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

Report No.: 50-400/90-11

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

Docket No.: 50-400 License No.: NPF-63

Facility Name: Shearon Harris

Inspection Conducted: October 29 through November 9, 1990

Inspector: Larry S. Mellen 11/19/90
L. Mellen, Team Leader Date Signed

NRC Team Members: L. King
E. Lea
R. McWhorter
D. Roberts
M. Shannon

Accompanying Personnel: P. Reagan, COMEX
G. Wilford, SAIC

Approved by: Linda J. Watson 11/19/90
L. Watson, Chief Date Signed
Operational Programs Section
Division of Reactor Safety

SUMMARY

Scope:

This was a special announced Emergency Operating Procedure team inspection. Its purpose was to verify that the Shearon Harris Emergency Operating Procedures were technically accurate and that their specified actions could be accomplished using existing equipment, controls and instrumentation.

Results:

The overall assessment concluded that the Emergency Operating Procedures (EOPs) adequately covered the broad range of accidents and equipment failures necessary for safe shutdown of the plant. The team identified weaknesses in Procedure Generation Package maintenance (paragraph 2), Step Deviation Document justifications (paragraph 2), the Writer's Guide (paragraph 4), nomenclature

inaccuracies (paragraph 4), Verification and Validation of locally performed actions (paragraph 4), and technical and human factors descrepancies (paragraph 4). In addition, the technical basis for the Abnormal Operating Procedure on refueling cavity integrity was weak (paragraph 3). The team identified the improved EOP logic (paragraph 3), design of foldout pages (paragraph 3), and the technical compliance with the Emergency Response Guidelines (paragraph 3) as strengths. The team reviewed the Safety Evaluation Report on the licensee's Procedure Generation Package commitments and determined that the commitments had been completed with the exception of revising the Procedure Generation Package and those items noted in Appendix C. Violations or deviations were not identified in this report.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

J. Abraham, Shift Foreman (SRO) - Operations
R. Basset, Senior Specialist - Operator Training
*J. Boska, Manager - Nuclear Training
*J. Bradley, Manager Operations Support - Operations
*E. Brooks, Operations Procedure Coordinator - Operations
M. Christopherson, Auxiliary Operator - Operations
M. Coffee, Control Operator (RO) - Operations
S. Hinnant, Plant General Manager
K. Holbrook, Control perator (RO) - Operations
H. Lipa, Shift Technical Advisor - Operations
S. Lowe, Auxiliary Operator - Operations
V. McGrew, Shift Technical Advisor (SRO) - Operations
*C. Olexik, Director - Regulatory Compliance
K. Olive, Control Operator (RO) - Operations
J. O'Tuel, Control Operator (RO) - Operations
K. Pace, Senior Control Operator (SRO) - Operations
M. Palmer, Shift Foreman (SRO) - Operations
J. Pierce, Senior Specialist - Operator Training
A. Schultz, Senior Control Operator (SRO) - Operations
S. Sewell, Shift Technical Advisor (SRO) - Operations
*H. Smith, Acting Manager - Operations
*D. Tibbitts, Manager Shift Operations
*M. Wallace, Senior Specialist - Regulatory Compliance
G. Ward, Senior Specialist - Operator Training
J. Warner, Control Operator (RO) - Operations
P. Watts, Control Operator (RO) - Operations

Other licensee employees contacted included engineers, technicians, operators, trainers and office personnel.

NRC Personnel

*S. Lawyer, Chief, Operator Licensing, RII
*R. Becker, NRR Project Manager

NRC Resident Inspectors

*J. Tedrow, Senior Resident Inspector

*Attended exit interview on November 9, 1990.

Procedures reviewed during this inspection are listed in Appendix A.

A list of abbreviations used in this report is contained in Appendix E.

2. EOP/GTG Comparison

The team compared the index of the Harris EOPs and AOPs against the index of ERGs and the list of emergency procedures recommended in Regulatory Guide 1.33. The team confirmed that the licensee developed sufficient procedures to encompass the spectrum of accidents and equipment failures addressed by the ERGs, RG-1.33, and the FSAR.

The Harris PGP described the EOP development and revision process. The PGP was composed of the PSTGs, the EOP WG, the EOP V&V Program Description, and the EOP Training Program Description. The PGP was inadequate because it was not being maintained as the top tier EOP program document. The WG had evolved into the controlling document that described most of the EOP development and revision process at Harris. PGP inadequacy was identified as IFI 400/90-11-01.

The licensee defined the Harris PSTG to be the EOP SDD, the SHNPP EOP/WOG Step Deviation Document - Generic Differences, the WOG/SHNPP Reference Plant Differences, the Setpoint Study, the WOG/SHNPP Plant Specific Step Matrix, Instrumentation and Control Deviation document, and the WOG ERGs. The licensee had made changes to individual EOP steps from those recommended by the ERGs. This was done to adapt those steps to the plant configuration, to improve human factors or to comply with the WG. While the resulting steps were technically sound, the SDD contained numerous steps where the differences between the EOPs and the ERGs were not clearly justified. This was identified as IFI 400/90-11-02.

Shearon Harris used Flow Paths (PATH-1 and PATH-2) which were a set of board mounted procedures kept in the MCR. The flow paths were used following a reactor trip or safety injection. PATH-1 encompassed Reactor Trip or Safety Injection (ERG E-0) and Loss of Reactor Or Secondary Coolant (ERG E-1). PATH-2 encompassed SGTR (ERG E-3). The arrangement of these path procedures provided a method to transition into the appropriate EPP or FRP using a systematic diagnosis of symptoms. The path procedures also facilitated place keeping and expedited initial transition to the appropriate EPP or FRP. Detailed information was contained in other documents. The use of the path procedures was considered to be adequate.

The licensee submitted an EOP PGP, including a WG, to the NRC for review and approval in April 1987. An NRC SER on the Shearon Harris procedures generation package was issued on June 20, 1990. The team reviewed the SER and determined that, with the exception of revising the PGP and those items identified in Appendix C, there were no open items.

No violations or deviations were identified in this area.

3. Independent Technical Adequacy Review of the EOPs

The team reviewed the procedures listed in Appendix A to determine their technical adequacy. They found that those procedures either followed the vendor recommended step sequence or deviated from it with acceptable documented deviations in most cases. Exceptions to this are noted in Appendix B. The team found that the EOPs were technically adequate and that the priority of accident mitigation strategies in the EOPs was appropriate. The licensee significantly enhanced the EOPs by improving EOP logic and decision points in comparison with the ERGs, and by moving continuous action items to foldout pages. The team considered these enhancements to be strengths. The AOPs were generally acceptable, but were not prepared, verified and validated to the same level of quality as the EOPs and training on AOPs was not as extensive as on the EOPs.

In some instances, the EOPs deviated from the ERG but inadequate justification was provided in the SDD. These deviations were noted in Appendix B as "PSTG". The licensee stated that the following general differences did not change the intent of the ERG: plant specific terminology, plant specific components and systems, plant specific means, step numbers, terminology and use of certain verbs and phrases, branching, entry points, plant specific foldouts, resetting of FW isolation, addition of EAL flags, logic changes, deletion of the red path summary in foldouts, and the other minor administrative changes. However, the GDD generally described the ERG deviation, rather than providing an adequate justification of the differences. Except as noted in Appendix B, the licensee followed the rules of the GDD, but the result was a number of instances in which the team questioned the adequacy of the SDD justification.

The team concluded overall that the GDD failed to justify some of the generic differences between the ERGs and the EOPs, did not have a requirement to identify all of the deviations in the SDD, and did not have a requirement to justify all of the generic differences. No instances were found where safety significant deviations were not addressed. No instances were found where the licensee failed to appropriately deviate from the ERGs when warranted by the plant specific design.

During the EOP walkdowns, system drawings and protective system logic were evaluated for accuracy and operator use. It was found that the drawings were accessible, well maintained, readable, and categorized such that the operator could readily find the desired drawing.

The review of AOP-17, "Loss of Instrument Air," identified that the drawings were not modified to reflect the installation of a new rotary instrument air compressor. The

APP concerned with this installation was inaccurate, and the applicable FSAR section required clarification concerning instrument air availability on LOSP.

The team found some EOP and AOP steps to be technically inadequate. Typical examples were:

In AOP-004, if the substeps were performed in the listed order, ESW for both EDGs would be isolated simultaneously.

Several EOPs and AOPs inadequately addressed the possibility of cross connecting both trains of ESW when aligning ESW to the TDAFW pump or the IA compressors.

Several EOPs inadequately addressed RNO actions to be taken when isolating feed to a SG. The SHNPP MFW and AFW systems differed significantly from the reference plant and required more detail in the EOPs for alternative ways of isolating feedwater.

AOP-031 failed to reflect important analytical data, such as radiation levels, various scenario times, pool water levels, containment evacuation times, and operator immediate action times, which resulted in a procedure only suited for smaller fuel pool leaks and inadequate for cavity seal failures such as the one described in IE Bulletin 84-03. The licensee agreed to give this matter prompt attention.

Five plant specific values from each EOP were reviewed for conformance with the ERGs and the setpoint document. Except as noted in Appendix B, the values were correct. Adverse containment values were given in the setpoint document and in the EOPs.

During the EOP walkdown, five P&ID drawings were evaluated for their accuracy. The drawings were found to be acceptable.

No violations of deviations were identified in this area.

4. Review of the EOPs and AOPs by Inplant and MCR Walkthroughs

The team conducted plant and/or MCR walkthroughs on all of the EOPs and AOPs listed in Appendix A. The walkthroughs were conducted for the following reasons: 1) to confirm that the procedures could be followed and would accomplish the stated purpose; 2) to verify that the listed instrumentation and controls were consistent with the installed plant equipment; and 3) to ensure that the listed indicators, annunciators and controls were available to the operator.

The EOPs and AOPs were found to accomplish their stated purposes except for the items noted in Appendix B.

Indicators, annunciators and controls referenced in the EOPs were found to be available to the operators except as noted in Appendix B.

The team also evaluated the location and availability of the EOPs in the MCR and verified that the current revisions were maintained. While the results of the EOP walkthroughs were generally acceptable, discrepancies in the areas of technical adequacy, WG adherence, and human factors were noted. The most significant deficiencies noted during the walkthroughs were the lack of detail in the procedures for locally performed actions and the technical inadequacies. The technical content of the AOPs was found to be of significantly lower quality than that contained in the EOPs. Technical and human factors discrepancies are noted in Appendix B while WG discrepancies are noted in Appendix C. The technical and human factors discrepancies and the WG discrepancies are identified as IFIs 400/90-11-03 and 04, respectively.

Labeling inconsistencies were found in a number of procedures. Appendix D is a listing of the labeling inconsistencies identified by the team. The following were examples of items appearing in Appendix D. EOP-EPP-001 described "control power to the CCW pump breakers" but the component label was "ACB CONTROL DISCONNECT." In EOP-EPP-006, "SI accumulator isolation" valves 1SI-246 were actually labeled "ACCUMULATOR A DISCHARGE." The inadequacies and inaccuracies in EOP nomenclature are identified as IFI 400/90-11-05.

V&V of EOPs was generally conducted in accordance with the PGP, as described in paragraph 6. However, V&V of locally performed EOP and AOP actions was not adequately performed in all cases. The following was an example of EOP and AOP weaknesses attributed to inadequate V&V of local actions. EOP-EPP-001, Step 8a, referenced OP-155, but OP-155 did not include a list of equipment and the key required to perform the task. When V&V was adequate, the EOP step was significantly improved. For example, EOP-EPP-001, RNO 19a1, required local operation of the SG PORVs. Adequate V&V of that step by the licensee resulted in implementation of the following changes:

a. Added reference to OP-126, including check list of equipment required for the local operation

b. Installed access platform and communication jacks

c. Improved emergency lighting

For those procedures that did have V&V of locally performed actions, the V&V was performed by licensed operators rather than non-licensed auxiliary operators. It was possible therefore, that a more qualified person would find the procedure to be adequate. However, the less qualified person who would normally do the task could find the procedure to be inadequate in some regard. Also, the V&V of local actions was generally not performed under the assumption of emergency lighting conditions. The inadequate V&V of locally performed actions was identified as IFI 400/90-11-06.

