U.S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos. 50-206/90-16, 50-361/90-16 and 50-362/90-16

License Nos. DPR-13, NPF-10 and NPF-15

Licensee: Southern California Edison Company
23 Parker Street
Irvine, California 92718

Facility Name: San Onofre Nuclear Generating Station

Inspection at: San Clemente, California

Inspection Conducted: May 21 - July 2, 1990

Inspectors: D. Corporandy, Reactor Inspector
F. Gee, Reactor Inspector
M. Miller, Reactor Inspector

Approved by: F. R. Huey, Chief, Engineering Section — 8/2/90 Date Signed

Summary:

Inspection During the Period of May 21 - July 2, 1990 (Report Nos. 50-206/90-16, 50-361/90-16 and 50-362/90-16)

Areas Inspected: A special unannounced inspection by regional based inspectors of the licensee's design, engineering and associated quality verification activities. Inspection procedures 30703, 35702, 37700, 37701, 37702, and 54704 were used as guidance for the inspection.

Results:

General Conclusions and Specific Findings

The areas of engineering design and equipment qualification were inspected to determine the quality of licensee engineering work.

The licensee appears to have implemented an aggressive self-audit program, which has identified a number of deficiencies in equipment qualification and engineering areas. Most of these deficiencies are not individually significant to safety, but may be precursors to more safety significant problems.

This inspection found evidence of continuing improvement in the licensee's engineering and equipment qualification program over the past 3 years.

Significant Safety Matters:

None

Summary of Violations or Deviations:

Main steam and feedwater isolation valves and actuators had been modified several times, but operability of the valves in the modified configurations was not properly assessed. This is an apparent violation of 10 CFR 50, Appendix B requirements to apply the same post-modification design criteria, which in this case verified operability, as was required during initial design of the components.

Open Items Summary:

Six open items were closed. One new open item was identified.

DETAILS

1. Persons Contacted

Southern California Edison

*D. Brevig, Onsite Nuclear Licensing Supervisor
*M. Merlo, Nuclear Engineering and Design Manager
*B. Katz, Nuclear Oversight Division Manager
*H. Morgan, Vice President and Site Manager
*D. Herbst, Site QA Manager
*D. Werntz, ONL Engineer
*M. Short, Manager, Station Technical
*M. Speer, ONL Engineer
*C. Brandt, QA Engineer
*G. Gibson, ONL Engineer
*A. Kaneko, Electrical Supervisor
*A. Brough, Site Engineering Supervisor
*L. Cash, Maintenance Manager
*J. Curran, Manager, Design Basis Documentation
*R. Rosenblum, Manager, Nuclear Regulatory Affairs
*R. Krieger, Station Manager
*P. Wattson, Supervisor, Compliance
*D. Lokker, Assistant Plant Superintendent
*M. Ramsey, Supervisor, Quality Assurance
*R. Sidhar, Quality Assurance Engineer
*P. Croy, Inservice Testing Engineer
*D. Schone, Design Basis Documentation Configuration Management
*I. Katter, Supervising Mechanical Engineer
*G. Hollaway, Professional Engineer
*F. Briggs, Supervising Engineer
*M. Wharton, Assistant Manager, Mechanical
*K. O'Connor, Manager, Construction
*R. Berkshire, Supervisor, Equipment Qualification
*A. Sistos, Supervising Mechanical Engineer
R. Belhumeur, Construction
G. Spurling, Environmental Qualification Engineer
J. Fee, Assistant Site Health Physics Manager

NRC

*C. Caldwell, Senior Resident Inspector
*M. Miller, Reactor Inspector
*F. Gee, Reactor Inspector
*D. Corporandy, Reactor Inspector

The inspectors also held discussions with other licensee and contractor personnel during the course of the inspection.

*Attended the Exit Meeting on June 15, 1990.

2. Inadequate Environmental Qualification (EQ) Control

Background: In 1987, the NRC took enforcement action as a result of omission of several equipment items from the Unit 1 qualified equipment list. In 1989, the licensee identified that, in Units 2 and 3, several transmitters and associated cabling were not installed in a qualified configuration. As a result of these findings, the licensee initiated several corrective actions in the EQ program; specifically, plant walkdowns during the upcoming outages to verify configuration, detailed review of all Equipment Qualification Data Packages (EQDP's), relocation of EQ engineers from the engineering center in Irvine to the site, and training of engineers, supervisors, and maintenance personnel.

During the exit meeting on April 20, 1990 (Report Number 50-361/90-14), NRC inspectors identified to the licensee that the lack of post-modification walkdowns by EQ engineers was indicative of inadequate engineering involvement in plant activities. In response, the licensee initiated post-modification walkdowns by EQ engineers.

On April 30, 1990, the licensee initiated walkdowns of EQ equipment in Unit 3 containment, as part of the corrective actions associated with the 1989 EQ discrepancies discussed above. The inspector randomly selected a group of EQ equipment in Unit 3 containment for walkdown with the licensee. The inspector also reviewed records of recent licensee walkdowns. The inspector noted the following deficiencies:

a. Non-Qualified Pressure Transmitter for Safety Related Services Inside Containment.

Wide range pressure transmitter 3PT-0102-4 (one of 4 transmitters providing low pressurizer pressure trip input to the reactor protection system) was identified by the licensee to be unqualified. This transmitter is located in containment and also supplies Engineered Safety Feature Actuation System (ESFAS), Post-Accident Monitoring Instrumentation (PAMI), the remote shutdown panel and plant computer system.

The design requirements of Design Change Package 3-1516.0J, EQ Master List (M37582) and EQ Document Package (M37631) indicated that the model for 3PT-0102-4 should have been Rosemount 1153GD9. The non-qualified model installed in the plant was Rosemount 1153GA9. A review of the records indicated that the non-qualified transmitter had been installed since March 1987.

