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

Report No.: 50-261/89-16

Licensee: Duke Power Company
422 South Church Street
Charlotte, NC 28242

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

Facility Name: H. B. Robinson

Inspection Conducted: September 18 to 29, 1989.

Inspectors: L. Lawyer, Team Leader 11/1/89 Date Signed

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11/1/89 Date Signed

SUMMARY

Scope:

This was a special announced Emergency Operating Procedure (EOP) team inspection. Its purpose was to verify that the Robinson 2 EOPs were technically accurate, and that their specified actions could be accomplished using existing equipment, controls, and instrumentation. The inspection evaluated the adequacy of the licensee's EOPs [including Abnormal Operating Procedures (AOPs)], conformance of these procedures to the Westinghouse Owners' Group Emergency Response Guidelines (ERGs), and conformance to the approved writer's guide. The inspection included a comparison of the EOPs to Westinghouse generic technical guidelines, a technical adequacy review of the procedures, control room and in plant walkthroughs, simulator evaluation of selected procedures, a review of on-going control of these procedures, and interviews of operators who use the procedures.

Results:

The overall assessment concluded that the EOPs adequately covered the broad range of accidents and equipment failures necessary for safe shutdown of the plant. The team identified weaknesses in availability of equipment, paragraph 4; plant design, paragraph 4; level of detail in procedures, paragraph 4; technical documentation, paragraphs 2 and 4; conformance with the writer's guide, paragraphs 2, 3, and 4; and management control of the EOP program, paragraph 6. The team reviewed the draft Safety Evaluation Report (SER) on the licensee's Procedures Generation Package (PGP) commitments and determined that, when the Inspector Followup Items (IFIs) in this report are completed, all licensee actions necessary in response to the SER will be completed. Violations or deviations were not identified in this report.

REPORT DETAILS

1. Persons contacted

Licensee employees

S. Allen, Manager - License Training
J. Barry, Reactor Operator
*C. Baucom, Senior Specialist - Regulatory Compliance
*D. Beith, Human Factors Specialist - Human Factors Interfaces
*C. Bethea, Manager - Training
D. Blakeney, Senior Engineer - STA
J. Boyd, Senior Specialist - Simulator Support
T. Byron, Senior Specialist - License Training
H. Carter, Senior Specialist - License Training
D. Cook, Auxiliary Operator
J. Curley, Manager - Environmental and Radiation Control
W. Cutright, Reactor Operator
*C. Dietz, Manager - Robinson Nuclear Project Department
W. Flanagan, Manager - Outage Modifications
S. Griggs, Technical Aide - Regulatory Compliance
J. Harding, Senior Control Operator
*E. Harris, Jr., Manager - Onsite Nuclear Safety
T. Hodges, Administration
R. Ivey, Auxiliary Operator
*J. Kloosterman, Director - Regulatory Compliance
D. LaBelle, Project Engineer - Onsite Nuclear Safety
F. Legette, Senior Control Operator
B. McFeaters, Project Specialist - Corp. Emergency Planning
R. Moore, Shift Foreman
*R. Morgan, Plant General Manager
D. Neal, Senior Specialist - License Training
*D. Quick, Manager - Plant Support
D. Seagle, Shift Foreman
*J. Sheppard, Manager - Operations
*E. Shoemaker, Project Engineer - Operations
V. Smith, Senior Specialist - License Training
*D. Stadler, Onsite Licensing Engineer
R. Stebbins, Senior Specialist - License Training
B. Stover, Senior Control Operator
T. White, Reactor Operator
*L. Williams, Supervisor - Emergency Planning & Security
*H. Young, Manager - Quality Assurance and Quality Control

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

NRC Personnel

*R. Lo, Project Manager - Robinson, NRR
*W. Regan, Chief - Human Factors Assessment Branch, NRR

NRC Resident Inspectors

K. Jury

* Attended exit interview on September 29, 1989.

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 reviewed the development of the Robinson emergency operating procedures (EOPs) as the basis for evaluating the relationship of the EOPs to the plant specific technical guidelines (PSTG).

The Robinson Operations Department developed Revision 0 of the Robinson EOPs directly from the emergency response guidelines (ERGs). The EOPs were produced by application of the principles in the Robinson writer's guide to the technical information in the ERG, the Robinson setpoint document and other sources. The licensee submitted an EOP Procedure Generation Package (PGP), including a writer's guide, to the NRC for review and approval in 1984.

The licensee conducted simulator validation of the EOPs on the Shearon Harris simulator in June 1983. Procedures that could not be validated on the simulator were validated by control room walkthroughs during July and August of 1984. No other plant walkthroughs were conducted as part of the EOP validation. The licensee revalidated a limited number of the EOPs on the Robinson plant specific simulator in 1987. Therefore, not all of the Robinson EOPs had been validated on the plant specific simulator. Robinson licensed operators conducted verification of the EOPs in July 1984 through tabletop reviews. The licensee conducted a final technical review of the EOPs in August 1984. The licensee implemented Revision 0 of the EOPs on November 17, 1984.

In early 1985 the CP&L nuclear safety review group conducted a technical review of the EOPs. Their major finding was the lack of a plant specific technical document. Robinson QA conducted a review of the EOP program in January of 1987 and issued a report in March 1987 with the major concern that the transition documentation was incomplete. In March 1988, the licensee issued an Emergency Operating Procedures Transition Document (TD). The purpose of the TD was to compare the Robinson plant to the Westinghouse Owners Group - Low Pressure Emergency Response Guidelines (WOG-LP ERG) reference plant, document a step by step comparison of the ERGs and the EOPs and justify step deviations between them, and to justify setpoints used in the EOPs.

The EOPs were developed without the use of an adequate PSTG in that the TD was incomplete, and were revised over a period of more than three years under the same conditions.

The team compared the EOPs to the Robinson TD and found that the TD was not up-to-date. As a result, they found numerous deviations between the current revision of the EOPs and the EOP supporting documentation in the TD. The Team identified these deviations from the TD by the designation "PSTG DEV" in appendix B.

In addition, the TD was incomplete. The setpoint document was not maintained to reflect procedure revisions including setpoint additions. Although a number of setpoints referenced other sources for supporting calculations, finding the appropriate documentation was often difficult. The licensee could not trace at least one setpoint to the calculations which established it. The team has addressed incomplete TD documentation more fully in other sections of this report.

The team met with the licensee to discuss the development and implementation of the as found PSTG. The licensee described this PSTG as "the Robinson PSTG consisted of the 11 volume TD plus Revision 1A WOG ERG-LP." The licensee indicated that in this form, the PSTG had been difficult to maintain current and difficult to use for the development of the EOPs. The inspection team indicated to the licensee that a PSTG was required which could be maintained and used effectively for the development and revision of the EOPs. The licensee committed to develop a new PSTG, including an improved setpoint document and step deviation document. The detailed description of this PSTG and schedule for its development are to be addressed by the licensee in their response to this inspection report. Resolution of this issue was identified as IFI 50-261/89-16-01.

The team compared the Robinson EOPs to the ERGs and in general found close agreement. The accident mitigation sequence of the ERG was generally followed in the EOPs and the EOPs were adequate to cover the broad range of accidents and equipment failures addressed in the ERG.

The team reviewed the role of the Robinson Quality Assurance Department (QA) in the development of the PSTG and upgraded EOPs. Robinson QA conducted technical comparisons of the EOPs against the ERGs in November 1984. The documentation describing these reviews consisted of approximately 19 pages; 5 pages bear no comments and the remaining pages contained a limited description of the procedures reviewed and no description of the review process. The few issues raised in the reviews were resolved prior to EOP implementation. The team concluded that the level of QA involvement in EOP development prior to implementation was not adequate. However, the team found that other management controls, as discussed above, were applied subsequent to implementation in lieu of a more aggressive QA involvement.

Review of the EOPs against the requirements of the writer's guide identified a number of deviations. These deviations suggested inadequate verification of the procedures against the writer's guide.

The team found that the format and wording of the abnormal operating procedures (AOPs) were substantially different from the other EOPs. The writer's guide had not been applied to the Robinson AOPs, and this had created for the operator a discontinuous and potentially confusing interface with the EOPs. The AOPs and EOPs used different formats (one column vs two column), different action verbs, and different transition methods. In one example, if operators tranitioned from the AOP for loss of CCW to the EOP for reactor trip by using an EOP method of transition, they would not have continued concurrently with the AOP. This could have resulted in immediate damage to all RCPs and CCW pumps. The licensee has committed to develop an AOP writer's guide. Resolution of this issue was identified as IFI 50-261/89-16-02.

There were no violations or deviations noted in this area.

3. Independent technical adequacy review of the EOPs

The team reviewed the procedures listed in Appendix A and found that generally the vendor recommended accident mitigation strategy and action sequence was followed. The main entry into the EOP network was via Path-1 on a reactor trip or safety injection. The only other EOPs that were entered directly were EPP-1, Loss of all AC power; EPP-5, Natural circulation cooldown; EPP-21, Energizing pressurizer heaters from emergency busses; and the AOPs. The EOP procedure entry and transition conditions closely followed the ERG.

Cautions and notes were often incorrect in application of the writer's guide. For example, cautions and notes were often found lacking identification of the potential hazard to equipment or personnel as required by the writer's guide. Both notes and cautions were written containing action steps or conditional steps, which is also contrary to the writer's guide. Specific examples are delineated in Appendices B and C.

Place keeping aids, such as pencil check marks or page markers, were not addressed in the writer's guide and were not used during implementation of the EOPs, with the exception of the grease pencils used to traverse the path procedures. Since most EOP steps were initiated without regard to completion of prior steps and there were many transitions between procedures, place keeping aids were important for keeping track of action steps that had been initiated and steps that had been completed. Because of the increased chance of operator error while transitioning within or between procedures, there was a need for clearly established place keeping.

The EOP procedures did not adequately reference nomographs, graphs, or additional procedures required to carry out steps. This lack of adequate reference required the operators to memorize reference material identifications or scan through manuals for the required information.

The quality of several operator aids was poor for determining the information required to carry out specified actions. For example, many of the operator aids in the curve book were not maintained to original quality standards. Reproductions had lost their clarity due to excessive photocopying. The team also observed examples of poor contrast between coordinate values and background, and inappropriate scale to present the full range of needed information.

The team inspected selected control room drawings to verify that EOP specified components were accurately presented. No discrepancies were noted.

Operator action setpoint values and justifications were contained in the EOP/ERG setpoint study of the TD. The team reviewed samples of these values and found them to be adequately documented and justified, except as listed in Appendix B.

The team found the degree of EOP adherence to the ERG to be generally acceptable. However, the TD was not current and there were many differences between it and the EOPs. This was primarily due to the licensee having made updates to the EOPs to reflect revision 1A to the ERG. The licensee completed these EOP updates in early 1989 without updating the TD. The existing, out of date, TD could not perform its required function of providing a basis for subsequent EOP revisions. The TD also failed to provide adequate justification for many EOP step deviations from the ERG.

There were no violations or deviations noted in this area.

4. Review of the EOPs by inplant and control room walkthroughs

The NRC found the relationship of procedure nomenclature to the equipment labeling to be difficult to compare because the procedures did not reference exact equipment labels in most cases. Because a precisely defined method of referencing equipment nomenclature was not addressed in the supporting EOP development documentation, the references to equipment and controls used in the EOP procedures was not consistent. In addition, steps requiring local actions did not consistently reference equipment or controller labels. The team conducted inplant and control room walkthroughs of the emergency and abnormal procedures listed in Appendix A. Where required by the writer's guide, the EOP nomenclature appeared to be generally consistent with installed equipment. The team enumerated noted discrepancies in Appendix D. The licensee committed to review these and make changes as appropriate. Resolution of this issue was identified as IFI 50-261/89-16-03.

Indications, annunciators and controls referenced in the EOPs were found to be available to the operators except as noted in Appendix B. Two sets of emergency and abnormal procedures were maintained in the Control Room at all times. These procedures were the latest revision.

While the results of the walkthroughs were generally acceptable, many discrepancies in the areas of technical adequacy, writer's guide adherence, and human factors were noted. Technical and human factors discrepancies are noted in Appendix B while writer's guide discrepancies are noted in Appendix C. Appendix B and C discrepancies were identified as IFIs 50-261/89-16-04 and 05 respectively. Important items noted by the team during the walkthroughs included:

- The availability and prestaging of needed equipment was weak for some required actions; Appendix B, paragraphs VI.14.h & k and III.1.n.

- Two procedural weaknesses in assuring compliance with technical specifications were noted; Appendix B, paragraphs VI.27.d and III.6.a.

- Design weaknesses that inhibited the operator's ability to respond to flooding in the service water pump pit and flooding in the residual heat removal pump pit were noted; Appendix B, paragraphs VI.22.e and III.9.l.

- The level of detail in the EOPs was inadequate in some cases; Appendix B, numerous examples.

- Some plant modifications that impacted the usability of the EOPs did not result in a proper EOP revision; Appendix B, paragraphs VI.27.a & c, III.21.s, VII.2.b, and IV.4.c.

The HBR verification and validation program established in paragraph 5.6 of OMM-013, the writer's guide, did not apply to the AOPs or the alarm response procedures but was limited to the PATHs, EPPs, FRPs and CSFSTs. V&V was required for all EOP revisions. V&V did not require in plant procedure walkdown. Either one SRO or two ROs were required for the verification process; for control room walkthrough validation, a minimum of one shift licensed operator was required. Of the two validation options, control room and simulator, the latter was defined as the preferred method.

The NRC evaluated the V&V program requirements and sampled supporting records for the initial EOP transition to the ERG Revision 0, the EOP upgrade to ERG Revision 1, and the EOP upgrade to ERG revision 1A, and found the following:

- Except for the absence of validation checklists, the procedure review and approval packages inspected were complete to the current program requirements.

- Simulator validation was conducted on all possible EOPs incident to the upgrade to ERG Revision 1. No simulator validation was conducted incident to the upgrades to ERG Revisions 0 or 1A.

- Although V&V was applied during the upgrade to ERG revision 1A, the latest revision, the process was insufficient in that it failed to identify the fact that the transition document (set points, deviations, generic to plant specific differences and I&C task analysis) had not been upgraded to ERG revision 1A. Since the transition document was a principal constituent of the HBR PSTG and was not upgraded, the NRC concluded that the HBR EOPs were not adequately based upon the PSTG and that the V&V process failed to identify that shortcoming.

- The licensee's V&V program did not require in plant EOP walkdowns. During this inspection, NRC walkdowns of EOPs identified many procedure deficiencies.

- These V&V deficiencies constituted a serious weakness in the HBR V&V program.

The licensee agreed with the V&V findings listed above. Resolution of this issue was identified as IFI 50-261/89-16-06.

There were no violations or deviations noted in this area.

5. Simulator observation

The team observed a crew performing the following five major scenario categories on the HBR Simulator.

