NOTICE OF VIOLATION
AND
PROPOSED IMPOSITION OF CIVIL PENALTIES

Commonwealth Edison Company
LaSalle Nuclear Power Station
Units 1 and 2

Docket No. 50-373
Docket No. 50-374
License No. NPF-11
License No. NPF-18
EA 85-95

During NRC inspections conducted during the period June 10 - July 24, 1985, violations of NRC requirements were identified. In accordance with the "General Statement of Policy and Procedures for NRC Enforcement Actions," 10 CFR Part 2, Appendix C (1985), the NRC proposes to impose a civil penalty pursuant to Section 234 of the Atomic Energy Act of 1954, as amended ("Act"), 42 U.S.C. 2282, PL 96-295, and 10 CFR 2.205. The particular violations and the associated civil penalties are set forth below:

I. A. Technical Specification 3.3.3.b requires that with one or more Emergency Core Cooling System (ECCS) actuation instrumentation channels inoperable take the action required by Table 3.3.3.1. Table 3.3.3.1 in Action 30 requires that when the number of operable channels is less than the required minimum of two, place the inoperable channel in the tripped condition within one hour or declare the associated system inoperable.

Contrary to the above, from 3:30 a.m. on June 5, 1985 until 12:10 p.m. on June 10, 1985 when the number of operable channels was less than the required minimum of two, the inoperable ECCS actuation instrumentation channel was not placed in the tripped condition within one hour and the associated system was not declared inoperable.

B. Technical Specification 3.5.2 requires at least two Emergency Core Cooling Systems (ECCS) to be operable in the shutdown condition. With both of the required subsystems/systems inoperable, one subsystem must be restored to operable status within four hours or secondary containment integrity be established within the next eight hours.

Contrary to the above, with the three ECCS Divisions inoperable on June 5, 1985, secondary containment integrity was not established within eight hours.

C. 10 CFR Part 50, Appendix B, Criterion VI, as implemented by the Commonwealth Edison Company's Quality Assurance Manual, Quality Requirement 6.1, requires that a document control system be used to assure that documents such as drawings be distributed to and used at the locations where the prescribed activity is performed.

Contrary to the above, Field Change Request 85-123 dated April 4, 1985 was issued to correct an error in Modification M-1-2-84-136; however, it was not distributed to and used at the location where the prescribed activity was performed. As a result, piping for two switches was installed backwards rendering Division I of the Unit 2 Emergency Core Cooling Systems inoperable.

D. 10 CFR Part 50, Appendix B, Criterion X, as implemented by the Commonwealth Edison Company Quality Assurance Manual, Quality Requirement 10.1, requires that Quality Assurance inspections be conducted at the site during modification activities to verify conformance to applicable drawings.

Contrary to the above, Quality Assurance inspections were not conducted at the site during Modification M-1-2-84-136 to verify conformance to the applicable drawing (FCR 85-123).

E. 10 CFR Part 50, Appendix B, Criterion XI, as implemented by the Commonwealth Edison Company Quality Assurance Manual, Quality Requirement 11.1, requires that the test program include those tests necessary to demonstrate that systems will perform satisfactorily in service following plant maintenance or modifications.

Contrary to the above, Operational Test LIS-NB-204 performed following the completion of Modification M-1-2-84-136 did not adequately demonstrate system operability in that the test only verified the instrument and electrical connections. The piping configuration of the reactor pressure vessel water level reference and variable legs was not verified.

II. A. Technical Specification 3.3.2 requires the isolation actuation instrumentation channels shown in Table 3.3.2-1 to be operable with their trip setpoints set consistent with the values shown in Table 3.3.2-2. The Regenerative Heat Removal (RHR) shutdown cooling pump suction high flow instrumentation is included for Operating Conditions 1, 2, and 3. Technical Specification 3.3.2.c. requires that with the number of operable channels less than the minimum operable channels per trip system required for both trip systems, place at least one trip system in the tripped condition within one hour and take the action required by Table 3.3.2-1. Action Item 25 of Table 3.3.2-1 requires the isolation valves to be closed and locked for the RHR shutdown cooling mode and the system to be declared inoperable.