No violations or deviations were identified in this area.

5. Simulator Observation

a. The team observed one crew performing the following scenarios on the SHNPP simulator:

1) SGTR with ERFIS failure

2) Loss of all AC power without SI required

3) Feed line rupture inside containment with failure of AFW to isolate

4) Loss of offsite power with a loss of instrument air; natural circulation cooldown required

5) Loss of CCW and seal injection to RCPs

b. Problems in EOP usage were noted in the following areas:

1) The annunciators were so loud that the SCO reading the procedures frequently could not be heard until the annunciators were silenced. (The licensee noted that the volume had been confirmed to duplicate actual MCR conditions.)

2) Notification of radiological control personnel of changes in plant conditions and equipment lineups which affect radiological concerns was inadequate. Specifically, on the SGTR, notifications were not made concerning the unmonitored radioactive release occurring via the ruptured SG PORV. Additionally, in other scenarios, radiological control personnel were not informed of increasing containment pressures, which could cause increased containment leakage leading to unmonitored radioactive releases.

3) There was no place for SCOs to set the Path 1 and 2 flow chart or the EAL network boards. The SCOs were distracted by constantly having to move about

to find a position where lighting and support for marking on the board was adequate. Also, since there was no place to lay the flow chart, when the SCO was reading from the bottom of the board, the board had to be held up where it obscured the SCO's view of the MCB.

4) There was no method for providing board operators with copies of needed portions of procedures (tables or foldout pages). The SCO had to take a page out of the procedure in use by the STA (path 2, table 1) and have it copied. Foldouts, although read and acknowledged, were not made available for reference by board operators.

c. General

During the simulator scenarios, the flow charts and EOPs were adequate to mitigate the consequences of the accidents, and were sufficiently clear to be correctly implemented under emergency conditions.

The simulator was able to generate plant conditions expected for those scenarios listed above. A minor fidelity problem was noted with dual SG A and B PORV indications when the valves were fully opened locally.

The EOPs did not cause interference between board operators nor was there any significant, unnecessary duplication of operator effort.

Initial and recurring EOP training for both licensed and non-licensed operators were reviewed and found to be adequate.

Comments noted during the simulator scenarios on specific procedures were included in Appendix B.

No violations or deviations were identified in this area.

6. Management Control of EOPs and AOPs

The team reviewed licensee's procedures and interviewed licensee personnel to determine if the licensee had established an on going evaluation program for the EOPs as recommended in Section 6.2.3 of NUREG-0899. The specific considerations from NUREG-0899 that were evaluated in this review were:

"Evaluation of the technical adequacy of the EOPs in light of operational experience and use, training experience, and any simulator experience and MCR walkthroughs,

Evaluation of the organization, format, style, and content and as a result of using the procedures during operations, training, simulator exercises and walkthroughs,

Evaluation of staffing and staff qualifications relevant to using the EOPs."

The team also gathered information to determine if the licensee's QA program was actively monitoring the EOPs/EOP program as identified in Section 4.4 of NUREG-0899.

There was not a formalized program, as described in Section 6.2.3, for an on going evaluation program for the EOPs. The licensee relied on INPO for identifying operational experiences from other utilities that should be reviewed for applicability to the Harris facility. LERs initiated by other CP&L facilities were reviewed by the general office and forwarded to the On Site Nuclear Safety Group. The On Site Nuclear Safety Group reviewed the LER and forwarded them to the responsible department.

Evaluation/reviews of the licensee's EOPs were performed under OFRs, OMM-6, and AP-006. OFRs provided licensee personnel with a method to identify opportunities for procedure improvement to management. OMM-6 provided details on the V&V program for the validation of the EOPs. The V&V process was intended to provide two independent phases of procedure review. EOP verification was required when a change to an EOP was processed and was performed by technical reviewers. Each technical reviewer was required to perform reviews in areas of technical accuracy, hardware accuracy and written accuracy.

The validation process consisted of two phases; on-going validation and pre-implementation validation. Minor changes to EOPs were validated using the on-going validation method. The on-going validation method required simulator and table top validation for each EOP every two years. Major changes to the EOPs required a pre-implementation validation. The pre-implementation validation method consisted of a table top validation followed by simulator validation. Pre-implementation validation was required to be accomplished after the verification and technical reviews were completed and prior to the issuance of a new revision.

AP-006 also required a two year periodic review of procedures. This procedure stated, "Plant procedures shall be reviewed by an individual knowledgeable in the area affected by the procedure no less frequently than once every two years to determine if changes are desirable." The two year review was required for procedures that were applicable to RG-1.33, Appendix A. The licensee provided documentation indicating that the procedural reviews were performed as required.

The QA department performed a surveillance in the area of EOPs from July 12, 1989 to August 30, 1989. The previous QA audit conducted specifically for EOPs was performed during start-up. No future QA audits, targeted specifically for EOPs, were scheduled. EOPs will be reviewed in the future as a segment of the licensee random procedure program. The QA surveillance, performed on EOPs in July 1989, was performed to verify compliance with NUREG-0737 and NUREG-0899 requirements. The licensee selected five procedures to evaluate: EPP-003, EPP-014, EPP-017, FRP-S.1 and FRP-J.3. Because of this review, the licensee identified three human factor related items. OFRs were initiated to correct the items identified.

No violations or deviations were identified in this area.

7. EOP User Interviews

The team conducted interviews with six licensed operators and one AO. Three SROs and three ROs were interviewed. The interviews were conducted to sample the operators' opinions on the quality, usability and adequacy of the EOPs; to collect information on the approach to training and to augment the identification of specific deficiencies in the EOPs.

Generally the operators were confident that the EOPs would work and could be used in an actual emergency. Operators understood the division of responsibility in the MCR, felt staffing was adequate except for some instances (i.e., if emergency communicator was unavailable), reported minimal problems locating and physically using procedures in the MCR, and reported no technical inadequacies in the EOPs. Operators generally described similar placekeeping methods. Communications in the MCR were practiced in accordance with OMM-009, "Shift Communications." Communications to outside the MCR were accomplished through the use of the phone system, PA, portable radios, and sound powered phones. Concerns by the operators in terms of accessibility for local actions have been addressed through the construction of access platforms throughout the plant. Emergency lighting and labeling was rated very good by all operators interviewed. The training program was generally rated positive by the licensed operators.

The following interview findings substantiate other findings/observations of this inspection report and were explained in detail in the appropriate section of the report:

a. The operators concurred that lack of sufficient desk space for the flowcharts (Paths and EAL) made flowchart use awkward.

b. The operators described similar placekeeping methodologies that were adequate. The WG and UG

however did not describe placekeeping to the same level of detail.

c. Several operators concurred that the use of the implied action verb "check" was confusing.

d. In general the operators concurred that the level of detail in the AOPs could be improved.

e. In general the operators thought that AO training on EOPs/AOPs could be improved.

The team made a comparison between the EOP WG (OMM-006) and NUREG-0899 for dual-column procedures. Also a comparison was made between the EOP WG and NUREG/CR-5228 for flowcharts. These comparisons were made in terms of topic areas and content. The WG addressed the appropriate topic areas as indicated by the sections contained in NUREG-0899. However, a few sections of the WG were written in a manner that required further clarification or amplification on specific methods or sufficient justification for deviation from the general guidance contained in NUREG-0899. The specific areas of the WG that were a concern to the team were discussed in Appendix C.

The team determined that no WG for AOPs existed. As a result the AOPs generally lacked the following:

a. RNOs, including alternate local actions, for the stated actions.

b. Consistency in level of detail, structure, action verb usage, and format.

c. Applicability of AOP steps during either loss of IA or loss of AC.

d. Paragraphs often contained long complex run-on sentences. The required action was not always clearly identified in such cases.

e. AOPs were not well integrated with the EOPs.

Specific examples of AOP related deficiencies are presented in Appendix B.

The team verified that the EOP UG was adequate and that all licensed operators were knowledgeable of the guidance contained therein.

No violations or deviations were identified in this area.

8. Exit Interview

The inspection scope and findings were summarized on November 9, 1990, with those persons indicated in paragraph 1. The NRC described the areas inspected and discussed in detail the inspection findings listed below. No proprietary material is contained in this report. No dissenting comments were received from the licensee.

Item Number	Description, Paragraph
IFI 400/90-11-01	PGP inadequacy, paragraph 2
IFI 400/90-11-02	Inadequate SDD justifications, paragraph 2
IFI 400/90-11-03	Technical and human factors discrepancies, paragraph 4
IFI 400/90-11-04	WG discrepancies, paragraph 4
IFI 400/90-11-05	EOP nomenclature inaccuracies, paragraph 4
IFI 400/90-11-06	Inadequate V&V of locally performed actions, paragraph 4

Appendix A

PROCEDURES REVIEWED

EOP-PATH-1	REV 5/2	Path-1
EOP-PATH-2	REV 4	Path-2
EOP-EPP-001	REV 4/1	Loss of All AC Power to 1A-SA and 1B-SB Busses
EOP-EPP-002	REV 3	Loss of All AC Power Recovery Without SI Required
EOP-EPP-003	REV 3	Loss of All AC Power Recovery With SI Required
EOP-EPP-004	REV 3	Reactor Trip Response
EOP-EPP-005	REV 4	Natural Circulation Cooldown
EOP-EPP-006	REV 3	Natural Circulation Cooldown With Steam Void in Vessel (With RVLIS)
EOP-EPP-007	REV 3	Natural Circulation Cooldown With Steam Void in Vessel (Without RVLIS)
EOP-EPP-008	REV 3	SI Termination
EOP-EPP-009	REV 3/1	Post-LOCA Cooldown and Depressurization
EOP-EPP-010	REV 3/1	Transfer to Cold Leg Recirculation
EOP-EPP-011	REV 3	Transfer to Hot Leg Recirculation
EOP-EPP-012	REV 3/1	Loss of Emergency Coolant Recirculation
EOP-EPP-013	REV 3	LOCA Outside Containment
EOP-EPP-014	REV 3	Faulted Steam Generator Isolation
EOP-EPP-015	REV 3	Uncontrolled Depressurization of all Steam Generators
EOP-EPP-017	REV 3	Post-SGTR Cooldown Using Backfill
EOP-EPP-018	REV 3	Post-SGTR Cooldown Using Blowdown
EOP-EPP-019	REV 3	Post-SGTR Cooldown Using Steam Dump
EOP-EPP-020	REV 3/1	SGTR with Loss of Reactor Coolant: Subcooled Recovery
EOP-EPP-021	REV 3/1	SGTR with Loss of Reactor Coolant: Saturated Recovery
EOP-EPP-022	REV 4	SGTR without Pressurizer Pressure Control
EOP-FRP-C.1	REV 3	Response to Inadequate Core Cooling
EOP-FRP-C.2	REV 3	Response to Degraded Core Cooling
EOP-FRP-C.3	REV 3	Response to Saturated Core Cooling
EOP-FRP-H.1	REV 4	Response to Loss of Secondary Heat Sink
EOP-FRP-H.2	REV 3	Response to Steam Generator Overpressure
EOP-FRP-H.3	REV 3	Response to Steam Generator High Level
EOP-FRP-H.4	REV 3	Response to Loss of Normal Steam Release Capability
EOP-FRP-H.5	REV 3	Response to Steam Generator Low Level
EOP-FRP-I.1	REV 3	Response to High Pressurizer Level
EOP-FRP-I.2	REV 3	Response to Low Pressurizer Level
EOP-FRP-I.3	REV 3	Response to Voids in Reactor Vessel
EOP-FRP-J.1	REV 4	Response to High Containment Pressure
EOP-FRP-J.2	REV 3	Response to Containment Flooding
EOP-FRP-J.3	REV 3	Response to High Containment Radiation Level
EOP-FRP-P.1	REV 3/1	Response to Imminent Pressurized Thermal Shock
EOP-FRP-P.2	REV 3	Response to Anticipated Pressurized

