meets the requirements of Regulatory Guide 1.97. This item is closed.

3.2.4 (Closed) TMI Action Plan Item II.D.3, Direct Indication of Relief and Safety Valve Position. By review of the safety relief valve position indication installation and in place procedures, the inspector confirmed compliance with NUREG 0737 Item II.D.3 and considers this item closed.

3.2.5 (Closed) Inspector Followup Item (50-353/89-201) In a letter to PECo dated August 23, 1989, the NRC documented that the licensee committed to perform:

(1) An evaluation of the effect of grid voltage swing to ensure that spurious separation of the onsite safety-related buses from the grid does not occur for the conditions defined in the inspection report.

(2) An evaluation of the sizing of the thermal overload relay heaters for safe-shutdown applications.

(3) An evaluation of the vital battery end-of-life capacity considering a nondetectable high impedance fault on the AC side of the inverter.

The commitment was to perform (1) and (2) above prior to 5% power and (3) prior to fuel load. The inspector has reviewed documentation including a voltage regulation study and procedure changes and has verified that the above commitments were satisfied.

3.2.6 (Closed) Inspector Followup Item (50-353/89-23-01) Completion of In-Place leakage test for the Reactor Enclosure Recirculation System Train "B". The inspector toured the reactor enclosure system and verified the installation of pre-High Efficiency Particulate Adsorber (HEPA), HEPA, charcoal bed, and charcoal canisters for laboratory tests. All components were installed as required by the Final Safety Analysis Report (FSAR). The inspector reviewed Procedure TTI-13, "HVAC HEPA and Adsorber Filter Efficiency Test," and test results for HEPA in-place leakage (0.0013%) and adsorption filter in-place leakage (0.0286%) for the "B" train. Section 3/4.6.5.4 of the proposed Technical Specification requirements for these in-place leakages is less than 0.05%. The inspector also reviewed the air flow capacity test result and noted it was within the licensee's acceptance criteria (60,000 ± 10% CFM). These test results (in-place leakage and air flow capacity) were approved by the Test Review Board on August 4, 1989. The inspector had no further questions. This item is closed.

3.2.7 (Closed) TMI Action Plan Item II.E.4.2, Containment Isolation Dependability. This item had remained open pending resolution of the concern for a circuit breaker trip during instantaneous reversal of a motor operated valve. Based on the actions described in section 3.1.1 of this report this item is closed.

3.2.8 (Closed) TMI Action Plant Item I.B.1.2, Organization and Management. The inspector reviewed section 6.2, "Organization," of the Limerick Unit 2 Technical Specifications (TS) Appendix A to Operating License NPF-85. The inspector verified that the site and corporate organizations conform to TS figures and shift manning exceeds TS requirements. This item is closed.

4.0 Surveillance/Special Test Observations

During this inspection period, the inspector reviewed in-progress surveillance testing as well as completed surveillance packages. The inspector verified that surveillances were performed in accordance with licensee approved procedures, plant technical specifications, and NRC Regulatory Requirements. The inspector also verified that instruments used were within calibration tolerances and that qualified technicians performed the surveillances.

Unit 1

ST-6-092-311-1, Monthly D-11 Emergency Diesel Generator Test
ST-6-092-314-1, Monthly D-14 Emergency Diesel Generator Test

Unit 2

Numerous Unit 2 surveillance tests were witnessed and reviewed. These test numbers are discussed in Section 6.3.

5.0 Maintenance Observations

The inspector reviewed the following safety related maintenance activities to verify that repairs were made in accordance with approved procedures, and in compliance with NRC regulations and recognized codes and standards. The inspector also verified that the replacement parts and quality control utilized on the repairs were in compliance with the licensee's QA program.

Unit 1

MRF 8906112, HPCI Room Cooler Emergency Service Water Pipe Replacement

9/8/89 Troubleshooting Control Form (TCF), APRM-F Hi-Hi Trip Troubleshooting

MRF's 8907142, 8908293, 8908331, 890332, RCIC Valve Packing Replacements

Unit 2

8906991, Control Rod 50-39 Ball Check Replacement

The inspectors noted the high pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) system maintenance and retests were well coordinated and promptly completed so that the system unavailability times were minimized.

6.0 Power Ascension Test Program (PATP) Unit 2 (35501, 72300, 72301, 72302, 72400, 72509, 72512, 72518, 72526, 72532)

6.1 Overall Power Ascension Test Program

Initial criticality occurred on August 12, 1989. Operating license NPF-85 was issued on August 25, 1989, authorizing full power operation. On August 26, 1989, 5% power was exceeded for the first time. The Open Vessel, Heatup and Test Condition (TC) One plateaus were completed on August 4, August 24 and September 3, respectively. TC 2 (approximately 25-45% power) was entered on September 3, and at the end of this inspection period TC 2 testing was ongoing.

