UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W.
ATLANTA, GEORGIA 30323

Report No.: 50-261/89-11

Licensee: Carolina Power and Light Company
P. O. Box 1551
Raleigh, NC 27602

Docket No.: 50-261 License No.: DPR-23

Facility Name: H. B. Robinson

Inspection Conducted: July 10-July 28, 1989

Inspector: _____ 9-6-89
R. H. Bernhard, Team Leader Date Signed

Team Members: R. Schin
R. Gibbs
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Approved by: _____ 9-6-89
for P. Kellogg, Chief Date Signed
Operational Programs Section
Operations Branch
Division of Reactor Safety

SUMMARY

Scope:

This was a special announced Operational Safety Team Inspection (OSTI). The OSTI evaluated the licensee's current level of performance in the area of plant operations. The inspection included an evaluation of the effectiveness of various plant groups including Operations, Maintenance, Quality Assurance, and Engineering in support of safe plant operations. Plant management's awareness of, involvement in, and support of safe safe plant operation were also evaluated.

The inspection was divided into the major areas of Operations, Engineering, and Maintenance. The team placed emphasis on interviews of personnel at all levels, observations of plant activities and meetings, extensive control room observations, and system walkdowns. The inspectors also reviewed plant deviation reports, LERs for the current SALP evaluation period, and evaluated the effectiveness of the licensee's root cause identification; short term and programatic corrective actions, and repetitive failure trending and related corrective actions.

Results:

The inspection team concluded that Robinson is enhancing current plant procedures and practices. In the areas examined, improvements were noted in many programs, however weaknesses were also discovered. Management is actively involved in the improvement process at the plant.

Strengths weaknesses, and enforcement items noted during the inspection included:

Strengths:

Access control to the control room was good.

The practice of rotating operation's watchstations allows personnel to enhance their knowledge of different areas of the plant.

Contaminated space in the plant is minimized due to the aggressive radioactive leak control program.

The team noted good equipment appearance and housekeeping in the plant.

LER program improvements since the AEOD report were noted.

The draft temporary modifications procedure, when implemented, should improve the current program.

Good control of the maintenance backlog was noted.

Weaknesses:

Independent verification procedures need improvement.

Inadequate freeze protection was noted for a RWST level instrument and steam rupture ESF detectors. In addition, the auxiliary operators interviewed did not have an understanding of the heat trace panel indications and the modes of failure for the heat trace.

Security badges were noted to be improperly worn.

Annunciator Panel Procedures were noted to have deficiencies.

Temperature inputs for the reactor calorimetric calculation have the potential for errors due to the current calibration practices.

Walkdown of the Service Water and Component Cooling Water Systems discovered discrepancies.

The plant procedure two year review does not have a time requirement for incorporation or review of comments generated during the review.

Weaknesses were noted in the Operations Corrective Action Program.

The Design Basis Reconstitution Program had weaknesses in the areas of verification and validation.

There is a lack of a comprehensive Motor Operated Valve test program.

Enforcement Items:

The Auxilliary Feedwater System was found to have NPSH deficiencies (Violation).

The plant's program for controlling and documenting application of torque to fasteners is inadequate (Violation).

Records indicated mechanics failed to follow procedures while performing work using the reviewed work orders (Violation).

The CCW Heat Exchanger had maintenance performed without an adequate safety review (Violation).

The ability of the Closed Cooling Water System to perform its design function with the current level of tube plugging has not been verified (Unresolved Item).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*R. Barnett, Maintenance Supervisor, Electrical
*C. Baucom, Senior Specialist, Regulatory Compliance
*D. Baur, QA Supervisor
*S. Clark, Project Engineer, Configuration Control
*D. Crook, Senior Specialist, Regulatory Compliance
J. Curley, Director, Regulatory Compliance
*C. Dietz, Manager, Robinson Nuclear Project
*J. Eaddy, Jr., Environmental and Chemistry Supervisor
*S. Griggs, Aid, Regulatory Compliance
*R. Hammond, Environmental and Radiation Control
*E. Harris, Director, Onsite Nuclear Safety
*E. Lee, Senior Specialist, Planning and Scheduling
A. McCauley, Principle Engineer, Onsite Nuclear Safety
*R. Morgan, Plant General Manager
*D. Nelson, Maintenance Supervisor, Mechanical
*M. Page, Acting Manager, Technical Support
D. Quick, Manager, Maintenance
D. Sayre, Senior Specialist, Regulatory Compliance
*E. Shoemaker, Senior Engineer, Operations
*J. Sheppard, Manager, Operations
*B. Slone, Document Control Supervisor
*R. Smith, Manager, Environmental and Radiation Control
*R. Steele, Operations Coordinator
*H. Young, Director, Quality Assurance/Quality Control

Other licensee employees contacted included technicians, operators, mechanics, security force members, and office personnel.

NRC Representatives

*L. Garner, Senior Resident Inspector
*K. Jury, Resident Inspector

NRR Representative

*R. Lo, Project Manager

*Attended exit interview on July 28, 1989

Acronyms used throughout this report are listed in Appendix C.

2. Operations (41400, 41707, 61700, 71707, 93802)

To assess the operational safety of the facility, the team performed extended observations of the control room activities, with the unit operating near 100 percent power. The team conducted system walkdowns and plant tours, and observed operations rounds. In addition, they interviewed operators, observed shift turnovers, and reviewed operator logs. The team also reviewed records used for indication or control of plant status for adequacy and verified operator awareness of their contents.

The team monitored operator performance, control room decorum, awareness of plant status, response to alarms, and use of procedures. The team also reviewed engineering evaluations, system design, equipment maintenance, operating procedures, and operator training as related to questions that arose from observations in the plant.

a. Control Room Observations

The team observed shift turnovers that were conducted efficiently and effectively. Individual operator turnovers were accomplished using turnover checklists with required signoffs. Then an oncoming shift meeting was conducted in the control room by the oncoming Shift Foreman. This meeting addressed plant status, abnormal conditions, and planned activities.

Operator control of access to the control room was good. This was facilitated by the control room arrangement, with the primary access door at the opposite side of the control room from the RTGB control area. The Senior Control Operator's desk was located by the control room door, which made it easy for him to control access.

The RTGB at the controls area, where the Control Operator was stationed, was clearly marked by use of a different color carpet.

Shift manning was clearly posted on a board just outside the control room. Each watch position was listed, along with the name of the on shift watchstander. Fire brigade assignments were shown. The number of watchstanders and their listed qualifications satisfied NRC requirements. The Shift Foreman stated that recent training had been performed to assure that, using none of the watchstanders who were assigned fire brigade duties, the remaining watchstanders could perform a safe shutdown of the plant from outside of the control room in an event where the control room had to be evacuated. Operators stated that there were sufficient numbers of qualified watchstanders and that overtime work was rarely required. Almost all of the Auxiliary Operator watchstanders on all of the shifts were licensed reactor operators. The plant practice was for operators to switch watch stations daily. The watchstation changes from Control Operator, to Inside Auxiliary Operator, Outside Auxiliary Operator, second Reactor Operator in the control room, and back to Control Operator.

This watchstation rotation practice provides enhanced operator awareness of plant conditions, improved ability to work together, and leads to an increased feeling of plant ownership. The team considered this watchstation rotation as an area of strength for the licensee.

The team reviewed lit or disabled annunciators in the control room. The RTGB annunciators were color coded to assist the operator. Twelve were colored black, indicating they may normally be lit during plant operation. Four were yellow, indicating urgent operator action was required if they became lit, such as RCP bearing high temperature. The remainder of about 470 annunciators were white. Only six white annunciators were lit - four indicated potentially abnormal conditions and two were incorrectly lit (these had WR stickers attached for calibration or repair of the annunciators). Four unlit white annunciators had WR stickers attached for maintenance to be accomplished on the related equipment. None of the annunciators indicated an urgent safety problem. The Control Operator demonstrated adequate knowledge of each of these conditions, and in each case had initiated adequate corrective action. The licensee had no practice of intentionally disabling annunciators. Overall, the team considered that the total number of lit or disabled annunciators was reasonably small and well controlled.

The team reviewed control room inoperable equipment. This included equipment located in or controlled from the control room. For each of these items, operators had initiated a maintenance WR. Out of the existing total of about 38 such WRs, the team selected four of the older ones for further review. The team found that two of these four had long unexplained delays in processing of 9 to 13 months. One had been delayed in maintenance planning (WR/JO 88-ACJC1), waiting for parts to be ordered.

The other was delayed in Engineering (WR/JO 88-AEKC1 and related EWR 88-324), apparently waiting to be assigned to an engineer. The team discussed unexplained delays in WR processing with maintenance management, who stated that use of the existing manual systems for tracking EWRs and parts orders was difficult and somewhat ineffective. They stated that computerization of outstanding EWRs and parts orders would enable more effective management control and follow-up, and would help to eliminate long unexplained delays in repairs to equipment.

Throughout this inspection, the operators displayed a professional attitude concerning the plant equipment and their responsibilities as operators. The team reviewed operator logs and records, and found them to be legible, clear, and complete, with only rare minor exceptions. The on shift operators appeared to be alert and safely performing plant manipulations. Operators were attentive to their panels, and control room decorum was good. The control room operators maintained an orderly appearance and proper behavior.

b. Independent Verification of System Alignments

The team reviewed the licensee's procedure for independent verification. A review was completed of OP valve lineup checklists for safety systems, completed tagouts on safety systems, and the I&C Safety Related Instrument Valve Line-Up procedure. Interviews of operators by the team on this subject were performed.

