U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-373/82-11(DETP)

Docket No. 50-373 License No. CPPR-99

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

Facility Name: LaSalle County Station, Unit 1

Inspection At: LaSalle County Station, Unit 1

Inspection Conducted: February 9-12, 16-19, 23, 24, and March 5, 1982

Inspectors:

R. Gardner — 4/7/82

J. Grobe — 4/8/82

F. Hawkins — 4/8/82

W. Key — 4/8/82

R. Mendez — 4/7/82

J. Neisler — 4-9-82

E. Nightingale — 4-9-82
Observer

R. Walker — 4-9-82

I. Yin — 4/7/82

H. Wescott — 4-9-82
Project Inspector

C.C. Williams

Approved By: C. C. Williams, Chief
Plant Systems Section

4/7/82

Inspection Summary

Inspection on February 9-12, 16-19, 23, 24, and March 5, 1982 (Report No. 50-373/82-11(DETP))
Areas Inspected: Special inspection to make a summary assessment of the conformance of as-built configurations to design requirements prior to issuance of an operating license. The areas of construction inspected were Civil, Electrical, Instrumentation, Fire Protection, Piping and Hangars, QA/QC, Welding, Preservice Examination. This inspection involved a total of 483 inspector-hours onsite by ten NRC inspectors, including 0 inspector-hours onsite during off shifts.
Results: Of the eight major areas inspected, no items of noncompliance or deviations were identified in seven areas; three apparent items of noncompliance were identified in one area (Paragraphs 4.A.(G) - failure to use documented procedures, Severity Level V; 4.B - failure to identify and correct deficiencies, Severity Level V; 4.C - failure to perform adequate inspections.

DETAILS

1. Persons Contacted

Commonwealth Edison Company (CECo)

D. Annis, Project Engineer
*R. Cosaro, Project Construction Superintendent
J. Dierbeck, Project Construction Engineer
*L. O. DelGeorge, Director of Nuclear Licensing
*J. Gieseker, Projection Construction Engineer
J. Groth, Project Construction Engineer
J. Harchut, Field Engineer, Civil
H. Hentschel, Assistant Technical Staff Supervisor
*R. Holyoak, Station Superintendent
*J. J. Maley, Manager of Projects
*T. E. Quaka, Site QA Superintendent
*R. T. Rose, Lead Structural Engineer
D. Schacht, Field Engineer, Civil
*C. Schroder, Nuclear Licensing
*D. L. Shamblin, Staff Assistant Project Manager
B. R. Shelton, Project Engineering Manager
*W. J. Shewski, Manager of QA
*D. J. Skoza, QA Engineer
*B. B. Stephenson, Project Manager
*T. E. Watts, Project Engineer
E. Wendorf, Project Construction Engineer
D. Zebrauskas, QC Engineer, Operations

Sargent and Lundy (S&L)

*E. B. Branch, Mechanical Design Director
E. H. DeBoo, Senior System Engineer
L. D. Dolder, QA Coordinator
R. Dzmbanski, Component Qualification Division, Senior Engineering Analyst
S. A. Gilbraiel, Supervisor
D. C. Haan, Project Manager
N. E. Hanna, Engineering Analyst
M. Hassaballa, Supervisor, Component Qualification Division
S. Jean, Senior Structural Engineer
S. M. Kazmi, Supervising Design Engineer
*S. D. Killian, Project Engineer
*G. T. Kitz, Head Mechanical Engineering Division
B. Lunde Engineering Analyst
R. J. Mazza, Project Director
P. R. Olson, Supervisor, Mechanical Engineering Division
*B. R. Parduhu, Mechanical Project Engineer
Y. A. Patel, Supervisor, Component Qualification Division
*C. Podczbrwaski,
R. H. Pollock, Mechanical Project Engineer
J. L. Smetters, Engineering Analyst

M. Vega, Mechanical Engineer
V. K. Vuma, Consultant
S. Yassin, Component Qualification Division Specialist

Walsh Construction Company

*M. R. Dougherty, QA Manager
D. Cushing, Project Engineer

Quadrex

J. Goldin, Manager, Corporate QA
R. Gostage, Project Engineer
T. Kaul, Applications Engineer
G. J. Lee, Consultant, Engineer
A. Morshedi, Project Manager
R. Naymark, Vice President
D. F. Seidel, Assistant Project Manager
S. Sud, Project Engineer

*Denotes those personnel attending the exit meeting held at the USNRC Region III office on March 1, 1982. During the inspection at the LaSalle County Station exit meetings were held on a daily basis in order to keep the licensee informed of any findings.

Other members of the licensee and contractors staff were interviewed during the course of this inspection.

2. Licensee Action on Previously Identified Items

(Closed) 10 CFR 50.55(e) Report No. 50-373/81-02, dated February 27, 1981. Subject: Inspection of HFA relays in response to I&E Information Notice No. 81-01 revealed bobbin assembly cracking.

A. The inspector reviewed CECo reports to NRC Region III as follows:

(1) Interim Report dated March 25, 1981.
(2) Interim Report dated July 31, 1981.
(3) Final report dated September 11, 1981.

B. The inspector further reviewed CECo's LaSalle Nuclear Station, HFA Relay Coil Replacement and Relay Inspection Report, Project No. 391D7003, containing permanent records as follows:

(1) Letter of Delegation
(2) Customer Order
(3) Document Index
(4) Items Lists
(5) Receiving Inspection Reports
(6) Material Certifications
(7) Traveller
(8) Nonconformity Reports

(9) Procedures
(10) Letters of Approval
(13) Correspondence
(12) Calibration Log
(13) Certifications of Calibration
(14) QC Personnel Qualifications
(15) Audit Reports

This item appears to be in conformance with CECo's Final Report to Region III and is considered closed.

(Closed) 10 CFR 50.55(e) Reports No. 50-373/81-04 and No. 50-374/81-04, dated June 16, 1981. Subject: Hydrogen Recombiner system deficiency in that the recombiner discharge lines were attached to penetrations M-95 and M-102 located at elevation 701'0". The normal suppression pool water level is 699'11". In the event that a postulated incident occurred wherein the suppression pool water level were to rise above the discharge line, the discharge head would increase causing the gas flow rate to decrease.

(1) The inspector reviewed CECo's report to NRC Region III as follows:

(a) Interim report dated July 16, 1981 (this report is also considered to be the final report).

(2) The inspector also reviewed P&ID M-859 SH. No. 1 to verify the required drawing changes had been made, and visually examined the re-routed lines that are now located at elevation 725'6".

This item appears to be in conformance with CECo's Final Report to Region III dated July 16, 1981, and is considered closed.

(Closed) 10 CFR 50.55(e) Report No. 50-373/81-07 dated September 22, 1981. Subject: Low pressure instrument sensing line excess flow check valves would not close on a differential pressure in the event of a sensing line break between the valve and the instrument.

(1) The inspector reviewed the CECo report to NRC Region III, dated October 22, 1981, stating that, replacement spring and poppet assemblies will be installed allowing the excess flow check valves to close should a sensing line break occur at the instrument.

(2) The inspector also reviewed documentation as follows:

(a) Material Receiving Report No. 9173, dated November 18, 1981, for the valve assemblies.

(b) Certificate of Compliance, dated November 10, 1981, for the stem and spring assemblies.

(c) Documentation check list.

(d) Certified Material Test Report stating the material was the same as SA479TY316.

(e) Low pressure excess flow check valve test Procedure LST 81-100, Revision 0, dated November 24, 1981.

The licensee stated that all required replacements had been installed in Unit 1.

This item is considered closed.

(Closed) 10 CFR 50.55(e) Report No. 50-373/81-09 dated October 6, 1981. Subject: Thirty-six ASCO solenoids installed in Units 1 and 2 were unqualified in that they did not meet performance specifications.

The inspector reviewed CECo's Final Report to Region III dated November 6, 1981, and the following documentation:

(1) Material Receiving Report No. 9116, dated November 2, 1981.

(2) Certificate of Compliance certifying that the valves meet IEEE Standards 323-1974, 382-1972, 344-1975, and were qualified to ASCO Specification AQS-21678, Revision B, dated February 15, 1978.

(3) Receipt Inspection checklist dated November 2, 1981.

(4) Visually verified that three of the solenoids were installed.

This item appears to be in conformance with CECo's Final Report to Region III and is considered closed.

(Closed) 10 CFR 50.55(e) Report No. 50-374/80-02, dated September 2, 1980. Subject: Cracks discovered in the insulation of certain feedthrough conductors as they enter or exit the epoxy module portion of the penetration.

(1) The inspector reviewed CECo's reports to NRC, Region III as follows:

(a) Interim report, dated October 2, 1980.
(b) Interim report, dated March 6, 1981.
(c) Final report, dated May 18, 1981.

(2) The inspector also reviewed documentation as follows:

(a) Nonconformance Reports Nos. 483 dated September 30, 1981, and 456 dated January 4, 1982.

(b) ASME Form N-2 for the penetration assemblies.

(c) Certificate of compliance.

(d) Gas leak rate test, dated March 10, 1981.

This item appears to be in conformance with CECo's Final Report to Region III dated May 18, 1981, and is considered closed.

(Closed) Open Item (50-373/81-42-01): Electro Hydraulic Control (EHC) oil was spilled on Class 1E electrical cables. The licensee initiated NCR 550, on August 21, 1981, to document this spill. The inspector observed that the licensee has closed NCR 550 and has determined that there will be no short or long term detrimental effects on the cables involved "Based on the short time exposure of cable with the fluid and the additional information obtained from the cable suppliers...."

(Open) Unresolved Item (50-373/81-16-01; 50-374/81-14-01): The licensee had not installed required tags on instrument sensing lines. The inspector observed that the licensee has now received from S&L, Piping and Instrument Diagrams (P&ID's) which identify the lines required to be tagged and the color requirements for the tags. However, the licensee has only partially installed the tags and is using Brady tape in lieu of metal tags. This item will remain open pending completion of the tag installations and the basis for the use of Brady tape in lieu of the specified metal tags.

3. Functional or Program Areas Inspected

A. The purpose of this special inspection was to provide an assessment of the licensee's readiness to obtain an operating license (OL) for safe operation of LaSalle County Station Unit 1, (Docket No. 50-373). The licensee's current expected fuel load date is March 15, 1982. It is the concensus of the special inspection team members that May 15 to June 1, 1982, is a more realistic time frame for fuel load. This predicted time frame is based on the following:

(1) During this inspection approximately twenty-nine (29) ASME N-5 forms remained to be signed by the Authorized Nuclear Inspector and the licensee. Work remaining to be done before the N-5 forms are completed are design review and approval, and final walkdown of the remaining systems involved.

(2) Close out of items on the licensee's open items list.

(3) Close out of the remaining 10 CFR 50.55(e) reports.

(4) Close out of NRC Region III findings.

4. Observation of Electrical Equipment

A. The Region III inspector observed the breaker settings pertaining to Motor Control Centers (MCC) 135X-1 and 135X-2. The required breaker setting data is delineated on Sargent and Lundy (S&L) Electric Service Order (ESO) data sheets. In comparing the actual MCC breaker settings with the required setting data the following discrepancies were observed:

(1) MCC 135X-1

(a) Cubicle A2 - Actual heater (overload relay) setting was .82. The required setting was .88.

(b) Cubicle B1 - Actual heater setting was 2.0. The required setting was 1.68.

(c) Cubicle B2 - Actual magnetic (instantaneous trip relay) setting was 24 on one phase. The required setting was 20.

(d) Cubicle C1 - Actual magnetic setting was 24. The required setting was 16.