6.2 Power Ascension Test Procedure (PATP) Review

The licensee's PATP startup test procedures (STPs) listed in Attachment A were reviewed for their conformance to the requirements and guidelines of the references listed in Attachment B and for the applicable attributes listed in Inspection Report 50-353/89-03, Section 2.2. All of the procedures were found to satisfy the attributes and to adequately meet the requirements and guidelines of the references.

6.3 Power Ascension Testing Activities

The inspectors witnessed portions of the power ascension testing activities discussed below. The performance of these tests were witnessed to verify the attributes previously identified in Inspection Report No. 50-353/89-24, Section 4.3.

2STP-4.1, Initial Criticality - The inspectors began 24 hour shift coverage of control room activities at 12:00 a.m. on August 11, 1989 in anticipation of initial criticality. Prior to commencement of test activities, the inspector verified that official working copies of the necessary procedures were available in the control area. By independent observations and reviews of records the inspector verified procedural prerequisites such as removal of the reactor protection system (RPS) shorting links, Source Range Monitor (SRM) operability including minimum counts and signal-to-noise ratio, and SRM scram and rod block setpoints. In addition, the inspector independently verified the predicted critical position and reactivity anomaly calculations.

At 4:30 p.m. on August 11, 1989 the Mode Switch was placed in "Startup" and the unit entered Operational Condition 2. At 5:30 p.m. the reactor startup commenced. During rod withdrawal, intermittent rod blocks were introduced by the rod worth minimizer (RWM). Rod withdrawal was stopped for troubleshooting after the 12th rod was fully withdrawn. The cause of the rod blocks was found to be inaccurate rod block indicator signal to the RWM which was read by the RWM self-checking circuitry. A temporary circuit alteration was installed and rod withdrawal restarted.

At 12:25 p.m. on August 12, 1989 the reactor was declared critical on control rod 46-11 at notch position 06. Following initial criticality the inspector verified SRM/IRM overlap when all 8 intermediate range monitors (IRMs) came on scale prior to the SRMs exceeding their rod block setpoints.

No unacceptable conditions were noted during the initial criticality testing sequence.

<u>2STP.5.4, Control Rod Drive (CRD) Scram Testing</u> - On August 16, 1989, the inspector witnessed scram testing of control rods 22-11 and 26-23 at 600 psig reactor pressure. Activities conducted in the control room were monitored and the inspector noted that required communications were maintained during conduct of the testing. The inspector observed scram time determinations being made from the Scram Control Rod Initiation Timing System (SCRITS) and a strip chart recorder. Problems were identified with the data from SCRITS, so troubleshooting was initiated while testing continued using only the strip chart recorder. All scram times were within the acceptance criteria limits.

<u>2STP-22.3, Pressure Regulator Testing</u> - The inspector witnessed portions of the pressure regulator response to bypass valve operation testing performed on August 29, 1989. Pressure regulator step changes of 2 psi and 5 psi were conducted resulting in about 2% and 4% power excursions. The inspector observed that testing was conducted in a well controlled manner. No discrepancies were identified.

2STP-25.1, Main Steam Isolation Valve (MSIV) Testing - The inspector observed the pre-test briefing and performance of portions of 2STP-25.1, "MSIV Functional Test," on August 18, 1989. The test involved stroking the MSIVs full shut, one at a time with reactor power at approximately 1-3%. The inspector noted that the briefing was adequate and that the operators thoroughly reviewed all plant parameters prior to starting the test. In addition, the operators discussed which parameters could be affected by the valve closure. During the test very little power change and little or no changes in other plant parameters were noted.

2STP-26.1, Automatic Depressurization System (ADS) Valve Testing - On August 15, 1989, the inspector witnessed ADS valve testing at approximately 250 psig reactor pressure. The five ADS safety relief valves responded as expected. Prior to testing the inspector listened to the shift briefing and determined it to be well conducted and thorough. In addition the inspector listened to licensee management discussions regarding the possibility of exceeding 5% power on Average Power Range Monitor (APRM) "B" which had a higher flux reading than the other APRMs. The discussion showed that the licensee was anticipating the possible consequences of the testing prior to conduct. During the testing, the inspector noted that a technical monitoring representative was present.

Reactor Core Isolation Cooling (RCIC) Testing - The inspector witnessed several runs of the RCIC system during power ascension testing. On August 14, 1989 the inspector witnessed performance of a RCIC manual quick start, Condensate Storage Tank (CST) to CST at 150 psig reactor pressure. The test was performed per surveillance test ST-6-049-320-2, "RCIC Operability Verification," and RCIC achieved 610 gpm at a pump discharge pressure of 260 psig with a turbine speed of 2200 rpm. On August 18, 1989 the inspector witnessed RCIC system response testing using 10% controller step inputs conducted per 2STP-14.2, "Functional Demonstration and Controller Optimization at rated pressure CST to CST." No discrepancies were noted with the testing discussed above.