The team found that the licensee's procedures for and implementation of independent verification were generally comprehensive and adequate. Four items for potential improvement were noted:

1) At least one of the verifiers should look at the valve or breaker. Procedure PLP-030, Independent Verification, Rev. 1, allows both verifiers to use the same remote indication to determine the position of a valve. This eliminates one last visual check for operability - an opportunity to detect such conditions as a leaking air actuator, damaged electrical connections, missing valve handwheel, or scaffolding over the equipment.

2) Both verifiers should be separate and independent from each other. PLP-030 does not require both verifiers to perform separate verifications. However, operators stated that they do typically perform separate independent verifications.

3) A valve that has had maintenance performed on it should have its position verified before returning it to service. Neither the independent verification procedure nor the tagout procedure require specifically that this be done. However, operators showed that they do perform and record this function.

4) OP-603, Auxiliary Feedwater System, Rev. 17, in Attachment 9.1, Valve Checklist, does not require independent verification for valves V2-20A and V2-20B being open. These are header section isolation valves, which if closed would prevent AFW flow to the A steam generator from the motor driven AFW pumps. PLP-030 requires the position of these valves to be independently verified.

These four items for potential improvement in independent verification are identified as inspector follow-up item 89-11-06: Independent Verification Procedures Should be Improved.

c. Freeze Protection for ESF and EOP Instruments

While reviewing MMM-19, Safety Related Instrument Valve Line-Up Procedure, Rev. 6, the team observed that valves for RWST level transmitters were not included. The team then reviewed the OP for the Safety Injection System to see if the RWST level transmitter valves were included in that system lineup checklist. Five valves for RWST level instruments were included in that procedure - a root isolation valve, a drain valve, an isolation valve for each of two level transmitters, and an isolation valve for a local level indicator. Each had independent verification required.

To verify that there were not actually more valves for the RWST level transmitters for use in calibration, the team reviewed drawing no. 5379-1082, Safety Injection Flow Diagram, Rev. 26. That drawing showed only the root isolation valve. The team then inspected the installed RWST level transmitter piping arrangement. The installed valves were all labeled, and were the ones listed in the OP. Adjacent to each level transmitter and the local level indicator was a removable pipe plug, which an I&E technician stated was used for calibration. An I&E foreman stated that a modification was planned to install additional valves to facilitate calibration.

While inspecting the RWST level transmitters, located outside near the RWST, the team noted that the pipe from the RWST to the two transmitters was insulated and supplied with two types of heat tracing wires. One type looked like copper tubing with approximately one-forth inch diameter. This heat tracing was connected through electrical conduits to a nearby heat tracing distribution panel, FPP-29. The second type of heat tracing looked like small insulated electrical wire, with a three pronged plug on one end. An I&C technician stated that the 'copper tubing' was the primary heat tracing, and was old and somewhat unreliable. The 'electrical wire' was the backup heat tracing. To power the backup heat tracing, an operator or technician would need to run an extension cord. Three other freeze protection devices were on the RWST level instruments: a heated box around the first level transmitter and the local indicator, a heated box around the second level transmitter (which looked like it had been more recently installed), and a heat traced pipe connecting the second level transmitter to the first section of pipe.

The team asked about how the licensee ensured that the RWST level transmitter piping did not freeze in the winter, and subsequently determined that:

1) The potential for freezing was a real concern. A Shift Foreman stated that freezing of the RWST level transmitter piping has happened before and could be detected in the control room. When the piping froze, the indicated level in the control room changed. The Control Operator was required to monitor the RWST level indicators on the RTGB each shift, and therefore was able to detect a change in indicated level. Whenever such freezing was identified, an operator or technician was promptly dispatched to heat the affected piping.

2) The design of installed indicators for the freeze protection circuits was inadequate. The freeze protection power supply panel FPP-29 had 12 indicating lights and 14 circuits. The heating circuit (#12) for one of the RWST level transmitters had no indicating light on the panel.

The related level transmitter box heater had no light at all and the strip heater on the pipe to the level transmitter had a separate indicating light that was located so that it was not readily visible to an operator. The heating circuit (#14) for the other RWST level transmitter had an indicating light on the panel that came on when the circuit was energized. But this light was incorrectly labelled #12.

3) The procedures for monitoring these freeze protection circuits were inadequate. The only formal monitoring was a weekly PM to be performed by I&C technicians during the months of November through April. A standing memorandum to the Shift Foreman on Cold Weather Operations directs the Shift Foreman, when outside temperature is 32 degrees F or less, to contact I&C to assure that all freeze protection panels are in service and operating as necessary. The Auxiliary Operator daily rounds sheets did not include a required check of any freeze protection. The team concluded that a weekly check is not frequent enough to ensure operability, because the RWST level transmitters serve an important emergency shutdown function. They provide RWST level indication and low level alarms in the control room that tell the operators when to switch to recirculation mode of core cooling. Emergency Operating Procedure Path 1, Rev. 6, dated January 6, 1989, relies entirely on RWST level indication for directing the operator to switch to recirculation mode, where pump suctions are taken from the containment sump instead of the RWST. Failure of the operator to switch to recirculation before the RWST emptied would result in a loss of NPSH to the safety injection pumps, RHR pumps, and containment spray pumps. This in turn could cause all of these pumps to burn up.

The licensee's TS do not address the emergency shutdown importance of the RWST level transmitters. In many other plants, the RWST level transmitters are ESF instruments which provide an automatic switchover to recirculation. As such, they are addressed in the related TS with LCO action statements that include requirements for prompt shutdown of the plant if less than a minimum number of channels are operable.

The team verified that the two RWST level transmitters are powered from different safety related power sources, one from instrument bus two and the other from instrument bus three.

4) Operator knowledge of this freeze protection was inadequate. Two licensed reactor operators who had stood Auxiliary Operator watches during the last winter stated that they would informally check freeze protection panels in cold weather. But both were not aware that indicating lights on FPP-29 did not include the freeze protection circuit for at least one RWST level transmitter.

They thought that, if all indicating lights on FPP-29 were lit, then all freeze protection circuits powered from that panel were operating properly. The I&C weekly PM contains instructions that indicate that a lit bulb does not necessarily mean an operable freeze protection circuit, as follows:

normal glow - circuit okay
bright glow - circuit shorted
weak glow - circuit grounded
bulb not burning - open circuit

Also, the operators both stated that there were a total of seven freeze protection panels in the plant. The I&C weekly PM lists ten freeze protection panels.

The team asked if any instruments providing an ESF signal were subject to freezing. A Shift Foreman stated that steam header pressure transmitters, which provide an automatic ESF signal, are located outside. They are subject to freezing and have heat tracing freeze protection. This freeze protection has no alarm and is officially checked only weekly during winter months by I&C technicians per the freeze protection weekly PM. The team concluded that a weekly check of this freeze protection was not frequent enough to ensure operability. The ESF function is to automatically initiate safety injection and containment isolation in the event of a steam line break. This would be sensed by two of three channels of high differential pressure between any steam generator and the steam header. The TS requires that a minimum of two channels be operable, and with less than that operable requires that the plant be shut down within eight hours. A weekly check of freeze protection during cold weather is not adequate to ensure operability of this ESF function.

Freeze protection of instruments required for emergency shutdown of the plant is considered an area of weakness. This will be identified as inspector follow-up item 89-11-07: Freeze Protection Measures for RWST and Steam Rupture ESF Detectors are Inadequate.

d. Control of Overtime

The team reviewed procedures for the control of overtime, audited records of work hours for some operators and maintenance technicians, and interviewed operators about overtime.

The team found that the licensee's policy on overtime, as described in OMM-01, Operations - Conduct of Operations, Rev. 22, and also in TS 6.2.3, is substantially less comprehensive than NRC recommendations described in Generic Letter 82-12, which revised NUREG 0737. Differences include:

1) The licensee's policy places overtime limits on only Shift Foremen, Senior Control Operators, Control Operators, and Shift Engineers. GL82-12 requires that overtime limits apply to all plant staff who perform safety-related functions (e.g., senior reactor operators, reactor operators, health physicists, auxiliary operators, and key maintenance personnel).

2) The licensee's policy applies overtime limits only when the Reactor Coolant System is greater than 200 degrees or when fuel is being moved within the Reactor Pressure Vessel. GL82-12 requires overtime limits at all times.

3) The licensee's policy applies different limits on working hours than those required by GL82-12.

4) Additional differences exist in wording of overtime rules.

The history of this item includes:

1) In 1980, NRC requirements on limiting overtime were issued as NUREG 0737 Item I.A.1.3.

2) On February 26, 1981, the licensee submitted to the NRC a policy on staff working hours to comply with Item I.A.1.3.

3) On November 15, 1981, the NRC approved the licensee's overtime policy.

4) On June 15, 1982, the NRC issued Generic Letter 82-12, which revised Item I.A.1.3. of NUREG 0737. In GL82-12, the NRC requirements on overtime policy were substantially changed.

5) On December 23, 1982, the licensee responded to GL82-12. In that response, the licensee incorrectly stated that the existing licensee policy on overtime limits was consistent with the intent of NRC policy as stated in GL82-12.

6) In December 1983, EG&G Idaho prepared a report for the NRC on the status of the licensee's compliance with NUREG 0737 items. In that report, the licensee's noncompliance with Item I.A.1.3. was identified, in that the licensee's TS had not been revised to include overtime limits and that the licensee's policy on overtime did not comply with NRC requirements as promulgated in GL82-12.

7) On May 15, 1985, the licensee requested a TS revision to incorporate the overtime policy that was based on the original 1980 NUREG 0737 requirements.

8) On September 12, 1985, the NRC approved the licensee's TS revision. This was based on the 1981 NRC approval of the licensee's overtime policy.