(1) Loss of all feedwater
(2) Intermediate size LOCA
(3) Steam line break inside containment
(4) Steam generator tube rupture with ATWS
(5) Loss of CCW

The simulator performed satisfactorily with one exception. The simulator would not model a loss of offsite power when grid voltage was degraded. The team looked closely at reactor vessel head voiding during natural circulation, and the simulation was satisfactory.

The procedures provided operators with sufficient guidance to fulfill their responsibilities and required actions during the emergencies, both individually and as a team. The procedures did not duplicate operator actions unless required.

The procedures did not cause the operators to physically interfere with each other while performing the EOPs.

The simulator group utilizes a computer tracking system to track relavent simulator modification requests (SMRs) which reflected modifications to the control room. This tracking of the differences was used to maintain the fidelity of the simulator. There were 56 open SMRs in varying degrees of completion, some only requiring documentation to be completed for close out. The simulator instructors felt obligated to inform the students of 15 of these SMRs, due to the SMR's significance, prior to a simulator session.

6. Management control of EOPs

The team found that weaknesses in management control of EOPs allowed them to degrade over time. Some of these weaknesses were described in previous paragraphs:

- Failure to revise EOPs when a plant modification was performed, paragraph 4.
- Failure to provide adequate guidance to operators to help ensure compliance with the TS, paragraph 4.
- Failure to provide justification for EOP step deviations from the ERG and to keep the PSTG current, paragraph 2.
- Deficiencies in the V&V program, paragraph 4.

The team reviewed the quality assurance measures utilized to incorporate operational and training experience into the EOPs. Training instruction 909, Simulator Conduct of Operations and Instructor Qualifications, was issued in October 1988. This TI required a "procedure discrepancies" book be made available to instructor and students during simulator training to collect any procedure problems identified in plant procedures. These comments were reviewed by the training staff and then forwarded to the Manager of Operations for resolution. Review of the comments indicated that both the training staff and operators were actively participating in the process. However, a potential weakness in the process was the lack of feedback to the comment orginators. Failure to provide feedback could eventually discourage participation in the process. The team verified that some comments had been incorporated into the EOPs. The process did not solicit comments from classroom training sessions.

Revisions to the EOPs were prepared in accordance with OMM-013, Emergency Operating Procedure Writer's Guide, and approved in accordance with AP-004, Development, Review and Approval of Procedures, Revisions, and Temporary Changes. Section 5.6, verification and validation program of OMM-013 required that the verification worksheet, Attachment 6.12, be completed prior to implementing the revision. The worksheet steps were general in nature and lacked detail to ensure that the steps were adequately addressed by the reviewer. This section also required that validation be performed on EOP revisions. The validation was to include a simulator or control room walkthrough validation or both. Interviews with plant personnel revealed that this validation process had not yet been implemented.

7. EOP user interviews

The team conducted interviews with twelve licensed operators. The operators felt that the EOPs had been improved with the recent revision. Those interviewed expressed their belief that the level of detail in the EOPs could be improved, but was adequate for the level of knowledge of the typical operator. Overall, the operators had confidence in the ability of the EOPs to perform their intended function although the level of detail in the EOP was inadequate in some cases.

Section 5.1.4, pages 7 and 8 of the writer's guide, stated that Path procedures relieve the operator of the burden of memorization of immediate actions. The ERG background document for E-0 stated that immediate actions "are those actions which the operator should be able to perform before opening and reading his emergency procedures." Whether the procedure is in a two-column or flow chart format is immaterial. The writer's guide must be clarified regarding the memorization of immediate operator actions and their training adjusted accordingly.

If memorization is not required, this deviation should be technically justified. This justification should specifically address both section 3.3.1 "Immediate action steps" and section 2 "Control room usage of guidelines" of the WOG ERG writer's guide. Resolution of this issue was identified on IFI 50-261/89-16-07.

The operators noted that the AOPs were not at the same useability level as the other EOPs. Those interviewed felt that an upgrade to the AOPs similar to that which the other EOPs received would be beneficial.

There were no violations or deviations noted in this area.

8. Exit Interview

The inspection scope and findings were summarized on September 29, 1989, 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	Status	Description/Reference Paragraph
IFI 261/89-16-01	Open	Develop a new PSTG (paragraph 2).
IFI 261/89-16-02	Open	Develop an AOP writer's guide (paragraph 2).
IFI 261/89-16-03	Open	Review each Appendix D item (paragraph 4).
IFI 261/89-16-04	Open	Review each Appendix B item (paragraph 4).

IFI 261/89-16-05	Open	Review each Appendix C item (paragraph 4).
IFI 261/89-16-06	Open	Correct V&V deficiencies (paragraph 4).
IFI 261/89-16-07	Open	Review memorization of operator immediate actions. (paragraph 7).

APPENDIX A

PROCEDURES REVIEWED

CFST - 1	Critical Safety Function Status Tree	REV 3
CFST - 2	Critical Safety Function Status Tree	REV 3
CFST - 3	Critical Safety Function Status Tree	REV 3
CFST - 4	Critical Safety Function Status Tree	REV 3
CFST - 5	Critical Safety Function Status Tree	REV 3
CFST - 6	Critical Safety Function Status Tree	REV 3
EPP-Foldouts	Foldouts	REV 6
EPP-SUPP.	Supplements	REV 5
EPP-1	Loss of All AC Power	REV 5
EPP-2	Loss of All AC Power Recovery without SI Required	REV 5
EPP-3	Loss of All AC Power Recovery with SI Required	REV 4
EPP-4	Reactor Trip Response	REV 4
EPP-5	Natural Circulation Cooldown	REV 3
EPP-6	Natural Circulation Cooldown with Steam Void in Vessel	REV 2
EPP-7	SI Termination	REV 6
EPP-8	Post LOCA Cooldown and Depressurization	REV 4
EPP-9	Transfer to Cold Leg Recirculation	REV 6
EPP-10	Transfer to Hot Leg Recirculation	REV 3
EPP-11	Faulted Steam Generator Isolation	REV 2
EPP-12	Post-SGTR Cooldown Using Backfill	REV 3
EPP-13	Post-SGTR Cooldown Using Blowdown	REV 3
EPP-14	Post-SGTR Cooldown Using Steam Dump	REV 3
EPP-15	Loss of Emergency Coolant Recirculation	REV 3
EPP-16	Uncontrolled Depressurization of All Steam Generators	REV 4
EPP-17	SGTR with Loss of Reactor Coolant: Subcooled Recovery	REV 4
EPP-18	SGTR with Loss of Reactor Coolant: Saturated Recovery	REV 4
EPP-19	SGTR without Pressurizer Pressure Control	REV 3
EPP-20	LOCA Outside Containment	REV 2
EPP-21	Energizing Pressurizer Heaters from Emergency Busses	REV 3
EPP-22	Energizing Plant Equipment using the Dedicated Shutdown Diesel Generator	REV 2
EPP-23	Restoration of Cooling Water Flow to Reactor Coolant Pumps	REV 3
FRP-C.1	Response to Inadequate Core Cooling	REV 2
FRP-C.2	Response to Degraded Core Cooling	REV 2
FRP-C.3	Response to Saturated Core Cooling	REV 2
FRP-H.1	Response to Loss of Secondary Heat Sink	REV 2
FRP-H.2	Response to Steam Generator Overpressure	REV 2
FRP-H.3	Response to Steam Generator High Level	REV 3
FRP-H.4	Response to Loss of Normal Steam Release Capability	REV 2
FRP-H.5	Response to Steam Generator Low Level	REV 2
FRP-I.1	Response to High Pressurizer Level	REV 2
FRP-I.2	Response to Low Pressurizer Level	REV 2

FRP-I.3	Response to Voids in Reactor Vessel	REV 3
FRP-J.I	Response to High Containment Pressure	REV 2
FRP-J.2	Response to Containment Flooding	REV 1
FRP-J.3	Response to High Containment Radiation Level	REV 2
FRP-P.1	Response to Imminent Pressurized Thermal Shock	REV 2
FRP-P.2	Response to Anticipated Pressurized Thermal Shock	REV 2
FRP-S.1	Response to Nuclear Power Generation ATWS	REV 2
FRP-S.2	Response to Loss of Core Shutdown	REV 2
PATH-1	PATH-1	REV 5
PATH-2	PATH-2	REV 5
AOP-001	Malfunction of Reactor Control System	REV 3
AOP-002	Emergency Boration	REV 2
AOP-003	Malfunction of Reactor Make-Up Control	REV 2
AOP-004	Control Room Inaccessibility	REV 2
AOP-005	Radiation Monitoring System	REV 5
AOP-006	Turbine Vibration	REV 2
AOP-007	Turbine Trip without Reactor Trip Below P-7	REV 0
AOP-008	Accidental Release of Liquid Waste	REV 0
AOP-009	Accidental Release of Waste Gas	REV 0
AOP-010	Inadequate Feedwater Flow	REV 4
AOP-011	Loss of Circulating Water Pump	REV 0
AOP-012	Partial Loss of Condenser Vacuum	REV 4
AOP-013	Fuel Handling Accident	REV 2
AOP-014	Loss of Component Cooling Water	REV 0
AOP-015	Secondary Load Rejection	REV 1
AOP-016	Excessive Primary Plant Leakage	REV 5
AOP-017	Loss of Instrument Air	REV 5
AOP-018	Reactor Coolant Pump Abnormal Conditions	REV 1
AOP-019	Malfunction of RCS Pressure Control	REV 1
AOP-020	Loss of Residual Heat Removal (Shutdown Cooling)	REV 6
AOP-021	Seismic Disturbances	REV 3
AOP-022	Loss of Service Water	REV 2
AOP-023	Loss of Containment Intergrity	REV 3
AOP-024	Loss of Instrument Buss	REV 1
AOP-026	Low Frequency Operation	REV 0
AOP-027	Operation with Degraded System Voltage	REV 0
AOP-028	ISFSI Abnormal Events	REV 0

APPENDIX B

TECHNICAL AND HUMAN FACTORS COMMENTS

This appendix contains technical and human factors comments and observations. Unless specifically stated, these comments are 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 (proposed or completed) in its answer to IR-89-16. These items will be reviewed during a future NRC inspection.

I. General comments:

1. Although the TD intended to provide operator action setpoints required by the HBR EOPs, there was no setpoint document to serve AOP unique requirements.

2. PSTG DEV: No deviations should have existed between the PSTG and the EOPs. Since the PSTG had been defined as a set of documentation which included the GTG, all deviations between the GTG and the EOPs became deviations between the PSTG and the EOPs, by definition. Although the EOPs were revised to conform to ERG rev. 1A, the PSTG had not been (e.g. setpoint, deviation and plant comparison documents). As a result, the Robinson revised EOPs were not adequately based upon plant specific technical guidance. The NRC considered this a significant weakness as documented in paragraph two.

3. As stated in the writer's and user's guides, there were no declared immediate action steps in the EPPs and PATHs. The NRC found that elimination of immediate action steps and of the requirement that operators commit these steps to memory was unacceptable and constituted a weakness in the EOP program. (see paragraph 7, interviews).

4. HBR did not declare an NOUE based upon hurricane HUGO. The HBR EALs did not conform to the guidance of NUREG-0654 Appendix I, EAL 13 d, to declare a NOUE given "Natural phenomenon being experienced or projected beyond usual levels... any hurricane". Hurricane HUGO passed through the area during the inspection. The area was declared a disaster area. Brunswick, a sister CP&L plant, declared a NOUE. HBR did not. HBR unit 2 was in cold shutdown; the control room wind velocity instrumentation was inoperative; and hurricane preparations were made. The operators were aware that Brunswick had declared a NOUE, that the hurricane eye was projected to pass nearby, that it was a category four hurricane and that winds were projected in excess of 135 mph when the hurricane came ashore near Charleston. As the local wind velocity increased, grid problems, telephone outages and on site wind damage were experienced. The HBR applicable NOUE stated "Hurricane or tornado within site boundary". The NRC concluded the hurricane impacted the site and that in the absence of wind velocity data, the operators were unable to determine whether it was or was not above hurricane velocity (e.g. 73 mph).

5. The licensee had organized neither the EPPs nor the AOPs such that multiple local actions to accomplish a single goal were contained in a procedure attachment which could be provided to the AO. Conversion to this format would have, in many cases, relieved the control room staff of a significant communications burden and would have enhanced the successful completion of the step.

6. I&C provided support in EOP actions (e.g. jumper installation; determination of NI undercompensation, etc.). I&C did not provide round the clock shift coverage nor were I&C personnel trained in the performance of I&C responsible EOP steps.

II. PATH comments:

NOTE: Since PATH steps were not numbered, step location is specified below by grid location.

1. PATH-1

a. Grid D-16, Paragraph 5.3.3 of the User's Guide required that CSFST monitoring be initiated at a particular step in PATH-1 or upon exit from PATH-1. Contrary to that requirement, the exit to EPP-11 at grid D-16 was made without initiation of CSFST monitoring nor was monitoring initiated within EPP-11.

b. Grid D-5, CV fans: The GTG required that CV fan coolers be verified running in the emergency mode. HBR required verification that the fans were running since there was no method of verifying that the intake dampers had shifted to the emergency position. No deviation existed.

c. Grid B-7 and elsewhere in the PATHs and EPPs, RCS pressure greater than or equal to 1520: Recorder PR-444 and meters PI-402 and 501 had scale increments of 50 psig. Using the half division rule, they could not be used to determine a value of 1520.

d. The three AFW flow controllers used in many places in the PATHs and the EPPs (FIC-1425, 1426, & 6416) were times 10 meters but were not so labeled.

e. Grid C-10 and elsewhere in the PATHs and EOPs; verify DG capacity to assume additional loads: The process by which the operator determined whether sufficient DG capacity existed to bring on additional loads was cumbersome and in some cases inadequate. Since DG KW was not available from the board meters, to verify that sufficient capacity existed to bring on additional loads the operator was required to read DG volts and amps and calculate KW from a curve.

The operator aid then directed the operator to FSAR table 8.3.1-1 to determine the load of the oncoming equipment. If the oncoming load was less than remaining capacity, the equipment could be loaded to the bus. Some loads (e.g. the charging pumps) were not shown in FSAR table 8.3.1-1, the source referenced on the operator aid.

f. Grid C-11, restart ES equipment: This step was illustrative of a general problem which existed in the PATHs and the EPPs; insufficient definition.

g. Radiation monitoring units, R-19 A/B/C: Neither the recorder nor the edge meters had engineering unit labels.

h. The CV water level meters did not have engineering unit labels. No instrument number labeling was provided.

i. There was no standard convention for steam generator designation. They were identified as units A, B or C; I, II or III; or 1, 2, or 3 (e.g. 15 edge meters on the RTGB and annunciator panel APP-006 used the I, II or III convention; most RTGB instruments used the A, B or C convention; plant valves generally used 1, 2 or 3).

j. The HBR standard abbreviation for pressurizer (PZR) had not been implemented universally. PZR and PRZR were both used (e.g. LI-459 meter vs. panel label).

l. Grid F-15 and elsewhere in the PATHs and EPPs, emergency oil pumps: This step did not clearly define which seal oil backup pump was to be started. During walkthroughs, two operators correctly started the air side DC seal oil backup pump; a third started the AC pump adjacent to the emergency oil pump on the RTGB.

m. Grid B-9 and elsewhere in other procedures: The 300 gpm AFW flow parameter for decay heat removal stemmed from the setpoint document generic footnotes attachment 1.0. The GTG bases document required allowances for normal channel accuracy. None were included in the HBR setpoint calculation.

n. HBR setpoint document, generic footnotes, attachment 2.0: Typo; paragraph 4.2 follows 2.1. Other typos; "valves" should be "values" in paragraph 4.2; attachment 8.0 mid page, "syste".

o. HBR setpoint document, attachment 1 pg. 2 and frequently elsewhere: the percent symbol was missing in the calculation string (e.g. item 6, 0.5 of span).