Contrary to the above, from April 7, 1985 until July 12, 1985, while the plant was in Operating Conditions 1, 2, and 3, the Unit 1 RHR shutdown cooling pump suction high flow sensors would not have met the designated isolation setpoint in that the isolation actuation instrumentation channels were inoperable. With the channels

inoperable, the actions required by Action Item 25 of Table 3.3.2.1 were not taken. The isolation valves were not closed and locked for the RHR shutdown cooling mode and the system was not declared inoperable.

B. 10 CFR Part 50, Appendix B, Criterion VI, as implemented by the Commonwealth Edison Company's Quality Assurance Manual, Quality Requirement 6.1, requires that a document control system be used to assure that documents such as drawings, be distributed to and used at the locations where the prescribed activity is performed.

Contrary to the above, Drawing Change Request 7383, issued to document a piping change to Modification M-1-1-82-054, was not distributed to and used in the development of Modification M-1-1-84-091. As a result, the Unit 1 Regenerative Heat Removal shutdown (RHR) pump cooling suction flow isolation channels were inoperable during power operations from April 7, 1985 until the unit was shutdown on July 12, 1985.

C. 10 CFR Part 50, Appendix B, Criterion XI, as implemented by the Commonwealth Edison Company Quality Assurance Manual, Quality Requirement 11.1, requires that the test program include those tests necessary to demonstrate that systems will perform satisfactorily in service following plant maintenance or modifications.

Contrary to the above, the post-installation testing performed following the completion of Modification M-1-1-84-091 did not adequately demonstrate system operability in that the test did not detect that the Regenerative Heat Removal pump suction high flow isolation switches were piped backwards prior to returning the instruments to service.

III. 10 CFR Part 50, Appendix B, Criterion XI, as implemented by the Commonwealth Edison Company Quality Assurance Manual, Quality Requirement 11.1, requires that the test program include those tests necessary to demonstrate that systems will perform satisfactorily in service following plant maintenance or modifications.

Contrary to the above, during this inspection period, the operability test for two Unit 2 shutdown cooling high flow isolation switches was not performed correctly. Specifically, a walkdown of the piping to these switches identified no problems although the piping to the switches was installed backwards. This error was discovered by an alternate test that was not specified for proof of operability testing.

Collectively, the above violations have been evaluated as a Severity Level III problem (Supplement I).
(Cumulative Civil Penalty $125,000 assessed equally among the violations.)

Pursuant to the provisions of 10 CFR 2.201, Commonwealth Edison Company is hereby required to submit to the Director, Office of Inspection and Enforcement, U. S. Nuclear Regulatory Commission, Washington, D.C. 20555, with a copy to the Regional Administrator, U. S. Nuclear Regulatory Commission, Region III, 799 Roosevelt Road, Glen Ellyn, IL 60137, within 30 days of the date of this Notice a written statement or explanation, including for each alleged violation: (1) admission or denial of the alleged violation; (2) the reasons for the violation, if admitted; (3) the corrective steps that have been taken and the results achieved; (4) the corrective steps that will be taken to avoid further violations; and (5) the date when full compliance will be achieved. If an adequate reply is not received within the time specified in the Notice, the Director, Office of Inspection and Enforcement, may issue an order to show cause why the license should not be modified, suspended, or revoked or why such other action as may be proper should not be taken. Consideration may be given to extending the response time for good cause shown. Under the authority of Section 182 of the Act, 42 U.S.C. 2232, this response shall be submitted under oath or affirmation.

Within the same time as provided for the response required above under 10 CFR 2.201, Commonwealth Edison Company may pay the civil penalties by letter addressed to the Director, Office of Inspection and Enforcement, with a check, draft, or money order payable to the Treasurer of the United States in the cumulative amount of One Hundred and Twenty-five Thousand Dollars ($125,000) or may protest imposition of the civil penalties in whole or in part by a written answer addressed to the Director, Office of Inspection and Enforcement. Should Commonwealth Edison fail to answer within the time specified, the Director, Office of Inspection and Enforcement, will issue an order imposing the civil penalties in the amount proposed above. Should Commonwealth Edison elect to file an answer in accordance with 10 CFR 2.205 protesting the civil penalties, such answer may: (1) deny the violations listed in this Notice, in whole or in part; (2) demonstrate extenuating circumstances; (3) show error in this Notice; or (4) show other reasons why the penalties should not be imposed. In addition to protesting the civil penalties in whole or in part, such answer may request remission or mitigation of the penalties.