The nonconforming condition was discovered by the licensee on May 3, 1990. A nonconformance report, NCR-90050164, was not written until May 22 (19 days after the deficiency was identified). The licensee's letter of July 16, 1990, stated that after the initial identification of the discrepancy, an additional walkdown was performed to verify that the discrepancy was the result of an incorrect model transmitter rather than inaccurate data recorded during the original walkdown. The licensee stated that, since Unit 3 was shut down, an incorrect model transmitter did not pose a safety concern to Unit 3. However, the inspectors noted that since

Unit 2 was operating, a safety concern may exist if the root cause of installation of the incorrect transmitter in Unit 3 could apply to Unit 2. Many programs supporting all units are common, and lack of prompt NCR issuance because the affected unit is shut down may not be valid.

The licensee walkdowns found that, for Unit 2, 35 of 35 Rosemount transmitters inspected were the correct model, and for Unit 3, 34 of 35 Rosemounts inspected were the correct model. Therefore the installation of an incorrect transmitter model appeared to be isolated. This justification did not appear to be documented during the time between identification of this nonconformance and the issuance of an NCR.

After the inspector asked the EQ group for justification of why the event was not reportable, the licensee issued revision 2 to the NCR to identify that the use of a non-qualified transmitter for safety related services was reportable to the NRC. The licensee issued LER 90-007.

Use of a non-qualified pressure transmitter for safety related service is considered to be an apparent violation of 10 CFR Part 50, paragraph 50.49 f. The violation is considered to be a non-cited violation in accordance with 10 CFR 2, Appendix C, paragraph V.G.1 (50-362/90-16-1).

b. Incorrect Environmental Qualification Records

Five Foxboro transmitters inside Unit 3 containment were models other than those indicated in the EQ Document Package. The tag numbers and functions of the Foxboro transmitters are listed below:

Tag Number	Functions
3LT-1113-2, 3LT-1113-3	Steam Generator No. 1 Level (Low and High), Reactor Trip (High and Low Level), Initiate Emergency Feedwater Actuation System (EFAS) (Low Level Only).
3LT-1123-1, 3LT-1123-2	Steam Generator No. 2 Level (Low and High), Reactor Trip (High and Low Level), Initiate Emergency Feedwater Actuation System (EFAS) (Low Level Only).
3PT-0101-1	High Pressurizer Pressure (Reactor Trip)

The installed models were N-Series, and the models indicated in the EQ Document Package were E-Series. The licensee indicated that the N-Series was bought as qualified, and the E-Series was upgraded in the field by replacing the internals. The licensee indicated that both series were equally qualified, that the EQDP stated that the N-Series transmitters were equivalent replacements, and that E series transmitters can no longer be obtained. Since the N series transmitters were documented as acceptable replacements by the EQDP, and the EQ improvement program corrective action was scheduled to revise all of the EQDP's, the licensee corrective action appears acceptab'e.

The dis.repancy between the as-installed condition and the EQDP was formally documented as a documentation error by SPR 900460, dated June 21, 1990. The inspector noted that this was over a month after the condition was discovered during a walkdown. Since the EQ improvement program is being implemented primarily through existing licensee corrective action programs, such as NCR's, SPEER's, SPR's, etc, these findings should be formally documented promptly in accordance with existing plant procedures.

The finding that correct records of EQ equipment were, apparently, not maintained is considered an apparent violation of 10 CFR Part 50, 50.49j. The violation is considered a non-cited violation in accordance with 10 CFR 2, Appendix C, paragraph V.G.1 (50-362/90-16-2).

c. Examples of EQ Nonconformance

The licensee identified additional examples of EQ nonconformance during Unit 3 walkdowns:

(1) The conduit installations for 18 Rosemount transmitters were identified to be not in compliance with the as-tested configuration. The flexible conduit was not looped below the transmitter and did not have a 1/4" drain hole drilled at its low point to prevent potential submergence of lead wires and to provide a condensate drain path. The NCR had a Mode 3 restraint. (Reference: NCR 90050183)

The licensee stated that the disposition of NCR 90050183 would be similar to that of NCR 2-3114. Wyle Laboratories test reports 57366 and 54099, for Foxoboro N-E10 series differential pressure transmitters and their associated flexible conduit, were being evaluated by the licensee for applicability to Rosemount transmitters.

(2) Heat shrink tubing was not completely shrunk over the insulation on connectors on containment post-LOCA hydrogen monitoring sensor 3AET-8100-1 (NCR 90050205, MO 89111609). The licensee stated that this work had been accomplished during the past weeks, and considered it a personnel error. Based on the large number of acceptable heat shrink tubing installations observed, the licensee considered this to be an isolated error. The licensee stated that the individual had been counseled, and maintenance training would be reviewed to ensure that heat shrink requirements were appropriately addressed.

(3) No heat shrink tubing, required by EQ, was covering the connectors for the pressurizer safety valve acoustic monitors.

There was no evidence that heat shrink tubing had ever been installed on these connectors (LER 90-007).

(4) NAMCO limit switch 3ZSL-9351-1, for safety injection tank T007 fill line isolation valve 3HV-9351, was found to have a black gasket for the top cover. This configuration was not consistent with the tested configuration which required both the top and bottom cover gaskets to be silicone rubber (color red). The EQ of this device was indeterminate. The NCR had a Mode 3 restraint. (Reference: NCR 90050130) This was one of 20 NAMCO limit switches reviewed during the walkdown.

(5) A non-qualified terminal block was identified in the switch compartment of the motor-operated valve 3HV-9337. This valve is in one of two trains used for shutdown cooling (LER 90-007).

Use of non-qualified configurations of equipment for safety related service is considered to be an apparent violation of 10 CFR 50, paragraph 50.49f. This violation is considered to be a non-cited violation in accordance with 10 CFR 2, Appendix C, paragraph V.G.1 (50-362/90-16-3).

Additionally, the licensee noted the following:

(1) The identification plates on five Unit 3 EQ ASCO valves were missing. (Reference: NCR 90050129)

(2) Cloudy oil, instead of clear oil, was found in the connection box of a GEMS level transmitter for the containment sump.