On August 18, 1989, the inspector witnessed performance of a RCIC quick start, CST to CST, at rated reactor pressure. The test was conducted per STP-14.2. During the quick start of RCIC, a level 1 acceptance criteria failure occurred when the system did not reach rated flow of 600 gpm in 30 seconds (actual was 78.5 seconds). Review of test data showed that rated flow was not reached in the required time because the operator did not throttle open the RCIC test loop shutoff valve (HV-49-2F022) enough at first. The Shift Superintendent placed the plant in a hold condition as required (due to level 1 failure), considered the other testing in progress, and determined that the ongoing testing could continue.

A Test Exception Report (TER) was processed to document the acceptance criteria failure and allow performance of a retest. The retest was performed a few hours later and the results were satisfactory.

Following conduct of the initial quick start of RCIC, the inspector discussed the apparent cause of the level 1 acceptance criteria failure with the Startup Test Program Supervisor who also witnessed the testing. ST-6-049-230-2, "RCIC Pump, Valve and Flow Test," was being conducted concurrently with STP-14.2, to meet Technical Specification (TS) requirements for RCIC at rated pressure. However, the TS does not have the 30 second requirement for reaching rated flow which the STP has. There appeared to be a miscommunication during the shift briefing regarding the existence of the 30 second requirement. Therefore, the operator was not aware of the requirement. The Startup Test Program Supervisor stated that Startup Training Bulletin No. 12 dated August 26, 1989 was issued to provide additional guidelines for appropriate conduct of test briefings. The inspector reviewed the bulletin and had no further questions.

Feedwater Controller Tuning - On August 27, 1989 the inspector witnessed portions of feedwater controller tuning performed per Hot Functional Test (HFT)-029, "Feedwater System Tuneup." Following the initial ± 2 inch step changes, the feedwater controller required adjustment since the decay ratio was 0.75 as opposed to the required 0.25. Minor adjustments were made to the controller and testing continued. No discrepancies were identified.

Initial Main Turbine Roll Activities - The inspector witnessed the initial main turbine rolls to 100 rpm and to rated speed (1800 RPM), and verified that activities were conducted in a well controlled manner. An extra licensed operator was assigned for the test, whose exclusive duties were the turbine rolls, reducing the number of activities under the control of the licensed reactor operator on shift.

On August 30, 1989 at approximately 11:30 a.m., the licensee initiated the initial roll of the turbine. The test required accelerating the turbine to 100 rpm, shutting off the steam supply and listening during the the coastdown for abnormal noise. None was noted. At approximately 2:45 p.m. the turbine roll to rated speed was initiated. At 3:13 p.m. 1800 rpm was achieved. The APRMs showed a power spike of about 5% at the beginning of the roll. The inspector walked around the turbine and noted rumbling on the 'B' Low Pressure Turbine (between bearings 5 and 6). The inspector reviewed vibration data and noted highest vibration readings at bearings 5 (approximately 8 mils) and 6 (approximately 7 mils). The inspector noted that the observed vibration is within the specifications.

No unacceptable conditions were noted during the turbine rolls.

6.4 Power Ascension Test Results Evaluation

The startup tests listed below were reviewed for the attributes identified in inspection report 50-353/89-24, Section 4.4. Except as noted below, all startup test results were found to meet the attributes referenced above. A summary of each startup test follows.

6.4.1 Test Condition (TC) Open Vessel

2STP-5.3, "Zero Reactor Pressure Scram Testing," results approved August 1, 1989

All acceptance criteria were satisfied. Test Exception Report (TER) 18 documents a missing pulse at position 17 for control rod 22-11. The TER remains open pending Position Indication Probe (PIP) replacement and subsequent retest of rod 22-11.

TER 20 documents discrepancies noted for several control rods as indicated by the Scram Control Rod Initiation Timing System (SCRITS) data. This TER remains open pending further investigation of the SCRITS data.

2STP-5.6, "Rated Reactor Pressure Scram Testing," results approved August 1, 1989.

This test was conducted during the reactor pressure vessel hydrostatic test prior to initial criticality. All acceptance criteria were satisfied. TER 21 was written for control rod 54-39, which could not be withdrawn from position 00 following individual scram time testing of the rod until the rod was rescrammed from its fully inserted position. The CRD was removed and the ball check valve assembly was replaced under Maintenance Request Form (MRF) 8906991. The TER remained open pending retesting of the rod at pressure. The inspector verified that the rod was successfully retested on August 25, 1989.

2STP-13.1, "Static System Test Case," results approved August 2, 1989.