In requesting mitigation of the proposed penalty, the five factors addressed in Section V.B of 10 CFR Part 2, Appendix C (1985) should be addressed. Any written answer in accordance with 10 CFR 2.205 should be set forth separately from the statement or explanation in reply pursuant to 10 CFR 2.201 but may incorporate parts of the 10 CFR 2.201 reply by specific reference (e.g., citing page and paragraph numbers) to avoid repetition. Commonwealth Edison's attention is directed to the other provisions of 10 CFR 2.205, regarding the procedure for imposing civil penalties.

Upon failure to pay any civil penalty due, which has been subsequently determined in accordance with the applicable provisions of 10 CFR 2.205, this matter may be referred to the Attorney General, and the penalties

unless compromised, remitted, or mitigated, may be collected by civil action pursuant to Section 234c of the Act, 42 U.S.C. 2282.

FOR THE NUCLEAR REGULATORY COMMISSION

James G. Keppler
James G. Keppler
Regional Administrator

Dated at Glen Ellyn, Illinois
this 27th day of September 1985

U. S. NUCLEAR REGULATORY COMMISSION

REGION III

ReportS No. 50-373/85023(DRP); 50-374/85018(DRP)

Docket Nos. 50-373; 50-374 Licenses No. NPF-11; NPF-18

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

Facility Name: LaSalle County Station, Units 1 and 2

Inspection At: LaSalle County Station, Marseilles, IL

Inspection Conducted: June 10 through August 15, 1985

Enforcement Conference At: LaSalle County Nuclear Station
Marseilles, IL on June 24, 1985

Inspectors: M. J. Jordan

J. C. Bjorgen

R. A. Kopriva

G C Wright

Approved By: G. C. Wright, Chief
Reactor Projects Section 2C

8/16/85
Date

Inspection Summary

Inspection on June 10 through July 24, 1985, and Enforcement Conference on June 24, 1985 (Report No. 50-373/85023(DRP); 50-374/85018(DRP))

Areas Inspected: Special unannounced inspection by resident inspectors of activities surrounding the inoperability of all three divisions of Emergency Core Cooling on Unit 2 and improperly piped RHR shutdown cooling isolation switches on Unit 1. The inspection involved a total of 41 inspector-hours onsite by three inspectors including 11 inspector-hours onsite during off-shifts. The Enforcement Conference involved a total of 70 hours by ten NRC personnel.

Results: Nine violations were identified (five - Limiting Condition for Operations; two - failure to have an adequate operability test; one - failure to incorporate design document changes into the site drawings; and one - failure to have inspection activities verify conformance of as-built drawings).

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PDR

DETAILS

1. Persons Attending Enforcement Conference

Commonwealth Edison

B. L. Thomas, Executive Vice President
C. Reed, Vice President of Nuclear Operations
D. P. Galle, Division Vice President and General Manager for Nuclear Stations
L. O. DelGeorge, Assistant Vice President of Licensing & Engineering
D. Farrar, Director of Nuclear Licensing
B. B. Stephenson, Manager of Production - Nuclear Stations
W. P. Worden, BWR Operations Manager
M. S. Turbak, Operations Plant Licensing Director
G. P. Wagner, PWR Operations Manager
F. A. Palmer, Director of Nuclear Safety
N. E. Wandke, Assistant Vice President - Nuclear Stations
L. F. Gerner, Superintendent - Regulatory Assurance
P. G. Kuhel, RPIP Staff Engineer
W. L. Duke, Administrative Service Director - Nuclear Stations
J. S. Abel, Station Nuclear Engineering Manager
R. F. Janecek, Station Nuclear Engineering, LaSalle Station Project Engineer
L. W. Rainey, Supervisor, Office of Nuclear Safety, LaSalle Station
E. D. Eenigenburg, Maintenance Manager, Nuclear Stations
R. D. Bishop, Services Superintendent, LaSalle Station
W. R. Huntington, Assistant Superintendent - Operations, LaSalle Station
C. E. Sargent, Production Superintendent, LaSalle Station
D. S. Berkman, Assistant Superintendent, Technical Services, LaSalle Station
P. F. Manning, Technical Staff Supervisor, LaSalle Station
J. V. Schmeltz, Operating Engineer, LaSalle Station
R. H. Raguse, Operations Engineer, LaSalle Station
W. E. Sheldon, Assistant Superintendent of Maintenance, LaSalle Station
E. E. Boyd, Master Mechanic, LaSalle Station
H. Mulderink, Master Electrician, LaSalle Station
F. W. Baker, Station Construction Site Superintendent, LaSalle Station
R. M. Jeisy, Station Quality Assurance Supervisor, LaSalle Station