(3) Two Rosemount transmitters were identified as having no grafoil tape in the flexible conduit connection installation. Revision 1 of licensee procedure SO123-I-4.6.1, "Conax Seal Assembly - Removal, Cleaning, Inspection, Repair and Installation", step 6.6.1.7, requires that grafoil tape be installed during conduit installation. There appeared to be no verification step required to ensure that grafoil has been installed, even though, after correct grafoil installation, grafoil may not be visible in the closed fitting. The licensee stated that grafoil was optional on EQ equipment, since EQ testing of Conax fittings had shown acceptable results both with and without grafoil. Also, the licensee stated that a step in this procedure for verification of correct grafoil installation would be recommended to the improvement program for EQ maintenance procedures, since it provides a more effective seal than the Conax threaded connections without grafoil.

As a result of corrective actions for earlier licensee identified EQ discrepancies, the licensee appeared to have identified the above discrepancies, and has been taking additional, more detailed and extensive corrective actions to review and revise EQDPs, train engineers and technicians, correct installed equipment, document findings, and increase EQ engineering involvement at the site.

In a quality assurance audit dated January 16, 1990, the licensee identified several findings, in ten different areas of the EQ process. Most of these errors involved failures to follow required practices and procedures in implementation of the EQ design and documentation process. These findings are documented in CARs, NCRs, and PRRs.

The QA EQ audit appeared to have identified findings which, although individually may not be significant to safety, when taken as a group with other EQ findings, gave indication of significant problems in the EQ area. These types of findings may be precursors to more significant problems. Specific findings and corrective actions associated with this audit are being tracked in the EQ program, along with findings of EQ audit activities, as part of the EQ improvement program. The large number of findings appear to require this broad scope of corrective action.

Based on review of the findings and the follow-up of the licensee's corrective action by NRC resident inspectors, the inspectors found that licensee's EQ improvement program appeared to be adequate.

3. Safety Related Active Components Used As Structural Attachments (37701).

During review of DCP 2/3-6674.00BJ, the inspector observed that the yokes of the Units 2 and 3 Main Steam Isolation Valves (MSIV's), Main Feedwater Isolation Valve (MFWIV's), and Main Feedwater Block Valves (MFWBV's) were being used as structural attachments for adjacent piping. Valve manufacturers generally discourage the use of valves as structural supports.

Background

Subsequent inspection provided the following background information.

a. The adjacent lines supported by the isolation valves are the hydraulic dump lines used to control the isolation valves.

b. The dump valves and associated lines were originally contained inside the isolation valve yokes.

c. The original isolation valve qualifications, demonstrating structural integrity and operability under dynamic loading, had been performed by the valve manufacturer at the time the dump line and associated dump valves were contained inside the isolation valve yokes.

d. The dump valves and lines were moved outside of the isolation valve yokes in order to locate them in a less harsh environment to provide for better reliability. Bechtel was contracted to qualify this revised configuration.

e. To further improve reliability, the Marotta hydraulic dump valves on these lines were replaced by Paul Munroe Enertech (PME) hydraulic dump valves. The PME valves are about 2.4 times heavier than the Marotta valves.

Findings

The inspector reviewed the design changes to the MSIV's, MFWIV's, and MFWBV's. The following findings appeared to be significant to safety:

a. None of these isolation valves were requalified for operability under dynamic loading after the dump lines and Marotta dump valves were moved to outside the isolation valve yoke.

b. None of these isolation valves were requalified for operability under dynamic loading when the Marotta dump valves were replaced with the heavier PME valves.

c. Design calculations for Unit 2 did not reflect the changes from Marotta to PME hydraulic dump valves.

d. In addition to the safety concerns above, the inspector observed that design calculations for the MFWBV's did not reflect the "as-built" configuration (e.g. the design calculation for Unit 2 MFWBV 2HV-4047 did not account for a downward vertical support which the inspector observed on a walkdown).

In the case of item (c), the inspector noted that the Unit 2 MSIV yoke supports and hydraulic dump line configuration appeared to be similar to their Unit 3 counterparts; hence the Unit 3 calculations which verified isolation valve structural integrity appeared by comparison, to d[illegible] structural integrity for the Unit 2 MSIV's.

Regarding item (d), the discrepancies between "as analyzed" and "as-built" configurations appeared either to be conservative or covered by other analysis conservatisms (e.g. The fluid transient loads calculated for fast valve closure of the Marotta valves were used even though it appeared that the valve closing times and flow characteristics of the PME valves would have yielded lower fluid transient loads than the Marotta valve characteristics).

During the inspection, the licensee performed preliminary analyses to demonstrate operability for these isolation valves. The inspector reviewed the operability calculations and they appeared to provide an adequate assessment of valve operability. In the interest of expediency, two enveloping analyses were performed; one for the MSIV's and one for the MFWIV's. Both calculations appeared to conservatively demonstrate that the "as analyzed" yoke deflections were .001 inch less than the "as-tested" valve yoke deflections recorded by the valve manufacturer in the original operability verifications; hence it appeared that the isolation valves were demonstrated to be operable.

The inspectors performed walkdowns of the Unit 3 containment and various areas in Units 1 and 2. The inspector did not find any other examples of safety related valves or equipment being used as structural supports.

Because operability determinations required during original design of the plant were not performed after design changes to the MSIVs and MFWIVs, the licensee appears to have violated Criterion III of 10 CFR 50,

Appendix B, Design Control, which requires that design changes be subject to design control measures commensurate with those applied in the original design (50-361/90-16-05).

For corrective action, in addition to updating the MSIV, MFWIV, and MFWBV calculations, the licensee committed to review Units 1, 2 and 3, Design Change Packages (DCPs) associated with changes to safety related valves and equipment by June 25, 1990. During a telephone conversation on July 25, 1990, the licensee stated that the DCPs for Units 1, 2, and 3 (about 3000 DCPs) had been reviewed. About 250 of the DCPs could be associated with using safety related components as structural attachments. About 150 of the 250 DCPs have been reviewed to date. No additional instances of components used as structural attachments have been found to date. Modifications to valve actuators were made to relocate solonoids, but review showed that changes in weight and center of gravity were insignificant compared to valve mass.

Completion of the DCP review is scheduled by September 1990.

A plant walkdown by design engineering to check for safety related during components used as structural attachments is scheduled to be completed during September 1990.