A team audit of recent records of work hours for a few operators and maintenance technicians did not reveal use of excessive overtime. In interviews, operators stated that in past years heavy use of overtime, especially during outages, had occurred. They also stated that more recently, substantial reductions in overtime had been made. They stated further that even during the last outage, relatively little overtime for operators or maintenance personnel had been used. Recent management initiatives to reduce overtime appear to have been effective. However, as these are informal controls, the potential for exceeding the recommendations of Generic Letter 88-12 in the future exists.

e. Observation of Daily Rounds

An inspector conducted observation of daily rounds for the purpose of identifying procedural or personnel weaknesses. No such weaknesses were noted, however, the following items were observed:

1) Deficiency Tags

A large number of outstanding equipment deficiency tags existed. These tags were in areas that are uncontaminated and readily accessible. Five deficiency tags were noted to be greater than one year old of which three were on safety-related equipment. Discussions with Operations personal indicated a lack of support by Mechanical Maintenance as the reason for the number of outstanding deficiencies.

2) Contamination Control

A lack of contaminated waste trash cans was noted. When an operator changed the filter paper on an air monitor, the operator had to walk a considerable distance to properly dispose of the filter paper. This increased the chance of dropping the filter paper and contaminating the area. More conveniently located cans, or small plastic bags to carry the contaminated paper in could reduce the chance of contamination.

3) Security Badges

The inspector noted security badges were routinely worn below the waist or were covered by pocket dosimeters or pens. Security badges are required to be worn between the shoulders and waist and not covered. These infractions went unnoticed by security personnel until informed by the inspector.

4) Industrial Safety

The inspector observed welding and electrical cables passing through door ways were unprotected. This allowed the door to close and pinch these cables causing damage that could lead to personnel injury. Guard blocks should be placed around cables passing through doorways to prevent such damage. Also, the landing at the entrance to the Spent Fuel Pool was too narrow and the door opened completely into the stairway.

5) Operator Access to Spaces and Equipment

The team observed that operator access to spaces and equipment was good. Auxiliary Operators carry keys for emergency access into locked high radiation areas and through failed security doors. In addition, the operators carry flashlights and many ladders are located throughout the plant, in designated storage racks. A book of system drawings, which were clear and legible, was available for use by the Auxiliary Operators.

6) Radioactive Leak Control

The plant has a very small amount of contaminated floor area, less than 1000 square feet, which enhances operator access to equipment rooms. A good program of radioactive leak control contributes to the small amount of contaminated area. The team noted that there were very few valves with leaks of radioactive liquid. Also, the primary coolant leak rate was very low, less that 0.04 gpm.

7) Loose Equipment

The team observed loose equipment carts stored near important plant equipment. A spare breaker on wheels was located in the 4160 volt switchgear room adjacent to breakers 12 and 13, which supply normal offsite power to vital 480 volt busses E-1 and E-2. Other loose carts were in the 4160/480 volt switchgear room and elsewhere in the plant, near nonsafety equipment. A better storage practice for this equipment would be to have it tied down or otherwise prevented from moving.

8) Housekeeping

The team observed housekeeping in general to be good. Rooms and equipment were clean and well painted. Virtually no loose trash or tools were seen in the plant. Ladders were stored in designated racks. The plant overall appeared clean and orderly.

f. Annunciators Panel Procedures (APPs)

The APPs listed in Appendix D were reviewed for accuracy and useability. The APPs are kept at the control panel and are readily accessible by the operators. However, the team found these APPs to contain inconsistent guidance, insufficient description of causes, incomplete description of actions, did not require verification of automatic actions, did not differentiate between local and control room indications or controls, and referenced setpoints not related to control room instrumentation scales. Examples of these deficiencies are given in Appendix E. The inspector also noted the RCS Pressure recorder Wide Range scale did not match the chart paper scale. The recorder is incorrectly scaled at 0 - 100 while the chart paper is correctly scaled at 0 - 3000 psig. Control room operators were unaware of any reason for this difference. The operators also stated only the chart paper scale is used for determining RCS pressure. This recorder is referenced in the Emergency Operating Procedures to determine Wide Range RCS pressure trend. The recorder scale should be changed to match the chart paper scale. These observations will be tracked as Inspector Follow-up Item 89-11-08: Annunciator Panel Procedure Weaknesses.

g. Instrument Calibration

The instrument calibration program was reviewed to identify any weaknesses. Discussions with Instrumentation and Calibration (I&C) personnel indicates a routine calibration schedule for all instruments designated as "required." When asked the criteria for designating an instrument as required, the team was told if the instrument is important, i.e. ESF or Technical Specification (TS) related, it is designated as required. Non-ESF or TS related instruments could also be designated as required. No definitive criteria was found by the team. Calibration sheets are retained for TS related instruments only and not all required instruments.

When the team asked how Operations is informed of which instruments require calibration, the inspector was told Operations is not informed until the calibration is to be conducted. Additionally, Operations is not informed of calibration results and is not required to signoff after the calibration has been completed. Calibration for control room instrumentation is scheduled during refueling only. One exception to routine calibration was found. The feedwater temperature computer points, used by Operations for calorimetric calculations, are calibrated by engineering staff assigned to the plant computer. I&C is only involved in the installation and initial calibration of the RTDs. The RTDs are calibrated using a generic calibration curve; not a calibration curve specific to the installed RTDs.

The computer points are not routinely calibrated and are checked only when Operations observes a difference in readings. When a calibration is conducted, only the computer points are calibrated, and not the entire loop including the RTDs. Calibration of the computer points only could cause a falsely low temperature value to be used in the calorimetric calculation. This could result in reactor power being unknowingly increased to greater than 100 percent by the operators. This item will be tracked as Inspector Follow-up Item 89-11-09: Weakness in Loop Calibration of Feedwater RTD Used in Calorimetric.

h. Service Water System Operations Walkdown

During the Service Water System walkdown with operations the team observed a number of equipment, procedure and training deficiencies. The team identified these deficiencies to the licensee for corrective actions. The deficiencies are summarized below and are discussed in detail in Appendix B.

In the Service Water System walkdown, the team used Operations Procedure OP-903, Service Water System, Revision 27 and system drawing G-190199, Revision 29. There were four cases noted where the drawing was inconsistent with the as-built configuration. There were 21 label plates missing from valves. A rubber hose was connected downstream of valve SW-219, which supplies water to a lubricating oil separator. There was no caution tag or information tag present. These Items will be tracked as part of Inspector Follow-up Item 89-11-10: Deficiencies Noted in Service Water and Component Cooling Water Walkdown.

i. Temporary Changes to Procedures

The NRC team reviewed the temporary change request program. Administrative procedure AP-004, Development, Review, and Approval of Procedures, Revisions, and Temporary Changes, Revision 28 dated June 8, 1989, provides guidelines used for initiating temporary changes. Temporary changes may be implemented for items that do not change the intent of the procedure.

A temporary change must be deleted or reviewed for permanent revision by the responsible manager within 21 days from the date the temporary change was approved. All temporary changes are assigned a control number and tracked by a temporary change log. The team reviewed the temporary change log to assure that changes were reviewed in a timely manner. Few changes were outside the 21-day limit. The coordinator uses the change log as a reminder to contact responsible personnel prior to the 21-day temporary change expiration date. One weakness identified by the team was that many temporary changes had been implemented prior to a safety evaluation being performed. The team observed a low backlog of temporary procedures existed.

PLP-026 provides a plant-wide methodology for reporting and investigating significant off-normal conditions. The Director of Regulatory Compliance is responsible for developing and maintaining a data base for tracking and trending significant off-normal conditions.

This is discussed further in section 3.a.2.

j. Periodic Procedure Review

The team reviewed the licensee program for performing a two year review for operations procedures. The program is addressed in procedure AP-004. Each procedure in the Plant Operating Manual (POM) is reviewed periodically by a person assigned by the approver or his designee. The team verified that the licensee has conducted two year reviews for operating procedures from 1985 to 1989.

Weaknesses identified are following:

-For those comments made during two year reviews, timely implementation of comments were not performed. Several comments for 1987 were generated again during 1989 reviews. AP-004 does not require a time limit for comment review and incorporation. This is identified as Inspector Follow-up Item 89-11-11: Lack of a Time Limit for Incorporation or Evaluation of Comments Made in Plant Procedure Two Year Review.

-The guidelines used by the reviewer were weak for both the administrative and technical reviews.

k. Operations Corrective Action Program

The NRC Team observed the functioning of the licensee's program for the evaluation of abnormal operating events. This was reviewed to assess its efficiency in increasing equipment availability through correct identification of root cause and by initiating the appropriate corrective action. OMM-027, Revision 2, dated June 14, 1989, establishes guidelines for Operations Corrective Action Program. The program provides criteria to identify, document, and evaluate off-normal conditions, both significant and non-significant. Off-normal condition refers to an adverse condition in any category that should be corrected, including failures, malfunctions, deficiencies, deviation defective material and equipment, and non-conformances. Off-normal conditions that are classified as significant are upgraded to the plant program, PLP-026, Corrective Action Program.

PLP-026 provides a plant-wide methodology for reporting and investigating significant off-normal conditions. The Director of Regulatory Compliance is responsible for developing and maintaining a data base for tracking and trending significant off-normal conditions. This is discussed further in section 3.a.2.

The team reviewed the operations corrective action tracking system and off normal condition analysis reports from August 18, 1988 to July 24, 1989. The following weaknesses were identified:

-Closeout of operations corrective actions were not performed in a timely manner. Only 13 out of 82 had been completed during the time period reviewed.

-Many off normal conditions analysis reports did not contain a root-cause analysis. In some cases this resulted in repeat events.

-Trending of non-significant off normal conditions needs improvement to prevent repeat events.

The Operations Corrective Action program as outlined in OMM-027, Revision 2, dated June 14, 1989, requires that off-normal conditions analysis in the trending program be periodically evaluated to determine if any adverse trends exist. The team review revealed that this was not being performed. This is identified as Inspector Follow-up Item 89-11-12: Weakness in Operations Corrective Action Program.