		Thermal Shock
EOP-FRP-S.1	REV 3/2	Response to Nuclear Power Generation/ATWS
EOP-FRP-S.2	REV 3	Response to Loss of Core Shutdown
EOP-CSFST	REV 3	Critical Safety Function Status Trees
AOP-001	REV 4	Malfunction of Rod Control and Indication Systems
AOP-002	REV 6/1	Emergency Boration
AOP-003	REV 3	Malfunction of Reactor Make-up Control
AOP-004	REV 5/3	Safe Shutdown in Case of Fire or Control Room Inaccessibility
AOP-005	REV 5	Radiation Monitoring System
AOP-006	REV 4/2	Turbine-Generator Trouble
AOP-008	REV 5	Accidental Release of Liquid Waste
AOP-009	REV 6	Accidental Release of Waste Gas
AOP-010	REV 5	Feedwater Malfunctions
AOP-012	REV 4	Partial Loss of Condenser Vacuum
AOP-013	REV 5/1	Fuel Handling Accident
AOP-014	REV 4	Loss of Component Cooling Water
AOP-015	REV 4	Secondary Load Rejection
AOP-016	REV 6	Excessive Primary Plant Leakage
AOP-017	REV 4	Loss of Instrument Air
AOP-018	REV 3	Reactor Coolant Pump Abnormal Conditions
AOP-019	REV 3	Malfunction of RCS Pressure Control
AOP-020	REV 6/1	Loss of RCS Inventory or Residual Heat Removal While Shutdown
AOP-021	REV 4	Seismic Disturbances
AOP-022	REV 4	Loss of Service Water
AOP-023	REV 5	Loss of Containment Integrity
AOP-024	REV 4	Loss of Uninterruptible Power Supply
AOP-025	REV 4	Loss of One Emergency AC (6.9KV) or One Emergency DC (125V) Bus
AOP-026	REV 3	Loss of Essential Services Chilled Water System
AOP-027	REV 3	Response to Acts Against Plant Equipment
AOP-028	REV 5	Low Voltage Operation
AOP-029	REV 5	Low Frequency Operation
AOP-030	REV 3	Metal Impact Monitoring System Trouble
AOP-031	REV 3	Loss of Refueling Cavity Integrity
AOP-032	REV 3	High RCS Activity
AOP-033	REV 4	Chemistry Out of Tolerance
AOP-034	REV 3	Axial Flux Difference
AOP-035	REV 2	Main Transformer Trouble
AP-301	REV 1/1	Adverse Weather Operations
EOP -USER'S GUIDE	REV 1/3	EOP User's Guide
OMM-006	REV 6/1	EOP Writer's Guide

Appendix B

TECHNICAL AND HUMAN FACTORS COMMENTS

This Appendix contains technical and human factors comments and observations. Unless specifically stated, these comments were not regulatory requirements. However, the licensee acknowledged that the factual content of each of these comments was correct as stated. The licensee further committed to evaluate each comment, to take appropriate action and to document that action. These items will be reviewed during a future NRC inspection.

I. EOP-EPP and PATH Comments

1. EOP-PATH-1 Reactor Trip or Safety Injection/Loss of Reactor or Secondary Coolant

a. General: PATH-1 contained less detail in some steps than the PG. Referring to PG step numbers, examples where the PG contained more detail than PATH-1 were noted as follows:

1) Step 4c: The AER and RNO were omitted in PATH-1.

2) Step 11b, 12a, and 13: Reference to OMM-004 was not included on PATH-1.

3) Step 12b: No list of isolation valves was provided to verify the step was complete.

4) Step 18: The PG stated a requirement for verification that one CNMT fan cooler was running at slow speed. But, PATH-1 stated "VERIFY CNMT FAN COOLERS RUNNING."

5) Step 21c: The RNO listed specific valves to be opened. But, the valves were not listed on PATH-1.

b. General: PATH-1 did not provide a method to designate step numbers that related to the PG.

c. General: PG Attachment 7.2 did not state that reactor trip and SI demand signals could be generated manually.

d. PSTG: ERG ES-0.0 was integrated with the PG and was not a separate EOP. Rediagnosis of the event was allowed any time the operator suspected the most appropriate post accident recovery guideline was not being followed. According to the PG,

rediagnosis was done by entering the top left of PATH-1 and being directed to the correct path or EOP. Under the licensee's path concept, ERG ES-0.0 was not needed. But, no justification for this deviation from the ERGs was provided in the SDD.

e. Step 13: The PG verified the MFW valves shut. But, PATH-1 verified FW valves shut.

f. Step 29, 2nd bullet: This step required operators to verify that one IA compressor was running. The methods for verification that an IA compressor was running were not specified.

g. Step 33: This step contained logic differences between path and PG.

h. Step 33 RNO c: This step required the use of OP-126 to dump steam until the SG pressure reached 1092 psig. This OP was not referenced in either path or PG.

i. Step 43: Guidance on alignments necessary for periodic activity samples was not present in path or PG, nor was any other procedure or attachment referenced.

j. Step 50b: This step required the operator to check the "EDG starting air receivers - REPRESSURIZED GREATER THAN 190 PSIG". This step lacked specific guidance in accomplishing this task, in addition this was a local action and was not specified as such.

k. Step 59a: This step checked secondary radiation. The listed monitors could be isolated and not available for use.

l. Step 72: This step checked RWST level. The flow path steps on Path 1 were not the same as the steps in the PG.

2. EOP-PATH-2 Steam Generator Tube Rupture

a. Step 17: Refer to EOP-EPP-008, step 3.

b. Step 19: This step established nitrogen to CNMT. The establishment of nitrogen to containment could not be accomplished without IA available.

c. Step 20f RNO: This step required assistance from

the Load Dispatcher to restore offsite power to all AC busses. This step did not reference OP-156 which was used to restore offsite power to the AC busses.

3. EOP-EPP-001 Loss of AC Power to 1A-SA and 1B-SB Busses

a. PSTG: The RNOs for steps 1 and 2 were omitted from the EOP without justification in the SDD. However, these RNOs would have been accomplished in PATH-1.

b. Steps 3, 13, 15, 16, 19c, and 29: No RNO was provided for some of the substeps. Some of the substeps stated to "verify" that an action was accomplished. Plant specific guidance was not provided.

c. Step 5a: This step required the start of the EDGs. However, the step did not address the possibility that the EDGs were previously started.

d. Step 5c: No reference was provided to describe the procedure for checking that any AC emergency bus was automatically energized.

e. Step 5e RNO: The RNO did not specify whether the emergency stop or EDG start/stop switches were to be used to trip the running EDGs.

f. Step 7a3 RNO: This step did not give a breaker or panel designation for the local operation.

g. Step 8a: A reference to OP-155 was provided, but the specific section of that OP was not stated. It was difficult to locate the appropriate section of OP-155.

h. Step 12a: The expected response "completely depressurized" was not clearly defined.

i. Step 16: A plant specific list of large non-essential DC loads and a plant specific procedure reference for monitoring the DC power supply were not provided. Adequate justification was not provided in the SDD.

j. Step 17 RNO: This RNO listed fire protection system, demineralized water system, and temporary piping to CST as the alternate AFW supplies. Those three alternates were actually sources to fill the CST.

k. Step 19a: This step did not provide adequate detail. In the event that one or more SG PORV(s) had to be locally operated, it was not clear if SG PORVs were to be operated locally or in combination with MCB operation of SG PORVs to cool down at the "maximum rate."

l. Step 23: This step did not include complete instructions for performing all actions required to complete the phase A isolation. Valve 1ED-95 had to be locally shut to obtain a complete phase A isolation on a loss of all AC.

m. Step 27b: Spent fuel was actually stored in the new fuel pool, but the AER referenced the spent fuel pool. No plant specific value was provided for locally determining if the fuel pool levels were greater than the "LO ALARM."

n. Step 29a: This step required verification that an ESW pump was running. At this step at least one EDG might be operating. But, no RNO was provided to stop the EDGs if ESW was not in service.

o. Step 30: No plant specific procedural references were provided for verifying that the listed equipment was loaded on the emergency bus.

p. Step 32: This step provided no specific guidance to determine which issues warranted TSC consultation. For example, restoring power to the sequencer in some instances could cause RCP seal failure due to injection of cold water to hot seals.

4. EOP-EPP-002 Loss of All AC Power Recovery Without SI Required

a. General: This procedure was not clearly written for the case when partial power restoration occurred. It lacked adequate instructions for valve lineup verifications, valve switching, and miniflow verification for the AFW pumps.

b. Step 9b: This step restored DC control power to the CCW pump breakers. Instructions were not provided on how to restore power.

c. Step 11a: This step started CNMT ventilation. This step did not specify the number of fans to be started.

d. Step 19a: This step checked that CCW flow to RCP thermal barrier HXs was isolated. This step did not specify how to determine that flow was isolated.

e. Step 22a: Refer to EOP-EPP-015 step 31b.

f. Step 22b: Refer to EOP-EPP-015 step 32b.

g. Step 23d: This step checked that the number 1 seal return flow from the RCPs was normal. This step did not reference the seal return flow graph in OP-100.

5. EOP-EPP-003 Loss of All AC Power Recovery With SI Required

a. Step 4a: This step required a local action that was not specified as such.

b. Step 4e: This step referenced OP-148 for starting essential services chiller. The specific section of this procedure (5.1) was not referenced.

c. Step 12e: The action contained in this step was local but was not specified as such. In addition, this step used the term "Manually" which denotes MCR manipulation.

d. Attachment 1, step 1 note: This note referenced EOP-EPP-010. The WG stated that procedures will not be referenced out of cautions or notes.

6. EOP-EPP-004 Reactor Trip Response

a. Step 7b: This step referenced OP-107 but did not include a reference to the proper section (5.4).

b. Step 10 RNO e: This step required the loading of one IA compressor and PRZ heaters, but did not provide instructions to energize busses A1 and B1.

c. Step 12a RNO: The applicable section of OP-100 (5.0) was not included in the reference.

d. Step 14c: This step stated "secure MSRs". The required guidance from OP-131.04, section 7.0, was not referenced.

7. EOP-EPP-005 Natural Circulation Cooldown

   a. Foldout b: Refer to EOP-EPP-014, step 6 RNO comment.

   b. Foldout d: This step (EOP-EPP-006 and EOP-EPP-007 transition criteria) did not include the condition where "a natural circulation cooldown and depressurization must be performed at a rate that may form a steam void in the vessel," as recommended by the ERG (step 12-note). No justification was given for deletion of this condition.

   c. Step 7c: This step did not provide an operating band for maintaining SG level.

   d. Step 11: The control band selected for maintaining pressure at 1950 psig, 1950-2000 psig, did not allow a sufficient dead band before the SI actuation circuits would unblock at 2000 psig. Also, the 50 psig band was too narrow for the situation where pressurizer PORVs were in use for pressure control. Accumulator pressure may be the only power available for PORV operation making it necessary to limit cycling.

   e. Steps 17b, 17d, and 21b.1: The action contained in these steps was local but not specified as such. Additionally, the breaker numbers were not given.

   f. Step 17c RNO: Refer to EOP-EPP-012, step 24c RNO.