(e) Cubicle E4 - Actual heater setting was .88. The required setting was .83.

(f) Cubicle F5 - Actual heater setting was .39. The required setting was .50.

(2) MCC 135X-2

(a) Cubicle A2 - Actual magnetic setting was 40. The required setting was 50. Actual heater setting was 6.0 while the required setting was 5.0.

(b) Cubicle B3 - Actual heater setting was 14. The required setting was 12.

(c) Cubicle C4 - Actual magnetic setting was 530. The required setting was 500.

The inspector determined that the root cause of the aforementioned discrepancies was the failure of the licensee to prescribe MCC breaker setting activities by an appropriate documented procedure. The inspector informed the licensee that a procedure was required to assure the following:

(d) Adjustments to MCC breaker settings correctly reflect the requirements delineated on the ESO documents.

(e) Consistent data is recorded concerning the actual MCC settings - the inspector observed numerous instances in which inconsistent data was recorded on electrical data sheets associated with the aforementioned MCC cubicles.

(f) Approved quantitative acceptance criteria is delineated - the inspector was informed that a 10% tolerance factor was "understood" by licensee personnel.

(g) Onsite revisions to the ESO requirements are properly reviewed and translated into revisions to the ESO documents - the inspector determined that, in some instances, the aforementioned discrepancies were a result of onsite decisions by the licensee to deviate from ESO requirements; however, no actions had been initiated to obtain approval for the deviations or to ensure that the ESO documents were properly revised.

This failure to accomplish activities affecting quality using documented procedures is considered to be in noncompliance with 10 CFR 50, Appendix B, Criterion V as described in Appendix of the report transmittal letter. (50-373/82-11-01)

B. The MCC's identified in Paragraph 1.a were manufactured by Kloctner-Moeller. The inspector has requested the licensee to obtain additional data concerning the overload devices. This data is needed to resolve concerns pertaining to the design of the overload device and the method used by the manufacturer in terminating internal wiring to the overload device. Pending review of this data, this is an open item. (50-373/82-11-02)

C. The inspector observed the breaker settings pertaining to High Pressure Core Spray (HPCS) Motor Control Center 143-1 (supplied by General Electric). The licensee informed the inspector that there was no approved data to which the actual HPCS MCC breaker settings could be compared. A letter had been sent to GE on March 23, 1979, requesting GE to review existing data and submit any missing data. The licensee stated that GE has not responded to this letter.

The inspector determined that the licensee has set the MCC breakers to a setting which will result in unrestricted operation of the MCC breakers. However, no approval has been given for these settings and the licensee has not submitted data pertaining to these settings to S&L for approval prior to this inspection. The licensee further stated that no nonconformance report (NCR) had been initiated to document and control this nonconforming condition.

This failure to establish measures to assure that the use of unapproved MCC breaker settings was promptly identified and

corrected is considered to be in noncompliance with 10 CFR 50, Appendix B, Criterion XVI as described in Appendix A of the report transmittal letter. (50-373/82-11-03a)

D. During the inspection of the aforementioned MCC's the inspector observed the following instances in which incorrect nameplates were installed on MCC cubicles:

(3) MCC 135X-1

(a) Cubicle A2 - The nameplate read "CRD Return Line Isolation Valve 1C11-F082." This cubicle is a spare and is required to be so identified.

(b) Cubicle F6 - The nameplate read "DW Cooler 1B Inlet Outboard Isolation Vlv 1VP053B." This cubicle actually feeds "DW Cooler 1A Inlet Outboard Isolation Vlv 1VP053A" and is required to be so identified.

(c) Cubicle G1 - The nameplate read "DW Cooler 1A Inlet Outboard Isolation Vlv 1VP053A." This cubicle actually feeds "DW Cooler 1B Inlet Outboard Isolation Vlv 1VP053B" and is requires to be so identified.

(4) MCC 143-1

Cubicle 4A - The nameplate read "Spare". This cubicle actually feeds "Petter Diesel Engine Air Compressor Air Dryer 1DG09DB" and is required to be so identified.

These nonconforming conditions had not previously been identified by the licensee.

This failure to establish measures to assure that the aforementioned nonconforming conditions are promptly identified and corrected is a further example of noncompliance as cited in Paragraph 1.c above. (50-373/82-11-03b)

E. The inspector observed the breakers associated with DC Distribution Busses 1A, 1B and DC Distribution Panels 111X, 112X, 111Y, 112Y. The size of the installed breakers was compared with the requirements delineated on applicable S&L Wiring Diagrams. During this inspection the inspector determined that the size of the breaker installed in position 20 on DC Distribution Panel 112Y did not conform to the requirements of S&L Wiring Diagram 1E-1-4442AA, Revision P. The installed breaker was rated at 60 amps while the required breaker rating was 15 amps. It was subsequently determined that Revision N, dated February 22, 1980,

to the aforementioned wiring diagram revised the subject breaker rating from a 60 amp rating to a 15 amp rating. However, the licensee had not previously identified and corrected this nonconforming breaker installation.

This failure to promptly identify and correct this nonconforming breaker installation is a further example of noncompliance as cited in Paragraph 1.c above. (50-373/82-11-03c)

F. During the inspection of the DC Distribution Panels the inspector observed that the calibration stickers pertaining to panel mounted voltmeters and ammeters reflected a 1977 calibration date. The licensee was requested to identify the calibration period for panel mounted meters and the controls which will ensure that the calibration period is not exceeded.

This matter is under review by the licensee and is an open item. (50-373/82-11-04)

G. The inspector observed the installation of six Electrical Protective Assemblies (EPA) installed in Unit 1. The assemblies were observed to be installed in accordance with applicable S&L installation drawings. However, the inspector has requested the licensee to provide additional information concerning General Electric (GE) NCR No. 32. This NCR identified GE's concerns with the impact of onsite modifications on the previously seismically qualified assemblies. The inspector has requested the licensee to provide evidence that the effects of the modifications on the original seismic qualification were evaluated. Pending review of this evidence, this item is unresolved. (50-373/82-11-05)

H. The inspector observed the protective relays installed on 4160 volt switchgear 141Y. The inspector determined that the correct type of protective relays were installed.

5. Observation of Instrument Sensing Lines

A. The inspector observed the installed condition of instrument sensing lines associated with Engineered Safety Feature (ESF) instrument LIS-B21N031A and Reactor Protection System (RPS) instrument PSH-B21N023A. The as-built condition of the installed lines was compared with the following Morrison isometric drawings:

Instrument	Drawing
LIS-B21N031A	INB-33, Revision D
	INB-34, Revision C
PSH-B21N023A	INB-27, Revision C
	INB-28, Revision B
	INB-138, Revision A

During the observations of the installed lines, the inspector observed the following:

(1) The slope of the 6'3-1/4" section of instrument sensing line on which hangers M-1302-17(76) and M-1302-17(12) are located (as shown on isometric drawing INB-138, Revision A) was determined to be .30" per foot. "Fabrication Requirement" number 12, as identified on drawing INB-138, Revision A, requires that the "slope shall be 1/2" per foot. (Min) per ME No. 1441."

(2) The slope of the 8'3" section of instrument sensing line on which hanger M-1302-17(10) is located (as shown on isometric drawing INB-138, Revision A) was determined to be .196" per foot. As previously stated, the drawing requires a minimum of 1/2" per foot slope. In addition, Amendment 4 to S&L Specification J-2530 states, in part, "Under no circumstances should a slope of less than 1/4" per foot of run be applied without approval from Consulting Engineers."

(3) The 9'3" section of instrument sensing line on which hangers M-1302-17(33) and M-1302-17(34) are located (as shown on isometric drawing INB-33, Revision D) is bent at the coupling resulting in a non-uniform (reverse) slope for that section of the line.

The aforementioned nonconforming conditions were not identified by the licensee during the QC linewalk inspection of February 17, 1981 and October 7, 1981.

This failure of inspection activities to verify the conformance of instrument sensing line installations to instructions, procedures, and drawings is considered to be in noncompliance with 10 CFR 50, Appendix B, Criterion X, as described in Appendix A of the report transmittal letter. (50-373/82-11-06)

6. Pipe Suspension Systems Review performed at the Site on February 9-10, 1982

The inspector performed system configuration line walkdowns on the following S&L and NSC designed subsystems. The observations included dimensional measurements of pipe sections, component locations and orientations, and piping suspension system types and installation positions in reference to pipe fittings and components. The purposes of the task are two fold. First, to ensure that the as-built configuration concurs with the design drawings at the site. This was subsequently checked out and found to be in order during a document review session performed by the inspector. Second, to carry these dimensional measurements to the design engineering offices to verify whether or not they were exact conditions as prescribed in the pipe stress analysis computer input isometric drawings and printouts. This, and many other design control issues, were reviewed by the inspector at the S&L and NSC engineering offices. The findings were documented in Paragraphs 7 and 8.

A. Subsystem HP-03 High Pressure Core Spray (HPCS)

(1) Portions of 1HP01B-24" HPCS pump suction, including the following pipe supports and restraints:

HP01-1012S
HP01-1014S
HP01-1019X
HP01-1016S
HP01-1018V

(2) Branch connection 1HP14A-24", including the following pipe supports and restraints:

HP01-1003S
HP01-1004S
HP01-1010S
HP14-1005S
HP14-1010S

The subsystem was analyzed by Sargent and Lundy. The design temperature is 212°F, and the design pressure is 100 psig.

B. Subsytems HP-02, 06, and 07 (HPCS)

(1) Portions of 1HP02A-16" (HP-02) HPCS pump discharge analyzed by Sargent and Lundy, with design temperature of 212°F and design pressure of 1325 psig. The suspension system included:

HP02-1009V
HP02-1021S
HP02-1011S
HP02-1515S
HP02-1517S

Two rigid struts supporting the valve motor operator.

(2) Branch connection, HP-07, designed by Quadrex, including the following line designations:

1HP20B-4" (212°F/1325 psig design)
1HP02C-3" (212°F/1325 psig design)
1HP02C-1" (212°F/1325 psig design)
1HP20C-2" (212°F/100 psig design)

The system connects to 1HP02A-16" header at 4" and 3" Weldolets at two places. No supports or restraints before the 1" relief valve. The system is supported solely on the 16" header.

(3) Branch connections 1HP09C-4" (HP-06) with 212°F/1325 psig design, analyzed by Quadrex, including the following supports and restraints:

HP09-1030S
HP09-1029X
HP09-1027X
HP09-1028X
HP09-1026X
HP09-1007G

C. Subsystem SC-01 Standby Liquid Control System Pump 1C41 C001 A Discharge

(1) Portions of 1SC02AA-1 1/2" (175°F/1400 psig design), with the following supports and restraints:

FSC-1201-H03S
FSC-1201-H02X
FSC-1201-H05R

(2) Portions of 1SC06A-1 1/2" (150°F/1400 psig design), with the following supports and restraints:

FSC-1201-H09S
FSC-1201-H08G
FSC-1201-H07S
FSC-1201-H07S
FSC-1201-H10G

(3) 1SC07B-1 1/2" (150°F/150 psig design), with pipe guide No. H01G. This is a Class D line connecting to a Class B system.

(4) 1SC08AA-3/4", relief valve inlet (175°F/1400 psig design) to valve 1C41-F029A, and 1SC08BA-1" (175°F/150 psig design) valve discharge. The one pipe guide installed at the discharge line B FSC-1201-H01G. This subsystem was analyzed by Sargent and Lundy.