1. Operator Aids

The team reviewed the operator aid program to assure authorization, documentation and periodic reviews were performed. The operations engineer is responsible for authorizing the posting and removal of operator aids. The controlling procedure for operator aids, OMM-016, Control of Operator Aids, Revision 2, dated March 29, 1988, provides guidance for using operator aids. The Operations Engineer performs a review of the operator aid log index monthly for correctness, and to verify a continued need for each posted operator aid.

Quarterly the Operation Engineer reviews the operator aid log to verify that all logged aids exist, ensures there are no unapproved pen and ink changes, checks for legibility, and tours the plant to identify and remove unauthorized OA's.

The team reviewed the OAL from 1985 to 1989 for periodic review compliance. There were five cases where operator aids had been in effect for longer than two quarters. The responsible supervisor had been notified as to the need to incorporate the aid into a permanent procedure.

The following operator aids were reviewed by the team:

89-01 -Provide guidance for determination of reporting requirement and notification.

89-03 -Provide instructions for installation of mechanical level device.

89-04 -Provide instructions for sampling containment vessel with cart monitors.

The reviewed operator aids appeared to be effective tools for providing additional guidance to the operators. No discrepancies were noted in the program.

3. Engineering (37700, 37701, 37702, 92703)

a. Licensee Event Reports

The team reviewed the Licensee's event/failure trending program and potential reportable events/LERs from January 1, 1988, to July 1, 1989, and evaluated the adequacy of the following:

1) Trending of Similar Events/Failures.

The licensee has no formal trending program that specifically tracks events/failures which lead to LERs. However, the licensee has an informal tracking and trending method which adequately complies with NUREG 1022, section V, paragraph B, which addresses the review of Previous Similar Events. The team discussed this informal method with the members of the Regulatory Compliance staff who routinely prepare the LERs. The team concluded that while the program is not formalized, the program is effective in identifying previous events and initiating programatic corrective actions, when appropriate. Additionally, the team reviewed a selected sample of recent LERs and concluded that the identification of similar events, although not formal, was adequate.

2) Corrective Actions.

The team reviewed procedure PLP-026, Corrective Action Program, Revision 2, June 30, 1989, which addresses the corrective actions program including both short-term and programatic aspects. The review, in part, consisted of a review of screening criteria, corrective action methodology, and organizational involvement. The team discussed the methodology for determining corrective actions with the licensee's Regulatory Compliance staff. Additionally, the team reviewed the corrective actions for a selected sample of recently completed LERs for special training, required reading, procedural revisions, program upgrades, increased surveillance frequencies, increased preventative maintenance, and human factor improvements.

The team concluded that in the selected sample of LERs reviewed the licensee had generally considered the appropriate factors when determining the scope of corrective actions.

3) Root Cause.

The team reviewed procedure PLP-026, Corrective Action Program, Draft Revision 3, which at the time of this inspection had not been issued. The team discussed the proposed procedure revision with the Regulatory Compliance staff. These discussions were primarily focused on the licensee's self initiated root cause determination methodology improvements. The draft procedure contains an attachment 7.6, Investigation Team Guidance For The Investigation Process. This attachment addresses use of an independent investigation group to determine the root cause of an event or condition which has been designated as significant, and was of such a nature that it exceeds the ability of a single individual to resolve. The basic methodology of this investigation team was to ensure that evidence required for a thorough investigation of the event is preserved and has been gathered as soon as practical after the event. Additionally, the procedure provides several possible methods for root cause analysis. Although this program has not been implemented, the procedure demonstrates a well conceived, licensee initiated program and should provide useful root cause determination results for complex events. The inspection team concluded the weaknesses in the current program were adequately addressed in the revised program. When the revision is issued the program should be adequate to effectively determine root cause.

4) 1989 LERs

At the time of this inspection the licensee had issued 9 LERs:

89-001	Hydrogen introduction into station air
89-002	RTD thermowell failure
89-003	Contractor exceeded dose limits
89-004	SI actuation
89-005	Inadvertent closure of MSIV
89-006	Loss of EH control power
89-007	OPDT setpoint
89-008	RHR common mode failure
89-009	Relative humidity >70 percent with CV purge

LER 89-04 and 89-07 had previous similar occurrences. The LERs were of the type that had a more thorough root cause analysis or corrective action determination been performed on the referenced events the events that resulted in these LERs might not have taken place. The licensee has made some improvement in these determinations in recent months, and has proposed some changes in the methodology for root cause determination.

These changes and recent improvements should reduce the number of similar events in the future.

5) Event Response Team.

The licensee does not have a formal event response team that determines root causes for complex events. However, the licensee has a pending procedural revision that provides the charter and direction for the formation of this team. This is discussed in paragraph 3) of this section.

6) Adequacy and Threshold of LERs.

The team reviewed the licensee's LER Handbook, dated June 15, 1988, which was created to provide guidance to the writers and reviewers of LERs. The handbook follows the latest guidance from NUMARK and NUREG 1022, supplement 2, for the preparation of LERs, and delineates the threshold for reportability of LERs. Additionally, the handbook provides a historical review of the AEOD identified LER problems at HBR, detailed information about the required entry for each block of the LERs report form, and which items/events require LERs. Information regarding the immediate notification of NRC, four hour notification, and thirty day notification is provided. For the sample of recent LERs reviewed, the handbook was followed by the LER preparers.

The threshold for reportability and information contained within LERs has improved significantly since the AEOD report was issued, and during the time period of the selected LER review. The LER reports reviewed appear adequate. Additionally, the handbook for LER preparation is clear, unambiguous, and contains all the pertinent information the LER preparer should need to prepare an adequate LER.

b. Information Notices

The team reviewed a selected sample of recently completed Information Notices to determine the licensee's review process, commitment tracking, and the adequacy of the internal communications. The specific Information Notices reviewed were:

88-84	Defective Shaft Keys In Limitorque Motor Actuators
88-74	Potential Inadequate performance of ECCS in PWRs During Recirculation Operation Following a LOCA
88-07	Failure of Air-operated Valves Affecting Safety Related Systems
89-16	Excessive Voltage Drop in DC Systems

On-site Nuclear Safety procedure, ONSI-1, Operating Experience Feedback, Revision 5, dated January 5, 1987, was established to delineate the responsibilities for assuring that operating information pertinent to plant nuclear safety is supplied to the operating and training organizations.

This program and the program of the Nuclear Safety Review Unit were established to meet the requirements of NRC Task Action Plan, Item 1.C.5. The specific documents that are screened by ONSI-1 are:

1) Operating Experience Reports for site events
2) NSSS/Vendor Service Bulletins
3) Documents from ONS or the NSR Unit that are designated as warranting Operating Experience Feedback.
4) INPO Significant Operating Experience Reports and Significant Event Reports.
5) NRC I. E. Notices
6) Other industry sources deemed appropriate by the Director - ONS

The Operating Experience Feedback path for Information Notices was reviewed. The Information Notices received an initial screening by On-site Nuclear Safety document coordinator and were dispositioned to other groups, as applicable. Where it was clear that the item was not applicable to HBR or was an item that could be easily dispositioned, the item was closed by On-site Nuclear Safety and the package was routed for information purposes only to applicable supervision in other areas. When further investigation or study was needed, the Information Notice was assigned to a responsible engineer, forwarded from On-site Nuclear Safety to responsible groups for final disposition, and a formal tracking number was assigned. The tracking number is in the commitment data base and appears to receive adequate management attention. The package is returned to the responsible engineer assigned by On-site Nuclear Safety when the work has been completed or other appropriate actions have taken place. The completed package is reviewed by the responsible engineer and returned to the designated organizations if the actions are inappropriate. If the package has been satisfactorily completed, a copy of each evaluation is maintained by the NSR Unit, and the original of the closed packaged is forwarded to the record storage group for inclusion in permanent plant records.

The team discussed this process with members of the ONS staff, and reviewed the applicable procedures and the selected packages. In general, the disposition of this sample of Information Notices appears adequate. The level of documentation and the tracking methods are adequate to provide reliable and retrievable records of the licensee's disposition of Information Notices.

c. Design Basis Reconstitution

The team reviewed the licensee's self initiated Design Basis Reconstitution Project. The licensee's definition of the objective of this program is to structure the current design basis and calculations/analyses of record, applicable to the plant systems required for safe shutdown and mitigation, and control them for future use. The critical design parameters, related to the plant procedures and hardware, will be validated against the structure design basis.

The systems that were in the pilot program were AFW, SIS and RPS. These systems have been completed, however, the validation process has not been completed for the RPS. Additionally, the Electrical Power Distribution System and the Electrical Cable/Raceway DBD have been completed, but the validation process was not complete. The other systems to be included in the DBD are Component Cooling Water System, HVAC System, Service Water System, Nuclear Instrumentation System, Residual Heat Removal System, Emergency Diesel Generators, Incore Instrumentation System, Chemical and Volume Control, Reactor Coolant System, and Reactor Vessel Level Instrumentation System. Only the post accident response portions of HVAC will be included in the HVAC DBD. The scheduled completion of this program is 1992.

The system's design basis, as defined by CP&L, is abstract in nature and consists of:

1) System functional Requirements
2) Regulatory Requirements/commitments relative to system design
3) Original design codes or standards of record, unless clearly superseded by a regulatory commitment to a later code or standard.