III. EPP comments:

1. EPP-1 Loss of all ac power

a. PSTG DEV, Step 3.0: The ERG note that stated steps 1 - 4 were immediate action steps has been deleted from this procedure. The ERG required immediate action steps to be memorized by the operators. The TD attempted to justify this step deviation based on the use of flow charts. This was not adequate justification for operators not to memorize these steps.

b. PSTG DEV, Step 3.1: The word "check" in this step deviated from the word "verify" in the TD. This same deviation appeared in steps 2, 3, 4, 6a2, 6b, 8c, 8e, 12b, 14, 15, 16, 17c and d, 18, 19, 20, 21, 22, 23, 24, 25, and 27.

c. PSTG DEV, Step 3.1: The ERG required the operator to check rod bottom lights and RPIs to verify reactor trip, and these actions were not included in this procedure. The TD attempted to justify this by stating that these indicators were not powered from the batteries. This justification was not adequate to explain the fact that these indicators were not powered in this instance.

d. Step 3d: The operator was unable to check some of these RCS ventilation system valves closed, because the power to them was deenergized and the position indicating lights were not lit.

e. PSTG DEV, Step 4a RNO: The steam generator levels in this step were different from those in the TD. This same deviation appeared in steps 14 and 17.a.

f. PSTG DEV, Step 5d: This item was not in the TD.

g. PSTG DEV, Step 7: The charging pumps were included in the ERG and were missing from this step. The TD justification was not adequate to explain the fact that the charging pumps were not automatically started on safety injection.

h. Step 9: This step required operators to contact I&C to connect steam line PORVs to nitrogen accumulators so they could be operated. I&C personnel were not always available and operators could do this step.

i. PSTG DEV, Step 10: Before this step, the TD included a step to locally close valves to isolate RCP seals. This step was missing from the procedure, due to use of the DS diesel to operate a charging pump.

j. PSTG DEV, Step 12, caution 2: This caution in the procedure was not in the TD.

k. PSTG DEV, Step 13: The ERG included condenser air ejector radiation as a symptom of a ruptured steam generator, but this was not included in the procedure. The TD justification that this instrument was deenergized was not adequate to explain the fact that it was deenergized.

l. Step 16 RNO: The operator was required to switch to an alternate AFW water supply, but was given no guidance on priority of alternate supply. Interviews with operators revealed that not all would choose the same alternate supply.

m. Step 16 RNO: The operator was directed to align Unit 1 fire main with unit 2 fire main, but was given no guidance on how or where to do this. The location of these valves and the tool to operate them were not common knowledge among operators.

n. Step 16 RNO: The operator was directed to fill the CST using fire hoses, but no dedicated pipe fittings were provided. In fact, a large flange fitting would have had to be manufactured. The operators needed to have all tools and equipment required to perform emergency actions to be readily available.

o. PSTG DEV, Step 17 caution 2: This caution was not in the TD.

p. Steps 20 and 21: The arrangement of these lights on the RTGB was poor. Not all containment isolation phase A lights were grouped together. Also, containment ventilation isolation lights were mixed with control room ventilation lights. This arrangement made it difficult for the operator to accurately check status as required.

q. PSTG DEV, Step 22: The TD included three items to check that were not in the procedure.

r. PSTG DEV, Step 23: This step required the operator to check CV radiation less than 1000 R/hr, while the TD used 100 R/hr.

s. PSTG DEV, Step 24 RNO: This step required the operator to return to the step 12 caution, while the TD required a return to step 17.

t. Step 25 caution: This cautioned the operator that loads placed on the E-1 or E-2 emergency busses should not exceed the capacity of the power source, but did not provide a reference to the information the operator would need to do this, such as an emergency load list including KW.

u. Step 26a: The labeling of the RTGB steam generator PORV controllers was inadequate. The demand signal was labeled from 0 to 100 percent, which represented a demanded setpoint of 1500 to 0 psig. The normal setpoint of 1035 psig was thus shown on the indicator as 31 percent. Operators had written "closed" and "open" in pencil on the RTGB by the 0 and 100 percent. In interviews, operators stated that better labeling was needed to assist them in proper operation of these valves.

v. PSTG DEV, Step 27: This step directed the operator to check SW booster pumps, which was not included in the TD.

w. Attachment A, page 4: To shed circuit 23 as directed, the operator would need a 10 amp fuse puller, which was available only in the control room. Information needed by the operator to get the correct tools for the job was not included in the procedure where it could avoid unnecessary loss of time.

x. Attachment A, page 5: The procedure did not adequately describe loads to be shed. Breaker or circuit numbers were not specified and load names did not match with labels on the panels. Operators could not identify by using this list all of the correct loads to shed.

2. EPP-2 Loss of all ac power, recovery without SI required

a. Step 17a RNO: This step required the operator to observe the caution statement prior to step 18 and go to step 18. There was no caution statement prior to step 18.

b. Step 18 RNO: Increasing feed flow and raising level to maximum allowed would assist in reestablishing SCM. This alternative was not included.

c. Step 18: The structure for natural circulation verification steps differed between procedures. This step consisted of a check with an RNO to establish natural circulation. EPP-16 step 29 RNO verified natural circulation. Since the end result is identical in both cases, the format should be standardized.

d. Step 23a: Backfeeding the aux transformer from offsite power is a lengthy, complex and infrequent operation. The backfeed procedure in OP-603 was not cited.

e. Step 23a: The alternative of shipping power from unit one was described in some procedures as "...IC turbines or unit one ..." and in others as "... IC turbines and unit one ...". The format was not standardized. (e.g. EPP-16, step 28 RNO and elsewhere)

3. EPP-3 Loss of all ac power, recovery with SI required

a. Step 3 RNO: These procedural directions contained no verb.

b. Step 6: The verb used in this step was not defined in the action verb list.

c. PSTG DEV, Caution 9: The key utility decision point contained in the GTG caution 8 was missing from this procedure with the result that the operator was not warned against establishing component cooling water to the thermal barrier of an RCP which has excessive seal leakage.

d. Caution 2: The ERG contained a caution prior to step 2 which was not in EPP-3.

e. PSTG DEV, Step 4: In addition to other equipment, step 4 of the TD required the operator to start the SW pumps and the SWB pumps. EPP-3 step 4 did not contain this requirement.

f. PSTG DEV, Step 6: The TD step 6 instructed the operator to "rack in CV spray pump breakers", but the corresponding EPP-3 step instructed the operator to "locally install control power fuses for the CV spray pump breakers".

g. PSTG DEV, Step 7: Step 7 of EPP-3 stated "Check if CV spray is required". The ERG and the TD did not contain a corresponding step.

h. Step 2a: This step did not provide the operator a valve list for guidance in aligning SI valves for cold leg injection.

i. Step 4b: This step did not specify which RHR pumps to load.

j. Step 4d: This step did not specify which HVH units to load.

k. Step 5: This step instructed the operator to control AFW flow and maintain S/G levels. It did not address control of the S/G pressure or verification of natural circulation.

l. Step 6: This step locally installed control power fuses for the CV Spray Pump Breaker. There was not a preceding step instructing the operator to "Reset CV signal"; such a step would prevent the breaker from auto closing if a signal was present when the operator was inside the open breaker cubical installing fuses.

m. Step 7a: The step did not specify the action to be taken if CV pressure had "ever" increased to or was presently greater than 20 PSIG.

n. Step 7d RNOj: This step required the operator to adjust the flowrate but did not specify a valve name or number. Adjusting this flowrate is an infrequent operation.

4. EPP-4 Reactor trip response

a. Step 3 RNO: The first asterisk does not specify how to dump steam to the condenser.

b. Step 4c RNO: Part a of step 5 RNO did not specify the number of pumps required for emergency boration.

c. Step 5, NOTE: This note did not inform the operator that letdown isolation could deenergize the PZR heaters. A level of 14.4 percent in the PZR will deenergize the heaters.

d. Step 5a RNO: Part a of step 5 RNO did not specify the number of pumps required for emergency boration.

e. Step 5b RNO: This subpart was confusing as written and contained more than two actions in each subpart.

f. Step 5d RNO: Part d of step 5 RNO had, as an option, "Open AUX PZR SPRAY, CVC 311". This statement did not inform the operator of the maximum delta T limit of 320 degrees F between the pressurizer temperature and the aux spray temperature.

g. Step 6a RNO: Step 6.a.1 RNO did not contain the valve name or number to be used to verify letdown isolation.

h. Step 6a RNO: Step 6.a.4 RNO was misleading in that it implied that the operator only "resets" a particular bank of PZR heaters "as necessary" after clearing a low level of 14.4 percent.

i. Step 7a RNO: This item did not specify how Safety Injection was to be initiated.

j. Step 7b RNO: Step 7b.2g RNO did not inform the operator which RCP is associated with which spray valve. B PZR spray valve was not associated with the B RCP.

k. Step 9 RNO: Step 9 RNO was not clear. The step implied that the operator was required to start and load the EDG's on the E1 and E2 busses even if power to them had not been lost.

l. Step 9 RNO: Step 9 RNO instructed the operator to "Verify EDGs have assumed the proper loads". No guidance was provided to the operator defining either "proper loads" or the KW rating of the individual loads. There was no EDG KW meter nor other indication of EDG KW in the control room to aid the operator in loading the EDG.

m. Step 9 RNO: Step 9.c. There was no KW meter nor indication of KW for the EDGs in the control room to aid the operator in verifying adequate EDG capacity and loading the instrument air compressor(s) and battery charger(s). The step did not give the operator the KW rating of the instrument air compressor(s) nor that of the battery chargers.

n. Step 10 RNO: This step stated "start pumps". The step did not specify which pumps to start, the starting priority of the pumps nor the number of pumps to be started.

o. Step 11 RNO: This step did not define whether the operator should dump steam to heat up, cool down, or to maintain a constant S/G pressure.

p. Step 12 NOTE: The note did not instruct the operator on which RCP produced the most effective PZR spray.

q. PSTG DEV, Step 8: Step 8 of EPP-4 which corresponds to step 6 of the ERG: "Check S/G levels" was not addressed by a deviation in the TD.

r. PSTG DEV, Caution 9: The TD contained a CAUTION C-9 (EOP: TD EPP-4 37) "On Natural Circulation, RTD bypass temperatures and associated function will be inaccurate" is not in EPP-4.

s. PSTG DEV, Step 13: Step 13 of EPP-4 and step 10 of the ERG "Check if Source Range detectors should be energized" is not addressed in the T.D..

5. EPP-5 Natural circulation cooldown

a. Entry Condition: The TD referred to pages 23, 16 and 27. The correct references are pages 24, 17 and 28.

b. Step 1, note 1: This note required the RCPs to be run in order of priority to provide PZR normal spray. The note did not provide the preferred order.

c. Step 2a: This step established conditions per OP-101 for running an RCP. The OP-101 sections contained actions which are not essential to starting an RCP.

d. Step 2b: This step started RCP(s). In other EOP steps, this was combined with the previous step, thereby requiring the RCP(s) to be started per OP-101.

e. Step 3, note: This note stated that boron addition should be based on total system volume. The aids used by operators to determine boron addition quantities are based on less than total system volume.

f. Step 4, note 2: This note indicated sample results should indicate an overborated condition to prevent dilution below cold shutdown concentration if a PZR outsurge occurred. During walkthroughs, the operator did not know how much overboration would be required. There was no specific guidance defining "overborated condition".

g. Step 5c: This step was not included in the TD.

h. Step 7, caution: This caution was a restatement of the AFW supply switchover criteria in Foldout A.

i. Step 8: This step required hot leg temperatures to be less than 540 degrees F. Step 7 of ERG ES-0.2 indicated less than 550 degrees F. The TD indicated 550 degrees F. Thus, the TD did not provide justification for the difference.

j. Step 9, caution: This caution warned that the SI initiation circuits would automatically unblock if PZR pressure increased to greater than 2000 psig or Tavg increased to greater than 543 degrees F. The caution in ERG-0.2 did not include the Tavg criteria. The TD did not include the Tavg criteria. Thus, the TD did not justify the additional criteria.

k. Step 10: This step blocked safety injection due to PZR Press/Hi stm line dp and Tavg. Step 9 of ERG ES-0.2 did not require the Tavg function to be bypassed. The TD did not require the Tavg function to be bypassed. Thus, the TD did not justify the difference.

l. Step 27: This step maintained required RCP seal injection flow. There was no guidance defining "required ... flow".

m. Step 29b: This step was described in the TD as part of step 28.

6. EPP-6 Natural circulation cooldown with steam void in vessel (without RVLIS)

a. Step 4c: This step required operators to maintain RCS temperature and pressure within the limits of curve 3.4, "Reactor coolant system pressure - temperature limitations for cooldown". The curve was not labeled with all of the information needed to ensure compliance with it, nor was this information provided in the procedure (eg. which instrument readings to compare with which part of the curve). In interviews, two of six licensed operators (33 percent) could not describe correctly how to comply with this curve. Some of these operators also did not know what the expected difference should be between the hot leg and the cold leg temperatures when on natural circulation cooling.

Curve 3.4 consisted of two parts: TS cooldown limits on maximum pressure allowed at any given cold leg temperature (to protect RCS integrity), and EOP saturation limits on minimum pressure allowed at any given core exit or hot leg temperature (to maintain core cooling). The operators needed to be able to use this curve correctly.

7. EPP-7 SI termination

a. Step 3: This step contained multiple actions contrary to the writer's guide.

b. Step 3: The alpha numeric listing rules of the writer's guide were not followed in listing the sequence dependent steps resetting the reactor trip breakers and resetting feed isolation.

c. Step 4 RNO: The procedure did not indicate this step as a local action.

d. Step 6: This step directed "stop SI and RHR pumps". There was no RNO. Therefore the substep bullets were superfluous.

e. Step 9: The step did not provide boration completion criteria. The worth of the most reactive rod was not promulgated officially nor was it documented in the control room. Only through training were the operators informed of the value and then only once per cycle.

f. Step 9 RNO: Since the step was identical to components of AOP-002, the step would be simplified by referring to AOP-002.

g. Step 14: This step checked whether seal flow should be established. Substep f, establishing seal flow, was inappropriate and should stand as a separate step.

h. Step 20 RNO c: This step provided insufficient definition as to which seal oil backup pump was to be started. During walkthroughs, two operators correctly started the air side DC seal oil backup pump; a third started the AC pump adjacent to the emergency oil pump switch on the RTGB.

i. Step 20 RNO e: Backfeeding the aux transformer from offsite power is a lengthy, complex and infrequent operation. The backfeed procedure in OP-603 was not cited.

j. Step 21 RNO a2 and elsewhere in other procedures: This step required trended values to verify natural circulation. Other equivalent EPP steps did not require trended values. The format is not standardized. Some of the operators were unable to expeditiously establish simultaneous trending on the three values which were not on recorders. This indicated a minor ERFIS training problem since ERFIS would support three simultaneous trends.

k. Step 21 RNO a2: This step neglected increasing feed flow within established S/G level limits.

l. Step 25a: The four manual actuation zone switches on the containment fire protection system panel did not have open or closed position indication labels.

m. Steps d, e, g and h: These steps were not shown as local actions.

n. Step 28: The substeps did not include a hold point at step b. The plant operations staff decision is mandatory prior to return to power, natural circ cooldown or forced flow cooldown.