This test had no acceptance criteria. The interface between the Traversing Incore Probe (TIP) System and Nuclear Steam Supply Software on the Plant Monitoring System (PMS) was verified to be operating properly. Various problems were identified with the PMS software. TERs were written and dispositioned as requiring GE San Jose to modify the software.

2STP-17.1, "Measured Pipe Displacements (Selected BOP Systems)," results approved July 27, 1989.

Baseline data for measuring future thermal movements of selected piping systems including portions of main steam, residual heat removal (RHR), core spray, high pressure coolant injection (HPCI) and RCIC was attained at a reactor water temperature of 123°F. This test had no acceptance criteria and no TERs were identified.

2STP-90.1, "Test Phase II- Initial Fuel Loading and Zero Power Testing," results approved August 4, 1989.

This procedure documented all TC Open Vessel testing as completed with the exception of four TERs which remained open at the time of the open vessel plateau review on August 4. TERs 18, 20 and 21 are discussed above. TER 16 was written against 2STP-5.1 when control rod 30-43 failed to indicate position 38 on the four rod display. A MRF was written to correct the problem and the rod will be retested following corrective action.

6.4.2 Test Condition Heat Up

2STP-1.2, "Chemistry Data," results August 24, 1989.

All acceptance criteria were satisfied with the exception of data for reactor water gross activity not being available until 7 days after sample was taken. TER 59 was written to assure sample was analyzed.

2STP-4.1, "In Sequence Critical," results approved August 18, 1989.

All acceptance criteria were met. Initial criticality was achieved on RWM Step 78, rod 46-11, notch 6 (2246 notches withdrawn). The predicted criticality position was 2236 notches and reactor anomaly limits were 1637-2397 notches withdrawn. Criticality occurred within ± 1.0% deltaK/K of predicted. The shutdown margin (SDM) determination was 2.09% deltaK/K. The inspector independently calculated the SDM and verified the 2.09% value. (Technical Specification Requirement is ≥ .38% deltaK/K).

2STP-5.4, "Scram Timing of Selected Rods," results approved August 21 and August 23, 1989.

This test was conducted at 600 and 800 psig reactor pressure. All acceptance criteria were satisfied. The results showed no apparent degradation in control rod performance due to effects of increasing pressure and temperature as evidenced by all rods reaching position 05 well within 3.5 seconds. The inspector reviewed several strip charts and independently verified the scram times.

2STP-5.7, "Rated Reactor Pressure Insert/Withdraw Checks and Scram Testing of Selected Rods," results approved August 24, 1989.

All acceptance criteria were met.

2STP-6.1, "SRM Signal to Noise Ratio and Minimum Count Rate Determination," results approved August 15, 1989.

The inspector independently verified that the calculated value of signal to noise ratio for each SRM was greater than or equal to 2. In addition, each SRM channel had a count rate with the SRM fully inserted of greater than or equal to 3 cps.

2STP-6.2, "Approach to Criticality - SRM Response to Control Rod Withdrawal," results approved August 15, 1989.

This test was performed in conjunction with 2STP-4.1, "In Sequence Critical." All data was taken. Three minor TERs were written and resolved by accepting as is.

2STP-6.3, "SRM Non-Saturation Demonstration," results approved August 15, 1989.

Values of greater than $3 \times 10^5$ cps for all SRMs were achieved.

2STP-9.1, "Reference Leg Temperature Comparison," August 24, 1989.

All test acceptance criteria were satisfied.

2STP-10.1, "SRM/IRM Overlap," results approved August 15, 1989.

IRM channels were verified to be on scale before the SRM rod block setpoints were reached. A one half decade overlap between the SRMs and IRMs was verified.

2STP-10.2, "IRM Range 6-7 Continuity," results approved August 15, 1989

IRM Range 6-7 continuity was successfully verified in that both range 6 and 7 indicated equivalent readings within ± 5%.

2STP-12.1, "Constant Heatup Rate APRM Calibration," results approved August 21, 1989.

All test acceptance criteria were satisfied.

2STP-14.1, "RCIC Functional Demonstration CST to CST at 150 psig," results approved August 21, 1989.

All acceptance criteria were satisfied.

2STP-14.2, "Functional Demonstration and Controller Optimization at Rated Pressure, CST to CST," results approved August 24, 1989.

During the initial conduct of this test, TER 38 was written to document a Level 1 acceptance criteria failure because RCIC time to rated flow was not met. The RCIC test return valve (2F022) to the CST was not throttled open far enough after initial initiation of RCIC. Therefore, the actual time to reach 600 gpm was approximately 78 seconds. A retest was conducted and RCIC reached 600 gpm in 14.5 seconds. All acceptance criteria were satisfied.

2STP-14.4, "Controller Optimization during Injection at Rated Pressure," results approved August 24, 1989.