Preliminary operability calculations for the MSIV's, MFWIV's, and MFWBV's have been completed and are scheduled to be finalized during September 1990.

4. <u>Change to IST Program for MSIV's in Response to Dump Valve Leakage</u>

The inspector reviewed NCR's 3-2504 and 3-2498 which documented seat leakage through the upstream (X) dump valves associated with the MSIV's. The final disposition required that the dump valves in series (the Y valve) with the leaking valves be exercised only at cold shutdown, instead of quarterly, since exercising the "Y" valves would result in leakage through the in-series "X" valve, allowing the MSIV to close. The NCR states that this may result in a partial loss of steam flow and an asymmetrical steam generator event. The "X" valves will still be exercised quarterly to demonstrate a partial stroke test of the MSIV to verify freedom of isolation valve movement.

The change to the IST program to stop quarterly testing of the "Y" valves had not been submitted to the NRC as a change to the ASME Section XI test program. The licensee IST coordinator stated that the NRC has requested that minor changes not be submitted to the NRC, to reduce NRC administrative workload associated with approving IST programs. The licensee IST coordinator and system engineer conclude this change is minor since:

1. No change will be made to the "X" valve testing, which is the partial stroke test program used at power to show freedom of MSIV movement.

2. No change will be made to the full stroke MSIV tests during cold shutdown.

3. The "Y" valve is designed to fail open, which would result in a conservative failure (closed) of the MSIV.

4. Before this configuration of 4 PME dump valves was installed, a less reliable configuration and type of dump valve, (Marotta) was installed, and was tested only at cold shutdown.

The inspector discussed this issue with NRR. It was agreed that, in view of the specific technical issue, which does not involve any relief requests, the licensee is not required to send NRC headquarters the notification that this particular technical change had been made to the IST program. However, although the NRC need not be notified of this change or typographical and minor administrative changes to IST programs, the NRC requests that all technical changes to the IST program be submitted to the NRC.

No violations of NRC requirements were identified.

5. Relocate Pressurizer Spray Line Check Valve (DCP 6759).

The inspector reviewed the piping and support calculations for the subject DCP's. The calculation input and procedures appeared appropriate. The calculation results and conclusions were reviewed to determine whether critical items affected by the DCP piping changes had been appropriately addressed.

Based on the inspector's review, these calculations appeared to provide adequate documentation to verify that the critical parameters remained within acceptable limits.

The inspector attended a licensee meeting with NRC Mechanical Engineering Branch to discuss licensee action in response to NRC Bulletin 88-11, Pressurizer Surge Line Thermal Stratification. The licensee had installed thermocouples on the pressurizer surge line piping, performed analysis on all 3 units, communicated with owners groups, and completed preliminary evaluations. The licensee concluded that the effect of pressurizer surge line thermal stratification on plant safety was not a concern for any of the units. More detailed evaluation will be completed by the licensee over the next year. Additional documentation of this meeting will be provided in a meeting report to be issued by NRC Mechanical Engineering Branch, Nuclear Reactor Regulation.

No violations of NRC requirements were identified.

6. Operability of Recirculation Piping Located in the Containment Emergency Sump (37701).

NCR 900500027 documented that two bolts connecting support S1-SI-004-H031 to pipe line 1204-004-24" recirculation piping were missing.

The licensee had performed calculations to check piping operability without the subject support. The licensee concluded that the pipe remained operable with the bolts missing but recommended that the missing bolts be installed. The inspector reviewed the calculation assumptions and analyses, and determined that they appeared to be adequate. The inspector noted that the axial force at penetration #54 exceeded allowables, but was determined by the licensee to be acceptable based on high load margins available for bending moment loads at penetration #54. The licensee analysis, conclusions and recommendations appeared adequate.

No violations of NRC requirements were identified.

7. Snubber Functional Testing (37701).

The inspector reviewed the relaxed snubber functional testing limits made available by the snubber manufacturer, Pacific Scientific Company (PSA). These relaxed limits were confirmed by analysis to be acceptable to maintain SONGS Unit 2 and 3 system operability. In cases where relaxed snubber functional test limits were not demonstrated to keep system loads or stresses within acceptable margins, the more conservative snubber functional test limits were maintained.

According to the snubber functional test procedures, a random sample snubber population was tested. If a snubber was found to fail test criteria, the random sample population was increased.

The inspector observed that, in the case of PSA size 1/4 and 1/2 snubbers, the licensee had demonstrated by analysis that snubber breakaway drag forces could be increased to 10% of the snubber load rating capacities without impacting system operability. However, the maximum drag allowed by PSA was 5% of rated load capacities. Licensee memorandums (refer to 3/4/86 and 4/11/86 memorandums to file from D. Tuttle) stated that "...according to PS, above 5%, snubber failure may be imminent...."

For PSA 1/4 and PSA 1/2 snubbers tested with snubber drag values greater than 5% but less than or equal to 10%, the snubber was replaced but the sample size was not expanded. The inspector expressed concern in this case that other PSA 1/4 and PSA 1/2 snubbers where..."failure may be imminent..." might not be tested because the sample size would not have been expanded. The licensee responded that experience at SONGS over 4 refueling outages did not support the case for imminent failure of PSA 1/4 and PSA 1/2 snubbers with drag greater than 5% but less than or equal to 10%. The inspector reviewed past snubber functional testing failure data for PSA size 1/4 and 1/2. Based on a lack of an increase in number of PSA 1/4 and 1/2 snubbers with drag values greater than 5% over 4 outages, the licensee conclusion appears acceptable.

The inspector observed some of the snubber functional testing and reviewed a calculation performed by the licensee to evaluate a piping system in which a snubber was found to have failed functional testing. The testing procedures and the methodology, results, and conclusions of the calculation for the snubber which failed the testing appeared adequate.

Based on the above discussion, the snubber functional testing program appeared to be acceptable.

No violation of NRC requirements were identified.

8. Poor Implementation of Radiological Control Practices

During a Unit 3 containment EQ walkdown, the inspector observed two inadequate radiological control practices.