NRC Representatives

J. G. Keppler, Regional Administrator
C. E. Norelius, Director, Division of Reactor Projects
N. J. Chrissotimos, Chief, Projects Section 2C
W. H. Schultz, Enforcement Coordinator
E. A. Hare, Project Inspector, LaSalle Station
B. Berson, Regional Counsel
M. Jordan, Senior Resident Inspector, LaSalle
J. Bjorgen, Resident Inspector, LaSalle
A. Madison, Senior Resident Inspector, Quad Cities
S. G. DuPont, Regional Inspector

2. Sequence of Events

On June 10, 1985 at 11:30 a.m., the licensee informed the NRC Resident Inspector that for approximately five days Unit 2 had been without Emergency Core Cooling System (ECCS) capability, and that for approximately three days during this period the plant had been without secondary containment integrity.

Unit 2 has been in an outage since February 1985 for installation of environmentally qualified electrical equipment and performance of the eighteen month surveillances required by the Technical Specifications.

The following table is a listing of the ECCS sequence of events to install environmentally qualified switches:

Date	Event
March 1985	Division III taken out-of-service
April 29, 1985	Division I taken out-of-service
June 4, 1985 (1:00 a.m.)	Modifications to Division I were completed and division declared operable although the licensee unknowingly had two level switches piped backwards. (This would have prevented the Division I pumps from automatically starting on a low reactor water level signal.)
June 5, 1985 (3:30 a.m.)	Division II taken out-of-service
June 10, 1985 (11:25 a.m.)	Mispiped switches for Division I identified during normal verification of excess flow check valves prior to leak rate testing.
June 10, 1985 (12:10 p.m.)	Jumpers installed to trip level switches logic for Division I making it operable.

The following table is a listing of the Reactor Building ventilation sequence of events for a modification:

Date	Event
June 3, 1985 (3:30 a.m.)	System taken out-of-service
June 8, 1985 (5:30 p.m.)	System returned to service

The inspectors reviewed the safety-related modification package (M-1-2-84-136) for the replacement of Barton switches with environmentally qualified (EQ) Static O-Ring (SOR) switches on Unit 2. Two of the switches (2B21-N037AA and 2B21-N037AB) were discovered, by the licensee to have been piped incorrectly, resulting in the switches being inoperable.

The design function of the switches was to provide: a Division I Low Reactor Vessel Water Level permissive for the Automatic Depressurization System; initiation for the Low Pressure Core Spray; initiation for the "A" Low Pressure Coolant Injection System; and a permissive for the Reactor Core Isolation Cooling System.

The configuration required for the switches to perform their design function was: the reactor pressure vessel level reference leg piped to the instrument's high pressure connection, and the reactor pressure vessel level variable leg piped to the low pressure connection. However, the reference and variable legs were reversed to 2B21-N037AA and 2B21-N037AB during installation of the modification (M-1-2-84-136).

Technical Specification 3.3.3.b states that with one ECCS actuation channel inoperable, place the inoperable channel in the tripped condition within one hour or declare the associated system inoperable.

Contrary to the above, inoperable Channel A went undetected from 1:00 a.m. on June 4, 1985 until 11:25 a.m. on June 10, 1985 without the channel being tripped or the system being declared inoperable. This is considered to be a violation (373/85023-01A(DRP); 374/85018-01A(DRP)).

Technical Specification 3.5.2 requires at least two Emergency Core Cooling Subsystems to be operable in the shutdown condition. With no subsystems operable, one subsystem shall be restored to operable status within four hours or Secondary Containment Integrity shall be established within the next eight hours.

Contrary to the above, Unit 2 was without Emergency Core Cooling capability from 3:30 a.m. on June 5, 1985 until 12:10 p.m. on June 10, 1985, and without secondary containment from 3:30 a.m. on June 3, 1985 until 5:30 p.m. on June 8, 1985. This is considered to be a violation (373/85023-01B(DRP); 374/85018-01B(DRP)).