8. EOP-EPP-006 Natural Circulation Cooldown With Steam Void in Vessel (With RVLIS)

   a. PSTG: AFW supply switchover criteria was added to the foldout page without adequate justification in the SDD.

   b. Step 1: This step referenced OP-100. The caution above note 2 in OP-100 required verification that secondary temperature was less than 50 Degrees F higher than RCS temperature prior to RCP start, but did not clearly describe how the step was accomplished.

   c. Step 2: It was not clearly understood that failure of RVLIS during performance of EOP-EPP-006 required transition to EOP-EPP-007.

d. Step 3a: This step did not clearly state that the PRZ heaters were required to be energized "as necessary."

e. Step 3b: Absence of an action verb caused confusion regarding the intended action.

f. Step 3b RNO: This RNO did not specify the operating range for PRZ level.

g. Step 3c: This step did not clearly define the preferred method of placing level controls in manual.

h. Step 11a: This step did not state that the action was to be performed prior to cooling down to less than 325 Degrees F.

i. Step 12a: The number of CRDM fans to be used for cooling the upper head region was not clearly defined.

j. Step 13b: The preferred method to depressurize the RCS was not clearly defined by referencing GP-007.

9. EOP-EPP-007 Natural Circulation Cooldown With Steam Void in Vessel (Without RVLIS)

a. PSTG: Refer to EOP-EPP-006, PSTG.

b. Step 3a: Refer to EOP-EPP-006, step 3a.

c. Step 3b: Refer to EOP-EPP-006, step 3b.

d. Step 3b RNO: Refer to EOP-EPP-006, step 3b RNO.

e. Step 3c: This step did not specify which controls were to be placed in manual. Also, the step did not clearly define the preferred method of placing level controls in manual.

f. Steps 15 and 19: The need to cycle PRZ level was noted above step 10. But, the note was not repeated above steps 15 and 19 even though substantial time could pass between the performance of those steps.

10. EOP-EPP-008 SI Termination

a. Step 3: This step reset Phase A, Phase B, and FW isolation signals. Guidance was not provided on indication available in the MCR to check that this step was accomplished.

b. Step 13b: This step checked CNMT isolation system radiation and high range CNMT post-LOCA radiation level normal. Normal parameters were not specified.

c. Step 19a: Refer to EOP-EPP-015, step 31b.

d. Step 19b: Refer to EOP-EPP-015, step 32d.

e. Step 22: This step required the operator to "Control Steam Dump AND Total Feed Flow To Establish AND Maintain Stable RCS Temperature". "Steam Dump" as written in this step actually referred to steam dump or SG PORV.

f. Step 25.3 RNO: This step required the operator to open the RCP thermal barrier flow control valve 1CC-252. There were no instructions provided for opening the valve, and no indication that local action was required.

g. Step 25 note: Step 25a.3 RNO required manual operation of 1CC-252. Due to manual operation of 1CC-252 its automatic closure signal was defeated. This information was not provided in the note preceding Step 25.

h. Step 25 RNOa.1: This step required the operator to open the CCW to RCPs isolation valves. There was no instruction to verify 1CC-252 shut before opening any of the isolation valves to prevent inadvertent CCW flow.

i. Step 27: This step established RCP seal injection flow. There was no caution: "RCP seal injection flow should be established slowly to minimize RCP thermal stresses and potential seal failures."

11. EOP-EPP-009 Post LOCA Cooldown and Depressurization

a. Step 3: This step required the establishment of IA. The operator was required to verify that one air compressor was running. No method was provided to verify that an air compressor was running. If the

plant process computer was not available, use of the MCR indication could provide a misleading indication. This was due to the bleed off time of the air compressor and its associated components after the IA compressors tripped.

b. Step 5e: This step required loading one air compressor and the PRZ heaters on the EDGs. Action was not specified to close emergency bus B-SB to XFMR B1-SB breaker B1A-SB (closure of A1A-SA may also be required). The air compressor and PRZ heaters should be verified to then auto start.

c. Step 8a.a: This step required the operator to "Observe NOTE prior to step 9 AND continue with step 9." There was no note prior to step 9.

d. Step 9: This step initiated RCS cooldown to cold shutdown. The ERG stated that the preferred steam release path was to the condenser to conserve inventory. It also stated that "If RCS temperature and pressure are below certain limits, the RHR system may be in service and should be used to cooldown the RCS to cold shutdown." As specified in the ERG background, if the RHR system was operating in the shutdown cooling mode, it was the desired method to be used to achieve the desired cold shutdown conditions. In this case, dumping steam to the condenser was not required in step "e".

e. Step 28a: This step required the monitoring of RCP radial bearing and seal water inlet temperatures using specific computer points. No RNO was provided for those instances when the plant process computer was out of service.

12. EOP-EPP-010 Transfer to Cold Leg Recirculation

a. No comments.

13. EOP-EPP-011 Transfer to Hot Leg Recirculation

a. No comments.

14. EOP-EPP-012 Loss of Emergency Coolant Recirculation

a. Step 2: This step referred the operator to OP-107. The reference to section 8.20 was not included.

b. Step 13 RNO 3: This step did not include the

requirements for opening breakers for the BIT valves.

c. Step 24b, 24d, and 28c: These steps required local actions that were not specified as such.

d. Step 24c RNO: This step delineated the requirements for venting any unisolable accumulator, but reference to OP-110, section 8.3, was not included.

15. EOP-EPP-013 LOCA Outside Containment

a. Step 2.2a: This step required verification that the RHR hot leg suction valves from RCS were shut (1RH-1, 1RH-2, 1RH-39, and 1RH-40). Local action was required to verify valve position. This was not indicated in the procedure.

b. Step 2.2c: This step required the operator to check any valves that failed to align in accordance with the SI verification. These valves were listed in the UG. The procedure did not include a reference to the valves that required repositioning as a result of the SI.

c. Step 3b: This step required dispatching an operator to the RAB to investigate SI and seal injection piping to attempt to identify the break. HP was required to accompany the operator. The procedure did not indicate that HP assistance was required.

16. EOP-EPP-014 Faulted Steam Generator Isolation

a. Step 2: This step stated "verify the MSIVs shut". This step did not provide the operator with appropriate guidance to perform actions required when an MSIV failed to shut. Local closure of the MSIV was a complex operation and appropriate guidance for alternate closure of the downstream valves was not provided.

b. Step 5: This step did not provide adequate details to isolate all sources of feed to the faulted SG. Specifically, the substep "Isolate main FW" involved five valves per SG (MFIV, MFBV, FRV, FRBV and preheat bypass valve.) The substep "Isolate sampling lines" involved four valves (shell sample isolation, tube sheet sample isolation, containment sampling isolation, and steam analyzer line isolation.) The substep "Isolate hydrazine AND

ammonia addition lines" involved four valves from two different systems (MFW and AFW).

c. Step 5 RNO: This step did not provide adequate details for actions to be taken if valves could not be shut. Specifically, the RNO for the substep "Isolate main FW" could not be performed as written because the MFIVs cannot be locally operated. The RNO for the substep "Isolate sampling lines" could not be performed because two of the four valves were inside reactor containment. The RNO for the substep "Verify SG PORV - SHUT" did not provide appropriate guidance for attempting to close the block valve instead of locally operating the PORV.

d. Step 5: The action contained in this step to open the breaker for the steam supply valve to the TDAFW pump was local but was not referred to as such.

e. Step 6 RNO: This step did not provide sufficient guidance or reference a procedure for the infrequent operation of switching to the alternate AFW water supply. The procedure which addresses the switchover, OP-137 section 8.1, contained no cautions or notes to avoid cross connecting the ESW trains at the TDAFW pump suction. The OP-137 steps to align the TDAFW pump suction to an ESW train were not clearly worded as "either/or" steps to avoid cross connecting the ESW trains. Procedure OP-137 also did not address locally shutting the CST supply valves to the AFW pumps in order to avoid extended reliance on the associated check valves for preventing filling the CST from ESW.

f. Step 8: This step did not specify which radiation monitors should be checked for secondary radiation. Also, the word "unisolated" was deleted without justification for deviation from the ERG.

17. EOP-EPP-015 Uncontrolled Depressurization of All Steam Generators

a. General comment: There was no indication available to ensure 60 gpm CSIP flow when on miniflow recirculation.

b. Step 1: This step checked secondary pressure boundaries. This step did not verify MS line drains or MS safety valves shut as additional means for verifying SG isolation.

c. Step 2a: This step checked RCS cooldown rate. Inadequate guidance was provided in that either T-hot or T-cold could be used for the calculation. The ERG guideline required measurement of cooldown rate in the RCS cold legs (T-cold).

d. Steps 7c and 9b: These steps checked if radiation levels were normal. Values for normal radiation levels were not specified.

e. Step 11: This step checked that RWST level was greater than 23.4 percent. There were two similar alarms in the MCR. Inadequate guidance was given to differentiate between the alarms.

f. Step 24 caution and step 44 caution: These cautions contained information on avoiding runout flow for the CSIP with simultaneous flow through the charging line and the BIT. The procedure did not state the value for runout flow.

g. Step 28 caution: This step cautioned that establishment of letdown could cause adverse radiological consequences. Guidance was not provided to notify HP and continue establishment of letdown.

h. Step 31b: This step required the operator to check that RCP seal parameters were normal. Normal parameters were not specified.

i. Step 32d: This step required the operator to check that RCP seal return flow was normal. Normal parameters were not specified.

j. Step 35a: Refer to EOP-EPP-009, step 28a.

k. Step 37: This step required the operator to verify all AC busses energized by offsite power. This step did not refer to the bus voltage indicators as devices that were used to verify that the busses were energized.

18. EOP-EPP-017 Post-SGTR Cooldown Using Backfill

a. Steps 2.2b and 2.2d: These steps required unlocking and closing SI accumulator isolation valve breakers. No breaker numbers were provided.

19. EOP-EPP-18 Post-SGTR Cooldown Using Blowdown

    a. General comment: This procedure did not provide definitions of intact, faulted, and ruptured SGs.

    b. General comment: The definition of normal containment conditions was not clearly understood.

    c. Step 2c RNO: Refer to EOP-EPP-012, step 24 RNO.

    d. Step 3a: This step did not specify that only one RCS loop hot leg can be aligned for sampling.

    e. Step 3b: This step required the calculation of shutdown margin per OST-1036. The procedure referenced curve A-2-22. The curve that was required for this calculation was A-3-22.

    f. Step 5 note: The procedure did not clearly state what actions would be necessary if RCP number 1 seal Delta P decreased below 200 psid nor did it address the potential consequences that could result from running the RCP with less than 200 psid across the number 1 seal.

    g. Step 10a: This step allowed the use of blowdown to reduce level to less than 40 percent. At 38.5 percent, blowdown automatically isolates. The band for operation was not practical.

    h. Step 14: This step checks RCP status by monitoring number 1 seal Delta P greater than 200 psid and number 1 seal leakoff greater than 0.2 gpm, and requires RCP stopping if the parameters could not be maintained. APP-ALB-008-3-2, RCP-A Thermal Barrier or Number 1 Seal Low Delta P did not require an RCP trip on low number 1 seal Delta P.

20. EOP-EPP-019 Post-SGTR Cooldown Using Steam Dump

    a. No comments.

21. EOP-EPP-020 SGTR With Loss of Reactor Coolant: Subcooled Recovery

    a. Step 9b: This step did not reference a procedure or method for the infrequent operation of sampling the containment sump.

    b. Step 31e and g: The action contained in these steps was local but not specified as such. Additionally,

the breaker numbers were not given.

c. Step 32a RNO: This step referenced a procedure which did not specifically address the expected situation of transferring an emergency bus from the EDG to offsite power. The operator was required to use a second operating procedure and skip steps not required.

d. Step 37: This step did not provide guidance for what parameters from AOP-018 were to be used to evaluate the RCP number 1 seal.

e. Foldout d: Refer to EOP-EPP-14, step 6 RNO.