The first incident involved an electrician in Unit 3 containment on the 17 foot elevation. The electrician moved a hose connected to the component cooling water (CCW) system, and some liquid spilled out of the hose and onto the floor. The electrician continued his work, ignoring the spill, and did not treat the spill as potentially contaminated. When prompted by the inspector, health physics personnel were contacted. The smear taken by the health physics personnel proved that the spill was not contaminated. Health physics personnel taped the open end of the CCW system hose with duct tape, and apparently did not contact the system engineer.

These observations took place in a contaminated area. Procedures for this area do not require immediate assessment and minimization of a spill. However, prompt assessment and cleanup is recommended.

The second incident involved a planner who accompanied the inspector during an EQ walkdown inside Unit 3 containment. Because of his prior schedule commitment, he was anxious to know the time and started to peel off the tape on his glove to see his watch. In view of potential personnel contamination, the inspector cautioned the planner to not untape his wrist. The planner stopped taking the tape off and did not uncover his glove.

The inspector informed Health Physics and Quality Assurance management of these observations. It appeared that the individuals discussed above did not follow recommended radiological practices. The individuals involved were counseled. No violations of NRC requirements were identified.

9. Quality Verification Function (35702)

The licensee has initiated a performance-based assessment technique that is separate from their approved QA program, but which is designed to enhance the Nuclear Oversight Organization's ability to identify performance degrading conditions before they become significant problems. This technique is entitled "Vertical Assessments of Design and Design Change Packages". The first vertical assessment was to verify the adequacy of selected aspects of in DCP 3-6674.00BJ, Main Steam Isolation Valve, Main Feedwater Isolation Valve and Main Feedwater Block Valve modifications. Deficiencies were identified in design calculations and drawings, processing of design calculations, and processing of EQ package changes.

The second vertical assessment reviewed DCP 3-6605.02 - ADV Modifications. The vertical assessment plan identified major areas of the DCP to be evaluated; including design calculations, testing, procurement, critical characteristics, and operability. The major findings of the assessment identified that:

a. The ADV positioner had not been seismically qualified. The licensee concluded that this was an error by the contractor supplying the part. Since an identical valve positioner was installed in Unit 2, which was operating, the licensee promptly initiated qualification testing, which determined satisfactory seismic performance and qualification for the positioner.

b. The vendor documentation requires 80 psig air to operate the regulator and ADV, however, the instrument air system nitrogen supply (70 psig for 24 hours) does not supply 80 psig. After recognizing the vendor requirement as a result of the vertical assessment, the licensee provided documentation of satisfactory operation of the ADV's at 70 psig and 60 psig. Therefore, there is little safety significance in this specific finding.

c. The Foxboro microprocessor digital computer program which controls the ADV position is verified upon installation by printing out the file contents to a printer to obtain a hard copy of the file contents. However, changes to the program after installation have only an optional step to print out the file contents. The steps to verify a design change should be identical to the steps required in installation.

Also, the assessment identified many other inconsistencies in documentation, specifically in areas of EQ, spare parts ordering, procurement, operations, and testing. All of these findings have been identified by the licensee QE program, and are each being followed by internal commitments such as NCR's and PRR's. The licensee corrective action to date for the specific findings appears adequate.

The vertical assessment of DCP's is continuing, and appears to be identifying significant findings and providing appropriate feedback.

No violations of NRC requirements were identified.

10. Nuclear Safety Group Safety Evaluations (37701)

The inspector reviewed eight of the safety evaluations performed by the Nuclear Safety Group (NSG). These evaluations performed safety analysis, pursuant to 10 CFR 50.59, of the DCP's being installed in Unit 3. These safety evaluations appeared to follow the guidelines of Nuclear Safety Analysis Center (NSAC) 125. They specifically addressed changes to probabilistic risk, assumptions in the updated FSAR and other specific guidelines of NSAC 125. The safety evaluations performed by NSG appear to be more detailed and more thorough in addressing the effect of a change on plant safety system response than the evaluations of the same DCP's performed by licensee design and system engineering groups. Based on discussions with NSG engineers, and since these safety evaluations were done in the last 4 months, the difference appears to be a result of NSG's implementation of NSAC-125 guidelines in December, 1989 as compared with system and design engineering's implementation of those guidelines in May, 1990. NSAC 125 guidelines appear to assist engineers in addressing a broader and more detailed assessment of the safety significance of a change to the plant than licensee procedures for safety evaluations in use before NSAC-125 guidelines.

The inspector noted that NCR's and associated 50.59 evaluations which are dispositioned as "accept as is" do not require review by NSG. The inspector questioned this lack of NSG review. The licensee stated that NCR's "accepted as is" must be reviewed by the Independent Safety Evaluation Group (ISEG), which provides an oversight function. The inspector reviewed 10 NCR's which had been dispositioned as "accept as is" and observed that safety concerns and design criteria appeared to have been reviewed and addressed in an acceptable manner. Based on this limited review, lack of NSG review of "accept as is" NCR's does not appear to be a safety concern.

No violation of NRC requirements were identified.

11. Assessment of Engineering Design Work by Engineering (37701)

The inspector reviewed the licensee's internal engineering quality improvement program. In addition to requiring training of engineers, it trends and tracks resolution of discrepancies and errors found in engineering work. This program appears to provide feedback to engineering personnel, and, in some cases, analysis of engineering errors. The discrepancies are grouped by outage. This program appears provide organization, analysis, control, and feedback concerning discrepancies in the engineering area. Also, the licensee has contracted engineering companies to perform independent audits of licensee design work. The inspector reviewed these audits. It appears that the more significant findings of these contractor audits most frequently occur at the interfaces between working groups.

No violation of NRC requirements were identified.

12. Applicability of 10 CFR 21 Reporting Requirements to ESF Sequencer Design Error

The inspector noted several instances in which the licensee procured assistance or components which did not appear to meet the specified requirements:

a. LER 89-004 dated April 3, 1989 reported a Unit 1 diesel sequencer logic deficiency. This deficiency resulted in the safety related/ESF loads being dropped and not picked up again when a bus loses the diesel and then is loaded back on the diesel.