The review of the modification revealed that several errors contributed to the erroneous configuration:

a. Inadequate Control of Design Drawings

The design drawings referenced by modification, M-1-2-84-136, were initially in error for the reference and variable legs connection configuration when the modification was released on April 1, 1985 to Morrison (contractor) for installation. The error on the design drawings (Sargent and Lundy drawing M-1303, Sheet 42, General Electric drawing 121D1916TD, and Morrison isometric drawings 2828-NB-062 and 2828-NB-066) was discovered on April 4, 1985 by the licensee's site personnel and corrected by a Field Change Request (FCR 85-123). Even though the licensee had corrected the configuration error on the drawings and had included FCR 85-123 as a design drawing, the isometric drawings being used to install the modification were not corrected. Because the drawings used in the field did not contain FCR 85-123, the configuration of the reference and variable legs was installed incorrectly.

10 CFR Part 50, Appendix B, Criterion VI, as implemented by the licensee's Quality Assurance Manual, Quality Requirement 6.1 states, "A document control system will be used to assure that documents such as specifications, procedures, instructions, and drawings are reviewed for adequacy and approved by authorized personnel...such documents will be distributed to and used at the locations where the prescribed activity is performed."

Contrary to the above, measures did not assure that the design change document, Field Change Request 85-123, issued to correct an error in Modification M-1-2-84-136, was distributed to and used at the location where the prescribed activities were performed. This is considered to be a violation (374/85018-01C(DRP)

b. Inadequate Inspection

In addition to the error in the design drawings, the contractor's quality control did not have inspection hold points for either electrical or piping connections on any of the 22 instruments replaced by modification M-1-2-84-136, including 2B21-N037AA and 2B21-N037AB. Because of the lack of witness points, the adequacy of the installation was not verified against the design documents. Such a verification could have detected the failure to implement the design drawing change or the configuration error of the installation.

10 CFR 50, Appendix B, Criterion X, as implemented by the licensee's Quality Assurance Manual, Quality Requirement 10.1 states, "Quality Assurance inspection and testing will be conducted....at the site during....modification activities to verify conformance to applicable drawings, instructions..."

Contrary to the above, the program for inspection of activities affecting quality was inadequate and did not verify conformance of the M-1-2-84-136 activity to documented instructions and drawings. This is considered to be a violation (373/85023-01D(DRP); 374/85023-01D(DRP)).

c. Inadequate Modification Test Control

In addition to the problems discussed above, the licensee's operational function test of the instruments, after the completion of the modification, failed to detect the inoperability of 2B21-N037AA and 2B21-N037AB. The test performed, LIS-NB-204, only verified the permissive and initiation calibration set points and did not demonstrate the operability of the system in light of the work actually performed by modification M-1-2-84-136.

The modification had re-routed the reference and variable legs to the instruments, replaced the instruments with a different manufacturer component (Static O-Ring replaced the initially installed Barton), and re-connected the electrical connections. The test functionally verified only the instrument and electrical connections. In light of the the work actually performed, the piping configuration

of the reference and variable legs was required to be verified by a pre-test walkdown. However, the walkdown was not performed. The licensee stated, in the letter to J. M. Taylor, Director, Office of Inspection and Enforcement (NRC) from C. Reed, Vice President (CECo) dated April 19, 1985, that measures had been developed to ensure that the post maintenance test adequately demonstrates system operability in light of the work actually performed.

10 CFR Part 50, Appendix B, Criterion XI, as implemented by the licensee's Quality Assurance Manual, Quality Requirement Q.R.11.1 states, "The (test) program will include ... those tests applicable involving and following plant maintenance or modifications."

Contrary to the above, the test conducted, after completion of modification M-1-2-84-136, did not demonstrate system operability in light of the work actually performed. This is considered to be a violation (374/85018-01E(DRP)).

The licensee walked down all safety-related systems modified during the Unit 2 outage to verify that the actual installation matched the planned modification. Completion of the walkdown on the two Shutdown Cooling pump suction high flow isolation switches (2E31N012AA, and AB) identified no problems. After the walkdown, a review of data associated with excessive flow check valve testing (LISNB-215, performed prior to the walkdown) identified a problem with the connection of the lines to the switches. An additional review of the data and a rewalkdown of the system identified that these two switches were pipe backwards. Technical Specification 3.3.2 did not require these switches to be operable in Modes 4 or 5, which the plant was in. However, the walkdown of the piping system to ensure correct installation was considered part of the operability test for these two switches; therefore, again the operability test was not performed satisfactorily. This is considered another example of inadequate measures to ensure that post maintenance test adequately demonstrates system operability in light of work actually performed. This is considered a violation (373/85023-01F(DRP); 374/85018-01F(DRP)).