D. Subsystems RI-06 and RI-63, Reactor Core Isolation Coolant System

(1) Portions of 1RI16B-8", RI-06 (170°F/100 psig design) was analyzed by Quadrex, with the following supports and restraints:

RI16-1021V
RI16-1015S
RI16-1016S
RI16-1025S
RI16-1014X
RI16-2811C

RI16-1023S
RI16-1022S
RI16-1024S

(2) Portions of 1RI17A-8", RI-06 (170°F/100 psig design) was analyzed by Quadrex, with the following supports and restraints:

RI17-1012V
RI17-1021X
RI17-1020X

(3) Portions of 1RI39A-4", RI-06 (170°F/100 psig design) was analyzed by Quadrex, with the following restraints:

RI39-1031X
RI39-1802X

(4) A portion of 1RI20A-2", RI-63 (190°F/100 psig design) was analyzed by Sargent and Lundy, connecting to 1RI16B-8".

E. Subsystem LC-02, Isolation Valve Leakage Control

The subsystem was analyzed by Quadrex, 212°F/300 psig design, including the following lines:

1LC09B-2 1/2"
1LC09CA-4"
1LC09CB-4"
1LC09C-4"

Supports and restraints include:

LC09-1002S
LC09-1005X
LC09-1011S
LC09-1004X
LC09-1012S
LC09-1008X
LC09-1001S
LC09-1010S
LC09-1003S
LC09-1007X
LC09-1009V

7. Inspection of Sargent and Lundy on February 11-12, 1982, and Followup

A. Subsystem HP-03

The inspector reviewed S&L Calculation No. EMD-022450, dated October 29, 1981, and concluded that:

(1) The piping and pipe suspension systems were installed and evaluated in accordance with the S&L procedure, Calculation No. 025244, "Piping Analysis Lesson Plan, Volume II, LaSalle County Nuclear Station Project Unique Procedures and Design Data," Revision 1, dated February 12, 1981.

(2) Pipe stres riser at Hanger HP14-1005V, where the attachment lug was welded to the pipe elbow was evaluated and considered to be acceptable by S&L design engineers.

(3) The piping support, rigid restraint, and snubber loads were checked to be in conformance with the latest computer design stress and suspension loading printouts.

(4) The equipment qualification analysis for the HPCS pump and motor is discussed in Paragraph 9.

B. Subsystem HP-02

The inspector reviewed S&L Calculation No. EMD-021965, dated March 3, 1981, and concluded:

(1) Same as 7.A.(1)

(2) Same as 7.A.(3)

(3) Same as 7.A.(4)

(4) The additional dead weight, and dynamic loadings from the branch connections 1HP20B-4", 1HP09C-4", and 1HP20A-3", which were analyzed by Quadrex were not factored into the existing variable spring hangers and snubbers. The inspection was continued at Quadrex. See Paragrph 8.A.(5).

(5) The motor operated valve 1E22-F012 installed on line 1HP09C-4" connecting to the 1HP02A-16" line was analyzed by Quadrex. The design interface included two rigid struts installed on the connecting flanges below the limitorque valve operator to the 16" header. The strut was measured to be approximately 45 transversed to the 16" header, and yet only horizontal valve loadings were transmitted to S&L for their header support evaluation. Continuation of this inspection at Quadrex was documented in Paragraph 8.A.(6).

C. Subsystem SC-01

The inspector reviewed S&L Calculation No. EMD-024674, dated February 1, 1981, and concluded:

(1) Similar to 7.A.(1). The restraint location of 1SC07B-1 1/2" H01G, that exceeded the procedure requirement, was described and approved in a FSCA No. 2243, dated December 4, 1981. The design drawing revision, Revision A, was issued on December 19, 1981.

(2) Same as 7.A.(3).

(3) The nonsafety-related line, 1SC07B-1 1/1", was modeled into the computer. The methodology applied was considered to be sound and adequate.

(4) The thrust loading reactions, including the discharge line pressurization in conjunction with other primary loading conditions during the relief valve 1C41-F029A lift, was not included in the calculation. The set pressure is 1400 psig. The relief valve discharge line was designed to 150 psig. This is an apparent lack of design consideration to include all the live occasional dynamic loadings required by the ASME Section III code. During the review, the inspector was presented a S&L Inter-Office Memorandum, MED-028320, "Feedwater Heater SRV Piping (DV Systems)," dated February 18, 1981, where it stated that the heater shell pressure of 400 psig relieves to the atmospheric pressure at 70°F resulted in insignificant reactive loadings. The inspector reviewed the IOM and considered the conditions could not represent the SC-01 relief valve in question. During the inspection conducted at Quadrex on February 17-18, 1982, the inspector was presented a S&L IOM, dated February 17, 1982, from EMD to Project, "Answers to Concerns Raised by I. Yin during his February 11-12, 1982 Audit," where the results show that the relief valve thrust to be insignificant. The relief valve calculation was presented to the inspector on March 1, 1982, at Region III. In addition, the licensee representatives presented the S&L Mechanical Department Standard, MES-M00D-5.1, "Main System Safety Relief Valve Location Guidelines," Revision 0, dated April 27, 1977. The inspector reviewed the standard, and had no adverse comment. Relative to the generic analytical requirements for safety valve, relief valve, safety relief valve, and power-actuated pressure relief valve, the inspector stated that the present EMD procedures for the La Salle project had not delineated under what design conditions that the thrust loading will be minimum and, therefore, require no actual calculation or evaluation. This is an unresolved item. (50-373/82-11-07)

(5) During discussions at Quadrex on February 18, 1982, the relief valve 1C41-F029A evaluation was selected to be reviewed in parallel with matters described in Paragraph 8.A.(2).

The inspector reviewed the "Valve Acceleration Summary" contained in Table 8.1 of the S&L EMD-024674, and had no adverse comment. In regard to the valve interface loads from piping system, the licensee representatives stated that this information was documented on microfische.

During the meeting held at Region III on March 1, 1981, the licensee representatives presented a S&L Inter-Office Memorandum, dated May 19, 1980, File No. EMD-0230444, where it stated that equipment reactions are within the manufacturer's allowables. The work performed was in accordance with S&L procedural requirements in "Checklist for Report Completion Status."

D. Subsystem RI-63

The inspector reviewed S&L Calculation No. EMD-023172, dated August 5, 1980, and concluded that:

(1) Same as 7.A.(1).

(2) All branch connection displacements resulted in OBE, SSE, SRV 1%, SRV 2%, SRV single activiation, CO1, CO2 and chugging analysis had been factored into the system calculation. These directional and rotational displacements were determined by Quadrex.

8. Inspection of Quadrex on February 17-18, 1982, and Followup

A. Subsystem HP-06 and HP-07

The inspector reviewed the Quadrex Calculation No. QUAD-1-80-131, Revision 2, dated December 11, 1981, and concluded that:

(1) The calculated stress intensification factor of 3.37 at the Bonney Forge Weldolet connection is conservative. The value of 3.37 was based on unreinforced tee connection, which is more than the calculated weldolet connection of i = 1.98.

(2) The relief valve 1E22-F035 dynamic reactive forces and moments at the 1" inlet and the 2" outlet connections were checked against the S&L acceptance valve acceleration and nozzle loading criteria. The procedural requirements were established in Quadrex document QUAD-7-79-025, "Safety Related Piping Stress Analysis Instructions," Revision 5, dated May 1, 1981. Form 5A-7A, "Acceleration of In-line Component" was based on S&L Lesson Plan No. 025244. Form SA-7B, "Interface Loads from Piping System on Components" was based on S&L IOM, File No. EMD-027515, "Allowable Nozzle Loads for Welded End Valves," dated January 15, 1982.

(3) The Quadrex Procedure QUAD-7-80-91, "EMD Piping Analysis Lesson Plan Volume II, LaSalle County Project Unique Procedures and Design Data," Revision 2, dated May 7, 1981 has incorporated the latest S&L Lesson Plan No. 025244 requirements.

(4) The modeling of dynamic branch connection movements in terms of displacements and rotations were performed in accordance with Quadrex QUAD-7-79-025, Revision 5, dated May 1, 1981, Header Displacement Analysis."

(5) In conjunction with Paragraph 7.B.(4), the following additional resultant forces and moments were determined near the HPCS pump discharge nozzle:

(a) 4" HP09C-S31" away from the nozzle

Condition B	F = 5,558 lb. M = 5,847 ft. lb.
Condition C	F = 5,494 lb. M = 7,348 ft. lb.

(b) 4" HP20B-28" away from the nozzle

Condition B	F = 1,073 lb. M = 1,509 ft. lb.
Condition C	F = 1,202 lb. M = 1,707 ft. lb.

Where:

Condition B = Primary loadings resulting from pressure, weight, OBE and SRV 1% effects.

Condition C = Primary loadings resulting from pressure, weight, SSE and other hydro dynamic effects.

This examination disclosed that the load increases at the HPCS pump discharge nozzle were not factored into the overall pump qualification analysis as discussed in Paragraph 4 of this section of the report. This could invalidate the S&L EMD Report No. 028452, "LaSalle Nuclear Station 1 and 2 Equipment Qualification of HPCS Pump (Equipment No. E22-C001)," Revision 0, dated May , 1981.

(6) In conjunction with Paragraph 7.B.(5), the inspector reviewed Quadrex Calculation HP09-1037R, Revision B, dated January 25, 1982, and found the following loadings at the two rigid struts from the valve to the 16" HP-02 subsystem:

NP-200 F_A = 6,976 lb.

F_B = 1,113 lb.

F_C = 147 lb.

M_A = 0

M_B = 303 ft. lb.

M_C = 2,256 ft. lb.

NP-201 F_A = 4,717 lb.

F_B = 1,181 lb.

F_C = 499 lb.

M_A = 0

M_B = 1,031 ft. lb.

M_C = 2,396 ft. lb.

In discussion with the licensee representatives, the inspector was informed that the above revised data were recently forwarded to S&L for incorporation into the support evaluation. During a meeting held at Region III on March 1, 1982, the licensee presented the inspector S&L Calculation No. EMD-021965, dated February 26, 1982, which showed loading increases at the header restraints and at the HPCS pump discharge nozzle pipe connection.

(7) The piping and pipe suspension systems were installed and evaluated in accordance with the Quadrex Procedure QUAD-7-80-91, as discussed in Paragraph 8.A.(3) above.

B. Subsystem RI-06

The inspector reviewed the Quadrex Calculation No. QUAD-1-80-179, Revision 1, dated November 13, 1981, in the area of dynamic anchor movements at the IRI-20A-2", (S&L Subsystem RI-63) which is connected to the IRI16B-8" (Quadrex Subsystem RI-06), and found some discrepancies between the values generated by Quadrex, and the values applied in the S&L branch line calculation. The inspector reviewed Quadrex Procedure QUAD-7-79-025, where it stated that, "Displacement of less than 0.01 inches and rotations of less than 0.5 may be neglected unless it is determined that these small movements can have significant impact on pipe stress or restraint loads, (i.e., high stiffness branch line support configurations)," and had no adverse comment. The S&L procedure, File EMD-025724, "Simplified Method to Determine Minimum Branch Pipe Length for Header Movement,"

dated September 22, 1980, had a different approach in evaluating the piping dynamic analytical anchor movements. The provisions in the S&L procedures were also considered to be acceptable.

C. Subsystem RH-23 Residual Heat Removal

In conjunction with the findings stated in Paragraphs 7.B.(4), and 8.A.(5), the present S&L system analysis separation criteria is that, if the moment of inertia (I) ratio between the header and the branch connection is 7 to 1 or more, the branch line can be analyzed separately. The stresses at the connection, and the reaction forces and moments imposing at the header can be ignored. While the inspector had no concerns at branch connections piping stresses, he could not concur with the S&L practices to disregard the following areas, particularly where the I ratios are close to 7 to 1:

(1) Equipment nozzle loading increases that could exceed the manufacturer's established allowables.