RCIC achieved rated flow of 600 gpm to the vessel in 17.8 seconds. TER 56 was generated to document a Level 2 acceptance criteria failure for decay ratios exceeding .25 during the ± 60 gpm step changes at flow of 300 gpm. Following evaluation by GE San Jose the observed RCIC control system behavior was found acceptable.

2STP-15.1, "HPCI Functional Demonstration CST to CST at 200 PSIG," results approved August 23, 1989.

Following automatic initiation, the HPCI pump discharge flow reached 5600 gpm in 27 seconds. All acceptance criteria were satisfied.

2STP-15.2, "HPCI Functional Demonstration and Controller Optimization at Rated Pressure CST to CST," results approved August 24, 1989.

All acceptance criteria were satisfied.

2STP-15.7, "HPCI Endurance Run," results approved August 23, 1989.

HPCI was verified to run continuously until pump and turbine oil temperatures reached equilibrium, thus satisfying the acceptance criteria.

2STP-17.1 ,"Pipe Displacements, Selected BOP," results approved August 23, 1989.

This test was performed three times during TC Heatup at reactor water temperatures of approximately 360°F, 450°F and 535°F. During this testing several TERs were written to document Level 2 acceptance criteria failures for measured pipe displacements exceeding allowable tolerances. The inspector reviewed the Plant Staff Field Reports (PSFR) written by Betchel Engineering which documented the acceptance criteria failures, the analysis performed, and the resolution. For all TERs, the measured pipe displacements were determined to be acceptable.

2STP-17.3, "Measured Pipe Displacements, (Main Steam Inside Drywell and Reactor Recirculation)," results approved August 23 and 24, 1989.

This test was performed three times during TC Heatup at reactor water temperatures of approximately 360°F, 450°F and rated. All Level 1 acceptance criteria were satisfied. During the rated temperature testing several Level 2 pipe displacement values were exceeded. TER 37 documented the analysis conducted by GE San Jose and accepted the values as is. The inspector reviewed the analysis and had no further questions.

2STP17.4, "Visual Pipe and Hanger Inspection, (Main Steam Inside Drywell and Reactor Recirculation)," results approved August 23 and 24, 1989.

The test was performed twice during TC heatup at reactor water temperatures of 365°F and 525°F. All acceptance criteria were satisfied.

2STP-25.1, "MSIV Functional Test," results approved August 24, 1989.

All acceptance criteria were satisfied. The MSIV stroke times and MSIV closure times were well within the requirements of $\geq$ 3 seconds and $\leq$ 5.0 seconds. The neutron flux margin to scram was 10.56% (>7.5% required) and the reactor pressure margin to scram was 110.3 psi (>10 psi required).

2STP-26.1, "Automatic Depressurization System (ADS) Valve Low Pressure Test," results approved August 21, 1989.

The ADS valve low pressure testing was conducted at a reactor pressure of approximately 286 psig. All ADS valves successfully actuated. TER 31 was written to document a Level 2 acceptance criteria failure for the tailpipe temperature of ADS valve PSV41-2F013E not returning to within 10°F of its initial temperature after the valve was cycled. The TER remains open pending further monitoring of the valve tailpipe temperature during rated pressure testing.

2STP-32.3, "Control Enclosure Temperature and Relative Humidity (A Equipment)," results approved August 24, 1989.

All acceptance criteria were satisfied with the exception of a Level 2 criteria for the temperature in the Remote Shutdown Control Room not being >65°F and <104°F. The actual temperature was 63°F. TER 51 documented the failure which was later analyzed by Betchel Engineering and found to be acceptable as is.

2STP32.4, "Control Room Temperature and Relative Humidity, (A Equipment)," results approved August 24, 1989.

All acceptance criteria were satisfied.

2STP-34.1, "Offgas Performance Verification," results approved August 24, 1989.

The Offgas System performance was determined to be acceptable.

<u>2STP-70.1, "Reactor Water Cleanup (RWCU) Blowdown Mode Performance Verification," results approved August 24, 1989.</u>

All acceptance criteria were satisfied.

<u>2STP-70.3, "RWCU Normal Mode Performance Verification," results approved August 24, 1989.</u>

The test was satisfactorily performed with the exception of the "C" RWCU pump not being run in response to a plant staff request for minimizing the thermal stress to the pump seals. TERs 46 and 47 document the inability to obtain and analyze vibration data since the pump was not placed in service. The TERs remain open pending future testing of the "C" RWCU pump later in the Power Ascension Program.

<u>2STP-71.1, "RHR Suppression Pool Cooling Mode, (Loop A and B)," results approved August 23, 1989.</u>

The test demonstrated the ability of the RHR system to operate in the Suppression Pool Cooling Mode with adequate heat exchange capacity (design - 26 MBtu/hr). The measured heat exchange capacity was 70.5 MBtu/hr for the "A" loop and 50.6 MBtu/hr for the "B" loop. The inspector independently verified these calculations.