8. EPP-8 Post-LOCA cooldown and depressurization

a. Step 2: Step 2 began on page 4 of 26 and ended on page 5 of 26. The high level step number "2" was shown only on page 4. Only the substep identifier was shown on page 5. Therefore, there was no complete identifier for the substeps on page 5.

b. PSTG DEV, Step 2: The verb "check" was used, rather than the verb "verify," as in the PSTG.

c. Step 3, caution: This caution incorrectly contained a conditional action step.

d. PSTG DEV, Step 10b, RNO: The words "Observe CAUTION and NOTE prior to step 11 AND" was not included in the PSTG.

e. PSTG DEV, Step 11, caution: This caution incorrectly contained a conditional action step.

f. Step 11: Step 11 began on page 11 of 26 and ended on page 12 of 26. The high level step number "11" was shown only on page 11. Only the substep identifier was shown on page 12. Therefore, there was no complete identifier for the substeps on page 12.

g. PSTG DEV, Step 11c, RNO: The words "Observe CAUTION prior to step 10 AND" were not included in the PSTG.

h. PSTG DEV, Step 11d1: The words "AND start one RCP" were correctly shown in the PSTG as a distinct substep.

i. Step 12: Step 12 began on page 13 of 26 and ended on page 14 of 26. The high level step number "12" was shown only on page 13. Only the substep identifier was shown on page 14. Therefore, there was no complete identifier for the substeps on page 14.

j. PSTG DEV, Step 12a: This step was not included in the PSTG.

k. PSTG DEV, Step 12a, RNO: This step was not included in the PSTG.

l. PSTG DEV, Table, page 13: The adverse containment value of 68 degrees F shown for required RCS subcooling when two or three SI pumps are running and two or more charging pumps are available was different from the PSTG value of 70 degrees F.

m. Step 14: Step 14 began on page 15 of 26 and ended on page 16 of 26. The high level step number "14" was shown only on page 15. Only the substep identifier was shown on page 16. Therefore, there was no complete identifier for the substeps on page 16.

n. Step 14, caution: This caution incorrectly contained a conditional action step.

o. PSTG DEV, Step 14: The PSTG included a caution prior to this step that was missing in this procedure. The caution read "On natural circulation, RTD bypass temperatures and associated functions will be inaccurate."

p. PSTG DEV, Step 14a1, RNO: The words "start one RCP" were a separate substep in the PSTG.

q. PSTG DEV, Step 15b: The words "turn on" were shown instead of the verb "control" that was shown in the PSTG.

r. PSTG DEV, Step 15c: The expected response values for RCS subcooling (35 degrees F; 55 degrees F for adverse containment) differed from those shown in the PSTG (25 degrees F; 45 degrees F for adverse containment).

s. PSTG DEV, Step 16: The verb "check" differed from the verb "verify" used in the PSTG.

t. PSTG DEV, Step 17: The verb "check" differed from the verb "verify" used in the PSTG.

u. PSTG DEV, Step 17b, RNO: The words "Observe CAUTION prior to step 10 and" were not shown in the PSTG.

v. PSTG DEV, Step 18a: See comment for step 15c above.

w. PSTG DEV, Step 18a, RNO: Only the words "go to step 19" were shown in the PSTG. The setpoint of 370 degrees F differed from the 400 degrees F shown in the ERG.

x. PSTG DEV, Step 18b: This step and its associated RNO step were not shown in the PSTG. The step "go to step 20" shown in the PSTG was not included in the procedure.

y. PSTG DEV, Step 20a, RNO 3: The terms "EMERG OIL PUMP and SEAL OIL BACKUP PUMP" differed from the terms used in the PSTG of "DC lube oil and seal oil backup pumps."

z. PSTG DEV, Step 20a, RNO 4 and 5: These steps did not appear in the PSTG.

aa. PSTG DEV, Step 20c: This step did not appear in the PSTG.

ab. PSTG DEV, Step 21: This step did not include the item "RCP upper and lower bearing oil cooling - NORMAL" that was shown in the PSTG.

ac. PSTG DEV, Step 21, RNO: The transition to EPP-23 was not included in the PSTG.

ad. PSTG DEV, Step 22b: The upper setpoint of 65 PSIG differed from the value of 75 PSIG shown in the PSTG.

ae. PSTG DEV, Step 22d: This substep did not appear in the PSTG.

af. PSTG DEV, Step 27b: This substep did not appear in the PSTG.

ag. PSTG DEV, Step 17, RNOs a and b: These steps did not appear in the PSTG.

ah. PSTG DEV, Step 27c1: The word "locally" was not shown in the PSTG.

ai. PSTG DEV, Step 27c: The PSTG also included substeps c3 and c4.

aj. PSTG DEV, Step 28a and 28a, RNO: These steps were not included in the PSTG.

ak. PSTG DEV, Step 30, RNO: The words "observe caution prior to step 5 and" were not included in the PSTG.

9. EPP-9 Transfer to cold leg recirculation

a. PSTG DEV, Step 1: In the TD, there was a step 1 that required the operator to open foldout B. That step was missing from the procedure.

b. PSTG DEV, Step 2: This step, which required the operator to reset containment spray, was not in the TD.

c. PSTG DEV, Step 4 caution: This caution was not in the TD.

d. PSTG DEV, Step 4: This step was in a different sequence than the equivalent steps in the TD.

e. PSTG DEV, Steps 8b, c, and d: These steps were in a different sequence than the equivalent steps in the TD.

f. PSTG DEV, Step 9: This step used the word "check" where the TD used the word "verify". This same deviation was in steps 10, 11, 14, 16, 22, 23, and 24.

g. PSTG DEV, Step 10: This step checked service water system operation and was not in the TD.

h. PSTG DEV, Step 12: This step was not in the TD.

i. PSTG DEV, Step 13 and caution: This caution and step were in a different sequence than in the TD.

j. Step 18 caution: This caution needed to be located prior to the step to which it applied; step 20.

k. PSTG DEV, Step 24: Three steps in the TD were missing from this procedure prior to step 20: close SI hot leg header valve, open loop 3 and 2 hot leg injection valves, and open breakers for RHR cold leg injection valves.

l. Attachment A, page 14: The inspectors observed design deficiencies that would inhibit operator actions in responding to flooding in the RHR pump pit. These included: pit level alarms not supplied with vital power and not EQ, sump pumps not supplied with vital power, and expected high radiation levels in the area of the isolation valves for CCW to the RHR pump pit during the recirculation phase.

10. EPP-10 Transfer to hot leg recirculation

a. Step 3, note: This note incorrectly contained a conditional action step directing a transition to step 10.

b. PSTG DEV, Step 3d, RNO: This step was not included in the PSTG.

c. PSTG DEV, Step 4b: The phrase "as available" was not included in the PSTG.

d. PSTG DEV, Step 4c: This step was not included in the PSTG.

e. Step 5: Flow indicator FI-605 used to determine flow rate did not contain adequate resolution to precisely read desired flow rate.

f. Step 7a: Step 7a did not adequately identify other available isolation valves addressed in the step (SI-878B & SI-888C).

g. Step 9: Step 9 began on page 8 of 10 and ended on page 10 of 10. The high level step number "9" was shown only on page 8. Only the substep identifier was shown on pages 9 and 10. Therefore, there was no complete identifier for the substeps on page 9 and at the top of page 10.

h. PSTG DEV, Step 9b2: The expected response was not included in the PSTG.

i. PSTG DEV, Step 9b6: The words "aligned to" were not included in the PSTG.

11. EPP-11 Faulted steam generator isolation

a. Entry Condition: Entry was specified whenever a faulted steam generator is identified or suspected. The entry condition stated in ERG E-2 did not address "or suspected". The TD did not address this addition.

b. Step 4, caution: This caution was an instruction on how to accomplish an item of step 4.

c. Step 4: This step closed the steam generator blowdown isolation valves. No preferred method to accomplish this task was provided. During walkthroughs, operators indicated that placing the RM-19 in alarm or locally actuating the valves would be possible ways to close the valves.

12. EPP-12 Post SGTR cooldown using backfill

a. Step 1, note: This note incorrectly contained a conditional action step containing transitions.

b. PSTG DEV, Step 4: The action verb "check" differed from the verb "verify" used in the PSTG.

c. Step 5, caution: This caution incorrectly contained a conditional action step.

d. Step 6, caution: This caution was overly complex.

e. PSTG DEV, Step 10b: The valve number "SI-869" differed from that shown in the PSTG ("SI-889").

f. PSTG DEV, Step 11b and 11b, RNO: These substeps were not included in the PSTG.

g. PSTG DEV, Step 11c, substeps 1 and 2: The word "locally" was not included in the PSTG.

h. PSTG DEV, Step 11c: The PSTG also contained substeps 11c3 and 11c4.

i. PSTG DEV, Step 12: This step was not included in the PSTG.

j. PSTG DEV, Step 13a: The adverse containment value was not included in the PSTG.

k. PSTG DEV, Step 13b: The adverse containment value of 320 PSIG differed from that shown in the PSTG (345 PSIG).

13. EPP-13 Post-SGTR cooldown using blowdown

a. Step 8b: This step required "energize" control power for selected valves. The ECCS valve's control power defeat panel switches were labeled "normal" and "defeat".

b. Steps 16c & 17a: Step 16c directed cooldown per GP-007. The cooldown rate limits in paragraph 5.2.11.3 of GP-007 were more restrictive than the "less than 100 degrees per hour listed in step 17a.

14. EPP-14 Post-SGTR cooldown using steam dump

a. First caution before step 1: The NRC found that survival of the control room dose calculation capability under accident conditions was degraded because of its dependency upon establishment of a link between the control room console and the Raleigh main frame computer.

b. Step 8b: This step required "energize" control power for selected valves. The ECCS valve's control power defeat panel switches were labeled "normal" and "defeat".

c. Steps 16c & 17a: Step 16c directed cooldown per GP-007. The cooldown rate limits in paragraph 5.2.11.3 of GP-007 were more restrictive than the "less than 100 degrees per hour listed in step 17a.

15. EPP-15 Loss of emergency coolant recirculation

a. Step 1a RNO: Step 1a RNO did not give the operator guidance on what actions to take if a component had not functioned properly. If an MOV failed to open, it could have been manually operated.

b. Step 3: Step 3 required that the operator "Initiate RCS Cooldown to Cold Shutdown", but did not give the operator guidance on what S/G levels to maintain.

c. Step 10, NOTE: The note did not provide the operator with priority guidance on which RCP produced the most effective PZR spray.

d. Step 10b RNO: Step 10b. the RNO had a typo. The RNO was labeled a. and should have been labeled b..

e. Step 10c1: Step 10c1 did not have an RNO for operator guidance if the RCP could not be started.

f. Step 15b RNO: Step 15b2 stated "Start CHARGING PUMP(s)" and did not give the operator guidance on the number of charging pumps, or charging flow needed.

g. Step 17a: Step 17a instructed the operator to use PZR spray to depressurize to decrease subcooling. At this point only one RCP was running. The step did not give the operator any guidance on which spray valve was associated with which RCP, ie. B spray valve goes to C RCP.

h. Step 18a: This step required the operator to take actions based on RCS temperature. The step did not specify which RCS temperature to use. ie. Th, Tc, T/C.

i. Step 20b and 29b RNO: Venting an accumulator was an infrequent operator action. There was no guidance given to the operator addressing required valve alignment.

j. Step 22: This step required the operator to take actions based on RCS temperature. The step did not specify which RCS temperature to use. ie. Th, Tc, T/C.

k. PSTG DEV, Steps 8 & 9: EPP-15 action steps 8 & 9, and the corresponding steps in the ERG were in the reverse order of the way they appear in the TD.

l. PSTG DEV, Steps 11 thru 23: Steps 11 thru 23 of EPP-15 were not addressed in the TD. EPP-15 was written against Rev 1A of the ERG and the TD was written to Rev. 1 of the ERG.

16. EPP-16 Uncontrolled depressurization of all steam generators

a. PSTG DEV, Step 3: The GTG bases for this procedure indicated that the first of three major decisions was the control room decision regarding which generator to concentrate their isolation efforts on. The assumption was that concentrating on one generator might allow early transfer from EPP-16 to EPP-11. The procedure did not isolate one generator at a time nor was there any caution or note concerning the need for that decision.

b. Step 4 RNO a: Aux feed flow could not be throttled to individual generators from the control room; only total flow throttling capability and individual S/G feed valve open/closed conditions were possible. To maintain 25 gpm per S/G, an AO would have had to be dedicated to throttling local valves at a time when AO talent was in short supply due to the isolations in progress and rapidly decreasing CST inventory. Selection of the conflicting alternatives of dedicating an AO to local throttling or doing the best that can be done from the control room to insure minimum constant flow to all three S/Gs was not covered in the procedure.

c. Step 31 RNO a5: The PZR heater transfer to the emergency bus which was accomplished in step 31 RNO a4 was not restored to normal after the substep 5 restoration of offsite power.

d. Step 29, caution 1: The GTG step description table for ECA-2.1 was incorrectly titled ES-1.1 on pages 66 and 67 of the LP plant set.

e. Foldout B-F: Item E of foldout D directed the user to go to EPP-24 if an RHR pit level reached the limit level. Since it was important to continue EPP-16 actions concurrently, the "go to" appeared to be in error; an instruction to refer to EPP-24 and continue concurrently in EPP-16 would have been more appropriate to the mitigation strategy.

f. Step 24 RNO: VCT level was one inch per gradation. The scaling was inconsistent with a parameter value of 12.4.