(2) Header support and restraint load increases of more than 10% that requires evaluations by the S&L structural design engineering department.

In selection of a system with closer I ratios, the inspector reviewed Quadrex Calculation No. QUAD-1-80-163, Revision 1, not yet issued, for Subsystem RH-23. The branch connections are as follows:

. RH-23, 1RH12BC-8" to S&L Subsystem RH-08, 1RH13BB-18" at Node 5.

. RH-23, 1RH12AB-8" to S&L Subsystem RH-08, 1RH02AB-18" at Node 145.

. RH-23, 1RH12AC-8" to S&L Subsystem RH-11, 1RH53A-18" at Node 65.

I (18") = 1,172 in Q4D
I (8") = 72.5 in Q4D
I ratio = 16.16

The following reactional forces and moments at the branch connections were observed:

Node 5

Condition B	F = 4,320 lb.
	M = 9,319 ft. lb.
Condition C	F = 4,630 lb.
	M = 9,881 ft. lb.

Node 145

Condition B	F = 3,389 lb. M = 9,958 ft. lb.
Condition C	F = 5,187 lb. M = 15,062 ft. lb.

Node 65

Condition B	F = 5,924 lb. M = 18,969 ft. lb.
Condition C	F = 6,020 lb. M = 19,169 ft. lb.

This issue was discussed during a meeting held at Region III on March 1, 1982. The S&L staff stated that they had reviewed the conditions, and committed to perform the following additional analyses:

(1) For the branch connections that are near the rotational equipment, such as pumps and turbines, except for branch lines of 2" or smaller and where supports or restraints were loacated at the headings near the branch connections;

(2) For the five branch connections with close header/branch I ratios (7 to 20), the lines will be re-analyzed to include the entire piping subsystems.

The inspector reviewed the preliminary results of some of the analyses during an inspection conducted at S&L office on March 5, 1982, the results of HP-02, 06 calculation showed small nozzle loading increases at the HPCS pump discharge. The inspector stated that S&L should formally document the loading changes at nozzles and the header suspension systems per the two conditions discussed above. Furthermore, S&L should include in the report the line frequency changes at every system vibration mode. This is considered to be an unresolved item. (50-373/82-11-08)

9. HPCS Pump Qualification Analysis

A. Documents Reviewed

GE 22A1483AJ, "Design Specification Data Sheet for HPCS System," Revision 6, dated July 16, 1981.

GE 21A9222DA, "Purchase Data Sheet for Motor, Vertical (HPCS), MPL No. E22-C001," Revision 5, dated December 14, 1979.

GE 21A9243CK, "Purchase Specification Data Sheet for HPCS Pump, MPL No. E22-C001," Revision 2, dated January 25, 1979.

Ingersoll Rand Company (IR) DR-2000-7-KD, "Design Report of the IR Model 12x20-KD-8 As Designed for GE Purchase Order AC-792, Design Specification 21A9243CK, HPCS at LaSalle 1 and 2," dated April 5, 1973.

S&L EMD File No. 028452, "LaSalle Nuclear Station 1 and 2 Equipment Qualification of HPCS Pump (Equipment No. E22-C001)," Revision 0, dated May , 1981.

CECo letter to S&L, Subject: "LaSalle County Station, Units 1 and 2 SQRT Evaluation Form and NSSS Equipment List," dated August 16, 1979.

S&L IOM from Mechanical Department to all partners, "Project Authorization Memorandum - Serivce in connection with NSSS Safety-Related Equipment Qualification Re-evaluation," dated November 20, 1979.

S&L letter to CECo, "Project Authorization and Estimate," dated November 27, 1979.

IR Drawing No. D-12X20KD86X1-H accepted by S&L engineering department on May 2, 1979.

B. Design Analysis Review

In conjunction with Paragraphs 7.A.(4) and 7.B.(3), the piping forces and moments obtained in S&L Calculations EMD-022450, and EMD-021965 had exceeded the equipment manufacturer's allowables shown on the IR Drawing No. D-12X20KD86X1-H. This condition was not in accordance with the GE Specification 22A1483AJ, where it stated in Paragraph 4.2.1, that, "The loads applied to the HPCS pump nozzles shall not exceed the values specified on the HPCS pump outline drawing." The seismic design and analysis were also in difference with the provisions stated in the GE Purchase Specifications 21A9222DA and 21A9243CK.

In discussion with the S&L responsible engineers, it was stated that the licensee was aware of the situation. A situation that was created due to GE design criteria upgrade subsequent to pump qualification analysis that had performed by the pump manufacturer. The S&L Component Qualification Division (CQD) was assigned the task to re-evaluate, based on the present analytical methodology and acceptance criteria, whether or not hardware modification was warranted. In reviewing of the CQD (previously under EMD) Report No. EMD-028452, the following design conditions were observed:

Pump Suction

F = 14,303 lb. (maximum of the two units)
F = 12,019 lb. (IR allowable)
M = 758,796 in. lb. (maximum of the two units)
M = 515,061 in. lb. (IR allowable)

Pump Discharge

F = 21,510 lb. (maximum of the two units)
F = 13,900 lb. (IR allowable)
M = 403,560 in. lb. (maximum of the two units)
M - 500,925 in. lb. (IR allowable)

The inspector considered the present conditions acceptable based on the fact that the licensee had the final responsibility for the equipment purchased and installed at the plant, and that S&L evaluation analysis appeared to be technically sound and comprehensive. The NRC-NRR Seismic Qualification Review Team (SQRT) has interfaced with the licensee relative to the subject matters on generic basis.

10. Design Control Procedures-Pipe Suspension System

During this and previous examinations of pipe suspension system design control procedures and methodology, it has been determined that approximately 500 snubbers have been installed which in fact were not necessary and/or were unable by virtue of design to function as required.

A historical review of the circumstances and events that led to these issues focused on the identification of the design controls and interface communication areas which could be improved to preclude or minimize the recurrence of these instances of deficient design.

In response to questioning regarding this issue, the licensee representatives recounted four major changes in the design loads for the subject suspension systems: It was also reported that early in construction, the licensee decided not to optimize the design for any system when the requirements changed. It was inferred that this decision contributed to the frequently unusually complex appearance of as-built suspension systems.

Observation of apparently deficient snubber/rigid support installation by the NRC inspector was the basis for the NRC finding which resulted in the planned removal of approximately 500 mechanical snubbers for the reasons stated above.

As a result of the above NRC finding and these discussions, the NRC inspectors have identified at least four areas of design control involving this matter which should be improved to increase the effectiveness of design control procedures. They are as follows:

A. Identify clear instructions regarding the criteria for snubber application, i.e., dynamic/seismic displacement and thermal movement. Indoctrinate and train all relevant personnel regarding these criteria.

B. Provide a mechanism to improve as-built feedback from the site to all design/engineering analysts involved in the design of a system, for example, provide more frequent field visits and observations by the responsible analyst. Improve and take better advantage of existing feedback procedures. Include as-built photography as appropriate.

C. Optimize system design each time there is a significant change in design load requirements to an extent adequate to verify the as-built integrity of existing systems.

D. Re-examine the existing administrative philosophy which instructs that existing piping suspension systems not be optimized in terms of design, when there are significant changes in design loads. Consider significant qualification of this practice.

The foregoing issues are considered to be open. It is our expectation that the licensee will develop a comprehensive corrective action program regarding these procedures that include as a minimum the four elements outlined above and other provisions as dictated by a prudent response to this apparent weakness in design control. Open item (50-373/82-11-09).

This matter will be examined during subsequent NRC inspections of LaSalle Units 1 and 2.

11. Civil Construction Review

This portion of the inspection consisted of documentation review and visual inspection of selected safety-related concrete placements in the Unit 1 reactor and auxiliary buildings. A detailed description of each review and inspection is presented in this section of the report.

A. Visual Inspection

The inspection methods used in this study are typical of those endorsed by ACI 201. Modifications to the inspection guidance provided by ACI 201 were made to embellish the plan and more properly tailor it to accomplish the desired objectives of this inspection.

Four concrete placements in the Unit 1 reactor building were selected based on their configuration and accessibility. The placements represented varying degrees of placement difficulty and were made over the period May 21, 1975 to August 10, 1977. The visual examination of each placement included the evaluation of the following attributes:

(1) General appearance of the surface.

(2) Nature and extent of cracking.

(3) Evidence of cement/aggregate reactions.

(4) Secondary deposits in cracks or void (efflorescence, leaching, incrustration).

(5) Construction joint and form alignments.

(6) Nature and extent of dislocations resulting in joint movement, tilting, shearing, or misalignment of structural elements.

(7) Apparent effectiveness of curing.

(8) Extent and significance of surface characteristics:

- (a) Scaling
- (b) Spalling
- (c) Peeling
- (d) Popouts
- (e) Pitting or construction scarring
- (f) Dusting
- (g) Cold joints
- (h) Pour lines
- (i) Corrosion of reinforcement
- (j) Soft spots
- (k) Sand streaks or pockets
- (l) Honeycomb
- (m) Air/water voids
- (n) Segregation or stratification
- (o) Staining or discoloration.

(9) Indications of adequate consolidation in general.

(10) Indications of adequate consolidation behind embedments.

(11) Adequacy of repairs based on soundness and appearance:

- (a) Cosmetic
- (b) Structural.

(12) Satisfactory embedment of penetrations based on appearance and sounding as applicable.

(13) Obvious dislocation or misalignment of embedded plates.

(14) Satisfactory embedment of plates based on appearance and sounding as applicable.

(15) Apparent consolidation surrounding anchor bolts.

Each placement was inspected on the basis of a rating system for each item given above. The system consisted of designating each inspection attribute a number from one to four, according to its acceptability. (1 excellent, 2 good, 3 fair, 4 poor). These ratings were assigned based on the judgement of the evaluator utilizing past experience in the concrete industry. Visual examinations were supplemented by manual sounding with a hammer to assess the integrity of completed concrete repairs, embedments, and anchor bolts.

Each inspection attribute was categorized as either substantial or minor. Substantial items are those with structural significance and minor are those of an architectural or aesthetic nature.

Results:

Placement No.	Date	Average Rating	Comments
1R7A	May 21, 1975	2	Minor surface anomalies (entrapped air at the formed surface).
1RCW15A	June 23, 1976	1	None.
1RB19W7	November 12, 1976	2	Minor surface anomalies (entrapped air at the formed surface).
1RB21W3 and 4	August 10, 1977	3	Minor surface anomalies (entrapped air at the formed surface, grout loss, and pour lines).

It is the evaluators' conclusion that the results of the detailed inspection of these four concrete placements indicate an acceptable and functional level of concrete serviceability at LaSalle. This conclusion is enhanced by the favorable results of other concrete placement inspections in the reactor and auxiliary buildings which were conducted during this and previous civil inspections.

B. Documentation Review

(1) Pour Package Review

Records for approximately twenty concrete placements were reviewed. The documentation package for each placement consisted of the following individual records:

- Pour Checkout Card
- Concrete Placing Record
- Reinforcing Steel Placement Audit Form
- Concrete Placement Control Audit Form
- Concrete Curing Card
- Concrete Batch Plant Tickets

With one exception, the documentation represented appropriate records of completed work and inspections conducted by craft and quality personnel. This exception dealt with the period February 21, 1975 through October 10, 1975; during which the concrete batch plant tickets were not signed by the batch plant inspector. It was confirmed that during this period there was no inspector present in the batch plant to monitor and verify proper batching material quantities.