As a followup to these programmatic problems, the licensee initiated a system operability testing program on Unit 1 for all safety systems affected by the installation of environmentally qualified instruments. This testing was initiated on July 16, 1985 while Unit 1 was in a short outage for minor valve repairs. The environmentally qualified instruments had been installed on Unit 1 during a maintenance outage completed in April 1985.

On July 17, 1985 the special test (LST 85-88) found that the four Unit 1 shutdown cooling pump high suction flow alarm and isolation switches (1E31N012AA, AB, BA, and BB) were piped backwards. These switches had also been previously walked down to confirm that they were piped correctly. The licensee's investigation determined that the modification package (M-1-1-84-091) utilized for the switch installation required the use of drawings that did not reflect the as-built condition of the plant.

During original Unit 1 construction (May 1982), the flow sensing lines had been found reversed inside the suppression pool. Rather than reroute the piping, the licensee exchanged the piping connections at the instrument rack (modification M-1-1-82-054). A Drawing Change Request (DCR 7383) was then issued to update the appropriate drawings. Due to an administrative error, this DCR was closed prior to being incorporated into the affected drawings. Accordingly, the drawings used to install the replacement switches per modification M-1-1-84-091 were incorrect. This is considered another example of inadequate measures to ensure that a design change document, Drawing Change Request 7383, issued to document a piping change to Modification M-1-1-82-054 was distributed to and used in the development of a Modification. This is considered to be a violation (373/85023-01C(DRP)).

During the review of this event, it was noted that again the post installation testing, including a system walkdown, failed to identify that the switch piping was incorrect. This is considered another example of inadequate measures to ensure that the testing performed, following the completion of Modification M-1-1-84-091 did not detect that the RHR pump suction high flow isolation switches were piped backwards prior to returning the instruments to service. This is considered to be a violation (373/85023-01E(DRP)).

Since these switches had been piped backwards and, therefore, were inoperable since the Unit 1 startup on April 7, 1985, the Limiting Condition for Operation of Technical Specification 3.3.2 was exceeded. Technical Specification 3.3.2 requires the isolation actuation instrumentation channels listed in Table 3.3.2-1 to be operable with their trip setpoints set consistent with the values in Table 3.3.2-2.

With less than the required number of isolation channels operable, Technical Specification 3.3.2.c requires that the affected trip system be placed in the tripped condition within one hour. Action Item 25 of Technical Specification Table 3.3.2-1 also requires that the associated valves be locked in the closed position and the associated system be declared inoperable within one hour. These requirements apply in Operating Conditions 1, 2, and 3.

Contrary to the above, the actions required by Technical Specification 3.3.2 were not taken when the Unit 1 RHR shutdown cooling pump high suction flow isolation channels were inoperable from April 7, 1985 until the unit was placed in Cold Shutdown (Condition 4) on July 12, 1985. This is considered to be a violation (373/85023-02A(DRP)).

In addition, since the applicable valves are required for primary containment integrity, the Limiting Conditions for Operation for the primary containment were also exceeded.

Technical Specifications 3.6.3 LCO for primary containment isolation valves states, in part:

"With one or more primary containment isolation valves inoperable

a. Maintain at least one isolation valve operable in each affected penetration that is open and within 4 hours either...

   (1) Restore the inoperable valve(s) to operable...
   (2) Isolate each affected penetration by deactivating automatically actuated valves
   (3) Isolate each affected penetration by closing manual valves

b. Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within following 24 hours."

Contrary to the above, with the Group 6 isolation system valves inoperable due to the RHR pump high suction flow isolation not being operable, the above action was not taken on those valves. This is considered a violation (373/85023-02B(DRP)).

The plant Technical Specifications also limit plant startup or certain power changes when otherwise not in compliance with the Technical Specifications. Unit 1 was started up on April 7, 1985 and underwent several startups and shutdowns until shutdown for maintenance on July 12, 1985. Technical Specification Section 3.0.4, Limiting Conditions for Operations Applicability states, in part: "Entry into an operational condition or other specified condition shall not be made unless the conditions for the LCO are met without reliance on provisions contained in the action requirements."

Contrary to the above, Unit 1 mode changes were made when other LCO requirements were not met. This is considered a violation (373/85023-02C(DRP)).