<u>2STP-99.2, "Test Phase III - Low Power Testing Plateau," completed August 24, 1989.</u>

The inspector reviewed the test plateau procedure to ensure that all testing planned for Test Condition Heatup had been accomplished and that all test exceptions identified had been properly documented and resolved. The review determined that RCIC and HPCI stability checks at low pressure following rated pressure testing were not performed because reactor pressure was not lowered. In addition, selected BOP pipe displacements following a reactor cooldown were not measured since a reactor cooldown did not occur. All of these tests were administratively moved to Test Condition 1. Additional control enclosure and control room temperature and relative humidity testing for the "B" equipment train was not accomplished because chiller OBK112 could not be placed in service. This testing will be performed in TC 3. the review of outstanding test exceptions revealed no problems that would require resolution prior to beginning TC1. The inspector concluded that the licensee's plan to complete required testing and resolve open test exceptions was adequate.

6.4.3 Test Condition 1

2STP-1.3, "Gaseous Effluent Sampling and Analysis," results approved September 1, 1989.

Various readings of the Offgas and stack monitors were taken and compared to the analysis of grab samples. No discrepancies were noted. One TER was written to document the inability to determine the radiolytic gas production rate due to power level being inadequate to yield valid results. The production rate will be obtained when the test is performed again in TC 3.

2STP-9.1, "Reference Log Temperature Comparison," results approved August 31, 1989.

Consistent response of the narrow range and wide range water level instrumentation was verified.

2STP-10.3, "IRM/APRM Overlap," results approved August 31, 1989.

One Level 2 acceptance criteria was not met. TER 66 documented for IRM "E", that the overlap between the IRM and APRM was not at least one decade. IRM "E" indicated 124/125 on range 8 and the required reading was less than 108/125. The TER remains open pending reperformance of this STP following Local Power Range Monitor (LPRM)/APRM calibration.

In addition, during review of the test results the inspector noted that gain adjustments were made to the IRMs during conduct of the test. The procedure states that if gain adjustments are necessary, a check of SRM/IRM overlap per 2STP-10.1 must be performed at the first opportunity. The inspector questioned a licensee representative regarding how the requirement to reperform 2STP-10.1 was being tracked. The representative stated that a Startup Test Change Notice (STCN) against 2STP-99.4, "Test Plateau B - Test Condition 2," would be written to include the required test. The inspector had no further questions.

2STP-11.4, "LPRM Operational Verification During Rod Withdrawal," results approved August 31, 1989.

Satisfactory LPRM detector response to changes in neutron flux was verified.

2STP-14.6, "RCIC Cold Quick start at Rated Pressure CST to Reactor Pressure Vessel (RPV)," results approved September 1, 1989.

RCIC reached rated flow in 17.8 seconds. All acceptance criteria were satisfied with the exception of the decay ratio for RCIC system flow being greater than 0.25 after achieving rated flow to the vessel. This decay ratio was evaluated and accepted as is based upon flow disturbances not being a function of the control system components. The inspector found the evaluation to be adequate.

2STP-22.3, "Pressure Regulator Response Bypass Valve Operation," results approved September 1, 1989.

TER 68 was written to document a Level 2 acceptance criteria failure for a decay ratio for the "A" regulator sensed pressure exceeding 0.25 (actual was 0.29) for the 10 psi positive step change on the "A" regulator. The failure was evaluated and accepted as is. The inspector reviewed the analysis and determined it to be acceptable.

2STP-23.1, "Feedwater System Startup Controller Level Step," results approved August 31, 1989.

All acceptance criteria for performance of the feedwater system startup level controller were satisfied.

2STP-25.1, "MSIV Functional Test," results approved August 31, 1989.

All acceptance criteria were satisfied. APRM margin to scram was 23.7% (>7.5% required) and reactor pressure margin to scram was 103 psi (>10 psi required).

2STP-34.1, "Offgas Performance Verification," results approved September 1, 1989.

All acceptance criteria were met.

2STP-99.3, "Test Plateau A - Test Condition 1," completed September 3, 1989.

The inspector reviewed this procedure to ensure that all planned testing for TC-1 had been completed and that all Test

Exception Reports remaining open could safely be carried forward into subsequent test conditions. Eight TERs remained open at the end of TC-1. The inspector reviewed the TERs and found it acceptable to allow the TERs to remain open into future test conditions. Six tests involving IRM/APRM overlap, RCIC and HPCI system testing and selected BOP pipe displacements were not performed during TC-1 because plant conditions did not allow testing. These tests have been administratively moved to TC-2.