17. EPP-17 SGTR with loss of reactor coolant: subcooled recovery

a. Step 5 RNO and step 27a RNO: This RNO required an attempt to restore offsite power. No reference was provided for the appropriate procedure to be used. During the walkthrough, the operator indicated that he would use a procedure to perform this task.

b. Step 5 RNO d and step 27a RNO 4: These RNO steps required verification of adequate DG capacity to load instrument air compressors and battery chargers. These steps did not provide the load that these components would require. No procedure was referenced for loading the battery chargers.

c. Step 5 RNO: Step 4 RNO of ERG ECA-3.1 required verification of adequate DG capacity to load charging pumps and shed non-essential loads if necessary. The TD did not justify why this action was moved to step 9.

d. Step 6b RNO: This step directed that the CV spray pumps be stopped when CV pressure is less than 4 psig. Footnote 2 of ERG ECA-3.1 required use of the CV signal reset value. The setpoint document indicated that a value of 4 psig is used instead of 20 psig, the initiation setpoint (reset value). The justification indicated that using the value corresponding to the adverse containment was more conservative. The more rapid depletion of the RWST supply was not addressed in the justification.

e. Step 16: This step required PZR heaters to maintain RCS pressure and subcooling. Step 15 of ERG ECA-3.1 required the heater switches to be turned off. The TD did not address this difference.

f. Step 18 and 21, notes: These notes required RCP(s) to be run in order of priority to provide PZR normal spray. The order was not specified.

g. Step 21a RNO: This RNO required that if natural circulation was not verified, then increase dumping steam from intact S/G(s). The RNO of step 20 of ERG ECA-3.1 did not limit dumping steam to only the intact S/G(s). The TD did not address this difference.

h. Step 22b: This step required turning on PZR heaters as necessary. There was no guidance defining "as necessary". During the walkthrough, an operator thought that this was to establish saturation temperature in the PZR. However, he was unsure that this was the intent of the step.

i. Step 23d: This step required shutdown margin to be adequate. There was no guidance defining "adequate".

j. Step 33 RNO: This RNO required refilling the S/G(s). No precaution was provided to slowly refill the S/G(s) so that the adverse conditions in the RNO might be avoided.

18. EPP-18 SGTR with loss of reactor coolant: saturated recovery

a. This procedure contained many step deviations from the TD, similar to those listed for other EPPs.

19. EPP-19 SGTR without pressurizer pressure control

a. Step 4a RNO: This RNO restored power to the PZR PORV valves. There was no guidance on how to accomplish this task. During the walkthrough, it took the operator between 3 and 4 minutes to determine which panels and circuits feed the valves.

b. Step 5 RNO: This RNO started a charging pump if one was not running. No check was performed to see if the RCP seal supply valves should be closed to prevent thermal damage to the RCP seals. Such a check was contained in the step 10b RNO.

c. Step 6, caution: This caution was the same as the AFW switchover criteria of Foldout G.

d. Step 10a RNO: This RNO provided no guidance on how to attempt to restore offsite power to the emergency busses. During the walkthrough, the operator indicated that he would not attempt this without a procedure.

e. Step 16a RNO 4: This RNO required verification of adequate DG capacity to load instrument air compressors and battery chargers. The anticipated air compressor and battery charger loads were not provided in the procedure. During the walkthrough, an operator required between 3 and 4 minutes to locate the information. Interview of another operator revealed that he did not know where this information could be obtained. Both operators indicated that they would not load a battery charger without a procedure. No procedure reference for performing this task was provided.

f. Step 22, note: This note conditionally transferred to PATH-2, Entry Point M. The ERG note of ECA-3.3 transferred to step 29 of E-3. Entry Point M transferred to step 30 of E-3. Entry Point M transferred below the caution associated with step 30. Step 29 of E-3 was sequenced to be completed before step 30. The transfer point difference was not justified in the TD.

g. Step 26, caution: This caution required pressures in the RCS and the ruptured S/G be maintained less than the ruptured steam line PORV setpoint. The procedure did not require the setpoint to be adjusted to maximum. The caution did not provide a value for what the maximum allowed pressure should be.

h. Step 29 RNO: This RNO did not require the ruptured S/G to be refilled at a specified slow rate. The discussion on p. 82 of ERG ECA-3.3 described that the refill should be slow to prevent the adverse consequences listed in the RNO.

i. Step 30, caution 1: This caution stated that steam should not be released from any ruptured S/G if water existed in its steam line. The method for determining if water existed in the steam line was not specified. Control room instrumentation can be offscale without water being in the steam lines.

j. Step 30a: This step provided three methods for depressurizing the RCS and ruptured S/G(s). The third method, dump steam from ruptured S/G(s), could be accomplished by two means, dumping steam to the condenser or to the atmosphere. Discussion contained on p. 87 of ERG ECA-3.3 indicated that dumping steam to the atmosphere was the least desirable alternative. This was not specified in the step.

k. Step 32d: This step checked that shutdown margin was adequate. There was no guidance defining "adequate".

20. EPP-20 LOCA outside containment

a. PSTG DEV, Step 1: The verb "check" differed from the verb "verify" used in the PSTG.

21. EPP-21 Energizing pressurizer heaters from emergency busses

a. Step 1 RNO: The verb used in this step could not be used for breakers as defined in the action verb list.

b. Step 1: The abbreviations SERV, TRANS, HTR, KW, AUX, BLDG, MG, TURB, and GEN were not on the "Abbreviations used in the EOP network" list.

c. Step 1: The use of the verb "check" together with "removed" (see page 5, bottom) is inconsistent and conflicting.

d. Step 2: The abbreviation EDG was not on the "Abbreviations used in the EOP network" list.

e. Step 3: The abbreviations BKR, ARM, PRESS, HTR, PNL, EDG, KW, PRZR, and RTGB were not on the "Abbreviations used in the EOP network" list.

f. Step 3: This instruction contained no verb.

g. Step 3c: The verbs used in this step were not defined in the action verb list.

h. Step 3d: The verb used in this step could not be used for breakers as defined in the action verb list.

i. Step 3f RNO: The verbs used in this step were not defined in the action verb list.

j. Step 4: The verb used in this step was not defined in the action verb list.

k. Step 4c: The verbs used in this step were not defined in the action verb list.

l. Steps 4c&d: The abbreviations BKR, ARM, PRESS, HTR, and PNL were not on the "Abbreviations used in the EOP network" list.

m. Step 4f RNO: The verbs used in this step were not defined in the action verb list.

n. Step 4g: This step required "Run controller down to obtain maximum output". This phraseology was confusing and needs to be reviewed.

o. Note 5: The "multiple statements within this note" were not "separately identified by noting them with asterisks" as is required by the writer's guide.

p. Step 5: The wording of this step was not definitive in specifying the "as required" action.

q. Step 6: The verb used in this step was not defined in the action verb list.

r. Step 1: One instruction stated "52/14C, Fuses Removed". There was confusion on the part of the operator regarding what fuses to remove.

s. Step 1: Breakers 52/22B, Power supply to B SI Pp and breaker 52/29b Power supply to B SI Pp were part of the B SI Pp Modification and were no longer required to be on the list.

t. Step 3: This step did not provide the operator with any reference to Group A power supply.

u. Step 3a: This step did not provide the operator with the physical location of the disconnects for SST-2A and 2F. During the walkthrough of the procedure, the operator was unable to locate the disconnects without assistance.

v. Step 3b: While performing the walkthrough of the procedure, step 3b. could not be performed because the 480V bus E-1 Main breaker tool could not be located.

w. Step 3f 1, 2 & 3: This step instructed the operator to "monitor emergency bus response to prevent DG overload." There was no indication of emergency bus current or voltage, but there was an indication of EDG current and voltage.

x. Step 4: This step did not provide the operator with any reference to control heater power supply.

y. Step 4f, 1, 2 & 3: These steps instructed the operator to "monitor emergency bus response to prevent EDG overload. There was no indication of emergency bus current or voltage, but there was an indication of EDG current and voltage.

z. Step 4g: This step was inconsistent between controller indication (process) and the procedure instruction. This was a reverse acting controller.

22. EPP-22 Energizing plant equipment using the dedicated shutdown diesel generator

a. This procedure contained step deviations from the PSTG, similar to those listed for other EOPs.

23. EPP-23 Restoration of cooling water flow to reactor coolant pumps

a. Step 4 RNO: This RNO required emergency cooling water to be established to the charging pump oil cooler. The materials to perform this task were not pre-staged.

b. Step 9a: This step checked that the charging flow control valve HCV-121 was open. The only indication in the control room was a demand signal on the flow controller. Actual valve position determination would have required local verification. Because the step required HCV-121 to be checked open instead of verified open, the operator would have had to perform the RNO to open the HCV-121 bypass valve instead of attempting to open HCV-121.

c. Step 9b RNO: This RNO opened the loop 1 hot leg charging valve without trying to open the loop 2 cold leg charging valve because step 9b stated "check" instead of "verify".

24. EPP-24 Isolation of leakage in the RHR pump pit

a. Step 1: This step required the use of a formula or graph to find the RHR pit level because of the use of the verb "determine". This was not the proper verb for this application.

b. Step 1: Substeps a and b were methods of accomplishing the action of step 1, unlike substep 1c which was an entirely unrelated action.

c. Step 1c: The verb used in this step was not defined in the action verb list.

d. Step 2c: This substep could not be started prior to completion of substeps 1a and 1b. However, this important ordering of actions was not "specifically stated in the step containing the task nor in an associated note" as required by the writer's guide.

e. Step 2c: The verb used in this step was not defined in the action verb list.

f. Step 2d: The verb used in this step was not defined in the action verb list.

g. Step 2d: The abbreviations CV, RECIRC, HX, and DISCH were not on the "Abbreviations used in the EOP network" list.

h. Step 3 RNO: The three verbs used in this step were not defined in the action verb list.

i. Step 3 RNO: The abbreviations CV, RECIRC, HX, and DISCH were not on the "Abbreviations used in the EOP network" list.

j. Step 5c: The verb used in this step was not defined in the action verb list.

k. Step 5d: The verb used in this step was not defined in the action verb list.

l. Step 5d: The abbreviations CV, RECIRC, HX, and DISCH were not on the "Abbreviations used in the EOP network" list.

m. Step 5d: Some of these five valves were already in the desired position and therefore the verb "perform" was inappropriate.

n. Step 6 RNO: The abbreviations CV, RECIRC, HX, and DISCH were not on the "Abbreviations used in the EOP network" list.

o. Step 7: The verb used in this step was not defined in the action verb list.

25. EPP-Supplements

a. No comment.

26. EPP-Foldouts

a. Foldout A:

1. Step b: This step contained the SI actuation criteria. During the walkthroughs, an operator, when asked how he would manually determine that RCS subcooling was less than 25 degrees F, indicated that he would use the cold leg temperature Tc. In this application, Tc would not provide the most limiting value.

2. Step b: Generic footnote, attachment 9.0 of the setpoint study addressed the error associated with the core exit thermocouple/core cooling monitor system as the basis for the selection of the 25 degree F setpoint value for the SI actuation criteria. The attachment did not address whether or not 25 degrees F bounded the errors if the value had to be determined manually from other process instrumentation.

IV. FRP comments:

1. FRP-C.1 Response to inadequate core cooling

a. Step 1 RNO: This step required the operator to "Align valves" in response to an SI. There was no list of valves provided.

b. Step 2c RNO: This step required the operator to "Align valves" in response to an SI. There was no list of valves provide.

c. Step 2d: This step required the operator to take action based on an RCS pressure of 170 psig. This pressure was based on the maximum pressure at which RHR would inject into the RCS. This figure was based on suction pressure, pump Delta P and instrument error. If the operator could not verify flow from the RHR system, he was to assume that there was a problem with the RHR system, and perform a valve line up as a method of investigating the loss of RHR flow. The suction pressure from the RWST was 13#, and the delta P across the pump ranged from 126 to 138 psig which would have produced the maximum pressure of 151# and the flow would have been zero. From this it appeared that instrument inaccuracies may have been applied in the wrong direction.

d. Step 6a: This step instructed the operator to obtain a hydrogen concentration measurement but provided no detailed guidance.

e. Step 6b: The operators did not know whether the containment hydrogen concentration monitors in the control room were calibrated for varying containment humidity following a degraded containment condition.

f. Step 7a: The main step stated "levels" and part a of the step stated "level". The number of S/G levels needed to satisfy step 7a was not specified.

g. Step 7b: This step was inconsistent with the rest of the EOPs in referring to feed flow. Other EOPs referred to "total feed flow" as meaning main and AFW flow, or AFW flow to mean strictly AFW flow.

h. Step 9c: The purpose of step 9 was to depressurize the S/G to 160 psig in order to depressurize the RCS to 160 psig and empty the accumulators to a point just before the nitrogen was introduced into the RCS. Step 9c required that "at least two hot leg temperatures less than 370 degrees F" be met before depressurizing. If the core was in a degraded condition with TCs greater than 1100 degrees F, the RTDs may have been in an area that was voided. The 370 degree F criteria may have been inappropriate in this case.

i. Step 10: The conditions for isolating an accumulator in step 10 "two hot leg temperatures less than 370 degrees F" were different than the equivalent step 18 "RHR pump flow indication" in this procedure. The comment on step 9c of this procedure applied here also.

j. Step 10b RNO: Venting an accumulator was an infrequent operator action. However, there was no guidance given to the operator addressing required valve alignment.

k. Step 14b, 19a, and 21a: The 350 degree provision was a generic Westinghouse number corresponding to a 1200 degrees F core exit T/C temperature for inadequate core cooling. The 1200 degrees F was changed for HBR to 1100 degrees F. The use of 350 degrees F was not justified.

l. Step 16 RNO: This statement, "Start RCPs as necessary until Core Exit T/Cs less than 1100 degrees F" was not clear. There was no operator guidance on the number of RCPs to be started or the time or other conditions between RCP starts.

m. Step 17: In the statement, "Try to locally depressurize all intact S/Gs to atmospheric pressure", the word: "locally" needed clarification.

n. Step 20: Step 20 instructed the operator to check for "SI flow". There was no guidance on what constituted an adequate amount of SI flow.

2. FRP-C.2 Response to degraded core cooling

a. Step 1, caution: This caution incorrectly contained a conditional action step directing a transition.

b. PSTG DEV, Steps 1 and 2: The verb "check" differed from the verb "verify" used in the PSTG.

c. Step 2b: Step 2b required a pressure reading of 1520 PSIG. The pressure indicators PI-402 and PI-501 did not exhibit adequate resolution to precisely read desired pressure.

d. Step 3, caution: This caution incorrectly contained a conditional action step.

e. Step 4, note: This note incorrectly contained a conditional action step.

f. PSTG DEV, Step 8, caution: This caution was not addressed in the deviation document.

g. PSTG DEV, Step 10a: The expected response value of 370 degrees F differed from the value of 400 degrees F that was included in the PSTG.

h. PSTG DEV, Step 13: The verb "check" differed from the verb "verify" used in the PSTG.

3. FRP-C.3 Response to saturated core cooling

a. Step 2a: This step checked SI and RHR pumps running. The associated RNO started pumps. No caution was provided to prevent both RHR pumps from running greater than 9 minutes with RCS pressure greater than 170 psig. The vendor had indicated that operation of both RHR pumps for greater than 9.3 minutes under these conditions could result in pump damage. This was included in applicable foldouts as an RHR Pump Trip Criteria. No Foldouts are applicable during execution of this procedure.

b. Step 2c RNO: This RNO aligned SI pump valves. During walkthroughs, the operators failed to identify that the hot leg injection path is available if the cold leg path is not available.

c. Step 3, caution: This caution contained an action step related to the performance of Step 3a.

d. Step 3a: This step says to check PZR PORVs closed. The ERG Background document FR-6.3 indicates that PZR PORVs are closed to preclude the possibility of an undetected stuck open valve. Turning the control switch to close may be required to fully close a PORV. Thus checking position indication may not be sufficient.

e. Step 3c: This step required other RCS vent paths to be closed. The phrase "other RCS vent paths" was not defined.