   The discrepancy was corrected. The LER identified the cause of this discrepancy as inadequate review of a vendor provided design by licensee engineering staff. Apparently, no 10 CFR 21 applicability was discussed, nor was a vendor requirement to provide acceptable logic design discussed.

   During a review of the Design Basis Documentation program, the inspector noted that in September 1989, engineers had independently identified the incorrect design of the ESF sequencer discussed above (Engineering Open Item Report 89-155). The issue was again reviewed by the licensee and closed.

The inspector reviewed the purchase specification for the logic sequencer (Specification 82-0956). It required the vendor to provide design of the logic and hardware, and stated in several sections that the review by SCE engineers did not relieve the vendor of responsibility for correct engineering design.

The licensee has not reported this apparent vendor discrepancy pursuant to the requirements of 10 CFR 21.

The licensee stated that the vendor, Consolidated Controls/EATON, supplies similar equipment to other utilities. The licensee was unable to determine if the vendor had been contacted concerning this error in ESF sequencer logic design.

b. The positioner for the atmospheric dump valves (ADVs) was procured as a certified seismically qualified component, from Control Components Incorporated (CCI) however, SCE review resulted in questioning the certification, qualifying the devices by test, and suspending CCI's vendor qualification to supply certified components to SCE.

c. The MSIV's and FWIV's were modified on two separate occasions to relocate the Marotta dump valves from inside the isolation valve yoke, and then again to replace the Marotta dump valves with (heavier) Paul Munroe dump valves. The engineering for this modification was performed by Bechtel. For both of these modifications, an operability evaluation of the isolation valve was not performed.

The inspector considers that the reporting requirements of 10 CFR 21 may apply in these cases. The reportability of these equipment discrepancy pursuant to 10 CFR 21 is considered an open item (50-361/90-16-4).

13. <u>Licensee Action on Previously Identified Items (71707)</u>

a. <u>(Closed) Item 50-361/88-22-08, Unresolved VCT Outlet Valve Spurious Closure</u>

The inspection report identified an NRC concern that fire induced circuit damage to the Volume Control Tank (VCT) outlet valve control cables, pressurizer low level instrumentation cables, and charging pump automatic start control cables could cause an automatic start of all charging pumps coincident with the loss of suction flow to the charging pump. The report also identified that the licensee indicated that proposed corrective actions for these deficiencies would be provided in a submittal to the NRC by November 4, 1988.

The inspector reviewed the licensee proposed corrective actions, licensee procedure TCN 2-8, Revision 2 of SO23-13-2, "Shutdown from

Outside the Control Room" and other licensee documentation. In the case of an identified fire, the reviewed documentation required:

(1) Immediate operator actions to select manual control and stop all charging pumps.

(2) Operator verification that at least one of the five charging pump suction paths is available prior to restarting pumps.

The inspector and an Auxiliary Control Room Operator (ACO) walked through the procedure to determine the capability of operators to successfully perform these actions outside the control room in the event of a fire in the control room.

The procedure appeared clear and the ACO appeared to be capable and knowledgeable of the actions required during a shutdown outside the control room. The procedure required that the charging pumps be stopped and control of the pumps be reestablished outside the control room and a suction path be verified prior to restart.

These actions appear to be able to be completed within the first six minutes of evacuating the control room.

During walkdown of the remote shutdown procedure, the inspector observed that items required to be operated for safe shutdown had small orange reflective triangles by the nameplates as an operator aid. The inspector observed that the charging pump electrical switches did not have these triangles, although the shutdown analysis requires that they be operated within 6 minutes of control room evacuation. Also, a panel of 20 switches, one of which was required for safe shutdown was not labeled with nameplates by the switches, but had marking pen marks on the cabinet surface to identify the switch numbers down the left side, thus identifying half of the switches. The safe shutdown component switch was on the right side. The licensee agreed to provide safe shutdown triangles by the charging pump switch nameplates, and stated that conventional plant labels had been provided instead of the labels written in marking pen for the switch panel.

Based on verification of the licensees ability to accomplish these actions outside the control room, this item is closed.

b. <u>(Closed) Unresolved Item 50-361/88-22-03A, Immediate Actions Associated with Safe Shutdown</u>

In 1988, inspectors noted that, in addition to a reactor trip, the licensee took credit for manual actions in the control room to effect a safe shutdown in the event of a fire. These manual actions are: actuate the main steam isolation system, stop the charging pumps, and deenergize reactor coolant pumps. At that time, the licensee indicated that these required manual actions were not analyzed to ensure they could be performed outside the control room in time to prevent either affected unit from being in an unrecoverable plant condition.

In a subsequent NRC Safety Evaluation Report dated June 29, 1988, the NRC stated that the licensee determined the manual actions required outside the fire area for safe shutdown can be completed in the time required to achieve safe shutdown. In addition, the NRC staff also stated that these required manual actions can also be performed outside the control room at remote shutdown stations. The NRC staff noted that the licensee had installed transfer switches at remote shutdown stations, allowing power sources to be changed and equipment operated without requiring fuse replacement. This requirement is further discussed in Information Notice 85-09, "Isolation Transfer Switches and Post Fire Safe Shutdown Capability." In an SER dated June 29, 1988, the NRC staff considered the issue of the adequacy of remote shutdown actions to be resolved only on the basis that the design of the transfer switches adequately covers the concern identified in Information Notice 85-09.

The inspector walked through the remote shutdown procedure, TCN 2-8, Revision 2 of SO23-13-2, Shutdown From Outside The Control Room. It was clear that the first actions by various operators included performing and independently verifying completion of required manual actions, both in the control room and outside the control room. For the required manual actions (trip the reactor, initiate main steam isolation, stop charging pumps, and stop reactor coolant pumps) the inspector and ACO walked down the procedure to determine approximate times of completion. These four actions appear to be able to be completed in the control room within 10 to 30 seconds. Also, during walkdown of the remote shutdown portions of the procedure, it was clear that performance of all four required steps from outside the control room could be completed by the different operators within about 3 minutes, and for difficult conditions, within about 6 minutes.

These times appear to correspond to the licensee estimates for completion of remote actions, and appear to be within the required limits of the licensee's safe shutdown analysis.