Since the plant was operated with the RHR pump suction high flow isolation inoperble, the shutdown cooling mode was technically inoperable during the period from startup on April 7, 1985 until reaching Cold Shutdown on July 12, 1985. When in Operation Condition 3 (Hot Shutdown), Technical Specification 3.4.9.1 requires the shutdown cooling loops to be operable.

Technical Specifications 3.4.9.1 for RHR when in Condition 3 states, in part:

> "With less than the required RHR shutdown cooling mode loops operable, immediately initiate corrective actions ..... Be in at least Cold Shutdown within 24 hours.
>
> With no RHR shutdown cooling mode loop in operation, immediately initiate corrective action .... Within one (1) hour establish reactor coolant circulation by an alternate method ....."

The licensee entered Condition 3 for the first time following the Unit 1 scram on April 11, 1985. Contrary to the above, each time the unit entered Condition 3, the shutdown cooling loops were technically inoperable according to Technical Specification 3.3.2 and the action required by Technical Specification 3.4.9.1 was not taken. This is considered a violation (373/85023-02D(DRP)).

The safety significance of this violation was reduced because of the number of backup isolation signals available to isolate the shutdown cooling mode of RHR. The redundant isolations include:

a. Reactor vessel level - low, level 3
b. Reactor pressure - high
c. RHR area temperature - high
d. RHR equipment area differential temperature - high

These redundant signals provide the same isolation function as the inoperable high flow isolation. This sequence of events, however, continues to illustrate a breakdown in management controls.

3. Confirmatory Action Letters

A Confirmatory Action Letter was issued to the licensee on June 17, 1985 stating the action needed to be taken prior to startup and long range actions being taken to prevent recurrence of this problem.

The following actions were to be taken prior to startup of Unit 2:

a. Review, for all safety-related electrical and mechanical modifications, made or planned during this outage, all packages to ensure that modifications properly implement the design concept and that drawings to be used by operational personnel accurately reflect the modification.

b. Physically walkdown all safety-related systems modified during the outage to verify that the actual installation matches the planned modification. This walkdown is limited to physically accessible items.

c. Review tests performed on all safety-related systems on which modifications or maintenance was performed during this outage to assure that testing adequately demonstrated operability in light of the work actually performed. Perform additional tests as required.

d. Test all level switches, modified during the outage by:

   (1) Up to instrument block---vary actual level and verify proper response to level change.

   (2) From instrument block to instrument---physically walkdown to verify proper alignment for operation.

e. Review all safety-related mechanical and electrical operational checklists to verify proper alignment of plant systems. This effort will provide an extra level of assurance on both systems that were modified and those that were not subject to modification during the outage.

f. Provide test results, your conclusions, and a summary of corrective actions to the NRC resident office. This action will be followed by open item (374/85018-02(DRP)).

The followup inspection addressing items a. through e. was completed in Inspection Report 374/85020.

The following actions were also to be taken by the licensee after startup of Unit 2:

a. Prior to initiation of any further safety-related modifications by a contractor, review and revise, as required, the current Quality Control guidance for safety-related modifications in the areas of drawing updates, QC hold points, and operability tests, and assure that the contractor involved has complied with these changes. This will be followed by open item (374/85018-08(DRP)).

b. By August 1, 1985, review all contractor Quality Control programs to assure that program modifications in the areas of updating field drawings, QC coverage during installation, and conduct of adequate construction tests are instituted by all contractors in light of lessons learned during this event. This action will be followed by open item (374/85018-09(DRP)).

Subsequent to the additional problem identified on Unit 1 on July 17, 1985, another Confirmatory Action Letter was issued on July 19, 1985 to address the additional actions to be taken prior to startup of either unit:

a. Review the entire list of Drawing Change Requests (DCR's) and determine those DCR's that have been rejected or cancelled (373/85023-03(DRP); 374/85018-05(DRP)).

b. Review all rejected or cancelled DCR's and determine the status of their disposition (373/85023-04(DRP); 374/85018-06(DRP)).

c. For those DCR's which have been rejected or cancelled or for which the dispostion is unknown, verify that critical drawings onsite are properly annotated to show the present status of the associated system and/or that drawing aperature cards show they are affected by a DCR. All remaining open DCR's will be reviewed within two weeks of startup. Completion of this action will be tracked as open item (373/85023-05(DRP); 374/85018-07(DRP)).