4. FRP-H.1 Response to loss of secondary heat sink

a. Step 1, caution: The shift to RCS feed and bleed with any S/G wide range level greater than or equal to 60 percent appeared to be premature since level in the other two units could have been on scale, greater than or equal to 25 percent NR and immediately recoverable (e.g. aux feed pump switching or feed flow increase). The licensee was aware of this and was conducting a plant specific analysis to determine the feasibility of relaxing the 60 percent in any S/G criteria.

b. Step 4, caution: I&C was required to install the jumpers in case of a false high level signal. No jumper installation procedure existed to support this step. Therefore, valuable time would have been lost chasing the wiring diagrams and making up a temporary procedure.

c. The procedure did not reflect the plant modification which shifted primary containment air to an external nitrogen supply, backed up by internal N2 supplies and external instrument air. (e.g. step 11 concentration on instrument air restoration while N2 restoration was not considered).

d. Step 11: Since step 11 was no longer critical due to the N2 modification, it appeared that the procedure should be reordered to put instrument air restoration after feed and bleed initiation.

e. Step 21: This procedure placed the operator in a loop between step 21 and 23. The ERG, at this point is looping until inventory addition can be terminated and normal charging and letdown established. FRP-H.1 as written did not accomplish this and the deviation document did not justify the difference.

5. FRP-H.2 Response to steam generator overpressure

a. PSTG DEV, Step 1: The verb "check" differed from the verb "verify" used in the PSTG. In addition, the item "FW isolation vlvs" was included in the PSTG.

b. Step 4, caution: This caution incorrectly contained a conditional action step.

c. PSTG DEV, Step 7: The RCS setpoint of 540 degrees F differed from the value of 535 degrees F shown in the PSTG.

6. FRP-H.3 Response to steam generator high level

a. This procedure contained step deviations from the PSTG, similar to those listed for other EOPs.

7. FRP-H.4 Response to loss of normal steam release capability

a. No comment.

8. FRP-I.1 Response to high pressurizer level

a. Step 2b: The procedure did not reflect the plant modification which shifted primary containment air to an external nitrogen supply, backed up by internal N2 supplies and external instrument air. (e.g. instrument air restoration while N2 restoration was not considered).

9. FRP-I.2 Response to low pressurizer level

a. Step 3c RNO: This RNO did not specify a value for the amount of charging flow required to cool letdown. Footnote 1 of ERG FR-I.2 says to enter minimum indicated charging flow to provide letdown cooling in the regenerative heat exchanger.

b. Step 6: This step required turning on PZR heaters as necessary. There was no guidance defining "as necessary". The ERG Background document FR-I.2 indicated that it was desirable to have stable RCS pressure prior to returning to the guide and step in effect.

10. FRP-I.3 Response to voids in reactor vessel

a. No comment.

11. FRP-J.1 Response to high containment pressure

a. Step 2a: This step did not provide the operator clear guidance concerning proper containment ventilation isolation. The containment ventilation isolation panel in the control room contained four windows that belong to other actuation signals.

b. Step 2a RNO: The preferred method of "Alarming R-11 or R-12" was not provided.

c. Step 3c and e RNO: This step lacked sufficient detail regarding proper valve alignment.

d. Step 6b: The step lacked detail regarding which valves were to be isolated.

e. Step 7a: This step instructed the operator to obtain a hydrogen concentration measurement. Guidance was not provided to the operator on where to obtain the sample or what methods of indication were acceptable.

f. Step 7b: This step stated "LESS THAN 0.5 percent IN DRY AIR". The operators did not know if the containment hydrogen concentration monitors in control room were calibrated for varying containment humidity following degraded containment conditions.

12. FRP-J.2 Response to containment flooding

a. No comments.

13. FRP-J.3 Response to high containment radiation level

a. No comments.

14. FRP-P.1 Response to imminent pressurized thermal shock

a. Step 1e and 12e RNO: The three asterisked substeps gave actions necessary to isolate the S/G, but did not specify "the faulted S/G".

b. Step 1e and 12e RNO: There was no guidance given to the operator addressing which feed valves needed to be shut to isolate the S/G.

c. Guidance to the operator addressing what actions to take if the level was less than 12.4 inches was lacking.

d. Step 20: This step did not provide guidance as to what pressure to maintain or the desired condition of the primary system.

e. Step 21: This step was restrictive and did not provide the operator with a tolerance band.

f. Step 22a1: There was no operator guidance on when the clock started for the one hour timed soak.

g. Step 23c1: There were no defined pressure limits to be maintained on ATTACHMENT A.

h. Step 23c2: This step contained a typo. The 50 degrees F should be 50 degrees F per/hr.

15. FRP-P.2 Response to anticipated pressurized thermal shock

a. Entry Condition: This statement indicated that the entry condition was YELLOW. Revision 1A of ERG FR-P.2 indicated that the entry condition is ORANGE. ERG F-1.4, revision 1, indicated that the critical safety function status tree for entering FRP-P.2 is YELLOW. The TD did not provide justification for selecting YELLOW as the entry condition. The licensee confirmed with the NSSS vendor that "ORANGE" in the ERG was in error.

b. Step 1: The ERG step 1 was preceded by a note defining a faulted S/G. No note was included in FRP-P.2 step 1. The TD did not justify the omission of the note.

c. Step 3: The referenced curve, reactor coolant system pressure-temperature limitations for cooldown, listed RT(NDT) after 15 EFPY for 1/4 T as 282 degrees F and 3/4 T as 139 degrees F. TS Figure 3.1-2.b listed these values as 290 degrees F and 149 degrees F, respectively.

d. Step 4b: This step provided RCS cooldown restrictions by referencing those of curve 3.4, reactor coolant system pressure-temperature limitations for cooldown and GP-007, Plant cooldown from hot shutdown to cold shutdown. The TD did not provide technical justification that these restrictions are appropriate.

16. FRP-S.1 Response to nuclear power generation/ATWS

a. Step 1: This procedure did not specify "Steps 1 through 4 are IMMEDIATE ACTION" as provided in ERG FR-S.1, Step 1, note.

b. Step 1 RNO: This step required an operator to be dispatched to locally trip the reactor trip breakers or rod drive motor generator sets. Page 70 of the ERG background document FR-S.1 indicated that boration had to be initiated before time consuming local actions to trip the reactor were taken. Local operator actions to trip the reactor were addressed in ERG FR-S.1, Step 5 RNO. No justification for inclusion of local actions in Step 1 RNO was documented in the TD.

c. Step 3a: This step required checking whether the AFW or FW pumps were running, and if not running, then to start the pumps. Step 3 of ERG FR-S.1 did not require FW pumps to be checked or started. No justification for inclusion of the FW pump in the procedure was documented in the TD.

d. Step 3b: This step required the SD AFW pump to be running if necessary. There was no guidance defining "if necessary".

e. Step 4b RNO: This RNO defined alternative pathways for boration if the emergency boration path was unavailable. This step did not address use of the other boric acid transfer pump if the one aligned to the system failed to start.

f. Step 4d: This step required the loop 2 cold leg charging valve to be checked open. If closed, the RNO action was to open the loop 1 hot leg charging valve. Thus, no attempt was made to open the loop 2 cold leg charging valve.

g. Step 4f RNO: This RNO required radiation monitor R-11 or R-12 to be alarmed if containment ventilation isolation valves were not closed. During walkthroughs, operators indicated that they would either pull the fuse or source check one of the monitors to generate an isolation signal. This RNO did not adequately specify the intended operator action.

h. Step 4e RNO: This RNO did not include alignment of the normal charging flow path if no charging flow to the RCS existed.

i. Step 5b RNO: This RNO required the operator to close the MSIVs and MSIV bypass valves if the turbine did not trip. This step did not address other actions such as tripping the turbine at the front standard or securing the EH oil pumps.

j. Step 11 caution 2: This caution was a conditional action statement.

k. Step 12 RNO: This step did not reference the procedure number for restarting the battery chargers. During procedure walkthroughs, operators indicated that they would not perform this task without a procedure in hand.

1. Step 14, Note: This note was identified as a caution in ERG FR-S.1. The ERG caution read: "Boration should continue to obtain adequate shutdown margin during subsequent actions". This note read: "Boration should continue to obtain adequate shutdown margin." No justification for the differences was addressed in the TD.

17. FRP-S.2 Response to loss of core shutdown

a. Step 1 RNO a: Determination that an intermediate range NI channel was undercompensated required assessment by I&C personnel. I&C staff were not available around the clock. This step did not clearly explain the operator actions when one channel hangs up above 10E-10 while the only other channel was decreasing with negative SUR. Two walkthrough operators concluded that it was appropriate to wait for I&C and not to borate since undercompensation was unknown.

b. Step 1 RNO, last paragraph pg. 3: There was uncertainty as to the boration lineup during walkthroughs. The operators were uncertain whether normal or emergency boration was intended.

V. CSFST comments:

1. Subcriticality

a. No comments.

2. Core cooling

a. No comments.

3. Heat sink

a. No comments.

4. Integrity

a. No comments.

5. Containment

a. No comments.

6. Inventory

a. CSFSTs 2 and 6 had been modified due to the absence of RVLIS. RVLIS had been installed for at least 17 months but was not yet operational.

VI. AOP comments:

1. AOP-001 Malfunction of reactor control system

   a. Step 1.1.2.6: The red pen on TR-408 was incorrectly labeled "High Tav (Red)". The instrument displayed median Tav as was required by this step.

   b. Paragraph 4.3.2, step 11: Three operators were unable to perform this step; two were uncertain whether it was an AO or licensed operator step. The external cabinet doors were not marked to reflect which one of the three contained the converter. When the converter was located, it had no instrument label nor was it identified in any fashion as the P/A converter.

2. AOP-002 Emergency boration

   a. Step 3.1.1.2: CVC-358 was a local valve; the others were operated from the control room.

   b. Step 3.2.10: The procedure did not refer to OP-301.

3. AOP-003 Malfunction of reactor make-up control

   a. Step 3.1.1: This step provided actions to secure potential sources of water into the volume control tank. This step secured the boric acid transfer pump but did not secure the primary water pump.

4. AOP-004 Control room inaccessibility

   a. Step 3.2, caution: This caution incorrectly contained a conditional action step directing a transition.

   b. Step 3.2.16.2: This step did not provide the criteria necessary to determine which containment fan coolers were to be started.

   c. The NRC observed several valves which did not follow the normal convention of open counterclockwise, close clockwise. This was not indicated at the local operating station (e.g. FCV-498C, FCV-488B and FCV-478A).

5. AOP-005 Radiation monitoring system

   a. Step 1.3.1.2, substeps 3-5: The sequence incorrectly implied that the paging system interrupted the evacuation alarm.

b. Step 1.3.2.1.4: This step referred to AOP-004 in the event of a control room evacuation. A "go to" transfer appeared to be more appropriate.

c. Step 1.3.2.6: No confirmation of sample station suction ventilation was included in the step.

d. Meters RI-014 and RI-018 on the unlabeled waste disposal boron recycle panel both contained two scales and only one pointer. There was no scale switching. The scale ranges were 10E0-10E4 and 10E0-10E6. The operator was uncertain which scale was in use and therefore was unable to read the instruments.

e. The "green" indicating lenses on the waste disposal boron recycle panel ranged from green to washed out blue to almost colorless.

f. Step 2.3.2.4.2: This step referred to service water flow but only stated "check fan cooler flows and outlet temperatures".

6. AOP-006 Turbine vibration

a. General: The conclusion of the team was that the procedure as written would not be an effective aid to the operator if needed in handling an abnormal turbine vibration. Two new recorders have been installed in the control room, and the procedure has not been updated to reflect the new terminology.

7. AOP-007 Turbine trip without reactor trip below P-7

a. Step 3.2.8 This step instructed the operator to shut the MSIVs and the MSIV bypasses if the turbine start-up was going to be delayed more than one hour. The purpose for shutting the valves was not clear.

8. AOP-008 Accidental release of liquid waste

a. No comment.

9. AOP-009 Accidental release of waste gas

a. Step 3.2.3: This step directed that fuel handling building ventilation be shifted but did not specify the desired lineup.

b. Step 3.2.5: "... REDUCE release rate ...". This step neglected the option of increasing dilution flow.

c. Step 3.2.7, caution: This step should be performed under the direction of RC personnel; E&C/RC personnel are not all HP qualified.

10. AOP-010 Inadequate feedwater flow

a. Symptoms: The following symptoms were duplications

1.1.5 High hotwell level (HOTWELL LEVEL Hi/Lo ALARM)
1.2.4 High hotwell level
1.1.6 Low feed pump suction pressure. (LOW CONDENSATE HEADER PRESSURE)
1.2.2 Low feed pump suction pressure
1.2.3 Low condensate pump discharge pressure

b. Symptoms, 1.3.4: This symptom was not appropriate as a control room symptom. There was no indication for LCV-1530B in the control room.

c. Symptoms, 1.3.5: Tavg and Tc would increase on an inadequate feedwater flow whereas the procedure did not address the possibility of a feedwater control valve or bypass valve failure.

d. Step 3.0: The procedure did not address the possibility of a feedwater control valve or bypass valve failure.

e. Step 3.1.1: The priority for running the pumps was not given.

f. Step 3.1.2: This step did not address the method or priority of reducing turbine load.

g. Step 3.1.2: The maximum power for the different feed/condensate pump combinations was not given.

h. Step 3.1.2: There was no caution to the operator warning of a S/G level decrease due to shrink on load reduction.

i. Step 3.2.1: This step was superfluous and was extra material the operator had to read through in a time critical situation.

j. Step 3.2.3: This step did not specify that the only place hotwell level could be read was locally.

k. Step 3.2.4: This step did not specify that the only place drain tank level and feedwater heater level could be read was locally.

l. Step 3.2.5: This step did not address the control rods as a means of control. Also the parameter the operator was controlling was Tavg/Tref and not equilibrium conditions.

m. Step 3.2.6: This step was superfluous and was extra material the operator had to read through in a time critical situation.

n. Step 3.2.7: This step was superfluous and was extra material the operator had to read through in a time critical situation.

o. Step 3.2.8: Reclosing HCV-1459 was not dependent upon starting the heater drain pump.

p. Step 3.2.10: This step was superfluous and was extra material the operator had to read through in a time critical situation.

q. Step 3.2.11: The step was superfluous and was extra material the operator had to read through in a time critical situation.

