WISCONSIN ELECTRIC

POWER COMPANY

POINT BEACH NUCLEAR PLANT

UNIT NOS. 1 AND 2

ANNUAL RESULTS AND
DATA REPORT
1990

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U.S. Nuclear Regulatory Commission
Docket Nos. 50-266 and 50-301
Facility Operating License Nos.
DPR-24 and DPR-27

PREFACE

This Annual Results & Data Report for 1990 is submitted in accordance with Point Beach Nuclear Plant, Unit Nos. 1 and 2, Technical Specification 15.6.9.1.B and filed under Docket Nos. 50-266 and 50-301 for Facility Operating License Nos. DPR-24 and DPR-27, respectively.

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I. INTRODUCTION

The Point Beach Nuclear Plant, Units 1 and 2, utilize identical pressurized water reactors rated at 1518 MWt. Each turbine-generator is capable of producing 497 MWe net (524 Mwe gross) of electrical power. The plant is located ten miles north of Two Rivers, Wisconsin, on the west shore of Lake Michigan.

II. HIGHLIGHTS

UNIT 1

Highlights for the period January 1, 1990, through December 31, 1990, included a 49-day refueling/maintenance outage, a nine day outage to repair a control rod drive canopy seal weld and a 90 minute outage to repair a turbine EH system control card.

Unit 1 operated at an average capacity factor of 83.1% (MDC net) and a net electrical/thermal efficiency of 32.3%. The unit and reactor availability were 84.1% and 84.7%, respectively. Unit 1 generated its 64 billionth kilowatt hour on February 2, 1990; its 65 billionth kilowatt hour on June 17, 1990; its 66 billionth kilowatt hour on September 17, 1990; and its 67 billionth kilowatt hour on December 7, 1990.

UNIT 2

Highlights for the period January 1, 1990, through December 31, 1990, included a 44-day refueling/maintenance outage.

Unit 2 operated at an average capacity factor of 89.3% (MDC net) and a net electrical/thermal efficiency of 32.8%. The unit and reactor availability were 88.1% and 88.3% respectively. Unit 2 generated its 64 billionth kilowatt hour on February 23, 1990; its 65 billionth kilowatt hour on May 14, 1990; its 66 billionth kilowatt hour on August 3, 1990; and its 67 billionth kilowatt hour on December 8, 1990.

III. LICENSE AMENDMENTS

During the year 1990, there were two license amendments issued by the U. S. Nuclear Regulatory Commission to Facility Operating License DPR-24 for Point Beach Unit 1 and two amendments issued to Facility Operating License DPR -27 for Point Beach Unit 2. These license amendments are listed by date of issue and are summarized in the following descriptions:

<u>Amendment 125 to DPR-24, Amendment 129 to DPR-27, January 10, 1990</u>: These amendments revised provisions in the PBNP Technical Specifications relating to the permissible heatup and cooldown curves. The revised heatup and cooldown curves are applicable through 18.1 effective full power years. The specifications were simplified by taking the most limiting set of curves derived for either unit and making that set applicable to both units.

Amendment 126 to DPR-24, Amendment 130 to DPR-27, March 1, 1990: These amendments revised Technical Specification 15.5.4.2 relating to fuel storage. The amendments increased the allowable U-235 content for optimized fuel assemblies to 46.8 grams per axial centimeter and permit the use of axial fuel blankets. The allowable U-235 content for this fuel corresponds to an enrichment of 4.75 weight percent. The U-235 content permitted for standard fuel assemblies was not changed by this amendment.

III. 10 CFR 50.59 SAFETY EVALUATIONS

PROCEDURE CHANGES

1. CP-222 (NNSR), SAS/PPCS Computers; Use of SAS/PPCS Computer Peripherals for Emergency Plan Drill, Revision 1. (Permanent)

   CP-222, Revision 1 permitted the use of the SAS/PPCS backup (B) computer to present an Emergency Plan drill scenario. In order to accomplish this, real-time data collection for the "drill" unit is interrupted and replaced with simulated data. Peripheral devices in the technical support center and emergency operations facility are bus-switched to the backup computer. Other devices on those buses are also switched. These other devices are turned off during the drill to avoid presentation of drill plant data in the real control room.

   During a drill, simulated data, including meteorological and radiological data, are saved in various history files on the backup computer. Real data continues to be saved for both units on the primary computer and on the backup computer for the "non-drill" unit only.

   Summary of Safety Evaluation: This change does not affect Technical Specifications since the primary computer continues to present real plant data to the control room facilities. In the event the primary computer should fail and the backup computer is needed, normal function of the backup computer can be restored in <15 minutes and is procedurally mandated.

   Although history files on the backup computer will be corrupt for the time period of the drill, the primary computer history files remain intact up to that time should the primary computer fail. Then there will be a discontinuity of data of up to 15 minutes during the period of time in which the backup computer is restored to normal function. This delay should not cause a violation of Technical Specifications.

   Section 7.7.5 of the FSAR describes the general functions of the SAS/PPCS. Neither the FSAR nor the Technical Specifications describe the hardware or software configuration of the SAS/PPCS. (SER 90-012)

2. CSP-C.1 (Major), Response to Inadequate Core Cooling, Revision 4. (Permanent)

   Safety Evaluation Detail: Step 18 was changed as a result of the addition of the standard step to this EOP regarding the battery charger. (SER 89-024-03)

3. CSP-C.2, (Major), Response to Degraded Core Cooling, Revision 4. (Permanent)

Safety Evaluation Detail: A step number referenced in Step 20 was revised as a result of the addition of the battery charger standard step in that procedure. The first caution for Step 13 was modified to add the phrase, "will cause accumulator injection which..." This phrase was inadvertently omitted from the ERG Revision 1A changes. (SER 88-095-03)

4. CSP-H.1, (Major), Response to Loss of Secondary Heat Sink, Revision 5. (Permanent)

Safety Evaluation Detail: Step 16 was added to manually reset battery chargers following a loss of all AC power when diesel generator loading permits. This prevents the batteries from running down. In conjunction with this step being added, a note was added to Step 1 to explain the use of boxes in EOPs. The symptom or entry conditions from EOP-0 were changed due to the reduction in the number of immediate action steps were reduced. (SER 88-096-04)

5. CSP-P.1, (Major), Response to Imminent PTS Condition, Revision 3. (Temporary)

Safety Evaluation Detail: Symptom or entry conditions and Figure 1 were temporarily changed due to new Technical Specification heatup and cooldown curves (Figures 15.3.1-1 and 15.3.1-2) as specified by Regulatory Guide 1.99, Revision 2. (SER 89-027-03)

CSP-P.1, (Major), Response to Imminent PTS Condition, Revision 4. (Permanent)

Safety Evaluation Detail: Step 11 was added to restore battery chargers after a loss of offsite AC power. This prevents the batteries from running down. The first note prior to Step 1 was added to explain the purpose of the boxes around new Step 11. The symptom or entry conditions were changed, along with Figure 1, to reflect new Technical Specification temperature and pressure limits associated with reactor vessel embrittlement. (SER 89-027-04)

6. CSP-P.2, (Major), Response to Anticipated PTS Condition, Revision 3. (Temporary)

Safety Evaluation Detail: Symptom or entry conditions and Figure 1 were temporarily changed due to new Technical Specification heatup and cooldown curves (Figures 15.3.1-1 and 15.3.1-2) as specified by Regulatory Guide 1.99, Revision 2. (SER 89-028-03)

CSP-P.2, (Major), Response to Anticipated PTS Condition, Revision 4. (Permanent)

Safety Evaluation Detail: The temperatures were changed in the symptom or entry conditions and the vertical line in Figure 1 as a result of new Technical Specification temperature and pressure limits associated with reactor vessel embrittlement. (SER 89-028-04)