Based on the above discussion, this item is closed.

c. <u>(Open) Open Item 50-361/88-22-07, Evaluation of Safe Shutdown and Non Safe Shutdown Loads</u>

The inspector noted that the procedure for safe shutdown from outside the control room appeared to deliberately remove power from both A and B emergency busses, and require use of the diesel to bring the plant to safe shutdown.

Upon receipt of a fire alarm and verification that a fire is threatening redundant safe shutdown equipment, the Shift Supervisor would decide to enter the procedure. The procedure intentionally disables all AC power to emergency bus 2A04 for shutdown train A, to mitigate fire induced short circuits, and then requires power to be provided to the bus by the emergency diesel generator.

The inspector's concern was twofold. First, the loads and potential for damage to the bus as a result of fire induced circuit failure did not appear to be thoroughly evaluated. Second, recovery of power to the bus was limited to only the diesel. However, in the event the diesel could not pick up the load, the option to align offsite power did not appear to be available. These two concerns are discussed in detail below.

a. Circuit Failure Analysis

The inspector examined the analysis of the loads which could impair safe shutdown as a result of circuit faults due to fire.

In a Compliance Assessment Report dated May 31, 1987, and subsequent correspondence, the licensee provided the staff with a common power supply analysis, a high impedance fault analysis, and an alternate analysis of faults expected during a fire.

The NRC staff, in a Safety Evaluation Report dated June 29, 1988, stated that the concern of losing electric power to the equipment needed for safe shutdown of the reactor has been appropriately addressed by the licensee and is adequately accommodated by the design.

This issue appears to have been satisfactorily addressed.

b. Safe Shutdown Using only the 'A' Train and 'A' Emergency Diesel

A licensee submittal dated December 30, 1988 discussed the methodology of safe shutdown by deenergizing both Train A and Train B ESF busses. The licensee concludes that operator time and manpower studies demonstrate that completion of these actions within the required time frames is feasible, and these time frames have been assessed to establish the actions to be completed in order to prevent an unrecoverable plant condition.

The licensee does not credit use of the Train B ESF bus, and has not protected it from fire for use in an alternate shutdown procedure. Therefore, only the Train A ESF bus is available. A loss of offsite power is assumed concurrent with the fire. The licensee states that, since limited information is available outside the control room to monitor non-Class 1E offsite power system, the operators must connect safe shutdown equipment to the protected source of power, even if offsite power is not lost.

The inspector is concerned that, in the event the Train A diesel generator does not start or cannot be loaded to the 'A' bus, alternative power may not be obtained.

Sources of power are the Train B diesel generator and offsite power. The circuits from these sources are not protected from fire. Also, alignment of these power sources is not addressed in the alternate shutdown procedure.

Although the time frames for completion of the safe shutdown actions to restore power appears feasible based on inspector review; the inspector has the following concerns:

(1) Operability history of the Train A diesel generator (number of demands vs number of failures) should be reviewed to determine the reliability of the 'A' diesel generator to start on demand, and the reliability of the 'A' diesel generator to load on demand. This source of power should be evaluated to be reliable enough to not require backup power in order to shut down the plant in the event of a fire.

(2) Even if the 'A' diesel is found to be reliable, a method to obtain power from another source (Train B diesel, offsite, or other source) should be considered to determine if there is an additional way to obtain necessary power in the event the 'A' diesel generator does not start or load.

This item remains open based on the above discussion.

d. <u>(Closed) Open Item 50-361/88-15-01, Inadvertent Actuations of the Cable Tray Fire Suppression Systems</u>

Four spurious actuations of cable tray fire suppression systems occurred between April and July, 1988. The inspector noted that the licensee had not fully assessed the long term safety impact of repeated soakings of cable spreading areas. The licensee stated that a detailed assessment of spurious actuations had been completed, and that additional emphasis and attention would be implemented to ensure additional actuations do not recur. This item remained open pending inspector review of the licensee corrective actions.

The inspector reviewed the assessment of the spurious actuations as documented in Root Cause NCR No. 3R-0041, dated September 14, 1988. The long term corrective action to adjust and selectively replace the pull stations which were most likely to allow inadvertent actuation appeared appropriate. However, the inspector noted the following concerns associated with evaluation of the effects of water on cable tray insulation which were not explicitly addressed in the NCR.

(1) The NCR stated that the cable tray design allowed for an additional 200 pounds per support, and that water (soaked into Cereblanket) adds about 20 pounds per support. The loading evaluation was not specified as horizontal or vertical, and the basis for 20 pounds of water loading was not discussed. Also, the loading of the trays, as opposed to only supports, was not discussed.

(2) Cereblanket and 3M insulation are used on cable trays. Although the effects of water on composition, physical characteristics, leaching, drying and degradation were discussed for Cereblanket; the NCR stated that the 3M blankets showed no adverse effects and did not need to be replaced. The basis for these conclusions about 3M blankets were not discussed.

After discussing the above concerns with the licensee, the inspector was provided calculation No. EC-210, "Extra Load of Wet Cerablankets" and telephone notes from 3M Fire Protection Products of St. Paul, MN, the 3M blanket vendor. The calculation addressed the basis for water loading, which was complete soaking of the Cereblanket plus ½ inch of water in the trays, resulting in a combined load of 112 pounds over an 8 ft. span. Calculation C270-01.02, Seismic Class I Cable Tray Supports, stated that a 200 pound live load to produce maximum bending and shear stress shall be supported by the cable tray in addition to electric cables and dead loads. Therefore, the licensee concluded that water loading was within allowable limits for the affected cable tray supports.

For the 3M blanket, the licensee provided telephone notes and documentation supplied by the vendor on 3M performance and characteristics in fire system actuation. The vendor stated that the 3M blanket without a weatherproof jacket would absorb water, and contains 13 ppm leachable chloride and is otherwise insoluble in water. Also, that proper installation with a metal weatherproof jacket would prevent water adsorption. This metal jacket appeared to be a metal foil. The licensee stated that this jacket is required to be properly installed with 3M insulation.