The program appears to be primarily for the use of design engineers. Within the limits of the program, the licensee appears to be expending sufficient resources to accomplish the Design Basis Reconstitution. Based on discussions with the design engineers and a review of the proposed program, the weaknesses in the program are that there is limited field verification in the validation phase and no apparent attempt to validate critical system parameters, such as flow, temperature, and pressure. An additional weakness in the program is the extended time after a discrepancy is discovered that a documented operability review is completed. In most cases reviewed, the operability review was made several months after the discrepancy was discovered. This untimely review can lead to a system being inoperable for an extended period of time without the licensee being aware of this condition. This is identified as Inspector follow-up item 89-11-13: Timeliness of Operability Reviews of Problems Discovered in Design Basis.

The team requested the licensee to verify a single system parameter, as a demonstration that design parameter verification was not necessary. The parameter selected was Condensate Storage Tank temperature effects on Auxiliary Feedwater Pump Net Positive Suction Head (NPSH) requirements.

After an initial engineering evaluation it appeared that there may be insufficient NPSH for the Steam Driven Auxiliary Feedwater Pump, if the CST is at minimum level. Subsequent to the onsite inspection, NPSH concerns led to a plant shutdown on August 22, 1989. Additional details of the NRC review and disposition of this issue will be documented in Inspection Report 50-261/89-18. This issue is identified as apparent violation 89-11-01: AFW System Inoperability Due to Inadequate NPSH.

The licensee is continuing the investigation of this finding and is considering changes in the DBD program. This identified as Inspector Follow-up item 89-11-15: Validation of Critical Design Parameters in DBD.

d. UFSAR Discrepancies

During a review of unrelated subjects, the team noted UFSAR Table 2.3.2-2 entry for July minimum temperature was in error. This appears to be a typographical error. The discrepancy will be evaluated by the licensee for revision to the UFSAR in Amendment 8 and will be tracked as SAR change request A8-095. The team reviewed the change request and proposed corrective actions. The team determined that there is no safety significance for this errant entry, as it provides no input to any of the analyzed accidents, nor to any critical component design. With the issuance of A8-095, this item is considered closed.

e. Design Change Packages

The team reviewed two recently completed safety-related Design Change Packages to determine the adequacy of 10CFR50.59 Evaluations. The documentation, work completion, functional testing, revisions to affected procedures and drawings, timeliness of completion, and QA/QC were reviewed. The packages were generally complete. The safety evaluations did not reference all of the pertinent information for a complete evaluation, however, the information was contained in the package. The post modification testing specified and performed was adequate. Portions of the packages could not be reviewed due to the poor quality of the micro film copy. Generally the packages indicated that a little more attention to detail in filling out the required paperwork would be appropriate, but the packages appeared to adequately accomplish the intended task.

f. Temporary Modifications

The team reviewed two temporary modifications to determine their adequacy.

The first temporary modification reviewed was installed as corrective actions for a finding in the DBD effort. Temporary Modification 89-709, RHR Sump Level Indication, Revision 1, dated April 13, 1989, was installed as a result of an SSFI of the Safety Injection System DBD.

It revealed that during a LOCA, with a 1 percent fuel failure and a loss of off-site power, if the RHR pump seal should fail, the control room operator might not have indication that the RHR pit sump was filling up.

- The final conclusion was that any accident that was accompanied with loss of off-site power would cause the sump pumps and the level indication to fail. The sump pumps and high level alarms would not function on loss of off-site power, since they do not have a safety-related power source. This temporary modification installed redundant mechanical level indication that will provide interim level indication outside the RHR pit until a permant solution is implemented.

  The temporary modification was installed and was scheduled to remain in effect until the the next refueling outage. Since temporary modifications are generally allowed for only a three month period without a further evaluation, a request for extension was requested. The modification extension was granted via memorandum on April 13, 1989, Serial number RNPD/89-1373. This extension was handled in accordance with applicable procedures.

  The licensee performed an engineering calculation, 89-04, to determine the expected off-site dose based on the modification to the RHR pit and the accumulation of post-accident reactor coolant. There was a slight increase in the off-site calculated dose, however, the licensee judged that this was not a significant increase. Due to the low probability of the RWST pipe breaking during the injection phase, the licensee and NRR agreed that prior to the next refueling outage the RWST pipe break need not be considered, and hence the source term for accumulated reactor coolant was not considered for this period for entry into the RHR pit. The calculation did not account for the dose to the operator that must perform post-accident manual manipulation of the cross-connect valve in the RHR pit. This was contained in engineering calculation 89-05, with the agreed upon exclusion of the accumulation source term. The licensee will provide motorized, class 1E operators for the cross-connect valves and will provide safety-related, class 1E sump pumps in each of the RHR pits.

  The interim level indication installation and the existing level instrumentation are not seismic. Since the level indication installed was non-seismic, no credit can be taken for it's availability post-accident. However, the licensee has demonstrated that either channel of the independent level instrumentation, if available, can be installed in a timely fashion.

  The licensee performed the required 10CFR50.59 analysis. The analysis concluded that this was not an unreviewed safety question, based in part on their agreement with NRR, that based upon Probabilistic Risk Assessment data, the circumstances that would lead to this situation prior to the next refueling outage were highly unlikely.

The second temporary modification reviewed, TEM 89-704, Isolation of PPS to Sleeves S-24, S-26, and S-30, Revision 0, dated February 8, 1989, isolated the Penetration Pressurization System to the containment penetration bellows assemblies S-24, S-26, and S-30. These bellows are located on the 3 inch steam generator blowdown lines. The Penetration Pressurization System's function is to provide early indication of primary containment penetration leakage.

The team reviewed the 10CFR50.59 analysis for this modification. While this modification clearly changed equipment and procedures referenced in the UFSAR, it does not change the Chapter 15 analyzed accidents. The isolation of the three leaking penetrations allows the Penetration Pressurization System to continue to provide it's intended function for the balance of the penetrations.

g. Temporary Modification Program

The team reviewed the temporary modifications program by selecting a sample of temporary modifications that were installed during the last two years and a sample of currently installed temporary modifications. A list of the temporary modifications examined for the program review, along with the team's comments are:

Number	Date	Description	Note(s)
88-001	2/2/88	SW HVH Piping	2
88-003	6/9/88	Main Steam Piping	2
88-004	6/21/88	FCV-1332C Leak	
88-005	7/25/88	Condensate Polisher	1,2
88-006	7/26/88	MS-128 Down Stream Piping	2
88-007	7/28/88	LCV-1508A Flange	2
88-010	8/30/88	AFW PI-1425	2
88-700	9/14/88	Belzona Repairs of SW	
88-701	10/12/88	Extraction Steam	
88-703	1/3/89	SW Temporary Repair	1
88-704	11/24/88	Fuel Handling System	3
88-705	1/21/89	Thermocouples for HVH-4	1,4
88-706	12/23/88	Pipe Cap On RWST Drain	1,4
89-700	1/13/89	RTD for CV Monitoring	1,4
89-701	1/24/89	FT-113 Leak	
89-702	1/30/89	CVC 1116 Substation	1,4
89-703	2/8/89	A and B Leakoff Lines	4,4
89-704	2/8/89	Isolate PPS Sleeves	1,4
89-705	2/25/89	Steam Turbine	1,4

note 1 - This item is currently installed as a temporary modification.

note 2 - The team reviewed Modification and Design Control Procedure MOD-018, Temporary Modifications, revision 2, dated December 20, 1988. Paragraph 5.9, Extensions, states "If it is desired to extend the TM beyond the three (3) months time limit, a revision must be written in accordance with Paragraph 5.8. All reviews performed on the original TM must be reperformed to verify the continued need for the TM. Extension must be approved prior to expiration of original TM... If it is known that a TM must remain installed for an extended period of time, the Plant General manager may grant a waiver to the TM three month time limit." These are examples where this procedure was not followed.

note 3 - All documentation for this package was lost. Modification and Design Control Procedure MOD-018, Temporary Modifications, Revision 2, dated December 20, 1988. Paragraph 5.10, Disposition of Records, delineates the records that should have been sent to the vault for retention as a permanent record. None of the required records were retained.

note 4 - Waiver from the three month installation limit was issued. For the majority of 1989 temporary modifications, the modifications were issued an extension. It is apparent that most temporary modifications, as used at HBR, generally are installed at least until the next refueling outage. The 10CFR50.59 evaluations, if performed, do not generally address the actual period of time the Temporary Modification is actually installed.

The team reviewed a number of recent QA Nonconformance Reports that addressed Temporary Modifications, 88/40, 88/41, 88/42, and 89/002. These documents identified a number of discrepancies and nonconformances in the Temporary Modification implementation. The licensee has a self initiated improvement program that specifically addressed these items and the Temporary Modification program in general. The team reviewed the draft of Modification and Design Control Procedure, MOD-018, Temporary Modifications, Draft Revision 4, and MOD-013, Safety Analysis and Review, Draft Revision 5. The team discussed these procedures and the proposed philosophy changes that these procedures represent with the responsible engineer and appropriate levels of management. The team determined that the changes in the procedures indicated that the licensee has proposed significant improvements in the program will address both the teams concerns and the balance of the unanswered QA nonconformances.

The magnitude of these changes warrant further inspection after the procedures have been implemented. This is identified as inspector follow-up item 89-11-14: Review Implementation of MOD-18, Revision 4 and MOD-13, Revision 5 in Temporary Modification Program.

i. Engineering Surveillance Testing

The team reviewed a selected sample of Engineering Surveillance Tests to determine the compliance with Technical Specification Schedules, Licensee commitments, and all applicable codes and standards. The test were accomplished in accordance with applicable procedures, which were based upon appropriate standards. The team did not note any discrepancies in the sample reviewed.

j. QA/QC

The team reviewed a selected sample of QA/QC audits in the areas of maintenance, operations, and modifications. The specific packages reviewed were:

89-007, Technical Specification Surveillance Program, dated January 18, 1989.

89-032, Maintenance Work Requests, dated May 1, 1989.

89-003, Modifications, dated January 16,1989.

88-088, Maintenance Work Requests, dated October 17, 1988.