7. CSP-Z.1, (Major), Response to High Containment Pressure, Revision 4. (Permanent)

Safety Evaluation Detail: Appendix A was changed to match the new containment isolation status panel. (SER 89-029-03)

8. CSP-Z.3, (Major), Response to High Containment Radiation Level, Revision 4. (Permanent)

Safety Evaluation Detail: Appendix A was changed to match the new containment isolation status panel. (SER 89-030-03)

9. ECA-0.0, (Major), Loss of All AC Power, Revision 5. (Temporary)

Safety Evaluation Detail: Step 21 was temporarily changed due to new Technical Specification heatup and cooldown curves (Figures 15.3.1-1 and 15.3.1-2) as specified by Regulatory Guide 1.99, Revision 2. (SER 88-091-05)

ECA-0.0, (Major), Loss of All AC Power, Revision 6. (Permanent)

Safety Evaluation Detail: Substep 2 was removed from Step 26 Substep b as it was decided by the control room design review team that this is an unnecessary action to be accomplished (reference HED 473). This revision adds Appendix D, which lists loads for the diesel which could possibly prevent overloading of the diesel. A note was added to Step 5 to reference this appendix. Step 21 Substep c changed "315°F" to "345°F" as a result of new Technical Specification pressure and temperature limits associated with reactor vessel embrittlement. The order and relabeling of Appendix C was accomplished to match that of the new containment isolation status board. (SER 88-091-06)

ECA-0.0, (Major), Loss of All AC Power, Revision 7. (Permanent)

Safety Evaluation Detail: Appendix D emergency diesel generator kilowatt loading values were changed as a result of new calculations performed which incorporate motor efficiency and other applicable engineering variables. This change addresses Deficiency 90-201-03 contained in NRC Inspection Report 266 & 301/90-201. In addition, the heading on Page 19 of Appendix A was corrected as documented via NCR N-90-162. (SER 88-091-07)

10. ECA-0.1, (Major), Loss of All AC Power Recovery Without SI Required, Revision 4. (Permanent)

Safety Evaluation Detail: A note was added to inform the operator that the seal inlet temperature indicates the general area of the bearing because the RCP lower bearing has no direct temperature readout. Substeps expanded to provide steps to establish CC flow and seal injection flow to the RCPs. This fulfills an ERG requirement to have plant-specific steps to describe these actions. (SER 88-092-03)

11. ECA-0.2, (Major), Loss of All AC Power Recovery With SI Required, Revision 4. (Permanent)

Summary of Safety Evaluation: An appendix of probable kW loads for the diesel was added to prevent overloading of the diesel. Step 8 was expanded to give plant-specific steps for establishing component cooling to the thermal barriers to fulfill ERG requirements. (SER 89-031-03)

ECA-0.2, (Major), Loss of All AC Power Recovery With SI Required, Revision 5. (Permanent)

Safety Evaluation Detail: Appendix A emergency diesel generator kilowatt loading values were changed as a result of new calculations performed which incorporate motor efficiency and other applicable engineering variables. This change addressed Deficiency 90-201-03 contained in NRC Inspection Report 266 & 301/90-201. (SER 89-031-04)

12. ECA-1.1, (Major), Loss of Containment Sump Recirculation, Revision 4. (Permanent)

Safety Evaluation Detail: Steps 20 and 21 were changed to the new standard steps that no longer require a flush if water was added to the safety injection system from the refueling water storage tank. Step 21 was changed to accommodate Step 20 where, if the RNO of Step 20 was accomplished, then the SI system must be placed in a "ready for use" lineup. The symptom or entry conditions were changed from EOP-1 as a result of the new battery charger standard step being added to that procedure. Step 9 was added to restore battery chargers when diesel loading permits after a loss of offsite power. This prevents the batteries from running down. The second note prior to Step 1 was added to explain the use of boxed steps due to the addition of Step 9. (SER 88-093-03)

13. ECA-1.2, (Major), LOCA Outside Containment, Revision 4. (Permanent)

Safety Evaluation Detail: Appendix A was changed to match that of the new containment isolation status board. (SER 89-032-03)

14. ECA-2.1, (Major), Uncontrolled Depressurization of Both Steam Generators, Revision 4. (Temporary)

Safety Evaluation Detail: Step 35 and the foldout page for the procedure were temporarily changed due to new Technical Specification heatup and cooldown curves (Figures 15.3.1-1 and 15.3.1-2) as specified by Regulatory Guide 1.99, Revision 2. (SER 89-034-04)

ECA-2.1, (Major), Uncontrolled Depressurization of Both Steam Generators, Revision 5. (Permanent)

Safety Evaluation Detail: Step 11 was added to restore the battery chargers when diesel loading permits after a loss of offsite power occurs. This prevents the batteries from running down. Appendix A was added to list loads for the diesel which could possibly prevent overloading of the diesel. The appendix is referenced in the first note prior to Step 14. The safety injection line flush was standardized to compensate for the flush that might be previously accomplished due to the refueling water storage tank level decrease which would sufficiently dilute the boric acid concentration. The second note prior to Step 36 changed 354°F to 360°F as a result of new Technical Specification temperature and pressure limits associated with reactor vessel embrittlement. (SER 89-033-05)

ECA-2.1, (Major), Uncontrolled Depressurization of Both Steam Generators, Revision 6. (Permanent)

Safety Evaluation Detail: The setpoint was changed for the pressurizer power-operated relief valve (PORV) nitrogen pressure regulator from 85 psig to 100 psig to meet the 2-second opening criteria set forth in Amendments 45 and 50. (SER 89-033-06)

ECA-2.1, (Major), Uncontrolled Depressurization of Both Steam Generators, Revision 7. (Permanent)

Safety Evaluation Detail: Appendix A emergency diesel generator kilowatt loading values were changed as a result of new calculations performed which incorporate motor efficiency and other applicable engineering variables. This change addresses Deficiency 90-201-03 contained in NRC Inspection Report 266 & 301/90-201. (SER 89-033-07)

15. ECA-3.1, (Major), SGTR with Loss of Reactor Coolant-Subcooled Recovery Desired, Revision 5. (Temporary)

Safety Evaluation Detail: Step 28 and the foldout page were temporarily changed due to new Technical Specification heatup and cooldown curves (Figures 15.3.1-1 and 15.3.1-2) as specified by Regulatory Guide 1.99, Revision 2. (SER 88-094-05)

ECA-3.1, (Major), Steam Generator Tube Rupture With Loss of Reactor Coolant-Subcooled Recovery Desired, Revision 6. (Permanent)

Safety Evaluation Detail: Step 4 was added to restore battery chargers after a loss of AC power. This prevents the batteries from running down. Appendix A was added to prevent the possible overloading of the diesel. The temperature listed in the second note prior to Step 39 was also changed from 354°F to 360°F to reflect new Technical Specification temperature and pressure limits associated with reactor vessel embrittlement. (SER 88-094-06)

ECA-3.1, (Major), SGTR With Loss of Reactor Coolant - Subcooled Recovery Desired, Revision 7. (Permanent)

Safety Evaluation Detail: Step 40 changed the setpoint for the pressurizer power-operated relief valve (PORV) nitrogen pressure regulator from 85 psig to 100 psig to meet the 2-second opening criteria set forth in Amendments 45 and 50. (SER 88-094-07)

ECA-3.1, (Major), Steam Generator Tube Rupture with Loss of Reactor Coolant-Subcooled Recovery Desired, Revision 8. (Permanent)

Safety Evaluation Detail: Appendix A emergency diesel generator kilowatt loading values were changed as a result of new calculations performed which incorporate motor efficiency and other applicable engineering variables. This change addressed Deficiency 90-201-03 contained in NRC Inspection Report 266 & 301/90-201. (SER 88-094-08)