11. AOP-011 Loss of circulating water

a. Step 3.2.3: This step failed to provide the criteria required to determine adequate circulating water flow.

b. Step 3.2.4: This step required local action without providing adequate reference to location or pressure gauges required to determine differential pressure. The step failed to provide the criteria required to determine high pressure.

c. Step 3.2.6: This step failed to provide the the necessary references required to take appropriate action.

12. AOP-012 Partial loss of condenser vacuum

a. Step 3.2.3: This step required local operator action without providing adequate reference to the plant location. This step did not provide the criteria required to determine high DP nor did it define high DP.

13. AOP-013 Fuel handling accident

a. No comments.

14. AOP-014 Loss of component cooling water

a. Step 3.1.2.1: The name of valve DW-711 was missing from this step.

b. Note 3.1.3: This note stated that a plant cooldown should be initiated, but did not tell the operators where to stop the cooldown with no RHR available. In this procedure, the RHR pumps have lost their CCW cooling water.

c. Step 3.1.3.1: The operator needs to continue with this procedure while concurrently using Path-1. Failure to continue with this procedure could result in immediate damage to the CCW pumps and the RCP shaft seals. This step did not clearly state the requirement to continue with this procedure.

d. Step 3.1.3.2: This step did not state the size and location of the required fuse puller.

e. Step 3.1.3.3.b. and c: The operator could not monitor these RCP temperature limits within two minutes since the recorder only printed approximately every five minutes. RCP temperature alarms were not included in this step as indicators to the operator for stopping RCPs.

f. Step 3.1.4: The labeling on the charging flow controller on the RTGB was inadequate. The demand signal indicator was labeled from 0 to 100 percent, with 100 percent indicating a demanded valve position of closed. Operators described it as a "backwards" indication. The operators who were interviewed stated that improved labeling, such as "OPEN" and "CLOSED", was needed.

g. Step 3.1.4: This step failed to direct the operator to run only one charging pump at a time. A previous procedure required two charging pumps to be operated. After charging and letdown flow were isolated in this step, only one charging pump was needed. Since the pumps were not being supplied with cooling water, running only one would avoid overheating two charging pumps.

h. Step 3.1.4: With charging and letdown flow isolated, the operators had lost the ability to control pressurizer level. Thus pressurizer level would have slowly increased due to RCP seal water flow. This was revealed as a potential problem during simulator exercises that the team observed. This procedure did not provide for prompt supply of alternate cooling water to the charging pumps (see step 3.2.9.2 below). It also did not provide a method to drain water from the RCS, to prevent excessive increase in pressurizer level.

i. Step 3.2.1: This temperature was required to be read locally, a fact that was not so indicated.

j. Step 3.2.3: The names of the valves in this step were not included. Also, required local action was not indicated as "local".

k. Step 3.2.9.2: The licensee had not provided dedicated fittings to enable the operators to supply temporary cooling water to the charging pumps, safety injection pumps, and residual heat removal pumps. These fittings were not readily available, and would have had to be manufactured. In this procedure, all of these pumps had lost their CCW cooling water, reducing the operators' ability to maintain the RCP seals intact and to inject water into the RCS. A number of design features of this component cooling water system made it more susceptible to failure than similar systems in newer plants.

For these reasons, good procedures for handling a loss of component cooling water were especially important, including readily available dedicated pipe fittings.

1. Step 4.3: This step was misleading, in that it stated "the only possible way of losing all three CCW pumps is by the complete loss of on and offsite power." The team observed a number of potential ways of losing all CCW, such as a fire or flooding in the CCW pump room, a pipe break in the CCW header, or a loss of service water to the CCW heat exchangers.

15. AOP-015 Secondary load rejection

    a. Symptoms 1.3: This symptom inappropriately read Unit "export" load. It should have read Unit "output" load.

    b. Symptom 1.10: This symptom is no longer applicable. The actuation circuit has been removed.

    c. Step 2.8: This step is no longer applicable. The actuation circuit has been removed.

    d. Step 2.9: The step is no longer applicable. The actuation circuit has been removed.

16. AOP-016 Excessive primary plant leakage

    a. No comments.

17. Loss of instrument air

    a. No comments.

18. AOP-018 Reactor coolant pump abnormal conditions

    a. Step 1.3.1.2.2: This step addressed actions associated with loss of all CCW which were also contained in AOP-014, Loss of component cooling water. It may have been better to exit to AOP-014 than stay in AOP-018 under those conditions.

19. AOP-019 Malfunction of RCS pressure control

    a. No comments.

20. AOP-020 Loss of RHR (shutdown cooling)

    a. No comment.

21. AOP-021 Seismic disturbances

    a. Step 3.2.2: The "Operating Supervisor" title has been changed to "Operation Coordinator".

22. AOP-022 Loss of service water

a. Step 1.3.2.1: This step required local action; that the action was local was not indicated. This same comment applies to many other steps in AOPs.

b. Step 3.3.2.1: The labeling for these valves was on the adjacent wall, and had been covered by wall mounts for seismic supports, such that the label for SW-18 was totally unreadable.

c. Step 3.3.2.2.3: This valve was not commonly operated, and was located in an out-of-the-way place, so that it was difficult for some operators to find. The operators needed its location to be stated in the step. This comment also applied to several other valves in this procedure that were located among the piping in the overhead of the auxiliary building, such as SW-52 and 53, SW-100, and SW-109. The operator needed enough information in the procedure to allow placement of a portable ladder in the right place the first time.

d. Step 4.3.2.10: Operators had no dedicated pipe fittings for use with hoses to supply alternate emergency cooling water to the safety injection pumps.

e. Step 6.1: Operators needed pit level alarms in order to effectively respond to flooding in the service water pump pits. All service water pumps plus motor operated discharge and cross-connect valves were located in these pits, and the pits were all connected at about three feet above the floor level of the pits. The plant was operated with the cross-connect valves normally open. As a result, flooding in one of these pits could disable all of these valves by causing them to be under water. A single pipe break could thus be unisolable by the time is was discovered, and could result in a loss of all service water. No pit level alarms were installed, and the pit sump pumps ware not supplied with vital power.

f. Step 6.3.3.3: Valve FP-10 was located underground. The steel plate above this valve at ground level was not painted red or labeled, making it very difficult for operators to find. Also, the name and location of this valve were not included in the step. In addition, the tool required to operate the valve was not painted red or labeled, and its location was not stated in the step. Similarly, the names and locations of FP-4 and FP-5 were not in the procedure.

23. AOP-23 Loss of containment integrity

a. Step 1.5: The stated symptoms were outside of the alarm setpoints. The control room alarm setpoints for containment pressure were +0.9 psig and -0.4 psig. This alarm was not included as a symptom.

b. Step 3.2: Many of these subsequent actions were copied from the TS, and the TS section was not referenced in the procedure. In order to assure compliance with the TS, the situation required the operator to look at the TS directly.

24. AOP-024 Loss of instrument bus

a. Step 3.1.2: This step required local actions without providing adequate reference to the plant location.

25. AOP-026 Low frequency operation

a. Step 3.1.1: This step did not require the operator to verify that the RCPs were tripped automatically by the underfrequency trip.

b. Step 3.1.2.1: A caution was missing prior to this step. When picking up additional generator load, the operator needs to ensure that generator reduced KVA limits are not exceeded.

c. Step 3.2.2: The procedure told the operator to adjust generator KVA, but not how to get a KVA number. In interviews, some operators did not know how to do this. To get the KVA number, calculation by the operator was required. Calculations by operators should not be required to accomplish steps in this procedure.

d. Step 3.2.3: This step directed the operator to verify proper voltage and frequency to the emergency busses. Verify meant that if it was not so, action was to be taken to make it so. The operator could not control voltage and frequency of the grid, and in this step was not instructed to place the emergency busses on the diesel generators.

26. AOP-027 Operation with degraded system voltage

a. Step 1.1: The 230 KV switchyard voltage had no indication or alarm in the control room, as this had been removed approximately one year before. Therefore, this symptom was not valid.

b. Step 1.2: The 115 KV switchyard voltage low alarm in the control room was set at 112.4 KV. However, during the simulator scenarios, operators found that the setpoint was required to be 110.4 KV for this alarm.

c. Step 3.2.3: This step required the operator to verify that the E1-E2 tie bus was powered from the running emergency diesel. Due to a plant modification that was done about one year ago, this step was no longer applicable.

d. Step 3.2.8: This step was not consistent with the intent of the TS. The step stated that if a plant start-up was in progress, then continue with the start-up. At this point in the procedure, the plant had both emergency diesel generators supplying power to the vital busses, with nonvital busses being supplied with degraded voltage from offsite power. Plant start-up with such a degraded electrical system was not within the intent of the TS.

e. Step 4.1: This step stated that the procedure was required if the plant was shut down or at less that 5 percent power. During simulator exercises, operators used this procedure when the plant was at 100 percent power. Initial conditions specifying when this procedure should be used needed to be better defined.

27. AOP-028 ISFSI abnormal events

a. Step 1.3.1.1.2: This step required the use of a ladder to clear blockage from the outlets, however, there was no dedicated ladder at the ISFSI.

b. Step 4.3.2.3: The procedure required to perform this step was not referenced (ERC-003).

VII. Other document comments:

1. OMM-022 Emergency operating procedures user's guide

a. Paragraph 5.1.3: This paragraph was in error; PATH-1 grid I-10 considered supplement D, not C.

b. Final paragraph of 5.3.4: The discussion concerning heat sink red path transfer to FRP-H.1 and hence to EPP-16 was in error.

c. Final paragraph of 5.3.4: There was no EPP-16 caution concerning conditions under which FRP-H.1 should be implemented.

2. Transition document, vol.1:

a. Table of contents: In some instances, the page numbers listed were incorrect.

b. Page 83, pneumatic power: This section did not reflect the plant N2 CV modification.

APPENDIX C

WRITER'S GUIDE COMMENTS

This appendix contains writer's guide 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 (proposed or completed) in the response to IR-89-16. These items will be reviewed during a future NRC inspection.

I. Deviations from the Writer's Guide

A sample of the EOPs was evaluated for deviations from the Robinson writer's guide. Types of deviations noted were characterized in this section and accompanied by a list of examples of the specific deviations. Note that some steps contained more than one example.

1. The following steps violated writer's guide directions for the structure of logic steps or the use of logic terms:

EPP-8	Step 1, caution
	Step 2d3 RNO
	Step 3, caution
	Step 4a RNO
	Step 5, caution
	Step 6, note
	Step 6b
	Step 11, caution
	Step 12c RNO
	Step 14, caution
EPP-10	Step 5a
	Step 5b
	Step 6c
	Step 6d
	Step 7
	Step 8
	Step 9
	Step 9a3
	Step 9a5
EPP-12	Step 1, note
	Step 5, caution
	Step 5a RNO
FRP-C.2	Step 1, caution
	Step 3b RNO
	Step 4, note
	Step 7, caution

FRP-H.2	Step 4, caution
PATH-1	A-5
	B-3
	B-11
	B-12
	E-8
	E-9
	E-10
	E-11
	F-2
	H-7
	H-9
	H-10
PATH-2	A-10
	B-2
	B-9
	B-12
	B-13 (2 examples)
	B-14
	D-4 (2 examples)
	D-12
	G-9
	G-12
	H-3
	H-4
	I-11 (2 examples)

2. The following steps violated writer's guide directions for the form of transitions:

EPP-8	Step 2d3 RNO
	Step 11d1
	Step 14a1 RNO
	Step 21 RNO
	Step 28b1
EPP-12	Step 13c
FRP-C.2	Step 1, caution
	Step 3, caution
PATH-1	H-6
PATH-2	A-10
	H-5
	I-12
FRP-C.2	Step 2c
	Step 2e
	Step 13

3. The following steps contained conditional actions within cautions or notes, in violation of writer's guide direction.

EPP-8	Step 3, caution
	Step 11, caution
EPP-12	Step 1, caution

	Step 5, caution
FRP-C.2	Step 1, caution
	Step 3, caution
	Step 4, caution
FRP-C.3	Step 3, caution
FRP-H.2	Step 4, caution
FRP-S.1	Step 11, caution

4. The following steps violated writer's guide directions for referencing other procedures.

EPP-2	Step 23a
EPP-7	Step 20e RNO
EPP-17	Step 5 RNO
	Step 27a RNO

II. Inadequacies in the Writer's Guide

The writer's guide did not thoroughly address each aspect of the procedures nor did it define restrictively the methods designated for use in order to assure consistency within and between procedures and to retain that consistency over time and through personnel changes.

The Robinson writer's guide contained a number of areas where lack of restrictive or thorough guidance had led to problems and inconsistencies in the EOPs. These weaknesses were as follows:

1. Inclusion of contingent transitions was incorrectly allowed in cautions by the writer's guide. Because contingency steps and transition steps required operator action, this contradicted other writer's guide directions which specified that no actions would be included in cautions. Action steps by definition belong in the numbered sequence of procedure steps.

2. The writer's guide failed to provide directions for structure of written steps, cautions, and notes in the path procedures.

3. Page 44 of 76 included a statement that proper logic statements were to be used in foldout items. That page also contained an example that included improper use of the logic term "if."

4. The writer's guide failed to require special emphasis for the transition terms "go to." Because transitions were important actions that could be difficult to perform, special emphasis would aid operators in their use of the procedures.

5. The writer's guide did not address nor require some method of reminder to operators of steps that might be performed at some time in the future (e.g., "WHEN condition, THEN action" sequences).

6. Attachment 6.8 of the writer's guide, the abbreviation list, lacked a number of acronyms commonly found in the EOPs. For example:

F, SPDS, FW, SW, CV, EDG, PSID, GPM

7. The writer's guide stated that steps in the RNO column would be written in complete sentence format. It failed to define complete sentence format or to describe how it differed from the instruction steps in the left hand column of the procedures.

8. The writer's guide failed to define a method for placekeeping.

9. The writer's guide did not address the method for identifying procedure steps when it was necessary to continue with that step on the following page of a procedure.

10. The writer's guide allowed handwritten changes to the path procedures and CSFSTs. This method of revision contained the potential for unreadable changes and was inappropriate.

11. The writer's guide failed to define the type size, type style or margins to be used in the EOPs.

12. The writer's guide failed to address the use of initial capitalization in high level steps, although this method was applied in a number of EOPs.

13. The writer's guide allowed but did not require an alpha-numeric border on path procedures.

14. The writer's guide required line spacing in path procedures to be "adequate". No objective criteria for determining adequacy was included.

15. The writer's guide failed to define the use of parentheses or quotation marks in the EOPs, although these forms of punctuation were used in the EOPs.

16. The writer's guide stated that procedure designators used in references in the path procedures must "positively and unambiguously identify" the reference. Specific directions and examples of procedure designators were necessary but not provided to ensure consistency.

17. Section 5.2.4.7, page 12 of 76, failed to provide criteria for editing the EOPs to meet the "expected minimum average level of operator knowledge."

18. The writer's guide failed to describe a method for indicating possible plural status. For example, as in the step "check faulted S/Gs."

19. The writer's guide failed to address certain action verbs used throughout the EOPs. Examples included; running, load, faulted, normal, contact, disconnect, and connect.