88-073, Performance of MST's, dated September 13, 1988.

88-044, Maintenance and Operational Surveillance Tests, dated June 2, 1988.

89-044, Maintenance and Operational Surveillance Tests, dated March 19, 1989.

Very few findings were identified, all of the findings in the sample reviewed were of the compliance type. The audits were generally compliance based. This review did not identify any specific deficiencies in the program.

4. Maintenance (62702, 71710)

During this inspection a review of the licensee's maintenance program was conducted.

This review focused primarily on maintenance activities on the Component Cooling Water System. The systems approach to this review was used in order to provide a more definitive basis for drawing conclusions concerning the effectiveness of the program. The review included several broad areas. A walkdown of the CCW system was conducted in order to determine the overall material condition of the system. The results of this walkdown are included in paragraph e of this section. Additionally, corrective maintenance, preventive maintenance, predictive maintenance, system deficiency backlog, and trending of component failures were included in the review. The paragraphs that follow provide the details of the areas reviewed and the results and conclusions reached concerning the effectiveness of the program.

a. Corrective Maintenance

In order to assess the effectiveness of the licensee's corrective maintenance program a number of completed maintenance work request packages were selected for a detailed technical review. The packages were selected based on the importance of the components to plant safety and also in an effort to provide a cross-sectional overview of the various different types of maintenance activities. The work request had all been completed within the past two years. For some of the work only the work request was reviewed. For other work, the entire work package was reviewed, which included, as appropriate, the associated maintenance procedures, the vendors technical manual, calibration records and procedures, material purchase orders and receipt inspection records, weld data reports, post maintenance testing records, etc. A detailed list of the work request and administrative procedures reviewed are provided in Appendix A. This review noted a number of technical problems:

-WR/JO 89-AACY1, CCW system check valve CC-721C: This work request removed the valve bonnet, inspected the valve internals, and replaced the bonnet. The WR did not specify a torque value for the body to bonnet fasteners, however, a Torque Wrench Certificate of Calibration Sheet attached to the WR indicated that a torque wrench calibrated at 215 in-lbs had been used to perform the work. The specific torque value for the body to bonnet fasteners was not documented in the WR nor was torquing independently inspected or verified. The licensee concluded that the fasteners had been torqued to 215 in-lbs which is the torque for a 3/8 inch fastener. Investigation determined that the valve has 7/16 inch fasteners for which the proper torque is 30 ft-lbs (360 in-lbs). In response to this finding, the licensee issued WR/JO 89-AGYI1 to retorque the fasteners to the proper value.

-WR/JO 88-AITF1, CCW system check valve CC-731: This work request removed the valve bonnet to support valve testing and reinstalled the bonnet once the testing was completed. The WR referenced corrective maintenance procedure CM-120, which is the incorrect procedure for work on this valve.

MC-120 provides instructions for repairing Anchor Darling type C48Z swing check valves. The site equipment loading list states that CC-731 is a Velan check valve. Even though the wrong procedure was specified, the mechanics used the procedure in performance of the work as evidenced by signoffs made in the record copy attached to the completed WR. The procedure was not followed, however, as evidenced by the following: Attachment 8.1 of CM-120 provides extremely high torque values for the body to bonnet fasteners (1020 or 1650 ft-lbs, depending on fastener size). A Torque Wrench Certificate of Calibration attached to the completed WR calibrated the torque wrench used in this work to 150 ft-lbs. The specific torque applied to these fasteners was not documented in the WR nor was there any independent inspection or verification of the torque applied. The licensee concluded that the actual torque applied was 150 ft-lbs. This torque value is incorrect for the Velan valve installed in the plant. The vendor manual for a Velan cast steel valve specifies a torque of 170 ft-lbs for the body to bonnet fasteners. The vendor manual also prohibits the use of all solvents for cleaning of the fasteners except acetone, alcohol or Freon PCA. The WR did not include this prohibition. As a result, the licensee issued WR 89-AHDH1 to correct the incorrect torque applied to the fasteners of CC-731. This also represents a case of failure to follow procedure.

-WR/JO 89-ABYB1, CCW flange joint between the "B" RCP upper oil cooler and valve CC-719B: This WR corrected a leak in the subject flange by disassembly of the flange, installation of a new gasket, and reassembly. The WR specified a torque value of 150 ft-lbs for the flange fasteners. The torque applied was documented on the WR, but there was no independent inspection or verification of this action. The torque value applied to these flange fasteners was obtained from a generic torquing table in a Crane vendor manual which bases torque values on fastener size, material type and desired stress in the fastener. The technical source for the torque value appeared to be appropriate, however, this same torque table had a note which stated that actual torque values obtained without lubricating the fasteners would be as much as 50 percent lower than the values indicated in the table. The WR did not specify any lubrication for the subject fasteners.

-WR/JO 89-ACRC1, CCW blind flange between valve CC-795J and the cooler to the "B" High Head Safety Injection Pump: This WR disassembled the flange, installed a new flexatalic gasket, and reassembled the flange to correct a flange leak. The torque value specified for the flange fasteners (45 ft-lbs) was documented on the WR, but this action was not independently inspected or verified. The technical source for the torque value specified by the WR was from a generic torque table in a Crane vendor manual which bases torque values on fastener size,

material type and desired stress in the fastener. A note to this table requires lubrication to obtain desired values. The WR did not provide instructions requiring lubrication of the fasteners. Additionally, vendor instructions for the installation of flexatalic gaskets emphasize the importance of proper gasket compression during installation. The WR did not provide any instructions for checking of gasket compression, such as the use of a feeler gage.

-WR/JO 87-AKWN1, CCW system relief valve CC-791L: This WR rebuilt CC-791L including complete disassembly, cleaning, stem replacement and reassembly of the valve. The WR and the associated maintenance procedure (CM-102) did not provide the vendor manual required assembly torque values for the body to bonnet fasteners included in section 7.5 of the vendor manual (Crosby Nozzle Relief Valve Maintenance Manual) and as a result the fasteners were not torqued to the required torque. The WR and CM-102 did not require lubrication of the O-rings and fasteners as required by section 7.5 of the vendor manual. Paragraphs 7.1.1, 7.1.11 and 7.3.13 of CM-102 required data to be recorded concerning the installed relief valve including the "as found" and "as left" blowdown ring position. This data was not recorded as required by the procedure during the performance of the work. This is a failure to follow procedure. As a result of these findings, the licensee issued WR 89-AHAK1 to rework the valve.

-WR/JO 89-ABIS1, motor operated valve CC-749B: This WR adjusted the packing on the valve. The WR required the packing gland to be tightened to a value of 6 ft-lbs. The WR further allowed the packing torque to be increased in 0.5 ft-lbs increments and required that planning be notified if the final torque exceeded 7 ft-lbs. The final torque applied in order to stop the packing leak was 8.5 ft-lbs. The maintenance foreman, not the planner, was notified of the overtorquing required. Investigation into the final disposition of this deficiency determined the following: The packing vendor (Chesterton) provides the licensee packing torque requirements based on the size of the valve, the number of packing rings installed and the valves service (system temperature and pressure). The vendor allows the licensee to torque the packing gland to a maximum of 115 percent of the specified torque before the valve is required to be repacked. In this case, the final torque (8.5 ft-lbs) exceeded 115 percent of the specified torque of 6 ft-lbs (115 percent * 6= 6.9 ft-lbs) and additional corrective action was not initiated by the licensee. As a result of this finding, the licensee issued WR 89-AGXZ1 to repack the valve.

-WR/JO 89-AATS1, "C" CCW Pump: This WR disassembled, inspected, repaired and reassembled the "C" CCW Pump.

The WR and associated maintenance procedure (CM-019) did not provide a torque value for the pump casing fasteners. Review of the vendor manual noted that no torque value was specified by the vendor for these fasteners, however, good engineering practice would dictate that torque values should be provided for all system closure fasteners to assure proper system integrity.

-WR/JO 89-AATS1, "C" CCW Pump: This WR disassembled, inspected, repaired and reassembled the "C" CCW Pump. No records of post maintenance testing of this pump following the work on this WR could be found by the licensee.

-WR/JO 88-ADEK1, CCW manually operated containment isolation valve CC-737A: This WR corrected a packing leak on this valve. The WR reported a packing leak on CC-737A and the description of the deficiency specifically stated "...Be careful, the valve is very hard to operate and tightening the packing may just make it worse." In spite of this description the packing was adjusted to eliminate the leakage. Post maintenance testing, such as cycling of the valve to prove proper operation, was not conducted (see WR/JO 88-AESK1).

-WR/JO 88-AESK1, CCW manually operated containment isolation valve CC-737A: This WR was issued approximately one month after WR/JO 88-ADEK1 and reported that CC-737A was extremely hard to operate. The corrective action for this WR included removal of the grease fitting, clean out of old hardened grease and regrease of the grease box and stem. No post maintenance testing was performed following this work. Approximately one month after the corrective action to WR/JO 88-AESK1, WR/JO 88-AFJK1 reported the same "valve hard to operate" problem. The corrective action for this WR included repacking of the valve. The post maintenance testing following this WR was done by performing OST-908 to verify proper valve functioning.

All of the above listed deficiencies were discussed with the licensee. Discussion of the torquing deficiencies with the mechanical maintenance supervisor, the supervisor of planning and one of the maintenance engineers resulted in a conclusion that the types of deficiencies noted are generic for much of the maintenance work on site which involves torquing. This conclusion was based on the fact that these personnel indicated that until about six months to a year ago the site did not provide torque values to maintenance personnel for accomplishing work. At about that time it was noted by the licensee that maintenance practices in this area were deficient. Since that time all torque values provided have been taken from a generic torquing table out of a Crane vendor manual. As noted above this practice results in incorrect torque values being applied to many of the components in the plant. The lack of adequate procedures to control torquing of system closure fasteners and the cases where personnel failed to follow procedures were of specific concern.