16. ECA-3.2, (Major), SGTR with Loss of Reactor Coolant-Saturated Recovery Desired, Revision 5. (Temporary)

Safety Evaluation Detail: Step 28 and the foldout page for the procedure were temporarily changed due to new Technical Specification heatup and cooldown curves (Figures 15.3.1-1 and 15.3.1-2) as specified in Regulatory Guide 1.99, Revision 2. (SER 89-034-05)

ECA-3.2, (Major), Steam Generator Tube Rupture With Loss of Reactor Coolant-Saturated Recovery Desired, Revision 6. (Permanent)

Safety Evaluation Detail: The wording in the second note prior to Step 1 was changed from "the first seventeen steps" to "Steps 1 through 18" because the battery charger standard step was added in ECA-3.1. This is consistent with terminology used in other EOPs. Addition of the battery charger standard step in ECA-3.1 also necessitated a corresponding change to the symptom or entry conditions. The second note prior to Step 28 changed 354°F to 360°F as a result of new Technical Specification temperature and pressure limits associated with the reactor vessel embrittlement. (SER 89-034-06)

ECA-3.2, (Major), SGTR With Loss of Reactor Coolant - Saturated Recovery Desired, Revision 7. (Permanent)

Summary of Safety Evaluation: The setpoint for the pressurizer power-operated relief valve (PORV) nitrogen pressure regulator was revised from 85 psig to 100 psig to meet the 2-second opening criteria set forth in Amendments 45 and 50. (SER 89-034-07)

17. ECA-3.3, (Major), SGTR Without Pressurizer Pressure Control, Revision 3. (Temporary)

Safety Evaluation Detail: The foldout page was temporarily changed due to new Technical Specification heatup and cooldown curves (Figures 15.3.1-1 and 15.3.1-2) as specified by Regulatory Guide 1.99, Revision 2. (SER 89-035-03)

ECA-3.3, (Major), Steam Generator Tube Rupture Without Pressurizer Pressure Control, Revision 4. (Permanent)

Safety Evaluation Detail: The entry condition from EOP-3 was changed due to the addition of the standard battery charger step in that procedure. (SER 89-035-04)

ECA-3.3, (Major), SGTR Without Pressurizer Pressure Control, Revision 5. (Permanent)

Safety Evaluation Detail: The setpoint for the pressurizer power-operated relief valve (PORV) nitrogen pressure regulator was changed from 85 psig to 100 psig to meet the 2-second opening criteria set forth in Amendments 45 and 50. (SER 89-035-05)

18. EOP-0, (Major), Reactor Trip or Safety Injection, Revision 6. (Permanent)

Safety Evaluation Detail: The immediate action steps were reduced to match the ERG to allow for less operator memorization. Step 13 RNO was changed to place the main feed, condensate and heater drain tank pump control switches in pullout instead of manually tripping in order to prevent the condensate pump from automatically restarting on low discharge pressure and injecting water into the steam generator.

Steps 19, 21 and 36 were revised to add equipment lists to match the nameplate information on the control room boards. A note was added prior to Step 20 which checks diesel capacity and Appendix C prior to starting loads on the diesel. This is a standard note to inform the operator of diesel limitations. A note about Appendix C use was added to Step 47. Appendix C is a new appendix which lists possible diesel loads to assist the operator in loading the diesel. Appendix A was revised to copy the new containment isolation panel. This reorganization includes order, nomenclature and valve identifiers. Step 28 of this procedure was eliminated and the RNO for this step was returned to its original placement in Step 19. It had been previously removed from Step 19 because an immediate action could not have local operator action implication. With the reduction in immediate actions, Step 19 is no longer an immediate action step. Step 19 now allows local tripping of nonessential loads.

Step 39 was added to restore battery chargers because there is no automatic actions for returning the battery chargers to service after a loss of offsite power. This step will only be accomplished if a loss of offsite AC has occurred. (SER 88-084-05)

EOP-0, (Major), Reactor Trip or Safety Injection, Revision 7. (Permanent)

Safety Evaluation Detail: Automatic actions to Step 4 were added for containment high pressure SI due to new modification MR 88-151(152) which adds these automatic actions. A note was moved to address audit finding AFR-A-P-88-10-042. In Step 19 RNO, the If, then statement is removed because Step 12 of this procedure restarts the CC pump and there is no need to shut off the pump after it has been restarted. This revision also added the pump designator for the turning gear oil pump in Step 26 to be consistent with other procedures. (SER 88-084-06)

EOP-0, (Major), Reactor Trip or Safety Injection, Revision 8. (Permanent)

Safety Evaluation Detail: Appendix C emergency diesel generator kilowatt loading values were changed as a result of new calculations performed which incorporate motor efficiency and other applicable engineering variables. This change addressed Deficiency 90-201-03 contained in NRC Inspection Report 266 & 301/90-201. (SER 88-084-07)

19. EOP-0.1, (Major), Reactor Trip Response, Revision 5. (Permanent)

Safety Evaluation Detail: Step 8 was changed to add nameplate information and to conform to standard step usage. (SER 88-085-04)

20. EOP-0.2, (Major), Natural Circulation Cooldown, Revision 5. (Temporary)

Safety Evaluation Detail: Figures 1 and 2 were temporarily changed due to new Technical Specification heatup and cooldown curves (Figures 15.3.1-1 and 15.3.1-2) as specified by Regulatory Guide 1.99, Revision 2. (SER 88-086-05)

EOP-0.2, (Major), Natural Circulation Cooldown, Revision 6. (Permanent)

Safety Evaluation Detail: The revision changed Figure 1 upper curve of RCS pressure and cold leg temperature limits with both control rod shroud fans operating and Figure 2 without both control rod shroud fans running. The changes were necessary as a result of new Technical Specification temperature and pressure limits associated with reactor vessel embrittlement. The purpose statement was also changed from 354°F to 360°F as a result of these revised limits. (SER 88-086-06)

EOP-0.2, (Major), Natural Circulation Cooldown, Revision 7. (Permanent)

Summary of Safety Evaluation: The nitrogen pressure regulator setpoint was changed from 85 psig to 100 psig to meet the 2-second opening criteria set forth in Facility Operating License Amendments 45 and 50. The notes prior to Steps 15 and 30 deleted the words, "steam void in vessel occurs, or." This deletion was needed because prior to the Revision 1A change to the ERGs, steam voids were not mentioned in Steps 17 and 32. (SER 88-086-07)

21. EOP-0.3, (Major), Natural Circulation Cooldown with Steam Void in Vessel, Revision 4. (Temporary)

Safety Evaluation Detail: Step 8 and the EOP-0 series foldout page were temporarily changed due to new Technical Specification heatup and cooldown curves (Figures 15.3.1-1 and 15.3.1-2) as specified by Regulatory Guide 1.99, Revision 2. (SER 89-036-04)

EOP-0.3, (Major), Natural Circulation Cooldown with Steam Void in Vessel, Revision 5. (Permanent)

Safety Evaluation Detail: The second note prior to Step 8 was changed from 354°F to 360°F and shifts the curve in Figure 1 to the right of the 360°F line. These changes were necessary as the result of revised TS temperature and pressure limits regarding reactor vessel embrittlement. (SER 89-036-05)

EOP-0.3, (Major), Natural Circulation Cooldown With Steam Void in Vessel, Revision 6. (Permanent)

Safety Evaluation Detail: The second caution prior to Step 1 was changed to a note to maintain the standard set for the EOPs. In Step 9, the LTOP nitrogen regulator setpoint was revised from 6? psig to 100 psig in order to meet the 2-second opening criteria set forth in Facility Operating License Amendments 45 and 50. (SER 89-036-06)

22. EOP-1, (Major), Loss of Reactor or Secondary Coolant, Revision 6. (Permanent)

Safety Evaluation Detail: Step 8 was added to restore battery chargers after a loss of offsite power. This prevents the batteries from running down. Step 17 had an "and" placed between the two bulleted items because both statements in the action/expected response column must be true to make the statement correct. If one of the statements is false, then the operator must return to Step 1 of the procedure. There were also symptom or entry condition changes made from EOP-0 to reflect a decrease in the number of immediate actions and from CS[illegible] to incorporate addition of the standard battery charger step, respectively. (SER 88[illegible]-05)

EOP-1, (Major), Loss of Reactor or Secondary Coolant, Revision 6. (Temporary)

Safety Evaluation Detail: The temporary change added Substep a to Step 8 to remove DC battery loads which would extend a battery's useful life and to prevent the load of the battery chargers onto a single diesel. This could occur in the case of a LOCA coincident with a loss of offsite power and one diesel generator inoperable until later in the EOP-1 series where EDG loading will permit these chargers to be loaded on the diesel.