Walsh personnel had performed a review of approximately five percent of the tickets for the period in question to verify proper batch weights. This review resulted in identification of numerous tickets with incorrect batch weights. Consequently, Walsh NCR Nos. 98 and 121 were written. The disposition of both NCR's was reviewed and determined to be adequate.

In light of the identified batching errors, questions regarding the correctness of the unchecked batch tickets arose. In response, CECo and Walsh personnel agreed to review material quantities for all batch tickets during the period February 21, 1975 through October 10, 1975. This review identified additional instances of batching error. These nonconforming conditions were identified on Walsh NCR No. 241 to assure proper disposition. Based on the results of the licensee's review, it is currently our assessment that these circumstances do not have significant concrete quality implications. The Region III inspector has no further questions regarding this matter at this time.

(2) Concrete Mix Review

Concrete Mix No. IC-40-90-0-1 was chosen from the LaSalle safety-related concrete mixes in order to evaluate if the approach to (1) mix design, (2) compressive strength evaluation and (3) disposition of low compressive strength test results complied to the requirements of ACI 211, ACI 214 and ACI 318.

The development and approval of the design mix by Wiss, Janney, Elstner, and Associates was verified. Proper computation and statistical evaluation of the strength test data was also verified.

Additionally, the 185 individual strength tests for Mix No. IC-40-90-0-1 were reviewed. The data indicated that certain test results did not meet the requirements of ACI 318-71, Section 4.3. These nonconforming conditions were identified on Walsh NCR 115 and CECo NCR 56. The disposition of each was verified to be in accordance with the guidance provided by ACI 318-71, Section 4.3.5.

12. Post Tensioning

A. Documentation Review

The LaSalle FSAR, Section 3.8.1.1.3.3 specifies the proper tendon stressing sequence to minimize unbalanced loads and differential stresses to the structure. The sequence requires the longer vertical tendons to be stressed first, followed by the shorter verticals, then the horizontal tendons. The stressing sequence for the Unit 1 tendons was verified to meet that specified on Inland-Ryerson Drawing No. 676-23, Revision F.

Walsh quality records relative to tendon installation, field buttonhead fabrication, tensioning, and greasing were reviewed for horizontal tendon Nos. H46AC, H47AC, H48AC, H49AC, H50AC, H51AC, H4CB, H5CB, H6CB, H7CB, H8CB, H9CB, H7BA, H9BA and vertical tendon Nos. V31C, V32C, V33C, V35C, V36C, V38C, V39C, and V40C. The documentation package for each tendon was complete and consitituted the objective evidence necessary to establish the acceptability of the Unit 1 post-tensioning system.

B. Tendon Surveillance Tests

Sargent and Lundy Report No. SL-3808, entitled "Post-Tensioning System Surveillance for June-July 1980" was reviewed. The report presented the results of the Unit 1 tendon surveillance program which was conducted in accordance with Regulatory Guide 1.35, Revision 2. Report No. SL-3808 concluded that: (a) the post-tensioning system consisting of casing filler, and anchorage components, and tendon wires was in excellent condition; (b) the trend of prestress loss was within the value allowed in the design; (c) the entire system is performing according to design requirements; (d) the structural integrity of the containment is being preserved. Independent review by the Region III inspector of the surveillance and test data reported during the licensee"s post-tensioning inspection fully supports their conclusions.

Preparation for the second inservice tendon inspection as required by Regulatory Guide 1.35, was underway during this inspection. Licensee personnel stated that the inspection was scheduled to be completed by April 30, 1982.

C. Structural Acceptance Test

Sargent and Lundy Report No. SL-3726 entitled "Structural Intergrity Test of the Containment Structure" was reviewed. The test was conducted on December 26-28, 1978, in accordance with Regulatory Guide 1.18. Sargent and Lundy concluded in Report No. SL-3726 that, "Evaluation of test results shows that the containment structure meets all the acceptance criteria for the structural integrity test..." The Region III inspector's review of Report No. SL-3726 supports this conclusion.

The February 5, 1980, Sargent and Lundy letter to CECo was reviewed. It concerned the need to repeat the structural integrity test because of the downcomer bracing, SRV pipe support, and the KWU quencher modifications to the containment structure subsequent to the first structural test. The letter stated that the alterations were not considered significant to containment strength and did not affect its pressure carrying capability; therefore, the structural intergrity test need not be repeated. The letter did however, state that the Integrated Leak Rate Test would be performed again to demonstrate that the leakage through the modified containment liner is within acceptable limits. Licensee personnel stated that the test would be completed before initial criticality.

13. Fire Protection

A. Selected System Construction Evaluation and Walkdown Verification

The inspector examined the licensee's fire suppression, automatic fire detection and emergency systems. They included the Cardox system, the pre-action sprinkler system, and the ionization smoke and rate-of-rise heat detectors. These systems were reviewed using the commitments and requirements of the LaSalle County Station FSAR and the National Fire Protection Association (NFPA) Codes 13 and 72E.

In addition, the inspection consisted of visual observations to determine whether as-built conditions of fire protection components were physically connected in position and installed in accordance with the latest construction drawings and specifications. The areas selected for inspection were chosen because of their potential to affect safety-related equipment.

(1) Areas of Inspection

(a) Print

Number	Description or Title	Date and Revision
Viking 1175307, Sheet 2	Diesel Fuel Storage Tank Rooms	4/5/77 Revision 4
Viking 1175307, Sheet 10	Diesel Oil Day Tank Rooms	8/21/77 Revision 2
Viking 1175307, Sheet 15	Cable Spreading Rooms	3/30/77 Revision 3
Viking 1175307, Sheet 16	Cable Spreading Room Cable Tray	2/14/77 Revision 2
Viking 1175307, Sheet 16A	Cable Spreading Room Details and Sections	5/26/78 Revision 2
Viking 1175307, E-08	Fire Detection System Cable Spreading Room Units 1 and 2	8/5/80 Revision 4
S&L M-820SH10F2	Diesel Generator Cardox System	2/3/81 Revision 14
S&L IE-1-3430 Sheet 1 of 2	Electrical Installation Auxiliary Building Plan	12/22/81 Revision AK
Chemetron FLR-20558, Sheet 2	CO_2 Schematic Piping Layout and Storage Unit	10/15/81 Revision G
Foley FS-19025-5 of 5	Foley Electrical Contractor's Field Sketch	7/30/81 Revision 2

(2) Plant Tour

The inspector examined automatic fire detection, fire suppression and equipment to confirm as-built construction and design using the latest drawings. The walk-down consisted of verifying detailed construction installation of the following: Piping size and connections including pipe reducers, location and spacing of sprinkler fusible link heads and detectors, sprinkler head types and actuation temperature, and color code rating of smoke detectors and sprinkler heads.

The following plant areas in Unit 1 were inspected:

Cable Spreading Room
HPCS Diesel Generator Room

HPCS Diesel Day Tank
HPCS Diesel Storage Tank
Control Room
Division I, II and III Battery Rooms

B. Findings

NFPA Code 72E requires that automatic spot-type smoke detectors be located between four and twelve inches from the ceiling to the top of the detector. If that condition is not met, then location and spacing shall result from an evaluation based on engineering judgment with ceiling shape and surfaces, ceiling height, and effects of smoke stratification to be considered. Amendment 45 to the FSAR question 010.45 asks that the licensee provide an analysis, supported by test data, as to the sensitivity of the detection devices and that placement be sufficient to provide detector response.

The drawing used by Foley, the electrical contractor, to install the detectors required them to be field routed. It appeared that while the detectors were installed to protect the cable trays, no apparent engineering analysis existed to consider the effects of smoke stratification or sensitivity to smoke given the three foot distance from the ceiling.

Although no evidence of an engineering analysis which would provide the basis for the location of the detectors could be provided during this inspection, the licensee stated that the information was being compiled.

Pending review of the licensee's engineering basis for the detector's present location or their relocation, this item is considered to be unresolved. (50-373/82-11-10)

NFPA Code 13 provides guidelines for the installation of sprinkler systems. A sprinkler system is a specialized device that requires design be based upon sound engineering principles, test data and field experience. The licensee could not, however, provide data to substantiate the design adequacy of the specialized application of the GEM type sprinkler system which protects the cable trays.

The major concern was that the conical flow pattern of the sprinkler heads would not provide adequate spray coverage of the cable trays. Since the system was not designed to flood the cable tray, the amount of water drained through the tray is indeterminable and the particular angle at which each spirnkler head is pointed may not provide adequate coverage. An additional concern in question is that the sprinkler system was not tested in the actual cable tray configuration to determine adequate fire protection coverage.

The licensee informed the inspector that an analysis or test data to support the qualification of this system would be provided in the near future. This matter is unresolved. (50-373/82-11-11)

During a review of the fire detection requirements, an apparent typing error was identified. The FSAR incorrectly stated that the number and spacing of detectors is in accordance with NFPA 72D. The actual spacing requirements is in accordance with NFPA 72E. The licensee stated that a correction would be made. This item is open, pending a revision in the appropriate FSAR section. (50-373/82-11-12)

Viking Print No. 11-75307, Sheet 10 did not represent the actual as-built conditions of the HPCS oil day tank room sprinkler system during this walkdown inspection. An additional sprinkler head had been inserted without design approval by the manufacturer. The licensee informed the inspector that the as-built conditions would be reflected on a future drawing after verification by the manufacturer. Pending Viking approval of the as-built condition, this item will remain open. (50-373/82-11-13)

C. Discussion

The horizontal sprinkler arm section along one vertical pipe drop in the cabel spreading room did not reflect Viking print No. 11-75307, Sheet 16. The problem consisted of an incorrect orientation of four of the five horizontal pipes extending into a section of cable tray. These pipes were 45° off the correct direction. The problem was discussed with the licensee and final corrective action was taken before the final exit meeting. The inspector has no further concerns regarding the matter at this time.

The licensee's insurance company identified a potential problem with the location of the sprinkler heads from the ceiling in the cable spreading room. It appeared that the location of the ceiling fire suppression system was too low and would not activate properly in the event of a fire. At the time of this inspection a field change request had been initiated to extend the fusible link heads closer to the ceiling. On the final day of inspection, installation of the risers was nearing completion. The inspector has no further questions regarding this matter.

14. Preoperational and Functional Test Results

The inspector examined fire detection and fire suppression preoperational tests in accordance with the FSAR, NFPA Codes and manufacturer requirements.

A. Areas of Inspection

The following preoperational tests were reviewed: The Cardox fire extinguishing system performed on August 1, 1979; hydrostatic testing of the pre-action sprinkler system in the cable spreading room; and a functional logic test of the detection system also located in the cable spreading room.

(1) The inspector examined the records of the hydrostatic test performed in the Unit 1 cable spreading fire suppression system. The test conformed to the NFPA 13, Paragraph 1-11.3, requirements of maintaining pressure for the necessary period.

(2) A functional preoperational test was performed in the Unit 1 cable spreading room ionization detection system on January 7, 1982. The signal actuation and logic test appeared to be acceptable and complete.

(3) The Cardox system in the HPCS diesel generator room was tested on August 23, 1979. The manufacturer's requirement was to allow flooding of the diesel generator floor up to a fifteen foot level with a twenty percent concentration of carbon dioxide. The test results were documented and appeared to be adequate.

15. Fire Protection Safety Evaluation Report Modification

The inspector examined the battery rooms and the control room to determine compliance with the Fire Protection Safety Evaluation Report (FPSER). All the following items are considered satisfactory.