d. Implement a documented review of all EQ work requests prior to performing the work to ensure that qualification is preserved. This review applies to all EQ work requests initiated subsequent to July 19, 1985, and will continue until the maintenance procedures have been updated to reflect EQ requirements. Completion of this action will be tracked as open item (373/85023-06(DRP); 374/85018-08(DRP)).

e. Implement a documented review of surveillances on EQ equipment prior to performance to ensure that qualification is preserved. This review applies to all surveillances on EQ equipment initiated subsequent to July 19, 1985, and will continue until the surveillance procedures have been updated to reflect EQ requirements. Completion of this action will be tracked as open item (373/85023-07(DRP); 374/85018-09(DRP)).

f. By August 5, 1985, complete a documented review of one EQ component of each type for all EQ binders that have been issued to the site and for which a site review has been performed. This review will ensure that all appropriate EQ requirements were accomplished during installation. Completion of this action will be tracked as open item (373/85023-08(DRP); 374/85018-10(DRP)).

g. By September 2, 1985, complete a documented review of all EQ binders that have been received by the site, but that have not yet been reviewed, and ensure that appropriate EQ requirements were accomplished during installation. Completion of this action will be tracked as open item (373/85023-09(DRP); 374/85018-11(DRP)).

The immediate actions required prior to startup were completed and Unit 2 was authorized to startup on July 20, 1985.

4. Summary

The safety significance of the events described in this report are minimized by the fact that Unit 2 was in cold shutdown during the evolutions. Notwithstanding the above, it is of significant concern to the NRC that the licensee allowed the condition of the unit to degrade to a point where ECCS systems would not have automatically responded to a reactor level transient. Additionally, secondary containment integrity was not maintained as required due to the licensee's failure to recognize its necessity. During the time when all ECCS systems were degraded and secondary containment integrity was not established, the primary containment was open to the secondary containment as such if a leak had occurred there existed a potential for release of radioactive material to the environs.

As previously noted, the safety significance of the improperly piped isolation switches on Unit 1 was also minor due to the redundant isolation features available. The affected valves are also normally closed during power operation.

These events illustrate a significant and continuing breakdown in management controls. Region III has repeatedly expressed concerns for similar LCO violations and repeated modification problems. Specifically, the October 1984 problems associated with a loss of Standby Gas Treatment (SBGT) and the resultant Civil Penalty, (373/84-036), the April 17, 1985 discovery of miswired switches for Automatic Depressurization (ADS) and, more recently, the May 3, 1985 discovery of miswired temperature detectors affecting RCIC operability. It is apparent that licensee management is not effectively addressing these concerns as witnessed by these continuing problems nor are they meeting their commitment in response to identified violations. The CECo April 19, 1985 response to the SBGT event stated: "In order to preclude this type of problem in the future, LaSalle Station will require that a test be conducted to demonstrate operability anytime a safety-related system is returned to service. A Post Maintenance Operational Test Checklist has been

developed to ensure that the post maintenance test specified adequately demonstrates system operability in light of the work actually performed. Nuclear Station Division has directed that each CECo Nuclear Station review this checklist for applicability."

5. Open Items

Open Items are matters which have been discussed with the licensee, which will be reviewed further by the inspector, and which involve some action on the part of the NRC or licensee or both. Open items disclosed during the inspection are discussed in Paragraph 3.

6. Enforcement Conference

The NRC staff met with licensee representatives (denoted in Paragraph 1) for an Enforcement Conference on June 24, 1985 at LaSalle County Nuclear Power Station. The Conference was held to review the circumstances that led to the inoperability of all three ECCS divisions during the period June 3-10, 1985 and the loss of secondary containment during the period June 5-8, 1985. The licensee stated they believed the problems were due to three principal causes: (1) errors in production drawings, (2) lack of adequate QC involvement, and (3) inadequate testing because there was no requirement for system walkdowns. The licensee's staff proposed eleven corrective actions that they believed would resolve these problems. Some of the more significant proposals included: (1) implement a maintenance and operation checklist for post maintenance testing prior to return to service, (2) upgrade station and contractor quality control hold point utilization, (3) upgrade contractor production drawing control, and (4) revise station modification procedure to clarify physical walkdown requirements. The staff also discussed the likely informational content of the inspection report with regard to documents or processes reviewed by the inspectors during the inspection. The licensee did not identify any such documents/processes as proprietary.