Substep c was added to Step 11 to deenergize the boric acid heat tracing circuits when checking diesel status and securing unnecessary plant equipment. By deenergizing these circuits 112 kw can be removed from the only running diesel which will prevent overloading the diesel in the scenario noted above. Deferring resetting of the battery chargers provides an ~124 kw reduction. Boric acid heat trace circuits are not required for an accident unit or shutdown unit because safety injection and RHR pumps add sufficient boric acid. If these loads are not secured, the operating unit will be placed in an LCO condition. (SER 88-087-06)

EOP-1, (Major), Loss of Reactor or Secondary Coolant, Revision 7. (Permanent)

Safety Evaluation Detail: An appendix was added to the procedure which lists some loads that may give the operator information to prevent overloading the diesel. Substep a of Step 8 removes the DC battery loads which would extend the batteries' useful life and prevent loading the battery chargers onto a single diesel in the case of a loss of reactor coolant accident coincident with a loss of offsite power and one diesel generator inoperable. Later in the EOP-1 series, where diesel loading will permit, the chargers will be loaded onto the diesel. A substep was added to Step 11 to deenergize the boric acid heat trace circuits. In deenergizing these circuits, load is reduced by 112 kW on the only running diesel which prevents overloading the diesel generator in scenario of Step 8 above. Deferring the starting of the battery chargers reduces the load by ~124 kW. Boric acid heat trace circuits are not required for an accident unit or shut down unit because SI and RHR pumps add sufficient boric acid. (SER 88-087-07)

EOP-1, (Major), Loss of Reactor or Secondary Coolant, Revision 8. (Permanent)

Safety Evaluation Detail: Appendix A emergency diesel generator kilowatt loading values were changed as a result of new calculations performed which incorporate motor efficiency and other applicable engineering variables. This change addressed Deficiency 90-201-03 contained in NRC Inspection Report 266 & 301/90-201. (SER 88-087-08)

23. EOP-1.1, (Major), SI Termination, Revision 5. (Permanent)

Safety Evaluation Detail: The symptom or entry conditions from EOP-1 and CSP-H.1 were changed because the standard battery charger step was added to these procedures. Likewise, Step 3 was added to this procedure to return the battery chargers to service following a loss of offsite power. This action prevents the batteries from running down. Steps 6 and 12 were changed to the new standard step to compensate for a flush previously due to refueling water storage tank decrease. This sufficiently dilutes the boric acid concentration to prevent crystallization in the system. Step 7 RNO was changed to present proper nomenclature when operating breakers per the EOP Writers Guide. Appendix A was added to include a list of diesel loads which could possibly prevent overloading of the diesel. (SER 88-088-04)

EOP-1.1, (Major), Safety Injection Termination, Revision 6. (Permanent)

Safety Evaluation Detail: Appendix A emergency diesel generator kilowatt loading values were changed as a result of new calculations performed which incorporate motor efficiency and other applicable engineering variables. This change addressed Deficiency 90-201-03 contained in NRC Inspection Report 266 & 301/90-201. (SER 88-088-05)

24. EOP-1.2, (Major), Small Break LOCA Depressurization & Cooldown, Revision 3. (Temporary)

Safety Evaluation Detail: Step 24 was temporarily changed due to new Technical Specification heatup and cooldown curves (Figures 15.3.1-1 and 15.3.1-2) as specified by Regulatory Guide 1.99, Revision 2. (SER 89-037-03)

EOP-1.2, (Major), Small Break LOCA Depressurization & Cooldown, Revision 4 (Permanent)

Safety Evaluation Detail: The second note for Step 24 changed 354°F to 360°F as a result of new Technical Specification temperature and pressure limits associated with reactor vessel embrittlement. The symptom or entry condition was also changed because the battery charger standard step was incorporated into EOP-1. (SER 89-037-04)

EOP-1.2, (Major), Small Break LOCA and Depressurization, Revision 5. (Permanent)

Safety Evaluation Detail: The setpoint for the pressurizer power-operated relief valve (PORV) nitrogen pressure regulator was changed from 85 psig to 100 psig to meet the 2-second opening criteria set forth in Amendments 45 and 50. (SER 89-037-05)

25. EOP-1.3, (Major), Transfer to Containment Sump Recirculation, Revision 6. (Permanent)

Safety Evaluation Detail: The words "or position" in Step 5 were deleted because the definition of the word "verify" means to check or reposition the valves as stated. In Step 10 Substeps f and g, Step 14 Substep a, Step 19 Substep c and d, a transition "Go to EOP-1.4, Transfer to Containment Sump Recirculation-One Train Inoperable," was added. These transitions were added to the procedure for the cases when an RHR or SI pump does not start. This could cause an interruption of flow to the core, which EOP-1.4 prevents. In Step 13 Substep a, the RWST low level alarm was removed because it is not good engineering practice to rely upon an alarm. Step 14a was added to check the status of the B train SI system. If the B train SI system is not lined up for recirculation, a continuation in this procedure would result in a total loss of flow to the core.

Step 22 Substeps a and b are reversed in order. It is possible to get to this step without B RHR pump running. This step shuts the discharge to A RHR pump which would secure all flow to the core. Step 22 Substep c of Revision 5 was deleted because there is no reason to verify A RHR pump running as the operator cannot reach this step without the pump running.

Step 26 Substep c was added to "locally shut the spray pump mini-recirc valves." This is to prevent potentially contaminated water from recircing back to the RWST which will not prevent the spray pumps from accomplishing their function. In Step 26 Substep g the words, "shift to manual" were added. In order to operate the sodium hydroxide eductor valves, the valves must be shifted to manual.

New Step 28 Substep c was added to "consult with the TSC to determine if NaOH should be added to containment." The TSC will then make a determination if any more sodium hydroxide additions are required. This can be determined by many factors such as sampling, determining the cause of the leak, severity of the leak, etc.

Figure 1 was revised to change the pattern for Unit 2 recirculation so the operators could distinguish between Unit 1 and Unit 2. (SER 88-089-05)

EOP-1.3, (Major), Transfer to Containment Sump Recirculation, Revision 6. (Temporary)

Summary of Safety Evaluation: The procedure was temporarily changed in accordance with approved safety evaluation report SER 90-120. This safety evaluation report authorized the changes in response to the evaluation of NCR N-90-157.

NCR N-90-157 was written to report the fact that ORT 2 tests performed during the Unit 1 1990 refueling outage showed that both Unit 1 RHR pumps develop less than the 95% of design head limit listed in ASME Section XI Subsection IWP. The Unit 1 Train "B" pump develops less than 89%. The evaluation of the NCR has shown that an operability concern exists with the emergency core cooling system (ECCS) while operating on containment sump recirculation. The evaluation establishes the NPSH requirements of the containment spray pumps by determining a conservative containment sump temperature at the time of switchover from injection to recirculation (containment saturation temperature up to 250°F).

The temporary changes state that the containment spray pumps shall not be operated if containment pressure is <50 psig or <40 psig containment pressure with train-specific low head safety injection flow secured, or the high head safety injection flow is secured with >10 psig containment pressure. Steps 24 and 25 of Revision 6 are deleted due to the operability impact of the spray pumps on recirculation or the containment sump using the RHR pumps as a suction source. These conditions are contained in the foldout of the EOP-1 series. The change prevents damage from occurring to the containment spray pumps due to inadequate NPSH.