22. EOP-EPP-021 SGTR With Loss of Reactor Coolant: Saturated Recovery

a. Step 3b: No reference was provided for determining if the RHR pumps were aligned for recirculation.

b. Step 7b: No reference to OP-111 was provided for operation of the RHR system in the shutdown cooling mode.

c. Step 7d: This step was out of sequence and no procedural reference was provided. Monitoring of shutdown margin in accordance with OST-1036 was not done before initiating the cooldown in step 7a. The term "monitor" was not clearly defined and there was no RNO for failure of the STA computer. When necessary to do so, the frequency of manually calculating shutdown margin was not specified.

d. Step 11: "Secure PRZ Heaters" was not clearly defined to mean place PRZ control switches in the "OFF" position.

e. Step 21c RNO: Refer to EOP-EPP-012, step 24c RNO.

f. Step 23a: No RNO was provided for obtaining samples when CCW was not available.

g. Step 23b RNO: This step did not state a boration method and no procedural reference was provided. It was not clear if boration was to be from either the RWST or emergency boration using AOP-002.

h. Step 26c: The method of stopping an unloaded EDG was not stated. It was not clear if either the emergency stop or DGA (DGB) stop switch was to be

used.

i. Step 27: No RNO was provided to minimize secondary contamination during a LOSP. References to OP-134 and OP-133 were not provided for steps 27c and 27d, respectively.

j. Step 28a3 RNO: Opening the RCP thermal barrier flow control valve would require an operator to locally monitor this action. But, no guidance for local monitoring was provided.

k. Step 29a: Refer to EOP-EPP-009, step 28a.

l. Step 38: This step did not list which specific RCS temperatures were to be less that 200 Degrees F.

23. EOP-EPP-022 SGTR Without Pressurizer Pressure Control

a. Step 6b RNO: This step referred the operator to FRP-H.1 for guidance concerning use of MFW and condensate. The guidance was unclear.

b. Step 11b: This step required shutting the BIT outlet valves to isolate high head SI flow. The explanation in the SDD for securing BIT outlet valves rather than inlet valves was inadequate because BIT pressurization concerns were not adequately addressed.

II. EOP-FRP Comments

1. EOP-FRP-C.1 Response to Inadequate Core Cooling

a. Step 2d RNO: This step required the verification of "Proper Emergency Alignment." Inadequate guidance was provided to accomplish this step.

2. EOP-FRP-C.2 Response to Degraded Core Cooling

a. Step 1: This step required verification of proper SI emergency alignment. The correct emergency valve alignment for an SI was located in attachment 7.3 of the UG. This was not stated in the procedure.

b. RNO 2b: This RNO required establishment of charging flow. Section 5.4 of OP-107 was used to establish charging flow. This was not specified in the procedure.

3. EOP-FRP-C.3 Response to Saturated Core Cooling

   a. No comments.

4. EOP-FRP-H.1 Response to Loss of Secondary Heat Sink

   a. PSTG: Steps 8c, 8d, 12c, and 12d were not contained in the ERG and justification for their addition was not provided in the SDD.

   b. PSTG: RNO 30b required shutting the block valve and transitioning to step 30d. Step 30d shut the block valve for any stuck open PRZ PORV. If the block valve was closed, the comparable ERG RNO required transition to E-1 step 1. The SDD did not adequately justify this deviation.

   c. Step 32: Refer to EOP-EPP-022 step 11b.

5. EOP-FRP-H.2 Response to Steam Generator Overpressure

   a. Step 2: This step did not check the hydrazine and ammonia addition valves. The RNO for the local closure of the MFIVs could not be performed as written. (Refer to EPP-014 steps 2 and 5 comments.)

6. EOP-FRP-H.3 Response to Steam Generator High Level

   a. Step 6: The actions contained in these steps for the local operation of opening the breaker for the steam supply valve to the TDAFW pump was local but not specified as such.

   b. Step 8a: This step called for checking radiation monitors that were isolated when MSIVs were shut in the previous step.

7. EOP-FRP-H.4 Response to Loss of Normal Steam Release Capability

   a. Step 1a: This step required the use of the condenser steam dump valves. However, the procedure did not describe the use of the MSIV bypass valves to accomplish this function.

8. EOP-FRP-H.5 Response to Steam Generator Low Level

   a. No comments.

9. EOP-FRP-I.1 Response to High Pressurizer Level

   a. No comments.

10. EOP-FRP-I.2 Response to Low Pressurizer Level

   a. General comment: Refer to EOP-EPP-015, general comment.

   b. Step 1: This step required the isolation of BIT flow. There was no guidance provided to accomplish this step.

   c. Step 2: This step required the isolation of letdown. There was no guidance provided to accomplish this step.

   d. Step 4c: This step did not provide clear guidance on the preferred method for establishment of "available" CCW to RCP thermal barriers.

11. EOP-FRP-I.3 Response to Voids in Reactor Vessel

   a. No comments.

12. EOP-FRP-J.1 Response to High Containment Pressure

   a. No comments.

13. EOP-FRP-J.2 Response to Containment Flooding

   a. Step 1a: When trying to identify unexpected sources of water to the sump, it was necessary to determine if the ESW booster pumps were in service prior to checking if ESW flows and pressures were normal. This was an additional task not stated in the procedure. Also, ESW discharge pressure was to be checked using PI-9302.1 which was not post-accident qualified.

      Specific guidance was not provided to determine if containment conditions were safe for entry. Considerable time was required to determine that ERC-106, "Confined Space Monitoring," was the applicable procedure. AP-524, "Confined Space Environmental Monitoring and Entry Procedure," was identified as the procedure that will supersede ERC-106 and will contain improved guidance for containment entry.

b. PSTG: Inadequate justification was provided in step 2 for omitting the ERG requirement to state the plant specific means to check containment sump activity level. Also, procedures HPP-46, CRC-244 and CRC-823 were not adequately verified and validated for use with the EOPs. Those procedures lacked contingency for either loss of IA or LOSP. No copies of applicable procedures were available at the PASS panel.

c. Step 3: The justification described a change from "Emergency Staff" in the ERG to "Operations Staff" in the EOP. But, the EOP used "TSC." It was possible to be in EOP-FRP-J.2 without having the TSC activated.

14. EOP-FRP-J.3 Response to High Containment Radiation Level

a. No comments

15. EOP-FRP-P.1 Response to Imminent Pressurized Thermal Shock

a. Step 5d: This step referenced TS Figure 3.4-4. This figure was not an attachment to this procedure.

b. Step 7c and 15c: The computer and manual subcooling designations were omitted.

c. Step 7d RNO and 15d RNO: These steps did not reference section 5.0 of OP-100 which provides guidance for establishing conditions for running an RCP.

d. Step 12b: Refer to EOP-EPP-021, step 3b.

e. Step 17b and d: These steps were local actions but were not specified as such.

f. Step 17c RNO: Refer to EOP-EPP-012, steps 24b and 24c RNO.

g. Step 18b RNO: "THEN" was not underlined.

16. EOP-FRP-P.2 Response to Anticipated Pressurized Thermal Shock

a. No comments.

17. EOP-FRP-S.1 Response to Nuclear Power Generation/ATWS

    a. Steps 8 (fourth bullet) and 13 (fourth bullet): These steps were local actions but were not specified as such.

18. EOP-FRP-S.2 Response to Loss of Core Shutdown

    a. No comments.

III. CSFST Comments

CSFST logic closely matched the ERG CSFSTs.

Nomenclature differences, listed in Appendix D, were found to exist between the CSFSTs and the SPDS displays.

Adverse containment values were adequately identified on CSFSTs and the SPDS. When SPDS was not available, instructions for manually using adverse containment values in the CSFSTs were not clearly defined for containment pressure and containment radiation level. No method, other than reinitializing the computer, was provided to switch the SPDS display to adverse containment values upon integrated containment radiation dose greater than the setpoint.

There were no specific comments on the six CSFSTs.

IV. AOP Comments

1. AOP-001 Malfunction of Rod Control and Indication Systems

    a. Section 4 steps 3.2.7b and c, and section 5 steps 3.2.5b and c: These steps required identification of which rod control group the dropped or misaligned rod belonged. No operator aid was available to identify which rods belonged to each group.

    b. Section 4 steps 3.2.7d and o, section 5 steps 3.2.5d and j, and section 5 step 3.2.5i.(2): The actions contained in these steps were local but not specified as such.

    c. Section 4 step 3.2.7q, section 5 step 3.2.5m, and section 5 step 3.2.7k: These steps did not specify use of the ERFIS "Update Bank Demand Pulse Counters" sub-function for updating computer rod group position.

d. Section 5, step 3.2.7a: This step required the use of Attachment 2, but did not refer to it. Also, the action contained in this step was local but not specified as such.

e. Section 6, step 3.2.3: This step did not identify either the local electrical panel or the breakers to be operated.

2. AOP-002 Emergency Boration

a. Section 1, step 6: The TS reference 3.9.1 for calculating Keff greater than 0.95 was not available in the MCR.

b. Step 3.1.2: The format for this step was different than that of a similarly structured EOP logical "OR" step.

c. Step 3.1.3: This step did not reference the appropriate recorder panel necessary to verify at least 30 gpm boric acid flow to the charging pump suction. Additionally, the recorder panel was across the CR from the boration controls. If emergency boration was required while the CR had a minimum crew, step 3.1.3 would require an operator to leave his duty station.

d. Step 3.1.5: This step was not formatted as an "IF, THEN" statement.

e. Step 3.2.7: This sentence was a complex, run-on sentence that was confusing to read.

f. Step 3.2.8: This step did not state that a chemistry sample was required.

3. AOP-003 Malfunction of Reactor Make-up Control

a. Step 16: This step did not specify that 1CS-565 was a locally operated valve.

4. AOP-004 Safe Shutdown in Case of Fire or Control Room Inaccessibility

a. General comment: Section 3.2 referenced numerous procedures and guidelines. This section required that the operator transition to several different procedural sections before the fire recovery actions were determined.

b. Section 2: This section stated that the MCR HVAC would realign for total recirculation on a high chlorine level signal. This was deleted from the MCR HVAC system.

c. Step 3.2.5: This step required that electrical busses be shut down and de-energized if located within the fire area. But, there were no actions to ensure that an EDG would not attempt to energize and carry the load of an affected bus.

d. Step 3.2.13: This step was a run-on sentence that contained a confusing "IF...THEN...BUT" conditional action statement, a transition statement to EOP-PATH-1, and references to EOP-EPP-004 and EOP-EPP-008.

e. Step 3.2.14: This step delineated the required actions for LOSP. These actions were also identified in the EOPs; however, the instructions in AOP-004 were more detailed.

f. Step 3.2.15.a1: This step established ESW flow to air compressors A and C from one operable ESW train by establishing a valve lineup from A or B ESW train. The step failed to open the locked closed ESW crosstie supply valve (1-SW-1375) to C and D air compressors and the locked closed ESW crosstie return valve (1-SW-1376) from C and D air compressors. It also failed to secure the locked open supply valve (1-SW-1259) from the service water system, and the locked open return valve (1-SW-1298) from the service water system.

g. Step 3.2.16.8: The substeps were out of sequence. If the substeps were performed in the listed order, the ESW for both EDGs could be isolated simultaneously. This step implied the closure of the suction from the auxiliary reservoir to both ESW trains prior to opening the pump suction from the main reservoir during a post-fire transfer. This order of actions could have rendered the ESW pumps and both EDGs inoperable during the transition. However, the normal method for doing these actions was to swap the suction for one ESW pump, then swap the suction for the other ESW pump.

h. Section 3.3: This was performed by five operators during the Appendix R validation process. Operators were required to walk through this section annually. But, there were no requirements

to do the walkdown with a team of operators.

i. Step 3.3.1a: This step required the use a key that was stored in the ACP room locker. The keys were listed on a document that was not procedurally controlled. Additionally, the procedure did not require the operator to obtain the key before doing the step.

j. Step 3.3.1d: This step required the use of a switch handle to transfer manually a relay that failed to transfer to the ACP. The location of the switch handle was not identified.

k. Step 3.3.2: This step required the opening of the DC control power switches on the RCP breakers. There were two switches for each RCP. The procedure did not specify which switch was to be opened.

l. Section 3.3 steps 3 3rd bullet, 13, 16, 23, 25-29, 33, 40, 49, 51, and 58: These steps did not include location/responsibility designation.