Completion and results review of 2STP-12.2, "Low Power APRM Calibration," 2STP-13.3, "Process Computer Program Testing," and 2STP-19.1, "BUCLE Calculation," were deferred to TC-2 so the TC-1 Test Plateau could be completed to allow reactor power to be increased above 20% to begin xenon buildup. STCN 142 documents movement of these tests to the TC-2 plateau which requires a change to FSAR Table 14.2-4. The inspector reviewed the Safety Evaluation for STCN 142 and determined it to be inadequate since it did not address any technical justification for allowing movement of the tests. The inspector attended the PORC meeting on September 1, 1989 at which the above changes and technical justification for moving the tests were discussed.

The inspector found the content of the justification discussed at the meeting to be adequate. The inspector also discussed the safety evaluation with a licensee representative who stated that the evaluation would be revised to include the technical basis and resubmitted to PORC for approval. The inspector had no further concerns.

6.5 Power Plateau Data Review Evaluation

The inspectors observed the conduct of Plant Operations Review Committee (PORC) and Sub-PORC meetings convened for the purpose of reviewing STP results. Those meetings attended were held on August 4, 23, 24 and September 1, 1989. STP results were reviewed, confirming the data to be within the expected ranges, and paying close attention to TERs and Startup Test Change Notices (STCNs) to determine the effects on the completed testing, and potential to affect planned tests.

During Sub-PORC meeting 89-38, held August 23, several packages were remanded to the startup engineers, one for rewriting of the safety evaluation for a TER, one for correction of a data transcription error, and another for writing a TER. Several procedures were held over for full PORC review due to exceptions which would remain open after the plateau was completed, or being related to the plant computer (the Unit 2 process computer differs substantially from that for Unit 1, so PORC decided that all related procedures/data will be reviewed by the full PORC).

During the PORC meetings of August 4, 24 and September 1, the open vessel, heatup and test condition 1 plateaus were reviewed. The PORC members adequately reviewed the impact of carrying uncompleted startup tests and open test exception reports into the next plateau.

The inspector found the PORC and Sub-PORC reviews of startup test related activities to be adequate.

6.6 Quality Assurance (QA) Interface with Power Ascension Test Program

The inspector reviewed numerous QA Technical Monitoring reports for the period August 11 to August 22, 1989. These reports documented monitoring of various power ascension activities including initial criticality; testing of nuclear instrumentation, RCIC, HPCI and the suppression pool cooling mode of RHR; and various drywell walkdowns during the initial plant heatup. The inspector verified that the monitoring was conducted per Limerick Quality Division Monitoring Guideline PA-01. The inspector noted that Monitoring Report LMR-89-0859 which documented startup activities conducted during the initial criticality sequence on August 12, 1989, identified the startup test personnel's failure to meet the intent of the Startup Program requirements regarding control of STP-6.2 implementation.

Corrective Action Request LA89016-10 was initiated to identify the problem encountered and assure corrective action was implemented. The inspector discussed the issue with a licensee QA representative who stated that the corrective action to date has been prompt and adequate. A Startup Training bulletin addressing the concerns was issued on August 21, 1989 and additional training of all startup test directors is ongoing. The inspector had no further questions.

7.0 Review of Periodic and Special Reports (90713)

Upon receipt, the inspector reviewed periodic and special reports. The review included the following: inclusion of information required by the NRC; test results and/or supporting information consistent with design predictions and performance specifications; planned corrective action for resolution of problems; and reportability and validity of report information. The following periodic report was reviewed:

Monthly Operating Report - July 1989

The inspector had no questions regarding this report.

In addition, the inspector reviewed the licensee's report "Limerick Generating Station, Unit No. 1 Startup Report - Cycle 3" dated June 1989. The report was required since fuel of a different design was installed during the second refueling outage of Unit 1. The inspector verified that the report included the information required by the Technical Specifications, the tests results reported were consistent with requirements and corrective action was adequate for the identified problems. No unacceptable conditions were noted.

8.0 Licensee Event Report Followup (90712, 92700)

The inspector reviewed the following LERs to determine that reportability requirements were fulfilled, that immediate corrective action was taken, and that corrective action to prevent recurrence was accomplished. In accordance with the above inspection modules the inspector considers the following reports closed. The inspector had no further comments or questions except as noted.