The major concern is providing adequate net positive suction head (NPSH) to the containment spray and SI pumps. When both the CS and SI pumps are running, the CS pump is limited when it comes to NPSH for two reasons. The absolute pressure at the suction of the SI pump is higher than at the CS pumps. Additionally, the NPSH required by the SI pump is less than that of the CS pump.

Calculation N-90-045 was performed in order to determine the amount of cooling required for the RHR heat exchangers to maintain adequate NPSH for the CS pumps during containment sump recirculation. The calculation was based on a uniform degradation of the manufacturer's pump curve by 20% of the design head of the pump (280 ft water) in order to provide some margin in the calculation.

In this calculation, it was determined that while on high head sump recirculation with containment spray, only one train operable, and RCS pressure = 0 psig, a containment pressure of 50 psig is required to maintain adequate NPSH to the CS pump. This assumed that the flow control valves in the core deluge lines had failed open due to loss of instrument air. If instrument air is available to these valves and they are completely shut, the CS pumps could not be operated at containment pressure <50 psig if the high-head SI pumps are running. If the high head SI pumps are secured (using low head recirculation), it was determined that adequate NPSH is available for the CS pumps only if containment pressure is >10 psig. It should be noted that the above containment pressure requirements do not include instrument error.

For two-train operation of high head recirculation, SI pump flow rate is less than that for a single train. This results in a lower flow rate through the common line feeding the CS and SI pumps, and therefore, less head loss. CS pump suction pressure will be higher, and thus less cooling of the sump fluid will be required by the RHR heat exchanger. This combined with the fact that more cooling will be available by the RHR heat exchanger with two trains of safeguards operable, means that the single train case is more limiting (two trains of ECCS cannot be operated with only one train of safeguards operable). The single train calculations bound the two-train case.

From a radiological perspective, containment spray is not required to operate while on sump recirculation to satisfy 10 CFR 100 (offsite dose) requirements, since most of the iodine released to the containment atmosphere has been scrubbed during the first 20 minutes of the injection phase.

The evaluation of NCR N-89-275 showed that sodium hydroxide addition was not required following the injection phase and could be secured. Therefore, new Step 25 was changed to secure sodium hydroxide addition prior to placing the containment spray pumps on containment sump recirculation. This is to prevent a pH excursion of the nozzles at spray system.

Lastly, in Section 6.4.2 of the FSAR it states that after the injection phase, it is expected that containment spray would not be required. The fan cooler units are sufficient to reduce containment pressure once on recirculation. Accordingly the setpoint in Step 9 is changed to stop the containment spray pumps when the spray additive tank reaches the setpoint of 12%. This is to prevent the sump from exceeding its FSAR sump pH limit of 10.0 stated in the NCR N-89-275. Also Step 24 adds a check to verify at least two containment accident cooling fans running. If this occurs, then containment spray is not necessary. Otherwise, containment spray may be started in accordance with the conditions described in the foldout page, as referenced in new Step 25 Substep f. Substep f also gives the criteria for stopping the spray pumps in accordance with the foldout page to prevent the pumps from running in an undesirable condition. (SER 88-089-06)

26. EOP-1.4, (Major), Transfer to Containment Sump Recirculation-One Train Inoperable, Revision 0. (Temporary)

Safety Evaluation Detail: The foldout page for the EOP-1 series was temporarily changed due to new Technical Specification heatup and cooldown curves (Figures 15.3.1-1 and 15.3.1-2) as specified by Regulatory Guide 1.99, Revision 2. (SER 89-100-02)

EOP-1.4, (Major), Transfer to Containment Sump Recirculation-One Train Inoperable, Revision 1. (Permanent)

Safety Evaluation Detail: Step 12 Substep c was added to locally shut the spray pump mini-recircs because of the possibility of recirculating potentially contaminated water into the refueling water storage tank. Step 14 was added to consult with the TSC prior to exiting this procedure to determine sodium hydroxide requirements to control sump pH and to reduce airborne iodine concentrations. In Figure 1, the appearance of the Unit 1 recirculation shield was changed for easier identification by the operators. A symptom and entry condition from EOP-1.3 (Revision 6) due to the added transitions caused by reevaluation of failure criteria to a single train operation. (SER 89-100-03)

EOP-1.4, (Major), Transfer to Containment Sump Recirculation, One Train Inoperable, Revision 1. (Temporary)

Safety Evaluation Detail: The temporary change added Step 15, to manually reset battery chargers when diesel generator loading permits. This is an EOP standard step and was added because of the possibility of a LOCA coincident with a loss of offsite power and one diesel inoperable. If one diesel is inoperable during the accident, the possibility of overloading the EDG exists until this point in the EOP. At this point, if diesel loading permits, the battery chargers should be reloaded onto the buses. (SER 89-100-04)

EOP-1.4, (Major), Transfer to Containment Sump Recirculation, One Train Inoperable, Revision 2. (Permanent)

Safety Evaluation Detail: A reset battery charger standard step was added because of the possibility of a loss of reactor coolant accident coincident with a loss of offsite power and one diesel inoperable. If one diesel is inoperable during the accident, the possibility of overloading the diesel generator exists until this point in the EOP-1.4 procedure. At this point, if the diesel generator loading permits, the battery chargers should be reloaded onto the buses. (SER 89-100-05)

EOP-1.4, (Major), Transfer to Containment Sump Recirculation-One Train Inoperable, Revision 2. (Temporary)

Safety Evaluation Detail: The procedure was temporarily changed in accordance with approved safety evaluation report SER 90-120. This safety evaluation report authorized the changes in response to the WE evaluation of NCR N-90-157.

NCR N-90-157 was written to report the fact that ORT 2 tests performed during the Unit 1 1990 refueling outage showed that both Unit 1 RHR pumps develop less than the 95% of design head limit listed in ASME Section XI Subsection IWP. The Unit 1 Train "B" pump develops less than 89%. The evaluation of the NCR has shown that an operability concern exists with the emergency core cooling system (ECCS) while operating on containment sump recirculation. The evaluation establishes the NPSH requirements of the containment spray pumps by determining a conservative containment sump temperature at the time of switchover from injection to recirculation (containment saturation temperature up to 250°F).

The temporary changes state that the containment spray pumps shall not be operated if containment pressure is <50 psig or <40 psig containment pressure with train-specific low head safety injection flow secured, or the high head safety injection flow is secured with >10 psig containment pressure. Step 10 is deleted due to the operability impact of the spray pumps on recirculation or the containment sump using the RHR pumps as a suction source. These conditions are contained in the foldout of the EOP-1 series. The proposed change will prevent damage from occurring to the containment spray pumps due to inadequate NPSH.

The major concern is providing adequate net positive suction head (NPSH) to the containment spray and SI pumps. When both the CS and SI pumps are running, the CS pump is limited when it comes to NPSH for two reasons. The absolute pressure at the suction of the SI pump is higher than at the CS pumps. Additionally, the NPSH required by the SI pump is less than that of the CS pump.

Calculation N-90-045 was performed in order to determine the amount of cooling required for the RHR heat exchangers to maintain adequate NPSH for the CS pumps during containment sump recirculation. The calculation was based on a uniform degradation of the manufacturer's pump curve by 20% of the design head of the pump (280 ft water) in order to provide some margin in the calculation.

In this calculation, it was determined that while on high head sump recirculation with containment spray, only one train operable, and RCS pressure = 0 psig, a containment pressure of 50 psig is required to maintain adequate NPSH to the CS pump. This assumed that the flow control valves in the core deluge lines had failed open due to loss of instrument air. If instrument air is available to these valves and they are completely shut, the CS pumps could not be operated at containment pressure <50 psig if the high-head SI pumps are running. If the high head SI pumps are secured (using low head recirculation), it was determined that adequate NPSH is available for the CS pumps only if containment pressure is >10 psig. It should be noted that the above containment pressure requirements do not include instrument error.