m. Step 3.3.6: This step required the closure of the MSIVs. The MSIVs would normally shut after transfer to the ACP. "Verify" was a more appropriate action verb.

n. Step 3.3.7: This step required the local start of the EDG. This step referenced OP-155, but it did not contain a specific section for locally starting the EDG under emergency conditions and loading it onto a dead bus. This required the operator to use more than one section of OP-155 and omit steps that were not required.

o. Step 3.3.8: This step directed operators to emergency stop the EDG if its corresponding ESW pump was not operating. It did not include steps or procedural references for restoration of the ESW pump(s).

p. Step 3.3.11 note: This note required the use of IA "to control FK-122 to 60 GPM". But, it did not specify that "charging flow" was the process parameter being controlled.

q. Step 3.3.11a: This step required the operator to "note" instead of "record" the BAT level.

r. Step 3.3.12 caution: The caution referred to OP-107 without including a section number.

s. Step 3.3.12 note: This note directed the operator to verify valve position using the indication on the MCC cubicles. The indicating lights for valve position on the cubicles were labeled "on" and "off" instead of "open" and "shut."

t. Step 3.3.16: This step was out of sequence. Operators were directed to stabilize SG levels when, under some conditions, all AFW pumps could be running with full flow causing a significant RCS cooldown and the possibility of SG overfill earlier in the scenario.

u. Section 3 step 17: The actions under substep "b" were required to be completed prior to the action of substep "a".

v. Step 3.3.18: Refer to EOP-EPP-014, step 6 RNO comment.

w. Step 3.3.19: Operators were directed to trip rather than verify that both MFW pumps had been tripped. Degraded secondary conditions could have already tripped these pumps.

x. Step 3.3.23: This step required that various parameters be recorded but, did not specify time intervals.

y. Step 3.3.27: This step stated "If conditions permit, place RHRS train B in service using steps 53 and 54," but the conditions were not defined until step 53.

z. Step 3.3.28: This step reversed the order of the required actions from normal operating convention. Pumps P-4 A-SA and B-SB were normally started before WC-2 A-SA and B-SB.

aa. Step 3.3.29: This step required the securing of HVAC. But, it did not specify MCR HVAC, which was the step's intent.

ab. Step 3.3.34: This step required the evaluation of operational status of plant equipment. But, it did not specify which equipment to include in the evaluation.

ac. Step 3.3.36b: This step required the use of a boron addition nomograph from the SHNPP Curve Book, but did not specify which boron addition nomograph (100 Degree F or 547 Degree F) to use.

ad. Step 3.3.37: This step required starting one of the CSIPs to borate the RCS. The CSIP was previously started in step 3.3.11e. "Verify" was a more appropriate action verb.

ae. Step 3.3.41 note: This note stated all available SGs should be steamed prior to cooldown to ensure even RCS boron concentration. No guidance was given for the performance of this step. Additionally, this note appeared on the page preceding the step.

af. Step 3.3.41: This step required the verification of RCS boron concentration by sampling. No specific guidance was given for this task. In addition, this step could not be accomplished from the ACP since the controls for the sample isolation valves were in the MCR.

ag. Step 3.3.43: Operators were directed to maintain certain levels of RCS subcooling for differing plant conditions. But, no subcooling curves were included in the procedure or available in the ACP room.

ah. Steps 3.3.53 and 54: When directed to these steps following the completion of step 27, operators were required to return to step 28 when finished with steps 53 and 54. But, no note was included at step 54 regarding a possible return to step 28. In addition, no note was placed at step 53 as a reminder for operators not to perform steps 53 and 54 if they had already been performed between steps 27 and 28.

ai. Steps 3.3.53j, k and l: The procedure required that 1SI-341 be opened to establish RHR cooling prior to being directed to position the flow control valves to control flow rate and cooldown rate.

aj. Step 3.3.54 note: This note required the operation of the RHR pump miniflow valve 1RH-69 "as required" without including guidance on an optimal flow range.

5. AOP-005 Radiation Monitoring System

a. Section 1, steps 3.2.A.3, B.3, and C.2: The procedure sequence required the operator to perform other time consuming actions (e.g., notify health physics, check primary leakage, or check automatic actions) prior to evacuating the areas with high radiation.

b. Section 1, steps 3.2.A.2 and B.2, section 2 steps 3.2.A.2 and 3.2.B.2: These steps did not provide sufficient guidance or reference a procedure for the infrequent operation of verifying automatic ventilation system isolation.

c. Section 1, step 3.2.B.5.a: This step did not require checking the level alarms for the new fuel pool (ALB 23-5-17 and -18), which was also an area where spent fuel was stored. Additionally, ALB-23 had not been changed to reflect the presence of spent fuel in the new fuel pool.

d. Section 2, step 3.2.B.6: This step used Curve Book curve H-6 for checking leakage at one hour intervals, but the curve had no one hour interval line. Additionally, Attachments 1 and 2, notes (4), (5) and (6) did not provide clear instructions on how to complete columns 4 and 5.

e. Section 2, step 3.2.C.4: This step did not state that verification of the lineup for the WPB was a procedure which would be performed locally by radwaste personnel.

f. Section 2, step 3.2.F.3: This step did not state that verification of the TSC ventilation lineup was a local operation. Additionally, in the TSC ventilation room, two dampers and three fans which were verified (using APT-110) lacked labels. All three of the fans lacked indicating lights for checking operation.

6. AOP-006 Turbine Generator Trouble

a. Section 2, step 4: The first continuation page of "4 General" was labeled "3.2 Follow-Up Actions (continued)" and the second continuation page was labeled "General (continued)."

b. Section 3, step 3.2.1: This step required the operator to trip the turbine if the differential

temperature between the highest and lowest stator cooling gas discharge temperature reached either 8 Degrees C uncorrected or 4 Degrees C corrected as indicated by a High-Low Differential Temperature Alarm. The procedure did not specify either the alarm location or how to obtain the corrected value for differential temperature.

c. Section 3, step 3.2.2: This step required reduction of turbine load to clear the generator overload (High Average Temperature Rise) alarm. This was an infrequently used alarm. The procedure did not provide the alarm location.

d. Section 3.2, step 10a: If the generator stator end winding vibration exceeded 20 MILS, this step required turbine load reduction to keep the vibration below 20 MILS. This was an infrequently used instrument. The procedure did not provide its location.

7. AOP-008 Accidental Release of Liquid Waste

a. General comment: No procedures were found that delineated the interface between Operations and Radcon personnel during EOP and AOP implementation.

b. General comment: During accident situations the ESW discharge to the reservoir was not monitored. If the ESW booster pump to the containment coolers failed to start, the containment pressure would be greater than ESW pressure and unmonitored releases to the reservoir could occur. Written instructions were not provided to notify chemistry to obtain required samples.

c. Step 2.1: This step required verification that the turbine building drain monitor 3528 shut 1MD-285 after its alarm was received. The location of the valve was not provided.

d. Step 3.2.7: This step did not specify the location of 1FD-109.

8. AOP-009 Accidental Release of Waste Gas

a. Section 1: This portion of the procedure required actions by both the MCR and the Rad Waste Control Room operators. The procedure did not delineate which group of operators had specific step responsibilities.

b. Section 1, step 3.2.4: This step required the operators to isolate leaks or to secure gas addition to the faulted waste gas system. This step did not address stopping the operating waste gas compressor or isolation of the associated waste gas decay tank. Additionally, no guidance was provided on how to isolate or locate the leaks.

c. Section 1, step 3.2.6: This step required the notification of HP, but did not delineate the responsibility for this task.

d. Section 1, step 3.2.12 and Section 2, step 3.2.16: These steps required the operator to verify the correct operation of the VCT, but they did not reference OP-107, which was the procedure for accomplishing this task.

e. Section 2, step 3.2.7: This step did not specify the location of the infrequently used valve 1HY-5.

9. AOP-010 Feedwater Malfunctions

a. Section 1, step 1.1a: This step addressed the condensate header low pressure alarm. APP-ALB-19-2-4 listed the alarm at less than 55 psig for 20 seconds and the condensate pump discharge low pressure trip was set at less than 195 psig for 5 seconds.

b. Section 2, step 3.2 caution: This caution directed that no feedwater be initiated through any line suspected of voiding. The procedure did not list the symptoms to be used to determine voiding.

10. AOP-012 Partial Loss of Condenser Vacuum

a. Section 1, step 9, section 3.2 steps 3, 4, 5, 6, 7, 8, and 9: These steps had local actions that were not specified as such.

b. Section 1, step 6 caution: This caution did not address equipment damage or personnel injury, which were the caution criteria defined by the WG.

c. Section 1, step 8: This step checked abnormal gland seal steam pressure, but did not specify normal ranges or provide appropriate reference to OP-131.03 which contains the normal ranges.

d. Section 1, step 12: This step contained actions that would normally be considered the follow up actions for step 8, but it did not directly follow the step.

e. Section 3.2, step 4: This step contained usage of the action verbs "verify" and "check" that conflicted with EOP usage of these verbs.

f. Section 3.2, step 10: This step did not provide adequate guidance for checking the condenser for air leakage.

g. Section 3.2, step 13: This step did not provide adequate guidance for determining major leakage for transitioning to step 14.

h. Section 3.2 caution within step 14: This caution contained a typographical error; cause was spelled "case".

11. AOP-013 Fuel Handling Accident

a. No comments.

12. AOP-014 Loss of Component Cooling Water

a. General comment: Throughout the procedure "Chromate" was used but was no longer appropriate.

b. General comment: The procedure did not address the use of personnel safety equipment when operating equipment inside 6.9 KV switchgear.

c. Section 2, step 3.2.3d: This step required the operator to locally operate the CCW emergency supply valve 1CC-121. This valve was located in the overhead with no apparent access for local operation.

13. AOP-015 Secondary Load Rejection

a. No comments.

14. AOP-016 Excessive Primary Plant Leakage

a. No comments.

15. AOP-017 Loss of Instrument Air

a. General comment: There was no positive method of

ensuring that the rotary air compressor was running. The compressor was installed by a temporary modification and the process drawings did not show the rotary air compressor. The FSAR stated in section 9.3.1.3 that "The two IA compressors and driers are connected to the emergency buses and to the ESW system so that a continuous IA supply was assured after a LOSP." The licensee was uncertain that one IA compressor could supply the necessary air on a LOSP. This was based on the fact that two IA compressors were needed to maintain a consumption rate of approximately 1000 CFM. The rotary air compressor was used as the normal supply for IA but was not powered from the emergency busses.

b. General comment: The nitrogen supply valve to the containment required IA for actuation. The nitrogen supply valve was not a self actuating valve and did not prevent loss of nitrogen to the PRZ PORV actuators on a loss of IA.

c. General comment: The actions to be taken at various IA pressures were not well tabulated. This complicated the transition to the appropriate section of the AOP.

d. Step 3.1.1: This step required tripping the turbine if loss of IA caused a significant decrease in SG level. The procedure did not indicate what constituted a significant decrease in SG level.

e. Step 3.2.6 note: The note provided instructions to "refer to follow up steps 11-13 and continue in this procedure" if IA pressure was not maintained above 85 psig. An exact procedure reference was not clearly stated.

f. Step 3.2.10 note: The note indicated that the IA compressors would auto start on LOSP without ESW. No guidance for IA compressor operation without ESW cooling was provided.

g. Step 3.2.11: This step shut the valves listed in Attachment 2 if "plant air capacity" was reduced. A clear definition of what constituted a reduction of plant air capacity was not provided. Additionally, there was no label on valve 1IA-662.

h. Step 3.2.13: This step required depressurization of the IA system when pressure could not be maintained

above 35 psig. An adequate explanation of the basis for that action was not provided in the procedure.

i. Attachment 1: This attachment provided a partial list of fail safe positions for IA valves. It was not clear that list was based on an engineering analysis.