These deficiencies are identified as Violation 89-11-02: Inadequate Plant Programs For Controlling and Documenting the Torquing Process, and Violation 89-11-04: Failure to Follow Procedures While Performing Maintenance.

b. Component Cooling Water Heat Exchangers:

During the inspection the licensee was asked to provide a list of all completed corrective maintenance work request which had been completed on the CCW system within the past two years. Team review of this listing noted two work requests (87-AJPT1 and 89-AFQE1) which had accomplished plugging of leaking tubes in the CCW heat exchangers. Because this work would more likely be accomplished under the design change program rather than as a maintenance task, an investigation into this area to determine the basis for the number of tubes allowed to be plugged was conducted. The investigation determined the following:

1) Each of the CCW heat exchangers has a total of 1976 tubes.

2) The licensee had plugged 36 tubes in the "B" CCW heat exchanger and had plugged 190 tubes in the "A" heat exchanger.

3) The licensee had accomplished the tube plugging in accordance with a maintenance procedure (CM-201) and did not consider that plugging of the heat exchanger tubes was a design change.

4) The basis for the number of tubes that could be plugged was included in an analysis which Westinghouse had provided the licensee. The licensee had interpreted the Westinghouse analysis as approval to plug up to 300 tubes in each heat exchanger.

5) Review of the Westinghouse analysis noted that there was some technical basis for plugging up to 100 tubes, based on calculations supplied from the heat exchanger vendor which showed no significant degradation in heat exchanger performance with up to 100 tubes plugged. However, the final conclusion that up to 300 tubes could be plugged was not supported by any detailed technical analysis. The Westinghouse analysis final conclusion addressed the adequacy of 75 tubes plugged. The review did not address the original design basis of the heat exchangers.

Further investigation into this area with the licensee determined that the heat capacity and specifications of the installed heat exchangers prior to plugging are the same as those described in Table 9.2.2-1 of the UFSAR. When the licensee started plugging tubes in the heat exchangers, thereby changing the flow and heat transfer of an item described in the UFSAR, a 10 CFR 50.59 evaluation was required. A 10 CFR 50.59 evaluation was not performed by the licensee. The failure of the licensee to conduct a 10 CFR 50.59 evaluation is a violation of NRC requirements and is identified as Violation 89-11-03: CCW Heat Exchanger Plugging Performed Without the Required 10 CFR 50.59 Review.

The licensee is currently conducting an evaluation to determine the operability of the CCW heat exchangers.

Until this item is completed and reviewed, this item will be identified as unresolved item 89-11-05: CCW Heat Exchanger Adequacy in Performing Its Intended Design Functions.

c. Maintenance backlog

During the inspection, the team attempted to assess the backlog of maintenance items which are outstanding. The team reviewed the backlog of work on the Component Cooling Water system including the outstanding deficiencies (WR/JOs, EWRs, Field Reports, Nonconformance Reports and Significant Condition Reports) which existed at the time of the inspection. This information was reviewed to assess both the total number of items outstanding, and the severity of each item. The review also assessed the prioritization of the items scheduled for completion by the licensee. This information, in conjunction with the walkdown of the system (see paragraph e of this section) was used to complete the overall assessment of the backlog. The walkdown of the system noted its material condition to be very good, especially considering the age of the plant. The listing of outstanding deficiencies on the system was very small (a total of 13 items) and were of no safety significance. Additionally, the licensee's prioritization was appropriate. The overall conclusion reached in this area was that the licensee properly controls the maintenance backlog. This area is assessed as a strength.

d. Preventative and Predictive Maintenance

The preventative maintenance and predictive maintenance programs at Robinson were also reviewed during this inspection. The team evaluated the types of PM or Predictive analysis techniques were in place, what specific components in the CCW system were maintained or analyzed by these techniques, and the frequency of the PM or predictive maintenance. The procedures used and the date of the last PM were also reviewed. The investigation also verified that preventative maintenance required in the vendor manuals for the specific components inspected under item (a.) were implemented in site PM procedures. The conclusion was that the licensee has adequate programs in place. One weakness identified is that the site does not have a motor operated valve testing program currently in place which attempts to predict MOV failures prior to their occurrence. The licensee has developed a very comprehensive valve program under a project called the Managed Valve Maintenance Program (MVMP) which is designed to manage valve performance, not only based on testing, but also on many other aspects of valve performance. This program will require a significant amount of resources and a considerable length of time for implementation. In the interim the lack of a motor operated valve testing program is considered a weakness.

e. System Walkdown: Component Cooling Water

The team conducted a partial walkdown of the Component Cooling Water System with the assistance of an auxiliary operator (approximately 80 percent of the accessible portions of the system were walked down). The operating procedure OP-306, Attachment 9.1, Rev. 12, Component Cooling System Checklist, and the system flow diagram 5379-376, Rev. 23 were used to conduct this portion of the inspection. The team traced out various portions of the system checking for proper labeling of components, material condition of the system, valves positioned in the proper position, and pipe caps installed where required.

The team observed that the majority of components were properly labeled with die stamped aluminum labels. The overall material condition of the system was very good, and housekeeping and material condition in the various plant spaces was excellent especially considering the age of the plant. Several deficiencies were noted, however, which were referred to the licensee for corrective action:

1. Valve CC-851C, root valve to pressure indicator PI-641C, was found out of position. The valve was open in lieu of closed as required by the operating procedure and the system flow diagram. The indicator was for local indication only. The operator immediately repositioned the valve in accordance with procedural requirements.

2. The following valves were not labeled:

CC-862C
CC-794A
CC-795G
CC-869
CC-899

These Items will be tracked as part of Inspector Follow-up Item 89-11-10: Deficiencies Noted in Service Water and Component Cooling Water Walkdown.

5. Management Meetings (30702)

The team attended regularly scheduled management meetings to evaluate their effectiveness. Tuesday and Thursday of each week a Unit Managers Staff Meeting is held. The participants discuss current major items of interest affecting plant operations and future plans for resolving problems. At the meeting attended, there was active participation from all members. The meeting was well focused and not too long to lose its effectiveness. The staff showed good knowledge of the issues and their potential impact on plant operations. Responsibility for issue resolution was clearly defined. The meeting was effective.

A Site Work Activity Coordinator Group Meeting was observed. The meeting not only discussed the coming day's activities, but also reviewed the next week's tentative schedule. The meeting was short and concise.

Necessary coordination was accomplished without excessive time being taken in the meeting. Participants interviewed indicated that since the daily meetings had been held, coordination on plant activities had improved.

A Robinson Nuclear Project Board of Directors meeting was attended. The BOD was formed in October 1988 as a management focus group for long term plant improvement. The BOD consists of the manager of the Robinson Nuclear Project and thirteen members, mostly supervisors and managers. The meeting was typified by open, free exchange of ideas and opinions. Teamwork and consensus were stressed. Six major goals have been published and the plant personnel have been briefed on them. The goals focus on generation, cost of generation, SALP and INPO ratings, radiation exposure, and the quality of the workforce and workplace. The group's effectiveness in reaching their goals cannot yet be determined due to the groups recent formation. The dates for achievement of the goals vary, but are as late as December 1993.

4. Exit Interview

The inspection scope and findings were summarized on July 28, 1989, with those persons indicated in paragraph 1. The inspectors described the areas inspected and discussed in detail the inspection findings listed below. The licensee did not identify as proprietary any of the material provided to or reviewed by the inspectors during this inspection. Dissenting comments were not received from the licensee.

Item number	Status	Description/Reference Paragraph
261/89-11-01	OPEN	VIOLATION - AFW System Inoperable Due to Inadequate NPSH. (Paragraph 3.c)
261/89-11-02	OPEN	VIOLATION - Inadequate Plant Programs For Controlling and Documenting the Torquing Process. (Paragraph 4.a)
261/89-11-03	OPEN	VIOLATION - CCW Heat Exchanger Plugging Performed Without the Required 10CFR50.59 Review. (Paragraph 4.b)
261/89-11-04	OPEN	VIOLATION Failure to Follow Procedures While Performing Maintenance. (Paragraph 4.a)
261/89-11-05	OPEN	URI - CCW Heat Exchanger Adequacy in Performing Its Intended Design Functions. (Paragraph 4.b)
261/89-11-06	OPEN	IFI - Independent Verification Procedures Should be Improved. (Paragraph 2.b)

261/89-11-07	OPEN	IFI - Freeze Protection Measures for RWST and Steam Rupture ESF Detectors are Inadequate. (Paragraph 2.c)
261/89-11-08	OPEN	IFI - Annunciator Panel Procedure Weaknesses. (Paragraph 2.f)
261/89-11-09	OPEN	IFI - Weakness in Loop Calibration of Feedwater RTD Used in Calorimetric. (Paragraph 2.g)
261/89-11-10	OPEN	IFI - Deficiencies Noted in Service Water and Component Cooling Water Walkdown. (Paragraphs 2.h. & 4.e)
261/89-11-11	OPEN	IFI - Lack of a Time Limit for Incorporation or Evaluation of Comments Made in Plant Procedure Two Year Review. (Paragraph 2.j)
261/89-11-12	OPEN	IFI - Weakness in Operations Corrective Action Program. (Paragraph 2.j)
261/89-11-13	OPEN	IFI - Timeliness of Operability Review of Problems Discovered in the DBD. (Paragraph 3.c)
261/89-11-14	OPEN	IFI - Review Implementation of MOD-18, Revision 4 and MOD-13, Revision 5 in Temporary Modification Program. (Paragraph 3.h)
261/89-11-15	OPEN	IFI - Validation of Critical Design Parameters in DBD. (Paragraph 3.c)