For two-train operation of high head recirculation, SI pump flow rate is less than that for a single train. This results in a lower flow rate through the common line feeding the CS and SI pumps, and therefore, less head loss. CS pump suction pressure will be higher, and thus less cooling of the sump fluid will be required by the RHR heat exchanger. This combined with the fact that more cooling will be available by the RHR heat exchanger with two trains of safeguards operable, means that the single train case is more limiting (two trains of ECCS cannot be operated with only one train of safeguards operable). The single train calculations bound the two-train case.

From a radiological perspective, containment spray is not required to operate while on sump recirculation to satisfy 10 CFR 100 (offsite dose) requirements, since most of the iodine released to the containment atmosphere has been scrubbed during the first 20 minutes of the injection phase (see Calculation N-90-068, Part 100 Evaluation for NCR N-90-157).

The evaluation of NCR N-89-275 showed that sodium hydroxide addition was not required following the injection phase and could be secured.

Lastly, in Section 6.4.2 of the FSAR it states that after the injection phase, it is expected that containment spray would not be required. The fan cooler units are sufficient to reduce containment pressure once on recirculation. Accordingly the setpoint in Step 3 is changed to stop the containment spray pumps when the spray additive tank reaches the setpoint of 12%. This is to prevent the sump from exceeding its FSAR sump pH limit of 10.0 stated in the NCR N-89-275. Step 11 Substep f was added to give the criteria for stopping the spray pumps in accordance with the foldout page to prevent the pumps from running in an undesirable condition. (SER 89-100-06)

27. EOP-2, (Major), Faulted Steam Generator Isolation, Revision 3. (Permanent)

Safety Evaluation Detail: The symptom or entry conditions from EOP-0 were changed because one immediate action step was eliminated in EOP-0. (SER 89-038-02)

28. EOP-3, (Major), Steam Generator Tube Rupture, Revision 6. (Permanent)

Safety Evaluation Detail: A standard step was added to restore battery chargers when diesel loading permits following a loss of offsite power. This prevents the batteries from running down. Appendix B was added to give the operator kilowatt load information for the diesel to prevent possible overloading of the diesel. An addition to the first note for Step 14 was made to prompt the operator to Appendix B. There were also symptom or entry condition changes from EOP-0 because of a decrease in the number of immediate actions and from ECA-3.1 because the standard battery charger step addition, respectively. (SER 88-090-05)

EOP-3, (Major), Steam Generator Tube Rupture, Revision 7. (Permanent)

Safety Evaluation Detail: An entry condition from ECA-2.1 was added when secondary radiation is abnormal. This entry condition was inadvertently omitted during the Revision 1A changes to the ERGs. This revision also locally isolates P29 turbine-driven auxiliary feedwater pump governor sensing line from the ruptured steam generator. These valves are needed to completely isolate the ruptured steam generator and prevent the spread of contamination. (SER 88-090-06)

EOP-3, (Major), Steam Generator Tube Rupture, Revision 8. (Permanent)

Safety Evaluation Detail: Appendix B emergency diesel generator kilowatt loading values were changed as a result of new calculations performed which incorporate motor efficiency and other applic ble engineering variables. This change addressed Deficiency 90-201-03 contained in NRC Inspection Report 266 & 301/90-201. (SER 88-090-07)

29. EOP-3.1, (Major), Post-SGTR Cooldown Using Feedwater, Revision 3. (Temporary)

Safety Evaluation Detail: A step was temporarily changed due to new Technical Specification heatup and cooldown curves (Figures 15.3.1-1 and 15.3.1-2) as specified by Regulatory Guide 1.99, Revision 2. (SER 89-039-03)

EOP-3.1, (Major), Post-Steam Generator Tube Rupture Cooldown Using Feedwater, Revision 4. (Permanent)

Safety Evaluation Detail: The temperature indicated in the second note for Step 11 was changed from 354°F to 360°F due to new Technical Specification temperature and pressure limits associated with reactor vessel embrittlement. The symptom or entry condition from EOP-3 was changed as a result of the addition of the battery charger standard step. (SER 89-039-04)

EOP-3.1, (Major), Post-Steam Generator Tube Rupture Cooldown Using Feedwater, Revision 5. (Permanent)

Summary of Safety Evaluation: The setpoint for the pressurizer power-operated relief valve (PORV) nitrogen pressure regulator was changed from 85 psig to 100 psig to meet the 2-second opening criteria set forth in Amendments 45 and 50. (SER 89-039-05)

30. EOP-3.2, (Major), Post-Steam Generator Tube Rupture Cooldown Using Blowdown, Revision 4. (Permanent)

Safety Evaluation Detail: The second note for Step 9 was changed from 354°F to 360°F as a result of new Technical Specification temperature and pressure limits associated with reactor vessel embrittlement. A symptom or entry condition was also revised as a result of battery charger standard step being added to EOP-3. (SER 89-085-04)

EOP-3.2, (Major), Post-SGTR Cooldown Using Blowdown, Revision 5. (Temporary)

Safety Evaluation Detail: The procedure was temporarily changed due to new Technical Specification heatup and cooldown curves (Figures 15.3.1-1 and 15.3.1-2) as specified by Regulatory Guide 1.99, Revision 2. (SER 89-085-03)

EOP-3.2. (Major), Post-Steam Generator Cooldown Using Blowdown, Revision 5. (Permanent)

Summary of Safety Evaluation: The setpoint for the pressurizer power-operated relief valve (PORV) nitrogen pressure regulator was changed from 85 psig to 100 psig to meet the 2-second opening criteria set forth in Amendments 45 and 50. (SER 89-085-05)

31. EOP-3.3. (Major), Post-SGTR Cooldown Using Steam Dump, Revision 5. (Temporary)

Safety Evaluation Detail: Step 9 and the foldout page for the EOP-3 series were temporarily changed due to new Technical Specification heatup and cooldown curves (Figures 15.3.1-1 and 15.3.1-2) as specified by Regulatory Guide 1.99, Revision 2. (SER 89-040-05)

EOP-3.3. (Major), Post-Steam Generator Tube Rupture Cooldown Using Steam Dump, Revision 6. (Permanent)

Safety Evaluation Detail: The temperature indicated in the second note for Step 9 were changed from 354°F to 360°F as a result of new Technical Specification temperature and pressure limits associated with reactor vessel embrittlement. The symptom or entry condition from EOP-3 was also changed to reflect addition of the new standard battery charger step. (SER 89-040-06)

EOP-3.3. (Major), Post-Steam Generator Tube Rupture Using Steam Dump, Revision 5. (Permanent)

Summary of Safety Evaluation: The setpoint for the pressurizer power-operated relief valve (PORV) nitrogen pressure regulator was changed from 85 psig to 100 psig to meet the 2-second opening criteria set forth in Amendments 45 and 50. (SER 89-040-07)

32. ICP 11.443A&B, Unit 2, (Major), Safeguards Train A Test Switch Replacement, Revision 0. (New Procedure)

Summary of Safety Evaluation: The procedure replaces Train A and B safeguards test switches in conjunction with AC relay replacement. This procedure is valid only if performed in conjunction with the relay replacement procedure. TS 15.3.8 requires that the containment purge and vent system be operable during refueling. This includes the purge and vent isolation system. Redundant containment ventilation isolation signals are generated in Train A and Train B of safeguards. This safety evaluation provides a basis for allowing the removal of a single train of safeguards during refueling.