This information appears to satisfactorily address the concerns regarding the evaluation of the effects of spurious fire system actuations in cable spreading areas, and licensee corrective action to avoid future spurious actuations. Therefore, this item is closed.

e. <u>(Closed) Open Item 50-361/89-26-02, Control of Feedwater Oxygen and Metal Concentrations</u>

In August, 1989, inspectors noted that oxygen, iron and copper concentrations were sometimes above the recommended levels for the plants. This was a concern because increased oxygen concentrations usually cause increased condensate system corrosion. This higher corrosion results in more metals concentrating in the steam generators.

To follow up on the licensee's continuing corrective action to reduce feedwater oxygen and metals concentration, the inspector reviewed records of condensate and feedwater chemistry for all 3 units from January through March, 1990.

The chemistry records showed that for these three months, oxygen and metals concentrations stayed within recommended levels, except for the following:

1. For Unit 1, feedwater copper concentrations ranged between 1 and 6 PPB, tending to average around 3 PPB, which was above the 2 PPB recommended action level. The licensee stated the apparent cause of higher copper concentration was a combination of the large amount of copper in the secondary plant, and relatively high condensate acidity used to increase condensate polisher efficiency. The inspector noted that high condensate acidity would also tend to remove copper from condenser internals and entrain it in the condensate and feedwater. Copper has been associated with some steam generator tube corrosion mechanisms; therefore, copper concentrations should be minimized. The licensee stated that copper concentrations on Unit 1 have ranged high since construction, and are lower now than they have ever been.

2. For the first ten days of January, 1990, feedwater iron concentrations in Unit 3 appeared to be about 30 ppb, which is above the action level of 20 ppb.

3. On January 29 and March 21, Unit 2 condensate oxygen concentrations appeared to be about 10.5 ppb which is above the action level of 10 ppb.

For Units 2 and 3, these elevations in concentration appear to be isolated, since records show that, for the condensate and feedwater iron and oxygen, concentrations trend toward 5 to 10 ppb less than the action limits. For feedwater copper, which has an action limit of 2 ppb, concentrations appeared to range between 0.05 and 0.8 ppb, and typically appeared to be about 0.5 ppb.

Based on the above discussion, the licensee appeared to be maintaining chemistry levels appropriately and taking appropriate corrective action where required. Therefore, this item is closed.

f. <u>(Closed) Open Item 50-361/89-26-03, Chart Paper for Recorders Used to Monitor Chemistry Parameters</u>

In August, 1989, an inspector noted that improperly scaled chart paper was being used in recorders which monitor on line chemistry parameters. The licensee stated that steps would be taken to provide the appropriate paper.

The inspector reviewed the licensee's corrective action. The licensee formally transferred the responsibility for chemistry recorder paper from the control room staff to the chemistry staff. The inspector confirmed that adequate supplies of appropriate paper are now kept on hand, and appropriate scale paper is installed in chemistry recorders.

Based on the licensees corrective action, this item is closed.

g. (Closed) Open Item 50-361/88-10-12, FSAR Accuracy With Respect to Critical Crack in CCW System Piping

The licensee identified inaccurate FSAR information concerning a CCW system critical crack. The assumed flow rate of water through a critical crack had been documented as 898 gpm in design basis calculation M26.4. The FSAR had documented 42 gpm, and "approximately 700 gpm" in sections 9.2.2.3H and QR 10.48, respectively. The inspector observed that Revision 5 of the updated FSAR had been revised to state that 898 gpm is the maximum leakage rate.

Further resolution of Open Item 50-361/88-10-2 will address CCW system critical crack assumptions. Based on the follow-up of the technical issue in another open item, and verification of an appropriate update of the FSAR to reflect current expected CCW leakage rates, Open Item 50-361/88-10-12 is closed.

h. (Open) Unresolved Item 50-361/85-22-03, Inservice Testing of Pumps May Not Be Bounded by Design Basis

This item discussed the inspectors concern that the IST acceptance criteria for satisfactory performance of pumps may not be bounded by the safety analysis. The licensee is resolving the issue as part of the design basis reconstruction program.

The inspector noted that the same lack of bounding by design basis may apply to the IST stroke time acceptance criteria for valves.

Since the design basis reconstruction is ongoing, and the licensee is aware of the valve IST issue, this open item has been expanded to encompass both pump and valve IST criteria.

During review of the licensee Design Basis Documentation (DBD) program, the inspector noted that the DBD scope required pump and valve information retrieval. However, originally the pump and valve information retrieval was to be obtained during the system-by-system analysis, rather than all at once. As a result of the concern regarding this open item, the licensee began design basis reconstruction for pumps. The licensee estimated that by addressing pumps as a group rather than by system, about a man-year of extra effort will be expended on pumps, with about 1-2 man-months gained by having the pump information available for the later system analysis.

The licensee stated a similar estimate applied to reconstruction of valve IST design basis. Since Generic Letter (GL) 89-10 requires valve design basis information, this effort will help satisfy GL 89-10 requirements.

Also, this open item includes the deviation issued concerning the schedule to resolve this item. The deviation is discussed in i., below. Establishment of an acceptable schedule to resolve this item in its entirety will be addressed during a future inspection.

i. (Closed) Deviation 50-206/90-01-01, Licensee Failure to Meet a Formal Commitment Date to Resolve Unresolved Item 361/85-22-03 (item h. above)

The licensee committed to provide resolution of Unresolved Item 361/85-22-03 by November 15, 1989, and did not meet that commitment.

The schedule to complete the entire evaluation has not been established. However, the licensee stated the design basis requirements for the pumps closest to the design margin would be completed within 12 to 15 months of the San Onofre 90-01 NRC inspection report. Therefore, NRC inspector review will occur after May, 1991 for those pumps close to the design margin. Schedules for analyses of valves and remaining pumps should be established by the licensee as part of the resolution of unresolved item 361/85-22-03.

14. Exit Meeting (30703)

The inspectors met with licensee representatives denoted in paragraph 1 on June 15, 1990. The scope and findings of the inspection were discussed as described in this report. Licensee representatives acknowledged the inspector's findings.