A. Battery

(1) All fire dampers and doors have been visually examined and were upgraded to provide the required three hour rating. This was accomplished by verifying that these doors and dampers were affixed with Underwriters Laboratory Class A approval labels.

(2) The exhaust ventilation duct in the Division II battery room has been moved to a position near the ceiling. The exhaust ventilation ducts for the other safety-related battery rooms were installed near the ceiling.

(3) All structural steel in the ceilings and in the floors is protected by the required three hour rated fireproofing. An additional concern questioned the material application of the fireproofing. It was determined that the licensee had proper controls for applying the correct thickness with consideration for humidity levels.

B. Control Room

(1) Smoke detectors were observed to be physically placed below the dropped ceiling in the area between the front and back row control panels.

(2) The licensee has provided water type fire extinguishers throughout the control room.

(3) The inspector was not able to verify, by direct observation, the installation of the three hour rated fire dampers in the

control room wall duct penetrations. However, review of QC inspections provided documented evidence that the fire dampers are actually installed in place and conform to the required three hour rating.

16. Preservice Examination, Documentation Review

A. Preservice examinations of Unit 1 systems and components were performed by General Electric Installation and Service Engineering Division, to establish a baseline for inservice inspections. The inspections were performed using GE procedures approved by the licensee and in accordance with the requirements of ASME Code and NRC Requirements.

During the review of Unit 1 automatic inspection data some discrepancies were noted. The inspector suggested that a complete review of the data be performed prior to further reviews. This was completed for Unit 1 on February 16, 1982, and is still in progress for Unit 2.

The following are some of the discrepancies and their resolutions.

LaSalle 1 - Discrepancies and Resolution

(1) CDSA110

Procedure reference should be APUV-S751 rather than APUN-S751 based on EDS A111 and raw computer data - weld BR Procedure No. corrected to read APUV-S751.

(2) CDSA112

Procedure reference should be APUV-S751 rather than APUN-S751 based on EDS 112 and raw computer data - weld BS Procedure No. corrected to read APUV-S751.

(3) EDSA158

Procedure reference should be APUV-S751 rather than APUN-S751 based on CDS A157 and raw computer data - weld AE. Amount of weld scanned not checked nor indications recorded. Procedure No. corrected to read APUV-S751. Review of the computer data revealed that indications were recorded so that the "YES" block for Line 7 has been marked accordingly. The Comments Section, Line 11, showed the amount of weld scanned to be partial so the "PARTIAL-SEE COMMENTS" block for Line 10 has been marked accordingly.

(4) CDSA178

Procedure reference should be APUN-S751 rather than APUV-S751 based on EDS A179 and A180 and raw data - weld N2B/N2E.

Procedure No. corrected to read APUN-S751.

(5) CDSA147

Date listed should be November 30, 1979, rather than November 30, 1980, based on EDS 148 and raw data - weld AB.

Date corrected to read November 30, 1979.

(6) EDS A148

Checked both "Partial" and "100%" amount scanned, Line 10.

Line 11 delineates only a partial scan was performed so the 100% block of Line 10 has been lined out accordingly.

(7) EDS A150

Checked neither "Partial" or "100%" amount scanned, Line 10.

Review of the computer data revealed that only a partial scan was performed, so Line 10 has been marked accordingly and the examination area was recorded in Line 11.

(8) EDS A171

Date omitted, amount of weld scanned not checked, Line 10.

The date of the examination was termined from the computer data to be December 10, 1979, and has been recorded on the data sheet. Line 11 delineates the amount of weld scanned as partial so Line 10 has been marked accordingly.

(9) EDS A167

Amount of weld scanned not checked, Line 10.

Line 11 delineates the amount of weld scanned as partial so Line 10 has been marked accordingly.

(10) EDS A115

Amount of weld scanned not checked, Line 10.

Line 11 delineates the amount of weld scanned as partial so Line 10 has been marked accordingly.

(11) EDS A193

Procedure number incorrect - should be APUN-S751, Line 8 not checked.

Procedure No. corrected to read APUN-S751. Indications were recorded during the examination so Line 8 has been marked accordingly.

(12) EDS A192

Procedure number incorrect hsould be APUN-S751.

Procedure No. corrected to read APUN-S751.

(13) EDS A108

All pages, except first, No. A107B.

EDS Nos. were corrected to read A108.

(14) LCS- Page 29

Nozzle N2J has wrong EDS entered.

EDS No. corrected to read A190.

(15) LCS-1 Page 31

Nozzle N4E omitted EDS 120 and CDS 116.

EDS No. 120 and CDE No. 116 have been added.

17. Procedure Review

The following procedures used for performance of preservice examinations were reviewed for conformance to ASME Code requirements.

MPUD-S751, Revision 3
Manual Ultrasonic Examination of Full Penetration Disimelar Metal Welds.

MPUP-S751, Revision 6
Manual Ultrasonic Examination of Full Penetration Piping Welds

PP-S751, Revision 1
Liquid Penetrant Examination of Nuclear Power Plant Components

PVI-S751, Revision 2
Visual Examination No. 1

APUN-S751, Revision 3
Automated Ultrasonic Testing of Nozzle to Vessel Welds

MPUSK-S751, Revision 1
Ultrasonic Examination of Support Skirt to Reactor Pressure Vessel Welds

N1RZ1-S751, Revision 0
Ultrasonic Examination Procedure for Nozzle Inner Radius Zone 1

N1RZ2-S751, Revision 0
Ultrasonic Examination Procedure for Inner Radius Zone 2

APUV-S751, Revision 3
Automated Ultrasonic Examination of Reactor Pressure Vessel Welds and Base Metal

18. Personnel Qualificition

Qualification records of the following GE examination personnel were examined for conformance to Procedure No. NDE-P-Q 8000, Revision 1, meeting the requirements of ASNT-TC-1A.

	UT	PT	MT	VT
L. Bowne	II	II		
P. W. Cox	II	II		
G. Craigo		II		
J. Decker	II	II	II	
T. C. Hall		1T		
M. P. Hart	III	III	II	
P. K. Olsen		III	III	
B. M. Dummer	II	II	II	II
M. Heath		II		
S. C. Mortenson	II	II	II	

Documentation Review

The following Examination Data Sheets (EDS) of preservice examinations were reviewed.

EDS No. 60026
Component - 1FW-1002, Weld No. 44
Examination - PT
Procedure - PP-S751, Revision 3

EDS No. 60028
Component - 1FW-1001, Weld No. 82
Examination - UT
Procedure - MPUP-S751, Revision 2

EDS No. 60032
Component - 1FW-1002, Weld No. 9
Examination - PT
Procedure - PP-S751, Revision 3

EDS No. 10133
Component - FW-1002, Weld No. 44
Examination - UT
Procedure - MPUP-S751, Revision 2

EDS No. 62018
Component - 1HP-1033, Weld No. 34
Examination - PT
Procedure - PP-S751, Revision 3

EDS No. 94045
Component - 1HP-1033, Weld No. 34
Examination - UT
Procedure - MPUP-S751, Revision 4

EDS No. 78030
Component - 1RR-1001, Weld No. 27B
Examination - PT
Procedure - PP-S751, Revision 6

EDS No. 91216
Component - 1RR-1001, Weld No. 27B
Examination - UT
Procedure - MPUP-S751, Revision 4

19. Inservice Inspection Program (ISI)

The inservice inspection program for LaSalle Unit 1 was reviewed and found to be in accordance with the requirements of Section XI ASME Code 1974, Summer 1975 Addenda for Class 1, 2, and 3 systems and components.

The program also includes Augmented Inservice Inspections (AISI) except where specific written relief has been requested in accordance with the requirements of 10 CFR 50, Section 50-55a(g)(6)(i).

Type 1A, High Energy line break exclusion region requested by NRC.

Type 1B, Emergency Core Cooling System lines exempted by ASME Section XI IWC-1220(A)(C) requested by NRC.

Type 1C, Volumetric Examination of RPV jet pump beams, using ultrasonic testing requested by NRC.

Type 2A, Reactor Core Isolation Coolant lines exempted by ASME Section XI IWC-1220(b), but are CECo required inspections at LaSalle Station.

All piping was reviewed against NRC quality group A-B-C-D+, corresponding to ASME Code, Section III Class 1, 2, 3, and 2(D+)

All Class 1 and 2 components are categorized in accordance with ASME Code Section XI Table IWB-2500, IWC-2520. Inspections to be performed to the requirements of Table IWB-2600, IWC-2600.

ISO's of Class 1 and 2 systems are used as working drawings during ISI.

Relief has been requested for some items due to various reasons, such as inaccessibility. This program is to be updated to the 1980 ASME Code requirements for the first refueling.

20. Radiographic Review

The following radiographic reports and radiographs of welds in Unit 1 systems were reviewed for conformance to ASME Code acceptance criteria.

Report No. 8207
ISO-G0121A-Z1RR01CA
Weld No. 16M

Report No. 3032
ISO-1RR01CB
Weld No. 18

Report No. 3299
ISO-1FW02ED
Weld No. 12

Report No. 4166
ISO-1FW02ER
Weld No. 26

Report No. 4040
ISO-1RH04C
Weld No. 525

Report No. 45
Feedwater safe end at 90°
Weld No. IWJ, 90 FWN

Report No. 47
Feedwater safe end at 30°
Weld No. IWJ, 30 FWN

Report No. 52
Feedwater safe end at 270°
Weld No. IWJ, 270 FWN

Report No. 54
Feedwater safe end at 330°
Weld No. IWJ, 330 FWN

Report No. 57
Feedwater safe end at 150°
Weld No. IWJ, 150 FWN

Report No. 56
Feedwater safe end at 210°
Weld No. IWJ, 210 FWN

Ultrasonic reports of feedwater nozzle welds.

Data sheet No. 103, Calibration Data Sheet No. 101
Nozzle 210 FWN, pipe to safe end weld

Data Sheet No. 105, Calibration Sheet No. 101
Nozzle 190 FWN, pipe to safe end weld

Data Sheet No. 106, Calibration Sheet No. 101
Nozzle 30 FWN, pipe to safe end weld

Report No. 49
Recirculation Nozzle N2A
Weld No. 3, 772' 30°

Report No. 26
Recirculation Nozzle N2C
Weld No. 3, 772' 90°

Report No. 35
Recirculation Nozzle N2F
Weld No. 3, 772' 210°

Report No. 36
Recirculation Nozzle N2H
Weld No. 3, 772' 270°

Report No. 46
Recirculation Nozzle N2K
Weld No. 3, 772' 330°

Report No. 62
Recirculation Nozzle N2G
Weld No. 3, 772' 240°

Report No. 76
Recirculation Nozzle N2D
Weld No. 3, 772' 120°

Report No. 80
Recirculation Nozzle N2B
Weld No. 3, 772' 60°

Report No. 54
Recirculation Nozzle N2J
Weld No. 3, 772' 300°

21. System Walkdown

During a walkdown of the RHR line, it was noted that three (3) welds appeared to have excessive outside reinforcement, the inspector requested the travelers of these welds. A dent was also noted in a 1 1/4" IN line No. 39AD on ISO No. IN67. Further examination of the area determined that it was below minimum wall thickness. This section of line was replaced and will be hydrostatically tested during preop testing.