The purge exhaust isolation valves are CV-3212 and CV-3213 and the purge supply valves are CV-3244 and CV-3245. The valves are in series, therefore, isolation can be achieved by closing one valve in the supply line and one valve in the exhaust line. The containment ventilation signal from safeguards Train A closes outer valves CV-3212 and CV-3244, while safeguards Train B closes inner valves CV-3213 and CV-3245. As a result of this system design, either train of safeguards is independently capable of isolating the purge supply and exhaust system. Operability of the circuit that trips the purge exhaust fans when the exhaust isolation valves close will not be compromised because closing either one of the exhaust isolation valves causes the exhaust fans to trip.

A test of the purge supply and exhaust isolation system is conducted prior to refueling in Step 6.4 of Operations refueling procedure RP-1C. The acceptance criteria states that both supply and both exhaust isolation valves close upon manual initiation or with a high radiation test signal. A temporary change to this procedure will be required. This test, however, wi: ensure that the isolation initiation circuit and associated isolation valves are operable prior to moving fuel.

The purge exhaust and supply isolation circuit and system incorporates redundant actuation and isolation features. These features, along v ʺh the testing that is conducted prior to fuel shuffle and periodically during fu. shuffle, if required, ensures single train isolation operability, thereby allowing one train of safeguards to be removed from service during the refueling evolution. (SER 90-081)

33. IT-14, (Major), Inservice Test of Fuel Oil Transfer System Pumps & Valves, Revision 0. (New Procedure)

Summary of Safety Evaluation: Procedure IT-14, Revision 0 performs a quarterly test of the fuel oil system as required by ASME Section XI. At several points in this procedure, one of the fuel oil transfer pumps is out of service. This test does not remove both fuel oil transfer pumps from service.

If the emergency diesel generators receive a start signal while either pump is out of service, the sump tank and day tank initially provides fuel oil. The remaining pump can supply fuel oil to the emergency diesel generators although the flow rate may be reduced. Experience has indicated that the sump tank and day tank will supply the emergency diesel generator for about one hour before the fuel oil transfer pumps start. If the day tank and sump tank are at their minimum level, with no low level alarms present, they will provide a supply for a minimum of two hours before the fuel oil is completely depleted.

The fuel oil pumps are administratively controlled and can be promptly returned to service should the need arise. The inservice test configuration is acceptable for the short duration required to perform the test. No LCO or other TS requirement has been found concerning removal of the fuel transfer pumps from service. (SER 90-005)

34. IT-515, Unit 2, (Major), Leakage Reduction & Preventive Maintenance Program Test of Safety Injection Test Line & Spray Additive Eductor Line (Refueling), Revision 2. (Temporary)

IT-515B meets the requirements of the leakage reduction and preventive maintenance program by performing a leak test of the SI test line, and the c ›ːainment spray system eductor supply line. The temporary change allowed for this surveillance test to be performed at power rather than during a cold or refueling shutdown.

Summary of Safety Evaluation: There are two concerns with performing this test at power. During the test of the SI test line, SI-897A and SI-897B will be closed, one at a time, to provide a leakage boundary. Secondly, during the spray system eductor supply line test, the spray additive tank will be isolated from the rest of the system. It is felt that proper administrative controls have been included such that these conditions will not jeoparcize the safe operation of the plant.

While the SI test line is being tested, a designated operator will be assigned to immediately open SI-897A or SI-897B or secure the SI pumps if the pumps automatically start with reactor coolant system pressure greater than 1500 psi. These valves are designed to shut if either containment sump recirculation valve (MOV-851A or B) opens from its shut position. They also fail shut upon loss of instrument air or loss of control power. The original design of the safety injection system had taken credit for operator action in the unlikely event that 897A and 897B go shut, while the SI Pumps are operating above shutoff head

As a result of an investigation in 1985, 897A and 897B are now gagged open to prevent them from shutting when the recirculation path is needed. There is extensive discussion documented concerning the loss of power to the 851A or B valves causing the 897A or B valves to shut. The control logic problems have since been corrected, but the valves remain gagged open since they will fail shut upon a loss of air.

An annunciator alarm is received on main control board CO1 when either test line valve 897A or B is shut. This provides a continuous reminder to the operators that these valves are not in their normal alignment. The combination of the annunciator, the designated operator, the tight procedural control over the test, and the relatively brief period that either 897A or B will be closed to provide adequate assurance that the SI system is not jeopardized during this test. SI-897A and SI-897B only provide pump protection if safety injection is not required. They have no effect on the operation of the SI system should injection be needed.

The test of the containment spray system eductor line isolates the spray additive tank by shutting SI-831A, SI-874A and SI-874B. In addition, valves SI-863B and SI-V-13 are open during the test. As for the SI system, a designated operator is assigned to reposition these valves. If a containment spray system actuation occurs while performing this test, the pumps will start and inject RWST water into containment, without any operator action.

Two containment spray pumps provide adequate cooling of the containment, even without the sodium hydroxide addition. This is stated in the basis for TS 15.3.3. This section also states that the purpose of sodium hydroxide is to reduce airborne iodine activity.

Immediate injection of sodium hydroxide is not required to reduce the containment pressure following an accident. The valves from the spray additive tank are designed with a two-minute delay in opening after the containment spray actuation. This delay provides time for the operator to ensure that sodium hydroxide injection is needed. The purpose of the sodium hydroxide is a long-term concern of iodine removal. An additional delay caused by the need to reposition the valves in the line would not significantly affect this function.

The designated operator to reposition valves, the procedural controls on the operation of these valves, and the short duration of this test provide assurance that, should an accident occur while performing this test, adequate cooling of containment is available.

Because a valve in the containment spray system will be inoperable, a 24-hour LCO when containment spray additive tank manual isolation valve SI-831A is shut. This LCO is stated in TS Section 15.3.3.B.2.c. (SER 89-148)

35. IT-1025, Unit 2, (Major), 10-Year Hydrostatic Test of Main Steam Generators & Associated Systems, Revision 3. (Permanent)

The safety evaluation was conducted to examine the effects of a higher than normal fluid temperature in the condensate storage tanks (CSTs) and AFW system during portions of the conduct of IT-1025, Revision 3.

Summary of Safety Evaluation: The test calls for the use of water in a temperature band of 120°F-140°F in the CSTs and AFW system during the fill and pressurization stages of the test procedure; which is a 10-year hydrostatic test of the main steam generators and portions of the main steam system. Four primary items of concern were addressed: (1) Condensate storage tank liner; (2) Affect on net positive suction head (NPSH) available to the AFW pumps; (3) Affect on stresses on power piping in the AFW system; and (4) The decay heat removal capability of the AFW system.

The evaluation identifies no effect on Items 1 through 4 above due to the slightly higher temperatures based on reviews of technical information, applicable codes and applicable accident analyses. (SER 90-086)

36. OP-1A; MWRs 902064/902065, (Major), Cold Shutdown to Low Power Operation, Revision 42, OP-3C, (Major), Hot Shutdown to Cold Shutdown, Revision 45, February 28, 1990. (Temporary)

The changes to procedures OP-1A and OP-3C removed the high pressurizer pressure open signal from the pressurizer power-operated relief valves when the low temperature overpressure protection (LTOP) system is placed into service and will restore the signal when LTOP is no longer desired.

Summary of Safety Evaluation: The changes remove the potential of a single failure causing both pressurizer power-operated relief valves (PORVs) to fail closed when the overpressure mitigating system is required as specified in TS 15.3.15. The single failure could occur since field cabling going into 1(2)C158 for both "A" and "B" trains runs in the same riser R82 (R92). This cabling is used to pick up interlocks which open the PORVs on high pressurizer pressure (2335 psig). With this cabling removed from the circuit, by opening sliders in C04, when the overpressure mitigating system is required, it will prevent the potential single failure placing the plant in a condition where the RCS must be depressurized and vented to the pressurizer relief tank (PRT) within 8 hours as required by TS 15.3.15.A.4. When the overpressure mitigating system is no longer required, the circuit will be reestablished.