Appendix A

The following are a list of Completed Work Request reviewed:

* WR/JO 88-AEPD1	Calibration of FIC-678 alarm switch
* WR/JO 87-AKWN1	Disassembly, inspection, repair, and reassembly of relief valve CC-791L
* WR/JO 89-AAWW1	Repack of valve CC-712A
* WR/JO 88-AMZI1	EQ repairs to valve CC-716A
* WR/JO 89-ABIS1	Adjustment of packing on valve CC-749B
* WR/JO 88-AITF1	Open and inspect check valve CC-731
* WR/JO 89-AACY1	Open and inspect check valve CC-721C
* WR/JO 88-ABZK1	Replacement of solenoid valve CC-739
* WR/JO 88-ABUX1	Replacement of the CCW piping to the "B" RHR pump heat exchanger
* WR/JO 89-AATS1	Replacement of the "C" CCW pump seals and bearings
* WR/JO 88-ANMR1	Replacement of the "C" CCW pump seals and bearings
WR/JO 87-AJPT1	Repair of "B" CCW heat exchanger tube leaks
WR/JO 89-ACRC1	Repair of leaking flange upstream of CC-795J
WR/JO 88-AEGE1	Replacement of fasteners in the "C" CCW pump and motor base
WR/JO 88-ADEK1	Repair of packing leak on valve CC-737A
WR/JO 88-AESK1	Correction of a problem with valve CC-737A being hard to operate
WR/JO 88-AFJK1	Correction of a problem with valve CC-737A being hard to operate
WR/JO 89-AEFZ1	Valve CC-730 would not cycle during performance of OST-703
WR/JO 89-AEGQ1	Valve CC-730 would not close from the RTGB
WR/JO 88-ABHD1	Valve CC-716B would not close from the RTGB
WR/JO 88-ADAP1	Valve TCV-144 has a packing leak
WR/JO 88-AJHC1	Valve TCV-144 failed it's stroke time test (OST-703)
WR/JO 89-AEGC1	Valve TCV-144 failed it's stroke time test (OST-703)
WR/JO 89-AFCM1	Valve TCV-144 has a packing leak
WR/JO 89-AFMJ1	Valve TCV-144 failed it's stroke time test (OST-703)
WR/JO 89-ABYB1	Flange leak between the RCP upper oil cooler and valve CC-719B

* The complete packages for these jobs were reviewed including, where appropriate, the associated maintenance procedures, the vendor technical manual, calibration records, material purchase orders and receipt inspection records, weld data reports, post maintenance testing records,etc.

The following are a list of the Administrative Procedures reviewed:

MMM-001, Rev. 7	Maintenance Administration Program
MMM-002, Rev. 4	Maintenance Procedure Preparation
MMM-003, Rev. 19	Maintenance Work Request
MMM-005, Rev. 10	Preventative Maintenance Program

APPENDIX B

Service Water System Walkdown - Discrepancies Identified

A. Safety Injection Pump

1. Valve SW-516 not labeled

B. Diesel Generator Room

1. Flow indicator FI-6614A for diesel air dryers not labeled

C. Service Water Booster Pump

1. Check valve SW-561 not labeled
2. Temperature indicator TI-1662A not labeled
3. Drawing does not show installed throttle valve upstream of PSL-1602A
4. Drawing does not show installed vent line upstream of PI-1601A

D. Station and Instrument Air Compressor

1. Valve SW-578 not labeled
2. Valve SW-531 not labeled
3. Valve SW-579 not labeled
4. PX points were capped off

E. Auxiliary Feedwater Pump and Component Cooling Heat Exchanger

1. FSL-1633A, inlet to the oil cooler, not labeled
2. SW-115 not labeled
3. TX-1682A not labeled
4. TX-1688A not installed but shown on drawing

F. Steam Driven AFW Pump Oil Cooler

1. Valve SW-251A not labeled
2. Valve SW-252 not labeled
3. Valve SW-272 not labeled
4. Valve SW-259 not labeled
5. PI-6623 contained a blue tag that stated it had been overranged

G. Feedwater Pump

1. SW-182 not labeled
2. SW-313 not installed but shown on drawing

H. Turbine Oil Cooler

1. SW-465 not labeled

I. Condensate Pump

1. SW-167 not labeled
2. SW-166 not labeled
3. SW-469 not labeled
4. SW-468 not labeled

J. Seal Water Booster Pumps

1. SW-170 not labeled
2. A rubber hose was connected downstream of SW-219 which goes over to the lube oil separator. There was no TM or Caution Tag associated with this modification.

K. Primary Air Compressor

1. TI-1620 not labeled

APPENDIX C
LIST OF ABBREVIATIONS

AC	Alternating Current
AEOD	Analysis and Evaluation of Operational Ddata
AFW	Auxiliary Feedwater
AP	Administrative Procedure
APP	Annunciator Panel Procedure
ANSI	American Nuclear Standards Institute
BOD	Board of Directors
CA	Auxiliary Feedwater System
CCW	Component Cooling Water
CFR	Code of Federal Regulations
CP&L	Carolina Power and Light
CST	Condensate Storage Tank
CV	Containment Volume
DBD	Design Basis Document
D/G	Diesel Generator
DPR	Demonstration Power Reactor
DRS	Division of Reactor Safety
EH	Electro Hydraulic
ECCS	Emergency Core Cooling System
EOP	Emergency Operating Procedure
EQ	Environmental Qualification
ESF	Engineering Safety Features
EWR	Engineering Work Request
F	Degrees Fahrenheit
FCV	Flow control valve
Ft-lbs	Foot pounds
GL	Generic Letter
HBR	H. B. Robinson
HVAC	Heating Ventilation and Cooling
I&C	Instrument and Controls
IFI	Inspector Follow-up Item
IEN	Inspection and Enforcement Notice
IN	Information Notice
in-lbs	Inch pounds
INPO	Institute for Nuclear Power Operations
JO	Job Order
Lb	Pounds
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
MOD	Motor Operated Disconnects
MSIV	Main Steam Isolation Valve
MST	Monthly Surveillance Test
MOV	Motor Operated Valve
NPSH	Net Positive Suction Head
NRC	Nuclear Regulatory Commission

NRR	Nuclear Reactor Regulation
NSR	Nuclear Safety Review
NSSS	Nuclear Steam Supply System
NUREG	Nuclear Regulation
NV	Chemical Volume and Control System
OA	Operator Aid
OAL	Operator Aid log
ONS	Onsite Nuclear Safety
OP	Operating Procedure
OPDT	Over Pressure Delta Temperature
OST	Operations Surveillance Test
OSTI	Operational Safety Team Inspection
PI	Pressure Indicator
PM	Preventative Maintenance
POM	Plant Operating Manual
PPS	Penetration Pressurization System
PSIG	Pounds per Square Inch Gage
PWR	Pressurized Water Reactor
QA	Quality Assurance
QC	Quality Control
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
REV	Revision
RHR	Residual Heat Removal
RPS	Reactor Protection System
RTD	Resistant Temperature Detector
RTGB	Reactor Turbine Generator Board
RWST	Refueling Water Storage Tank
SALP	Systematic Assessment of Licensee Performance
SAR	Safety Analysis Report
SF	Shift Foreman
SI	Safety Injection
SIS	Safety Injection System
SG	Steam Generator
SSFI	Safety System Functional Inspection
SW	Service Water
TM	Temporary Modification
TS	Technical Specifications
UFSAR	Updated Final Safety Analysis Report
WR	Work Request
WR/JO	Work Request/Job Order

Appendix D
APPs Reviewed:

APP-001-08
APP-007-09
APP-007-40
APP-008-14
APP-008-15
APP-007-30
APP-005-19
APP-006-06
APP-006-01
APP-006-02
APP-006-09
APP-006-10
APP-006-17
APP-006-18
APP-006-25
APP-006-26
APP-006-33
APP-006-34
APP-006-41
APP-006-42
APP-001-17
APP-001-03
APP-001-22
APP-002-04
APP-003-27

Appendix E
Examples of APP Weaknesses:

APP-001-08: Requires check of position for valves CC-716A, CC-716B, CC-730 but not position is given. CCW flow and CCW Surge Tank level are also required to be checked but no values are given. This APP also states to start Standby Cooling Water Pump but no switch number is given. Without proper guidance, the operator has no reference to assess system performance.

APP-007-09: States Standby pump automatically starts but does not require verification of pump start and does not give switch number.

APP-008-14,15: APP-008-14 requires check of all turbine valves closed but APP-008-15 does not. Since both APPs address a turbine trip, the required operator actions should be identical.

APP-005-19: The automatic action given in this APP is not an automatic action but is a caution that a protective feature is disabled. This APP deviates from the basic structure of the APPs since automatic actions are expected to occur versus being disabled.

APP-006-25: This APP has several deficiencies. Automatic actions are given as 'None Applicable.' However, there are several automatic actions that occur at LO-LO level. A reactor trip will occur as will an AFW automatic start. These are listed as plant effects but are directly related to the LO-LO level. Since these are safety-related actions, the APP should list these actions as automatic actions to ensure the operator will make appropriate verifications. This APP lists several parameters to verify such as SG level, steam flow, and feedwater flow. No expected values are given for these parameters so the operator is unaware of system performance. Setpoints are given as percent of span while control room instrumentation indicates percent of level. Setpoints should referenced to the instrument the operator will use. These deficiencies were noted in other APPs that have safety-related functions or actions.

APP-007-38: This APP references pump trip and alarm setpoints to elevation while control room instrumentation indicates in percent level.

APP-002-04: The APP states accumulator pressure should be observed but does not give a value for accumulator pressure. If accumulator pressure could cause an accumulator low level condition, a value should be referenced for the operator to assess system performance.