20. The verbs "close" and "open" were defined inconsistently in the action verb list in that "close" addressed both fluid flow and electric current whereas "open" addressed only fluid flow, not breaker operation. This inconsistency led to undefined actions being specified in the EOPs. See for example EPP-21, Energizing pressurizer heaters from emergency busses, step 1 RNO.

21. The writer's guide did not include a method for easily identifying sections or subsections in the EOPs, such as tabbing, in order to facilitate rapid reliable movement within the EOP network.

22. The writer's guide sections 5.3.4.6 and 5.3.4.7 provided guidance for formatting tables and figures. However, it did not provide examples of these formats to help procedure writers to prepare consistently formatted tables and figures.

23. The writer's guide section 5.3.4.14 provided guidance for labeling of equipment or controls within the EOPs. Clear criteria defining "operator language" terms was not provided. In addition, several examples of control panel equipment nomenclature and their respective labels presented in the procedures were not provided.

III. AOPs

The AOPs were reviewed for application of human factors principles and consistency with the presentation of information in the EOPs. Presentation of information in ways that conflicted with the structure of the EOPs was of concern because it required operators to cope with inconsistencies, thereby increasing the burden on training and operator memory. Specific concerns were characterized below and accompanied by a list of examples. Note that some steps contained more than one example.

1. The following steps applied logic structure in a manner inconsistent with that defined for use in the EOPs:

AOP-004	Step 3.2.5, note
	Step 3.2.7.1
	Step 3.2.8
	Step 3.2.9.a
	Step 3.2.10
	Step 3.2.11, note
	Step 3.2.12, note
	Step 3.2.12
	Step 3.2.14
	Step 3.2.16
	Step 3.2.16.2
	Step 3.2.16.4
	Step 3.2.19

AOP-011	Step 4.1
	Step 4.2
AOP-012	Step 3.2.1
	Step 3.2.2
	Step 3.2.9
	Step 3.2.11
	Step 3.2.15
	Step 4.2
AOP-013	Step 1.3.1.1.1
	Step 1.3.1.2.2
	Step 1.3.2.10
	Step 3.3.1.2.1
	Step 3.3.1.3
	Step 3.3.1.6
	Step 3.3.2.2
	Step 3.3.2.2.3
	Step 3.3.2.2.6
	Step 3.3.2.3
AOP-024	Step 2.1
	Step 2.2
	Step 3.2.3
	Step 3.2.4
	Step 4.3
	Step 4.4
AOP-028	Step 1.3.1.1.2
	Step 1.3.1.1.3
	Step 1.3.2.3
	Step 1.3.2.4
	Step 1.3.2.5
	Step 1.4.1
	Step 1.4.2
	Step 1.4.3
	Step 2.4.1
	Step 3.3.2.3
	Step 3.3.2.4
	Step 3.3.2.6
	Step 3.4.1

2. The following steps structured transition steps in a manner inconsistent with that defined for use in the EOPs:

AOP-004	Step 3.2.19
AOP-005	Step 1.3.2.1.4
AOP-011	Step 3.2.8

AOP-012	Step 3.2.14
AOP-013	Step 1.3.2.1 Step 3.3.2.2.6
AOP-024	Step 3.1.2
AOP-028	Step 1.3.2.5 Step 2.4.1 Step 2.4.2 Step 3.3.2.4 Step 3.3.2.5 Step 3.3.2.6

3. The following steps were preceded by cautions or notes structured in a manner inconsistent with that defined for use in the EOPs:

AOP-004	Step 3.2
AOP-013	Step 1.3.2.7
AOP-028	Step 3.2.1

4. The following steps used past tense, passive voice, or were not written as directives, in contrast with the present tense, active voice, directives used in EOPs and the rest of the AOPs:

AOP-004	Step 4.0
AOP-011	Step 3.1.1 Step 4.1 Step 4.2 Step 4.3
AOP-013	Step 1.4 Step 2.2.1 Step 2.4.1 Step 3.4.1
AOP-024	Step 4.0 Step 4.4
AOP-028	Step 1.4 Step 2.4 Step 3.4

5. The following steps included two actions, in contrast to the convention used in EOPs and the rest of the AOPs:

AOP-011	Step 3.2.4 Step 3.2.6
AOP-013	Step 1.3.2.4

AOP-024 Step 3.2.2

6. The following procedures used a typestyle that was different from that used in EOPs and the majority of AOPs:

AOP-011

AOP-024

APPENDIX D

NOMENCLATURE

This appendix contains NRC observations of instances where Writer's Guide application to the EOP would cause the reader to expect an exact nomenclature match with component nomenclature, yet there was no identity. It also includes instances where a complete match was neither required nor found and the mismatch was sufficient to cause concern. The licensee agreed in each case to evaluate the difference and make the appropriate change. These items will be reviewed during a future NRC inspection.

Procedure	Step/pg.	EOP nomenclature	Component nomenclature
---	---	SD AFW	(ON MCC9 & 9) STM DRIVEN FWP ...
---	---	---	(ON RTGB PHASE A ISOL. STATUS PANEL) ACC NZ SUPPLY VA 855 ...
EPP-1	16/4	CST Level	Cond. Storage Tank Level
	Attach. A/28	Control and Indication	?480 V Switchgear?
EPP-8	2.c RNO/4	SEAL OIL BACKUP PUMP	TURNING GEAR AND SEAL OIL
	11.a/11	ALL STOPPED	OFF
	19.b/19	ACCUMULATOR DISCHs	DISCH SI-865A
			DISCH SI-865B
			DISCH SI-865C
	26.c/23	SI-865A	V-865A
		SI-865C	V-865C
EPP-10	2/3	STOPPED	status light OFF
	3.a/4	CLOSED	status light SHUT
	3.b/4	CLOSED	status light SHUT
	9.b.1/9	HCV-121	HIC-121

	9.b.4/9	CLOSED	status light SHUT
	9.b.7/9	HCV-142	HIC-142
	9.d/10	HCV-758	HIC-758
EPP-20	1/3	CLOSED	status light SHUT
EPP-21	1/5	52/11C Makeup water Treatment	MCC 20 Makeup water Treatment
EPP-21	1/6	52/22B, 480V Bus E-2 Tie Bus Breaker	52/22B 480 Bus E-1 supply SI Pump B
EPP-21	1/6	52/29B, 480V Bus E-2 Tie Bus Breaker	52/29B 480 Bus E-2 supply SI Pump B
EPP-21	3e/8	PRESS HTR PNL #1 Breaker 1, 2, & 3	No lables
EPP-21	4e/10	PRESS HTR PNL #3 Breaker 1, 2, & 3	No lables
EPP-SUPP	1.A/4	Injection Mode Valves closed	status lights SHUT
	1.B.6/5	IA-1716	PCV-1716
	1.B.15-B.18/5	RC-516	VA-516
		RC-519A	VA-519A
		RC-519B	VA-519B
		RC-553	VA-553
		C-739	VA-739
		S-855	VA-855
	1.B.19/5	CC-739	VA-739
	1.B.20/5	SI-855	VA-855
	1.B.25-B.32/5	WD-1721	WDS:VA-1721
		WD-1722	WDS:VA-1722
		WD-1723	WDS:VA-1723

		WD-1728	WDS:VA-1728
		WD-1786	WDS:VA-1786
		WD-1787	WDS:VA-1787
		WD-1789	WDS:VA-1789
		WD-1794	WDS:VA-1794
	1.E/8	off	STOP
	3.A.1/10	HCV-758	HIC-758
		HCV-142	HIC-142
FRP-C.2	4.a/6	RUNNING	START
	11/9	Stop	OFF
FRP-H.2	2/3	FW REG(s)	FCV-478 A FEED REG VALVE FCV-488 B FEED REG VALVE FCV-498 C FEED REG VALVE
	2/3	FW REG BYP(s)	FCV-479 A S/G FEED REG VALVE BYPASS FCV-489 B S/G FEED REG VALVE BYPASS FCV-499 C S/G FEED REG VALVE BYPASS
	2/3	FW HDR SECTION(s)	V2-6A V2-6B V2-6C
	4/4	MSIV BYP(s)	MSIV V-3A BYP MS-353A MSIV V-3B BYP MS-353B MSIV V-3C BYP MS-353C

FRP-J.2	2/4	CV	not in abbr list
	3/4	FW	not in abbr list
	5/4	SPDS	not in abbr list
AOP-001	1.1.2.6	... MEDIAN ...	TR-408 HIGH Tav ...
AOP-004	3.2.4.3/4	START a Boric Acid Transfer Pump	label not on equipment
	3.2.15.2/8	panel LP-28, circuit No. 4	circuit not labeled
	3.2.16.4/8	HVH-2	HUH-2
AOP-008	1.3.2.3.1	WASTE CONDENSATE RECIRCULATION PUMP SUCTION VALVE	C WCT TO WASTE COND RECIRC PUMP
AOP-010	1.1.2/3	LOW FEEDWATER FLOW	FWP A/B FLOW LOW
AOP-010	1.1.5/3	HIGH HOTWELL LEVEL	HOTWELL LEVEL HI/LO
AOP-010	1.1.7/3	Low Feed Pump Seal Water DP	FWP SEAL WTR PUMP A/B TROUBLE
AOP-010	1.1.8/3	Electrical fault on FW pump	FWP A MOTOR FWP B MOTOR
AOP-010	1.1.9/3	LOW LUBE OIL PRESSURE	FWP A LUBE OIL TROUBLE FWP B LUBE OIL TROUBLE
AOP-010	1.2.1/3	Electrical fault on Condensate Pump	COND PUMP A MOTOR COND PUMP B MOTOR
AOP-010	1.3.4/4	Electrical fault on Heater Drain Pump	HTR DR TANK PUMP A MOTOR HTR DR TANK PUMP B MOTOR
AOP-011	3.2.3/4	S/G PORVs	handwritten labels on equipment "open" and "closed"
AOP-012	3.1.3/3	closed	SHUT
	3.2.11/4	No. 2 LP guage	label not on equipment
AOP-013	1.2.1/4	stop HVE-15	OFF

	1.3.2.3/5	CLOSE	SHUT
AOP-014	3.1.2/4	PW MOV-832	Makeup CC-832
	3.2.5/7	DW-711	CC-711
AOP-015	1.8/3	STEAM DUMP ACTUATION	STEAM DUMP ARMED
AOP-022	1.3.1.1.1/4	South Supply Header Isolation Valve	SW Pump Disch
	1.3.1.1.2/4	SW Pump Discharge Header Cross-Connect	SW Pump Disch
	1.3.2.2/5	Chemical Injection Supply Lines	Hypochlorite/SW Isol
	1.3.2.3/5	deep well supply	Potable water
	3.3.2.2.3/18	IVSW Tank	seal water injection tank
	5.3.2.2.4/14	E. H. Oil Pump	Gov Fluid Pump
	6.3.3.3/16	jockey pump	booster pump
AOP-023	1.5/3	Internal pressure	CV pressure

APPENDIX E

AC	Alternating Current
AFW	Auxiliary Feedwater
AO	Auxiliary Operator
AOP	Abnormal Operating Procedure
AP	Administrative Procedure
ATWS	Anticipated Transient Without Scram
AUX	Auxiliary
BKR	Breaker
BLDG	Building
CCW	Component Cooling Water
CP&L	Carolina Power and Light
CSFST	Critical Safety Function Status Tree
CST	Condensate Storage Tank
CV	Containment Vessel
CVS	Chemical and Volume Control
DC	Direct Current
DEV	Deviation
DG	Diesel Generator
DISCH	Discharge
DP	Differential Pressure
DS	Dedicated Shutdown
DW	Demineralized Water
EAL	Emergency Action Level
E&C/RC	Environmental and Chemistry/Radiation Control
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EFPY	Effective Full Power Year
EH	Electro-hydraulic
EMERG	Emergency
EOP	Emergency Operating Procedure
EPP	End Path Procedure
ERC	Environmental/Radiation Control
ERFIS	Emergency Response Facility Information System
ERG	Emergency Response Guidlines
F	Fahrenheit
FCV	Flow Control Valve
FIC	Flow Indicating Controller
FP	Fire Protection
FRP	Functional Recovery Procedure
FW	Feedwater
GEN	Generator
GP	General Procedure
gpm	gallons per minute
GTG	Generic Technical Guidelines
HBR	H. B. Robinson
HCV	Hand Control Valve
Hi	High
HP	Health Physics

hr	hour
HTR	heater
HVH	Heating Ventilation Handling
Hx	Heat Exchanger
I&C	Instrumentation and Control
IC	Internal Combustion
IFI	Inspector Followup Item
IR	Inspection Report
ISFSI	Independent Spent Fuel Storage Installation
KV	Kilovolt
KVA	Kilovolt Ampere
KW	Kilowatt
LCV	Level Control Valve
LO	Low
LOCA	Loss of Coolant Accident
LP	Low Pressure
MG	Motor generator
MOV	Motor Operated Valve
MSIV	Main Steamline Isolation Valve
mph	mile per hour
N2	Nitrogen
NOUE	Notice of Unusual Event
NR	Narrow Range
NRC	Nuclear Regulatory Commission
OMM	Operations Management Manual
OP	Operating Procedure
P	Premissive
P	Pressure
P	Page
P/A	Public Address
Pg	Page
PGP	Procedures Generation Package
PI	Pressure Indication
PNL	Panel
PORV	Power Operated Relief Valve
Pp	Pump
PRESS	Pressure
PRZR	Pressurizer
PSID	Pressure Square Inch-differential
PSIG	Pressure Square Inch-gage
PSTG	Plant Specific Technical Guidelines
PZR	Pressurizer
QA	Quality Assurance
R	Radiation
RC	Radiation Control
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RECIRC	Recirculation
RHR	Residual Heat Removal
R/hr	Roentgen/hour
RI	Radiation Indicator

RM	Radiation Monitor
RNO	Response Not Obtained
RO	Reactor Operator
RPIS	Rod Position Information System
RTD	Resistance Temperature Device
RTGB	Reactor Turbine Generator Board
RT(NDT)	Reference Nil-ductility Temperature
RVLIS	Reactor Vessel Level Information System
RWST	Reactor Water Storage Tank
SCM	Subcooling Margin
SER	Safety Evaluation Report
SERV	Service
S/G	Steam Generator
SGTR	Steam Generator Tube Rupture
SI	Safety Injection
SMR	Simulator Modification Request
SPDS	Safety Parameter Display System
SRO	Senior Reactor Operator
SST	Station Service Transformer
STM	Steam
SUR	Startup Rate
SW	Service Water
SWB	Service Water Booster
T	Temperature
T	Thickness
Tavg	Temperature-Average
Tc	Temperature-Cold
TC	Thermocouple
TD	Transition Document
Th	Temperature-Hot
TI	Training Instruction
TR	Trend Recorder
Tref	Temperature-Reference
TRANS	Transformer
TS	Technical Specifications
TURB	Turbine
V	Volt
V&V	Verification & Validation
VCT	Volume Control Tank
V/V	Valve
WOG	Westinghouse Owners' Group