| LER Number | Inspector Subject/Comments |
|---|---|
| 1-89-043* | Refuel Floor Isolation and Standby Gas Treatment System Initiation due to a deficient operating procedure and personnel error. (NCV 352/89-18-01) |
| 1-89-044* | Missed "C" feedwater/main turbine reactor high level trip surveillance test due to personnel error in scheduling. (NCV 352/89-18-02) |
| 1-89-045 | Group VI "C" Isolation due to failure of a radiation monitor. |
| 1-89-046* | Standby Gas Treatment System potentially inoperable due to charcoal sample canister removal and reinstallation. (NCV 352/89-18-03) |
| 1-89-047 | Potential High Pressure Coolant Injection and Reactor Core Isolation Cooling Systems unavailabilty due to improper normal service water system valve lineup. The inspector found the procedure revisions, which were implemented to prevent recurrence, to be a good example of in depth problem review and corrective action. |
| 1-89-048 | Various primary and secondary containment isolation valve closures due to a personnel error during surveillance testing. |
| 1-89-S03 | Safeguards Event Report dealing with improperly stored safeguards material. |

| | |
|---|---|
| 2-89-003 | Two reactor scrams due to an Intermediate Range Monitor preamplifier failure. The first scram occurred while the reactor was shutdown and all control rods were fully inserted. The second scram occurred with the reactor shutdown and all but one rod fully inserted. The withdrawn rod had been hydraulically disarmed for maintenance, thus no rod motion occurred during either scram. The Reactor Protection System was in a non-coincident trip configuration since a shutdown margin test had not yet been performed. The licensee's actions involving these scrams was appropriate and in accordance with procedures. |
| 2-89-004* | Reactor Enclosure Cooling Water radiation monitor setpoints incorrect due to personnel error. (NCV 353/89-26-01) |
| 2-89-005 | This is a special report to document an emergency diesel generator failed during surveillance testing. The failure was due to a lube oil system leak and appears to be an isolated failure. |
| 2-89-006* | Missed emergency core cooling system actuation instrumentation surveillance test due to personnel error in scheduling. (NCV 353/89-26-02) |

*These reports identify conditions which are violations of the plant technical specifications. The inspectors have reviewed these events and determined that they satisfy the criteria for licensee identified violations as stated in 10 CFR 2 Appendix C, Section G.1 and as such a notice of violation will not be issued.

## 9.0 (RI-89-A-0096) Allegation concerning the Limitorque Motor Operators

An individual alleged that on certain Limitorque models (00 and 000) damage to the key and keyway of the manual tripper handle was occurring and indicated he had proposed a new design to PECo to eliminate the problem. The individual also said he did not receive a whole body count upon exiting the site when his job was terminated. The inspector conducted a review of the allegation and noted the following:

- The individual was dismissed from the site when he was tested for drug usage and found to be positive.
- He was not given a whole body count because on May 4, 1988 he had received a whole body count with negative results. His last entry into a radiological area was on April 18, 1988, and he was terminated from the site on October 17, 1988.

- The damage to key and keyways of the Limitorque tripper handle occurs in shipping probably because this handle is a convenient way to lift and move the motor operator and limitorque assembly. Several of the limitorque motor operators were found damaged and repaired; however, after installation in the plant no further damage has been observed.

Although the alleger's suggestion for a new design seems reasonable, the licensee cannot change the manufacturers design. Based on no identified failures in the field the licensee believes the original design is sound and does not require modification. The inspector considers this allegation unsubstantiated and this matter is closed.

10.0 Exit Interview (30703)

The NRC resident inspector discussed the issues in this report with the licensee throughout the inspection period, and summarized the findings at an exit meeting held with the site Vice President, Mr. G. M. Leitch and the plant manager, Mr. M. J. McCormick, Jr., on September 8, 1989. No written inspection material was provided to licensee representatives during the inspection period.

Attachment A

Power Ascension Test Procedures Reviewed

2STP-19.0, Core Performance, Main Body, Revision 0, March 29, 1989

2STP-19.1, Bucle Calculation, Revision 0, March 29, 1989

2STP-19.2, Process Computer Calculation, Revision 0, March 29, 1989

2STP-23.0, Feedwater System, Main Body, Revision 1, July 12, 1989

2STP-23.1, Feedwater System Startup Controller Level Step, Revision 1, July 12, 1989

2STP-23.2, Feedwater System Manual Flow Step, Revision 1, July 12, 1989

2STP-23.3, Feedwater System Level Setpoint Changes, Revision 1, July 12, 1989

2STP-23.4, Loss of Feedwater Heating, Revision 0, March 31, 1989

2STP-23.5, Feedwater Pump Trip, Revision 1, July 12, 1989

2STP-23.7, Maximum Feedwater Runout Capability, Revision 0, March 31, 1989

## Attachment B

## References

Regulatory Guide 1.68, Revision 2, August 1978, "Initial Test Program for Water Cooled Nuclear Power Plant"

ANSI N18.7-1976, "Administrative Controls and Quality Assurance for Operations Phase of Nuclear Power Plants"

Limerick Generating Station Unit 2, Technical Specifications, August 25, 1989

Limerick Generating Station Unit 2, Final Safety Analysis Report (FSAR), Chapter 14, "Initial Test Program"

GE Specification, NEBO 23A1918, Revision 3, "Startup Test Specification, Limerick Units 1 and 2"