16. AOP-018 Reactor Coolant Pump Abnormal Conditions

a. General comment: This procedure did not provide adequate guidance for operator actions required for long term recovery from a simultaneous loss of CCW and seal injection to the RCPs. Section 1, step 4.3 did provide guidance, but was located in the general section of the procedure.

b. Section 1, step 3.2.2: This step did not provide direction to locally verify that seal injection was being supplied to each RCP.

c. Section 2, step 3.2.1: This step did not include the appropriate reference to OP-107 for normal charging pressure range.

d. Section 2, step 3.2.9c: This step required local action but did not specify it as such.

e. Section 5, step 3.2.1: This step did not provide specific guidance on what constitutes "noticeable" fluctuations in RCP motor current.

f. Section 5, step 3.2.6: This step did not provide all the criteria required to determine RCP motor winding high temperature and did not specifically address containment cooling.

17. AOP-019 Malfunction of RCS Pressure Control

a. Section 1, step 3.2.5 note: This note stated that reactor power greater than turbine power would result in a heat up of the RCS. The procedure did not address first stage turbine pressure as a method for verifying turbine power.

18. AOP-020 Loss of RCS Inventory or Residual Heat Removal While Shutdown

a. Applicability of Sections 1 and 2: The terms "RCS filled" and "RCS partially drained" were not

defined and no entry conditions were given. It was not clear when section 1 versus section 2 should be used.

b. Section 1, step 3.1.1: A specific list of valves was not provided and it was not clear that the step could be accomplished without more specific guidance.

c. Section 1, step 3.1.2c: Since PATH-1 was only applicable in modes 1 through 4, it was not clear how PATH-1 would be used for guidance.

d. Section 1, step 3.2.4, third bullet: This step did not reference OP-111 and the method of conducting that RHR evolution was not specified.

e. Section 1, step 3.2.4, fourth bullet: The specific RHR and RCS sample valves were not identified as in section 2, 3.2.2c.

f. Section 1, step 3.2.8 note: Incorporated with the note was an action statement. In the EOPs, EAL references were steps.

g. Section 1, step 3.2.8e: A reference to OP-126 was provided. More appropriate references were OP-1831.01, 02, and .03.

h. Section 1, step 3.2.12: Additional guidance was required for the local manual actions to be taken in case of valve malfunction.

i. Section 2, step 1.11: This step did not caution that alarms ALB 10-1-3, 10-2-3, and 10-3-3 would only be valid if the nozzle dams were installed in accordance with the applicable procedure.

j. Section 2, step 3.1.2: This step stated that the vessel level of 80 inches was in reference to the standpipe level. Standpipe level was not available on MCR instrumentation.

k. Section 2, step 3.2.2 note: The curves referenced were H-8 through H-11. But, the correct curve numbers were H-X-8 through H-X-11.

l. Section 2, Steps 3.2.7 and 3.2.8: It was not clear which RHR pumps were to be started.

m. Section 2, Step 3.2.14b: This step did not specify

how the water level was to be determined from the MCR to be at least 23 feet above the top of the fuel.

n. Attachment 1: A reference to OST-1107, Attachment 3, was not provided for additional RHR venting guidance.

19. AOP-021 Seismic Disturbances

a. Attachment 1: This attachment was a high level checklist of areas to be visually inspected for seismic disturbance damage. Elevation information was not included in this checklist.

b. Attachment 1: A check of the MCCs was not included following step 1.2.

c. Attachment 1: A check of the RCS Filter Valve Gallery was not included following step 1.3.

d. Attachment 2, steps 2.27 and 2.28: These steps did not provide specific emphasis on checking spent fuel pool level.

20. AOP-022 Loss of Service Water

a. Section 2, Step 3.2.6: This step required that the operator verify ESW auxiliary reservoir intake valves 1SW-1 and 1SW-2 open. These valves were located in pits at the intake structure. It was necessary to have security provide access to the pit prior to entry. This step did not address security actions.

b. Section 3, Step 3.2.6: This step required the operator to shut 1SW-301 and 1SW-655. These valves were located in pits and required a crane to remove the pit covers for valve access.

c. Section 3, Step 3.2.8: This step referred to OP-139 for aligning ESW to the air compressors. OP-139 contained neither cautions nor notes to avoid cross connecting the ESW trains by opening both the train A and B valves simultaneously.

d. Section 3 Step 3.2.9: If the gland steam exhausters started to overheat, this step directed the operator to break condenser vacuum, secure gland sealing steam, and secure the gland steam exhausters. There was no method available to

determine if the gland steam exhausters started to overheat. No instrumentation was available for that purpose in the MCR.

21. AOP-023 Loss of Containment Integrity

    a. No comments.

22. AOP-024 Loss of Uninterruptible Power Supply

    a. General comment: There was a difference in nomenclature between the electrical cabinets and the procedure. Noun names and identification numbers in the procedure did not match component labels.

    b. Section 1, step 3.2.9: This step referred to Attachment 2 for determination of instrumentation that was affected by loss of the Vital Instrument bus. Attachment 2 indicated that all three hot leg temperature indications were lost when IDP-1A-SI was lost.

    c. Section 1.0, Step 5: When power was lost to an instrument bus, this step required transferring the instrument bus to the AC bus bypass supply breaker per OP-156.02. The step did not reference a specific section of OP-156.02. It was not quickly apparent which section of OP-156.02 was to be used. Step 3 of OP-156.02 did not clearly caution against energizing the UPS breakers prior to de-energizing the associated PIC cabinets. Severe damage to the PICs could result if the step was incorrectly done.

23. AOP-025 Loss of One Emergency AC Bus (6.9 KV) or One Emergency DC (125V) Bus

    a. Section 1, step 1.1: This step required the operator to respond to the ALB 24-1-2 and 25-1-2 for 6.9 KV emergency bus trouble. AOP-028 Step 2.1.c had a similar step; however, the alarm and trip values used for the low voltage trip and alarm were different. The alarm response did not list the alarm setpoints.

    b. Step 1.2: This step stated alarms on breakers feed from bus 1A-SA or 1B-SB. Bus low voltage alarms on busses fed from 1A-SA or 1B-SB appeared to be a more appropriate symptom.

24. AOP-026 Loss of Essential Services Chilled Water System

    a. Step 3.2.1: This step verified the automatic actions for isolation of the non-safety loops, but did not list the eight valves that auto isolated.

25. AOP-027 Response to Acts Against Plant Equipment

    a. No comments.

26. AOP-028 Low Voltage Operation

    a. Step 2.2: This step did not address the fact that a reactor trip also may occur if one auxiliary bus was lost above P-8.

    b. Step 3.2.6: This step did not refer the operator to AOP-025 for the loss of emergency bus created by the actions of the step.

27. AOP-029 Low Frequency Operation

    a. Step 3.1.1: This step directed operators to trip the unit output breakers and follow AOP-015 if system frequency was less than 58.4 Hz. But, MCR instrumentation could not measure frequency to the degree of accuracy required.

    b. Step 3.2.4: This step was a run-on sentence which combined two separate actions with an "and/or ....excluding" logic statement and a procedural reference. The reference to OP-155 did not specify which action was to be accomplished in accordance with this procedure.

28. AOP-030 Metal Impact Monitoring System Trouble

    a. Step 3.2.1c: This step required the operator to verify abnormal conditions in containment, but did not list parameters or conditions.

    b. Step 3.2.1d: This step required the operator to verify power density changes. Specific guidance on how to accomplish this step was not provided.

    c. Step 3.2.1e: This step required the operator to monitor the gross failed fuel detector for abnormal indication. This equipment had been out of service for an extended period.

d. Step 3.2.2: This step required the operator to identify any indication of primary system leakage in order to exit this procedure. No specific guidance was provided to continue with the procedure with a minimum amount of leakage.

e. Step 3.2.3: This step required the operator to determine if there was any indication of loss of fuel integrity. Specific guidance on how to accomplish this task was not provided.

f. Attachment 1, step 1 note: This attachment required the operator to log ERFIS computer information. The attachment did not reference the list of ERFIS computer points in Attachment 2.

29. AOP-031 Loss of Refueling Cavity Integrity

a. General comment: Loss due to seal leakage was covered in a general statement in step 4. There were no immediate action steps to restore seal pressure.

b. General comment: The procedure did not check either IA or bottled air to the seals as a possible cause of leakage (due to seal deflation).

c. Step 3.1: The immediate actions did not clearly define either "dropping rapidly" or "high radiation levels." No estimate was provided for expected radiation levels at either the pool or the crane.

d. General - This procedure was technically deficient in several areas. Most importantly:

1) The maximum cavity leak rate for which this procedure was applicable was not stated or otherwise conveyed to the operators.

2) The maximum leak rate or bridge radiation level at which the operator should continue efforts to return the fuel element to the nearest storage position was not specified.

3) The procedure did not indicate that the only appropriate action for the operator to take in the event of loss of offsite power coincident with initiation of this procedure (e.g., seismic event causing both the cavity leak and loss of non-1E power) was evacuation.

4) The necessary engineering evaluations to define radiation levels expected as a function of water height over the fuel, bridge radiation levels at which the operator should abandon mitigation efforts, the contribution to bridge radiation levels from the upper internals package and operator immediate actions in the event of a total blackout were not available to the procedure writer when preparing this procedure.

5) Mechanisms for developing the stated symptoms other than cavity seal failure were not clearly addressed. For example RHR failures suggested by SOER 85-1 and IE Bulletin 84-03 were not adequately considered.

e. Step 1.5: Typo - first quote mark was missing.

f. Step 1.6: The maximum rate of water level decrease for which this procedure was to be used was not defined.

g. Step 3.1: The immediate actions of the FHB and CNMT building operators did not include notification of the MCR, therefore MCR operator step 3.1.1 "If notified the water level is dropping ..." could never take place.

h. Step 3.1.2 FHB and CNMT: The licensee's investigation during the inspection disclosed that, in the event of a loss of offsite AC, this procedure as written was not adequate. Immediate action step 3.1.2a could not be performed in a time interval that would prevent operator overexposure.

i. Step 3.1.2 FHB and CNMT: This step did not instruct the operator on the proper actions to take in the event the MCR operator sounded the local evacuation alarm as stated in CRO immediate action 3.1.1. Some operators stated that the appropriate action was to stay on the refueling bridge and continue their immediate actions, evacuating only non-essential personnel. More recent analysis indicated that, under certain situations, immediate evacuation was required (Rad levels could increase to as much as 2500 R/hr on the refueling bridge).

j. Step 3.2.2: This step required the MCR to evacuate all non-essential personnel despite the fact that evacuation had been performed in immediate action

steps of both the CNMT operators and the CR operators.

30. AOP-032 High RCS Activity

    a. Step 4: This step did not provide either adequate guidance or refer to a procedure for the infrequent operation of placing the cation bed in service.

31. AOP-033 Chemistry Out of Tolerance

    a. No comments.

32. AOP-034 Axial Flux Difference

    a. Step 3.2.5: This step allowed the reset of a power range high neutron flux setpoint. There were no criteria given for this reset.

33. AOP-035 Main Transformer Trouble

    a. Step 3.2.1: No RNO was provided for the event that ERFIS was not available. Specific methods for verifying proper oil pump and cooling fan operation were not specified. Labels were missing on the A & B transformer local control panels. No reminder was provided for the AO to obtain necessary equipment upon being dispatched to the main transformer.

       ALB-022-5-1 provided MCR guidance for response to the main transformer trouble alarm. But, no annunciator response procedure existed for the local control panel annunciators at each main transformer.