The following travelers of RHR welds were reviewed:

Traveler No. RH-T-61
Drawing No. M839-3-4
Weld No. WRH531V
Component No. 1, 1RH04DA-18" Pipe
Component No. 2 1RH04DA-18" Pipe
Radiographic Report No. 10741/10757

Traveler No. RH-T-61
Drawing No. M839-3-4
Weld No. WRH-531W
Component No. 1, 1RH04DA-18" Pipe
Component No. 2, 1RH04DA-18" Pipe
Radiographic Report No. 10718

Traveler No. RH-T-61
Drawing No. M839-3-4
Weld No. RH531X
Component No. 1, 1RH04DA-18" Pipe
Component No. 2, 1RH04DA-18" Pipe
Radiographic Report No. 10756

The outside weld reinforcement of these welds was measured and found to meet the requirements of ASME Code Section III Subsection NB, Table NB-4426.2 for material thickness of .375".

22. Control Rod Drive Housing Data Review

During installation of the CRD housings, it was discovered that alignment of some of the housings was out of tolerance. General Electric (GE) initiated FDDR No. HA1-096 to accept those housings that were out of tolerance .005" or less on top, and up to .020" radially on the bottom. In all, 155 housings were found to be out of alignment in excess of the acceptance limits of FDDR-HA1-096. To correct the misalignment, it was decided to use the draw bead welding technique where required. Two (2) housings located at 2643 and 4243 were not accessible for draw bead welding. A decision by GE San Jose was made to cold spring these housings into alignment. Thermal sleeve gage checks were made on all housings by utilizing an actual thermal sleeve and trail fitting in each housing. A back seat gage check was made using a plug gage with a machined radius the same as the CRD housing top, with a feeler gage

of .001" as a go/no-go gage on the sealing surface. Final inspection and acceptance of the sealing surface was performed in conjunction with installation of the control rod drives.

23. Heating, Ventilation and Air Condition Control (HVAC)

The following Zack Company (ZACK) procedures for installation of the HVAC system were reviewed.

ACP-2, Revision 7, Receiving and Inspection
QCP-3, Revision 2, Welder Qualification
QCP-9, Revision 2, Repair Procedure
QCP-11, Revision 6, Training of QC Inspectors
QCP-20, Revision 11, Visual Examination of Welds

24. Historical Review and Examination of NRC Inspection Activity, Licensee Performance and Audit Activity. Operational Readiness Assessment.

During this inspection 37 NRC Region III inspectors who have previously inspected LaSalle County Unit 1 during the period January 1, 1979 through the present were interviewed to determine operational readiness. In addition to the foregoing NRC personnel interviews, the following activities were also accomplished: reviewed 155 NRC Region III inspection reports written for LaSalle County Unit 1 during the period January 1, 1979 through the present, interviewed four QA auditors who have conducted audits of LaSalle County operational readiness during the period January 1, 1980 through December 31, 1981, reviewed 148 audits performed by the LaSalle County Operating QA Group during the period January 1, 1980 through December 31, 1981, reviewed four audits of LaSalle County site acitivities performed by the corporate QA function during the period January 1, 1980 through December 31, 1981, and reviewed two audits of LaSalle County QA activities performed by Commonwealth Edison Company's consultant, Energy Incorporated, in 1981 and 1980.

As a result of the examinations and discussions outlined above, the inspectors conclude that:

A. NRC Region III inspectors responsible for construction and operational readiness inspections would recommend issuance of a license to LaSalle County Unit 1 providing that:

(1) The utilities construction and preoperational testing program is completed as presently defined.

(2) The NRC's inspection program for the construction and preoperational phase is completed as presently defined.

(3) Unresolved issues defined in inspection report open items are satisfactorily resolved.

B. The LaSalle Operating QA Group has adequately scheduled and performed audits in the area of operational readiness and required corrective action has been adequate for each individual finding.

C. The inspector has identified four areas where the licensee must take corrective action to prevent potentially adverse conditions and correct programmatic deficiencies mutually perceived by both the NRC Region III inspection staff and the Commonwealth Edison Company QA department. The areas of concern which require corrective actions are:

(1) The jumper and lifted lead controls used by the Preoperational Test/System Demonstration System Test Engineer are virtually unauditable by the people using these devices, the personnel responsible for control of the systems, or personnel responsible for auiting compliance with these controls. Action on this item should be completed immediately but must be completed prior to Unit 1 fuel load. Open Item. (50-373/82-11-14)

(2) The system used by the station to control revisions to Preoperational Test/System Demonstration Procedures is not effective and results in errors found in significant portions of the preoperational test program audited. These errors could result in systems not being tested properly if left uncorrected. Open Item. (50-373/82-11-15)

(3) The volume of jumpers, lifted leads, out of service cutages, caution tags, hold cards, etc. associated with running a preoperational and construction test program make it a safety concern that Unit 2's logs governing these items are combined with Unit 1's. Provisions must be made to separate control of these items by unit. Action on this item must be completed by Unit 1 fuel load. Open Item. (50-373/82-11-16)

(4) The LaSalle County Station Startup Manual (LSU's) has been only moderately effective in controlling the preoperational test program for LaSalle County Unit 1. This manual does not appear to be adequate for controlling the preoperational testing program for Unit 2 concurrent with Unit 1 startup and power ascension. We will require the licensee to complete a review of this manual and recommend steps to be taken to strengthen the controls of this manual as well as clarify and define activities specified by procedures in this manual. Subsequent to the licensee's review, the NRC Region III Test Programs Section will review this manual for acceptability. Action on this item must be completed prior to any FSAR Chapter 14 tests on Unit 2 other than those required to be completed to support Unit 1 operation or by August 1, 1982, whichever occurs later. Open Item. (50-373/82-11-17)

25. Interview of LaSalle County Station QC and Other Quality Program Personnel

The purpose of interviewing station QC personnel was to determine whether there are any previously unidentified problems with installation of safety-related components and equipment that may affect the safe operation of LaSalle County Station Unit 1, and to obtain their opinions regarding the quality of this construction activity.

A total of seventeen (17) randomly selected personnel were interviewed. Thirteen (13) of these were QC inspectors involved in direct inspection of welding, electrical, pipefitting, nuclear steam supply system, and component installation. QC inspector experience, of those interviewed at LaSalle County Station, ranged from one (1) year to five and one-half (5.5) years with an average of three and one-third (3.3) years. Most of the inspectors have prior inspection experience at other CECo nuclear sites as well as experience in related disciplines. All personnel interviewed stated that they knew of no problems that would affect the safe operation of the plant. When asked if there had been any unresolved problems between construction and QA/QC inspection, all stated that all problems were satisfactorily resolved. In response to questions concerning the nonconformance reporting system there were no adverse findings. All personnel interviewd stated that nonconformances were handled properly and satisfactorily resolved and that they knew of no difficulties in initiating, writing and forwarding nonconformance reports. In addition to the above, various management, engineering and third party inspection personnel were interrogated relative to the construction quality effort. No adverse conditions were identified.

26. Review of Construction QA Audit Reports

The inspector performed a detailed review of reports of audits, performed by the licensee's Quality Assurance department of activities associated with the construction of La Salle County Station. The review encompassed fifty-six reports of audits of eleven organizations.

The reports reviewed were:

A. Zack Company - HVAC contractor - 7 audits of the site organization and 1 audit of contractor's facility.

B. Reactor Controls Inc. - reactor components, rod drive and pipe supports contractor - 5 audits of the site organization and 2 audits at contractor's facility.

C. Sargent and Lundy - architect/engineer - 4 audits of the site organization and 1 audit at the A/E facility in Chicago.

D. General Electric Company - NSSS - 6 audits of the site organization - 1 audit at region headquarters, and 2 audits of GE facilities at San Jose, California.

E. Commonwealth Edison Company - station construction department - 5 audits of site activities and 1 general office audit.

F. Commonwealth Edison Company - operations analysis department - 4 audits of site activities and 1 audit at QAD offsite facility.

G. Morrison Construction Company - piping and mechanical contractor - 5 audits of the site organization - 1 audit of the contractor's offsite fabrication facility and 1 special audit of activities relating to N-5 code data reports.

H. B. F. Shaw Company - pipe supplier/fabricator - 2 audits of the supplier's facility at Laurens, South Carolina.

I. A&H Engineering Corporation - engineering and testing contractor - 1 audit of site activities.

J. Johnson Controls - reviewed 1 audit of site activities of control systems for HVAC subcontractor.

K. NSC (Quadrex) - pipe suspension system design subcontractor - 1 audit of site organization design activities.

In general, the audits appeared to have been conducted according to the audit schedule. Audits were comprehensive and conducted in sufficient depth to assure compliance with licensee commitments and the quality assurance program. Corrective action and followup to close audit findings was performed in a timely manner.

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

27. Review of Audits Conducted by the Operating QA Group, Audits Performed of Site Activities by the Corporate QA Department, and Audits Performed by Licensee Contractor/Consultants of Site Activities

This inspection consisted of a review of all audits conducted by the Operating QA Group assigned to LaSalle County Nuclear Station during the period January 1, 1980 through December 31, 1981. The review was conducted to determine if the frequency, depth, and required corrective actions of the QA Audits were appropriate.

A. Inspection Findings

1981 Audits - The Operating QA Group scheduled 53 regular audits in 1981 and 53 were performed. In addition to the 53 regular audits, 36 audits of the preoperational testing program were performed in 1981.

B. Summary of Results of 53 Scheduled Audits Performed in 1981

53 audits were performed, 34 of these audits were clear, the remaining 19 audits had a total of 7 findings, 18 observations, 4 comments, and 2 open items. The inspector reviewed each audit

performed, follow up on all findings, observations, comments and open items and has found that the frequency, depth and required corrective actions were appropriate.

C. 36 Audits of the Preoperational Test Program 1981

Test Audited	Results
PT-DO-101 Unit 1 Diesel Oil	1 Observation
PT-FC-101 Fuel Pool Cooling	1 Observation
SD-HD-101B Moisture Separator	Clear
PT-AR-101 Area Radiation Monitors	1 Finding
SD-FC-101 Fuel Pool Demineralizers	Clear
PT-AP-202 Auxiliary Power Unit 2	3 Comments
SD-TO-102 Hydrogen Seal Oil Unit 1	4 Comments
PT-NR-101B Unit No. 1 Neutron Monitoring	1 Finding
PT-VD-101 Diesel HVAC	Clear
PT-VP-101 Primary Containment Ventilation	Clear
PT-RD-101A Rod Drive Control and Rod Position Indication	2 Observations
SD-CX-102 Rod Worth Minimizer	1 Observation
SD-CY-101 Cycled Condensate System Unit 1	Clear
SD-EH-101B Turbine Supervisory Control	CLear
SD-FW-102 Feedwater Control	Clear
PT-AP-201 AC Distribution Unit No. 2 Portion Required for Unit 1 Startup	1 Finding
SD-WR-101 Reactor Building Closed Cooling Water	Clear
SD-HD-101 Heater Drains	1 Finding
SD-HY-101 Hydrogen Cooling System	1 Finding
SD-PS-101 Process Sampling	1 Finding
PT-VP-202 Primary Containment Ventilation for Unit 2 Required for Unit 1 Operation	Clear
SD-TO-101 Turbine Lube Oil	Clear
PT-NB-101 Nuclear Boiler	Clear
PT-VY-201 CSCS Equipment Cooling System	1 Finding
SD-WE-101C Laundry Drain Reprocessing and Disposal	Clear
SD-WW-101 Well Water	Clear
PT-AP-102 Auxiliary Power Unit 1	Clear
PT-RD-101B Control Rod Drive Hydraulics	Clear
PT-VD-201 Diesel Ventilation Unit 2 Required for Unit 1 Startup	Clear
SD-SH-101 Station Heat Recovery	Clear
SD-CH-101 Condensate and Condensate Booster	1 Deficiency
PT-LD-101 Leak Detection System	Clear
PT-VD-101 Diesel Generator Ventilation Unit 1	Clear
PT-HP-101 High Pressure Core Spray System	Clear
PT-PR-101 Process Radiation Monitoring	Clear
PT-HC-101 Reactor Building Cranes	1 Finding 1 Observation

D. Summary of Results of 36 Audits of Preoperational Testing Performed in 1981

36 audits were performed, 21 of these audits were clear, the remaining 15 audits had a total of 8 findings, 6 observations, 7 comments, and 1 deficiency. The inspector reviewed each audit performed, follow up on all findings, observations, comments, and deficiencies has found that the frequency, depth and required corrective actions were appropriate.

E. The Operating GA Group scheduled 38 regular audits in 1980 and 38 were performed. In addition to the 38 regular audits, 21 audits of the preoperational testing program were performed in 1980. A summary of the functional areas and results are shown below.

(1) 38 Scheduled Audits Functional Areas

Audit	Results
QAA 01-80-01 Training	Clear
QAA 01-80-02 Station Procedure Control	1 Finding 1 Observation
QAA 01-80-03 Product Audit of Quality Receipt Inspection 80-024	Clear
QAA 01-80-04 Tagging	1 Finding
QAA 01-80-05 Hoisting and Rigging Equipment	3 Findings
QAA 01-80-06 Nuclear Procedures	Clear
QAA 01-80-07 Technical Specification Support Surveillances	Clear
QAA 01-80-08 Weld Rod Control	1 Finding
QAA 01-80-09 Central File Station Procedures	1 Finding 1 Observation
QAA 01-80-10 NRC Correspondence	Clear
QAA 01-80-11 Product Audit of Work Request No. LO 3745 Reactor Water Cycle Cleanup Recycle Valve	Clear
QAA 01-80-12 Operating Department Adherence to Station Procedures	3 Findings 1 Observation
QAA 01-80-13 New Fuel Receipt Inspection	Clear
QAA 01-80-14 Corrective Actions Taken to Correct Deficiencies	Clear
QAA 01-80-15 Training Qualifications of Personnel and Records Special Processes	Clear
QAA 01-80-16 Onsite Review/Offsite Review	1 Observation
QAA 01-80-17 Station Security Plan and Procedures	2 Comments 1 Observation
QAA 01-80-18 Station QA Manuals	Clear
QAA 01-80-19 Environmental Requirements	Clear
QAA 01-80-20 Discrepancy Records	Clear
QAA 01-80-21 Portable Test and Measurement Equipment	1 Finding

Audit	Results
QAA 01-80-22 Product Audit of Quality Receipt Inspection QRI-80-149	Clear
QAA 01-80-23 Radiation Protection, Surveys, Instruments and Records	Clear
QAA 01-80-24 Facility Staff Qualifications to ANSI N18.1 - 1971	1 Finding
QAA 01-80-25 Fire Protection - Station Procedures	Clear
QAA 01-80-26 Nuclear Procedures	1 Observation
QAA 01-80-27 Equipment Tagging	1 Observation
QAA 01-80-28 Instrument Calibration Standards and Controll of Standard Solutions	Clear
QAA 01-80-29 Transfer of Records and Distribution of Engineering Documents and Drawings	Clear
QAA 01-80-30 Jumper and Lifted Lead Control	Clear
QAA 01-80-31 Surveillance Procedure Adherence	Clear
QAA 01-80-32 Identification and Control of Materials, Parts, and Components	Clear
QAA 01-80-33 Handling Storage and Shipping	Clear
QAA 01-80-34 Station Emergency Plan and Procedure	Clear
QAA 01-80-35 Corrective Actions Taken to Correct Deficiencies	1 Finding
QAA 01-80-36 Hazardous Material - Senate Bill 1950	1 Observation
QAA 01-80-37 Environmental Protection Agency 401 Certification	Clear
QAA 01-80-38 IE Bulleting 79-19 Radioactive Waste Transport and Burial	3 Observations

F. Summary of the results of 38 scheduled audits performed in 1980, 23 of these audits were clear, the remaining 15 had a total of 13 findings, 11 observations, and 2 comments. The inspector reviewed each audit performed, follow up on all findings, observations and comments and has found that the frequency, depth and required corrective acitons were appropriate.

G. 21 Audits of the Preoperational Test Program 1980

Test Audited	Results
PT-RI-101 Reactor Core Isolation Cooling System	Clear
PT-SC-101 Standby Liquid Control System	1 Finding
PT-LP-101 Low Pressure Core Spray System	1 Finding
PT-IN-101 Primary Containment Instrument Air	Clear
PT-VP-101 Primary Containment Chilled Water	1 Deficiency
PT-VO-101 Off Gas Filter Building HVAC	3 Findings
PT-RP-102 Remote Shutdown System	1 Finding
PT-VR-101 Reactor Building HVAC	1 Finding
PT-NR-101A Source Range Monitors	1 Finding 1 Observation

Test Audited	Results
PT-PC-101 Primary Containment Integrated Steam Leak Rate Test	1 Finding
PT-PV-101 Confirmatory Vibration Flow Tests and Reactor Flow Vibration	Clear
SD-AC-101 Caustic-Acid Systems	1 Finding
PT-NR-101C Power Range Monitors	Clear
PT-DO-201 Preoperational Test of Unit 2 Diesel Oil Systems Needed for Unit 1 Operation	Clear
SD-ES-101 Extraction Steam	Clear
PT-RP-101 Reactor Protection System	1 Finding
SD-GC-101 Stator Water Cooling	Clear
SD-FW-101 Feedwater System	Clear
PT-OG-101 Unit 1 Off Gas System	Clear
SD-RT-101 Reactor Water Cleanup System	1 Finding 1 Observation
PT-RD-102 Control Rod Drive Hydraulics	1 Finding 1 Observation

H. Summary of the results of 21 audits of preoperational testing performed in 1980. 21 audits were performed, 9 of these audits were clear, the remaining 12 audits had a total of 14 findings, 3 observations, and 1 deficiency. The inspector reviewed each audit performed, follow up on all findings, observations, and deficiencies and has found the frequency, depth and required corrective actions were appropriate.

I. 1981 Audits Performed of Site Activities by The Corporate Quality Assurance Department and Licensee Contractor/Consultants

(1) Offsite Audit I-81

Areas audited and references were:

Area	Reference
Procedure Adherence	Q.P. 5-51 Maintenance, Instrument, Warehouse Procedures ANS 3.2
Training, Staff Qualifications	FSAR
Corrective Action	Q.P. 15-51, 52, 53, Q.P. 16-51 Station DVR's, NRC Inspection Reports, IE Bulletins, Circulars, Station Audits/Surveillances
On Site/Off Site Review	Station Procedures
Facility Emergency Plan GSEP,	Station Procedures, FSAR 13.3

Station Security Plan	Security Plan Chapter 6-9, Chapter 15 Items Contingency Plan 10 CFR 73.46
Fire Protection	NML Inspections, Administrative Procedures, FSAR
Quality Assurance Program - Operations	Q.P. 10-52, 53, Q.P. 11-51, 14-51, 18-51

The results of this audit were that 3 observations and 3 open items were initiated. All observations have been followed up on and closed. The 3 open items remain open and the QA department had not scheduled a surveillance to follow up on these items; however, after discussions with the inspector a follow up surveillance was scheduled.

(2) Offsite Audit II-81

Areas audited and references were:

Area	References
Procedure Adherence	Radiation Chemistry Procedures
Corrective Action	QP 15-51, 52, 53, 16-51, Station DVR's NRC Inspection Reports, IE Bulletins, Circulars, Audits/ Surveillances QR's
Security	Security Plan Chapter 10-14, Appendix C, NRC Open Items
Q.A. Program Operations	QP 2-53, 3-51, 3-52, 9-51, 10-51, 18-52, Associated QR's
GSEP	GSEP, NRC Open Items

The results of this audit were that 2 findings, 1 observation, and 1 open item and 6 comments were initiated. All findings, observations, and 5 comments have been followed up and closed. The open item and 1 comment remain open and deal with security information. A Quality Assurance Surveillance has been scheduled to close these items.

(3) Energy Incorporated Audit for 1981

The organizations audited at LaSalle County were:

LaSalle Site: CECo Contractors - Morrison Construction Company Reactor Controls, Inc. Foley Electric Company Zack Company

CECo Contractors - Quality Assurance Project Construction Operations

The results of this audit were that 1 finding and 4 observations were initiated. All items are closed in this audit; however, action to close observation 5 of this report has not been completed and the QA department had not scheduled a surveillance to follow up on. This item; however, after discussions with the inspector, a follow up surveillance was scheduled.

1980 Audits Performed of Site Activities by the Corporate Quality Assurance Department and Licensee Contractor/Consultants.

(1) Offsite Audit I-80

Areas audited and references were:

Audit Area	References
Procedure	QP 5-51, FSAR ANSI 3.2, Radiation Control Procedures Chemistry Control
Training & Staff Qualifications	ANSI 18.1 FSAR Production Instruction 1-3-A-32
Corrective Action	QP 15-51, 52, 53, QP 16-51 DVR's, DR's, NRC Inspection Reports, IE Bulletins, Circulars, QA Audits, Surveillances
Emergency Plan	GSEP, FSAR 13.3 EPIP's
Security Plan	LaSalle Security Plan Sections 10-15
QA Program Operations	QP 7-51, 7-52, 12-51, 12-52, and 12-53
Fire Protection	FSAR, Safe Shutdown Analysis, Station Procedures

The results of this audit were that 8 findings and 1 observation were initiated. All findings and the observation have been followed up on and closed.

(5) Offsite Audit II-80

Areas audited and references were:

Audit Area	References
*QA for Maintenance	NRC Questions 1-4, 6, 13-16, 18-20, 26, 28, 32-33, 35, 38-39, and 41
*QA for Operations	NRC Questions 5, 8-9, 17, 21, 23, 27, 29, 34, 36, 37, 40, and 42
QA for Operations	NRC Questions 5a and 8; NUREG 0694 1.c.2-5; QP Nos. 5-51, 10-52, 10-53, 11-51, 14-51, and 8-51
QA for Maintenance	NRC Questions 4, 5d, 8, and 38; QP Nos. 2-53, 3-51, 3-52, 9-51, 10-51, and 18-52.
QA for Maintenance	NRC Questions 8, 9, and 27; QP Nos. 12-51, 12-52, 12-53, 15-51, 15-52, 15-53, and 16-51
QA for Maintenance	NRC Questions 5f and 35; QP Nos. 4-51, 7-51, 7-52, 8-51, 13-51, 14-51, 10-54, and 5-51; Station QAM Section 3.6.1
QA for Maintenance	NRC Questions 14-16; QP Nos. 6-51, 6-52, 2-52, 2-53, 14-52, 12-52, and 17-51

*Indicates this portion of the audit was performed by the licensee's contractor/consultant, Energy Incorporated.

The audit resulted in the identification of 7 findings, 8 observations, and 15 comments. All findings, observations and comments have been followed up and closed.

28. Unresolved Items

Unresolved items are matters about which more information is required in order to ascertain weather they are acceptable items, violations, or deviations. Unresolved items disclosed during this inspection are

discussed in Paragraphs 4.B, 4.F, 4.G, 6.C.(4), 9.D., 12.B (3 issues), 23.C.(1), 23.C.(2) and 23.C.(3).

29. Exit Interview

The inspectors met with licensee personnel (denoted in Paragraph 1) at the conclusion of the inspection on March 1, 1982, in the NRC Region III Office. The inspectors summarized the scope and findings of the special inspection, which were acknowledged by the licensee.