       No caution was provided for the AO to avoid bumping into and causing an accidental actuation of the main transformer deluge system. Deluge system piping partially obstructed the stairway to the local control cabinet and was not marked with a high visibility color.

    b. Step 3.2.3a: The alarm to be checked was not clearly stated to be "PRESS. RELIEF DEVICE."

    c. Step 3.2.4: This step did not clearly state which local oil drop level alarm was to be checked. There were both "SMALL DROP OIL LEVEL" and "LARGE DROP OIL LEVEL" alarms.

d. Step 3.2.4a: Due to the level of lighting in the area, it was uncertain if this step could be done at night under adverse weather conditions.

e. Step 3.2.4d: This step did not specify what temperatures to monitor.

f. Step 3.2.5: This step did not specifically identify which of the eleven local alarms to check at each of three transformers.

34. AP-301 Adverse Weather Operations

a. General comment: Adverse weather operations were described in AP-301. As a result, the steps in this procedure were formatted differently from the AOPs. Operators had to compensate for the format difference between APs and AOPs to effectively execute the steps in this procedure. In addition, APs were not included with the licensee's administrative program for upgrading and modifying EOPs and AOPs.

Appendix C

WRITER'S GUIDE COMMENTS

This Appendix contains WG comments and observations. Unless specifically stated, these comments were not regulatory requirements. However, the licensee acknowledged the factual content of each of these comments as stated. The licensee agreed to evaluate each comment, to take the appropriate action, and to document that action. These items will be reviewed during a future NRC inspection.

The WG in general included the appropriate topics as specified by NUREG-0899. The following comments apply to those areas of the WG that did not thoroughly address the applicable NUREG-0899 topic, or addressed the topic in a nonrestrictive manner. The team considers these to be concerns because the WG must: 1) produce and maintain high quality procedures, 2) ensure consistency within and between procedures, and 3) retain that consistency over time and through personnel changes. The following concerns were identified:

a. WG paragraph 5.2.10 specified that directional arrows were only required when connecting lines ran upward or to the left for a distance of greater than three inches. Specific guidance was not provided for connecting lines exiting from symbols in a nonstandard method. The addition of directional arrows reduces the probability of errors by operators especially under stressful conditions. (SER Item B.3)

b. WG paragraph 5.2.13 stated that type size may vary depending on the space available. The character height of text was a significant factor in determining minimum readability requirements. The WG lacked specific guidance on minimum type size. (SER Item B.2)

c. WG paragraph 5.11.3 described the V&V program. However, requirements for a multidisciplinary team with Human Factors expertise as part of the V&V team were not specified.

d. Neither WG paragraph 5.6.16 nor the UG specified formal methods for placekeeping. Formal placekeeping methodology reduces the probability of errors of omission by operators, especially under stressful conditions involving procedure transitions and branchings.

e. WG paragraph 5.6.3.14 allowed the omission of the action verb "check" in decision or action - EXPECTED RESPONSE statements. This caused confusion in some cases regarding the required action. The use of "check" throughout the EOPs was inconsistent.

f. The WG stated that the guidance contained in the WG did not apply to those EOPs with a revision date prior to the revision date of the new WG. It also stated that if an advance change to an EOP was required, only the change was to be done in accordance with the new WG. This methodology will result in inconsistencies between EOPs and within a given EOP itself.

g. The WG authorized verb list did not include all verbs used in the EOPs. Some examples of unauthorized verb usage in EOPs were as follows:

EOP-FRP-C.1:	step b page 15 foldout - "switch"
	step c page 15 foldout - "occur"
Path 1:	I 15 - "remove"
	step b foldout A - "switch"
	step c foldout A - "supply"

(SER Item B.7)

i. The WG provided guidance regarding the numerical values that can be read on instruments in the MCR. In general it states that "the precision of numerical values should not exceed 1/2 the value of the smallest subdivision of the instrument display." A few numerical values were given that could not be read on MCR gauges exactly as specified in the EOP because the values exceed the accuracy of the instrument. The WG was not adequately restrictive in the definition of numerical value precision.

j. WG paragraph 5.6.5 allowed the use of AND/OR list formats for connecting three or more conditions. The only differentiating feature between these two types of lists were the usage of the terms "any", "all", "one" or "both" which were printed in standard lower case text. Additional emphasis or highlighting of these terms reduces the probability of operator error under stressful conditions.

Appendix D

NOMENCLATURE

This Appendix contains basic plant nomenclature weaknesses. For example, instances where the WG would cause the reader to expect an exact nomenclature match with component nomenclature, yet there was no match. Although WG paragraph 5.5.11.1 allowed procedures to use common usage terminology differing from the control board labels, several cases were included where extreme difference was a source of confusion. The licensee agreed in each case to evaluate the problem and make the appropriate changes. These items will be reviewed during a future NRC inspection.

STEP/ ATTACHMENT	EOP NOMENCLATURE	COMPONENT NOMENCLATURE
	EPP-001	
RNO 7a	DP-1A-SA	1A-SA
	DP-1B-SB	1B-SB
	control power to the CCW pump breakers	ACB CONTROL DISCONNECT
15e	MSIV before seat drains	MAIN STEAM A ISOL BEFORE MSIV
	(Note: the control switches immediately above these on the MCB were labeled as follows:	MAIN STEAM A DRAIN BEFORE MSIVS)
	EPP-005	
4a	RCS loops "2" and "3"	RCS loops "B" and "C"
	EPP-006	
7c	SI accumulator isolation 1SI-246	ACCUMULATOR A DISCHARGE 1SI-246 SA
	SI accumulator isolation 1SI-247	ACCUMULATOR B DISCHARGE 1SI-247 SB
	SI accumulator isolation 1SI-248	ACCUMULATOR C DISCHARGE 1SI-248 SA

8b	low pressure letdown control	LTDN PRESSURE ICS-38
	EPP-007	
11c	(same as EPP-006 step 7c)	
	EPP-021	
6b	low steam pressure SI	MAIN STEAM PRESSURE TRAIN A SI & MS ISOL BLOCK
	AOP-004	
3.3.12c	...No. 6 MTC-4	...No.6 MTC-4 (PNL-2)
3.3.17.(b)	AUX FW TURBINE STEAM STOP	AUX FW TRIP & THROTTLE VALVE
Attachment 4	FAN COOLER AH-10 B-SB	CSIP SAB AREA FAN COOLER AH-10 B-SB
	CCW NONESSENTIAL RETURN TO HEADER B 9371 (1CC-127)	CCW NONESSENTIAL RETURN TO HEADER B (1CC-127)
	FAN COOLER AH-9 A-SA	CSIP SAB AREA FAN COOLER AH-9 A-SA
	AFWP S HVAC CHILLER FAN AH-20 B-SB	AFWP & HVAC CHILLER FAN AH-20 B-SB
	CCW HEAT EXCHANGER B TO NONESSENTIAL SUP 9385 (1CC-113)	CCW HEAT EXCHANGER B TO NONESSENTIAL SUP (1CC-113)
	CCW FROM RHR HEAT EXCHANGER B-SB 9431B (1CC-167)	CCW FROM RHR HEAT EXCHANGER B-SB (1CC-167)
	ACCUMULATOR B DISCHARGE 8808B (1SI-247)	ACCUMULATOR B DISCHARGE (1SI-247)

	ACCUMULATOR A DISCHARGE 8808A (1SI-246)	ACCUMULATOR A DISCHARGE (1SI-246)
	EMERGENCY BUS A2-SA SUPPLY BREAKER	EMERGENCY BUS A2-SA SUPPLY BREAKER A2B-SA
	EMERGENCY BUS A3-SA SUPPLY BREAKER	EMERGENCY BUS A3-SA SUPPLY BREAKER A3B-SA
	ACCUMULATOR C DISCHARGE 8808C (1SI-248)	ACCUMULATOR C DISCHARGE (1SI-248)
	AOP-020	
3.1.1	RCS to RHR loop suctions	RCS LOOP A TO RHR PUMP A-SA (typical of 4 valves)
	AOP-024	
6	PIC 4	1IC-E010 NSSS PIC CABINET PROTECTION ASSEMBLY IV CAB-4 (Note, the following was the label on an abutting cabinet:) 1TC-E014 NSSS PIC CABINET CONTROL ASSEMBLY 4

CSFST

The SPDS display had numerous differences from the CSFSTs. Listed below were examples of these differences:

CSF	CSFST	SPDS
CSF-2	CORE EXIT TCs GREATER THAN 1200F	T EXIT ≥ 1200 DEG F
	NO RCPs RUNNING	ALL RCPs STOPPED
CSF-4	ALL RCS COLD LEG TEMPERATURES GREATER THAN 240F	ALL > 240 DEG F CAB-8
CSF-5	HIGH RANGE CNMT POST LOCA RADIATION MONITORS GREATER THAN ALARM SETPOINT	CONTAINMENT RADIATION > 17 R/HR

Appendix E

ABBREVIATIONS

ACP	Auxiliary Control Panel
AER	Action Expected Response
AFW	Auxiliary Feed Water
ALB	Alarm Light Board
AO	Auxiliary Operator
AOP	Abnormal Operating Procedure
AP	Administrative Procedure
APP	Annunciator Panel Procedure
APT	Administration Periodic Test
ATWS	Anticipated Transient Without Scram
BIT	Boron Injection Tank
CCW	Component Cooling Water
CFM	Cubic Feet per Minute
CNMT	Containment
CP&L	Carolina Power and Light
CRDM	Control Rod Drive Mechanism
CRO	Control Room Operator
CSFST	Critical Safety Function Status Tree
CSIP	Charging and Safety Injection Pump
CST	Condensate Storage Tank
EAL	Emergency Action Level
EDG	Emergency Diesel Generator
EOP	Emergency Operating Procedure
EPP	End Path Procedure
ERG	Emergency Response Guideline
ERFIS	Emergency Response Facility Information System
ESW	Essential Service Water
FHB	Fuel Handling Building
FRBV	Feed Regulating Bypass Valve
FRP	Function Restoration Procedure
FRV	Feed Regulating Valve
FSAR	Final Safety Analysis Report
FW	Feed Water
GDD	Generic Differences Document
GPM	Gallons per Minute
GTG	Generic Technical Guidelines
HPP	Health Physics Procedure
HVAC	Heating Ventilation and Air Conditioning
HX	Heat Exchanger
IA	Instrument Air
I&C	Instrumentation and Controls
IFI	Inspector Follow-up Item
INPO	Institute of Nuclear Power Operation
KV	Kilovolts
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
LOSP	Loss of Off Site Power
MCB	Main Control Board
MCC	Motor Control Center
MCR	Main Control Room

MFBV	Main Feed Bypass Valve
MFIV	Main Feed Isolation Valve
MFW	Main Feed Water
MSIV	Main Steam Isolation Valve
MSR	Main Steam Reheater
NRC	Nuclear Regulatory Commission
OFR	Operational Feedback Request
OMM	Operation Maintenance Manual
OP	Operational Procedure
OST	Operational Surveillance Test
PG	Path Guide
PGP	Procedure Generation Package
PIC	Process Instrumentation Cabinet
PORV	Power Operated Relief Valve
PSID	Pounds per Square Inch Differential
PSIG	Pounds per Square Inch Gage
PSTG	Plant Specific Technical Guideline
PRZ	Pressurizer
QA	Quality Assurance
RAB	Reactor Auxiliary Building
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RG	Regulatory Guide
RHR	Residual Heat Removal
RNO	Response Not Obtained
RO	Reactor Operator
RVLIS	Reactor Vessel Level Indicating System
RWST	Refueling Water Storage Tank
SCO	Senior Control Operator
SDD	Step Deviation Document
SER	Safety Evaluation Report
SG	Steam Generator
SGTR	Steam Generator Tube Rupture
SHNPP	Shearon Harris Nuclear Power Project
SI	Safety Injection
SOER	Significant Operating Experience Report
SPDS	Safety Parameter Display System
SRO	Senior Reactor Operator
STA	Shift Technical Advisor
SW	Service Water
TDAFW	Turbine Driven Auxiliary Feed Water
TS	Technical Specifications
TSC	Technical Support Center
UG	User's Guide
VCT	Volume Control Tank
V&V	Verification and Validation
WG	Writer's Guide
WPB	Waste Processing Building
XFMR	Transformer