Most of the time when LTOP is in service, the RHR system is connected to the RCS so the RHR relief valve provides redundant and independent means of overpressure protection. The LTOP system is considered to be control grade, Seismic Class 1, as accepted in the safety evaluation for Amendment 45 (Unit 1) and Amendment 50 (Unit 2). Therefore, removing the high pressurizer pressure signal when on LTOP only better assures operability of the control grade LTOP system. Also, by removing the potential single common mode failure, the PORVs would not fail open when LTOP is in service. Disabling the high pressurizer pressure signal from the PORVs is acceptable since the LTOP setpoint will be substituted at this same time and the high pressurizer pressure setpoint cannot be attained.

Reestablishing the high pressurizer pressure open signal path when LTOP is not desired is considered to be acceptable. The single common mode failure will exist; however, it will not degrade any safety function. Failures could occur that would cause both PORVs to fail open or fail closed. If both were to fail open, a small break LOCA would be the result. However, the consequences of this accident or malfunction would not be significantly greater than the failure of one PORV open.

This double PORV open failure is also within the analysis of the small break LOCA. This may also be mitigated by shutting the upstream block valves. If both PORVs were to fail closed, pressure transients could not be mitigated by use of the PORVs (e.g., as used in EOP-3, "Steam Generator Tube Rupture"). This use, however, is not the primary or secondary choice for depressurization. The use of PORVs to mitigate overpressurization is not mentioned in the accident analyses, FSAR Chapter 14. Therefore, the Technical Specifications that exist for the PORVs (TS 15.3.1.A.5) are to control operability of the control function and system, and not the operation of a safety-related function.

The changes being performed are to better assure operability of the PORVs when needed for LTOP, which is considered control grade. Also, since operability of the PORVs is not considered to be a "safety-related" function, the safety-related designations that exist on PORV elementary wiring diagrams and on system cabling should be removed. (SER 90-043)

37. RMP 2M, (Minor), Proposed Revision 8, Reactor Coolant Pump Maintenance. RMP 2P, (Minor), Proposed Revision 7, Reactor Coolant Pump.

The procedural temporary modification, temporary procedure changes and subsequent permanent procedure changes to RMP 2P and RMP 2M, involve installing a strongback on a reactor coolant pump with or without the motor installed. These evolutions were previously evaluated in safety evaluations via SER 86-073-01 and SER 86-073-02.

Summary of Safety Evaluation: Two evolutions are considered: One being the installation of a strongback to make up the seals when the motor is not installed; the other is the installation of a strongback with the motor installed to enable flywheel removal. The strongback used was evaluated in Calculation P-88-031 and determined to be capable of supporting the pump rotating element, motor rotor and flywheel. An evaluation is required because the proposed evolution constitutes an alteration to a system, structure or component as described in the FSAR.

Case 1. Motor Removed (RMP 2P): The strongback provides the axial force needed to raise the pump shaft and make up the seals to allow flooding of the reactor cavity. Failure of the strongback, resulting in a leak of reactor coolant system water, would not allow the RCS to drain low enough to prevent residual heat removal operation nor would it drop low enough to enter OP-4F mid-loop operations (55% reactor vessel level). Sufficient time is considered to be available in the event that a leak develops due to strongback failure to replace a fuel assembly back into the reactor vessel if one is in the manipulator at the time of the hypothesized failure.

Case 2. Motor Not Removed; Flywheel To Be Removed (RMP 2M): The flywheel holds the thrust bearing runner in place. Thus, a means of holding the pump rotating element and motor rotor in axial position when removing the flywheel is required. If the pump is held in axial position, the seal faces would open up, creating a leak. The strongback was designed with adequate margin to support the pump rotating assembly motor rotor and flywheel. Should the strongback fail and the pump shaft drop, the leakage out through the pump seals would still be restricted. This leakage would be relatively slow and would be detected by the seal leakoff alarm or containment sump alarm. Action could then be taken to provide makeup to the RCS and to place a fuel assembly, if one is in the manipulator, back into the core.

If the shaft should drop, the shaft has a step machined on it that sets on a ledge in the thermal barrier. This was designed into the pump to be a leak limiting seal and is used by some plants to allow seal work with the cavity flooded. A leak from the pump seal area will not uncover the reactor core and in fact, will not drain the RCS to below the top of the loops. Thus, residual heat removal will remain operable.

Common Considerations: The strongback shall not be installed or removed during mid-loop operation unless an acceptable RCS hot leg vent exists in accordance with OP-4F. Mid-loop conditions may not be entered with the strongback in place unless an acceptable hot leg vent exists in accordance with OP-4F. The strongback is not capable of holding the shaft down and RCS pressurization on a loss of RHR at mid-loop could lift the shaft and possibly damage the seals; and create a cold leg break. (SER 86-073-03)

38. RMP 23A, Unit 1, (Minor), 480 V Breaker Maintenance, Revision 1. (Permanent)

Temporary jumpers are installed and removed in the control circuit for 1B52-16B, 1B52-16C and 1B52-17B to allow remote operation of the breakers under "non-dead bus" conditions.

Summary of Safety Evaluation: The dead bus interlock is presently bypassed by manual operation of the breaker (by use of the breaker operating bar) or by physically picking up the "x" coil contact of the breaker and allowing the breaker to electrically operate. This manual operation can be a safety hazard to the personnel operating the breaker. By use of the jumpers, operation of the breakers is done remotely and keeps some of the interlocks in the circuit (e.g., 4 kV feeder to 1X13/1X14 must be shut to ensure transformer is not energized from the low side).

Use of the jumpers is minimized during breaker operation and since there is no automatic closure of these breakers, it is still administratively controlled by the control room. All operations are strictly controlled by the procedure and double verification is used during the installation and removal of the jumpers. (SER 89-059-02)

39. RMP 23B, Unit 2, (Minor), 480 V Breaker Maintenance, Revision 1. (Permanent)

Temporary jumpers are installed and removed in the control circuit for 2B52-25B, 2B52-40B and 2B52-40C to allow remote operation of the breakers under "non-dead bus" conditions.

Summary of Safety Evaluation: The dead bus interlock is presently bypassed by manual operation of the breaker (by use of the breaker operating bar) or by physically picking up the "x" coil contact of the breaker and allowing the breaker to electrically operate. This manual operation can be a safety hazard to the personnel operating the breaker. By use of the jumpers, operation of the breakers is done remotely and keeps some of the interlocks in the circuit (e.g., 4 kV feeder to 2X13/2X14 must be shut to ensure transformer is not energized from the low side).

Use of the jumpers is minimized during breaker operation and since there is no automatic closure of these breakers, it is still administratively controlled by the control room. All operations are strictly controlled by the procedure and double verification is used during the installation and removal of the jumpers. (SER 89-053-03)

40. RMP 30, (Minor), Routine Maintenance Procedure, Opening of Pressurizer Manway, Revision 3. (Permanent)

The revision specified and described the temporary cover to be installed over the pressurizer manway. An evaluation was required because installation of the cover over the pressurizer manway could have an impact on the consequences of a loss of RHR accident when in mid-loop operation. This accident is not described in the FSAR but is the subject of NRC Generic Letter 88-17.

Summary of Safety Evaluation: Installing a temporary cover over the pressurizer manway has the potential of impacting the assumed vent path for RCS protection during loss of RHR during mid-loop. An evaluation was performed to determine acceptable hot leg vent paths to prevent RCS pressurization and ejection of fluid from a cold leg opening. The analysis states that a vent capable of maintaining RCS pressure <2 psig following boiling in the core is required to minimize or prevent spillage out of a cold leg opening. Figures 7 and 8 of the subject letter show the vent size needed (in terms of resistance factor) to meet this requirement.

The resistance for the pressurizer vent path was calculated to be 26 ft^{-4} with the surge line being the limiting path. The cover over the manway will result in a pressure buildup in the pressurizer until the cover is lifted off. This pressure buildup will reduce the available pressure drop through the surge line. The static pressure required to move the cover is calculated to be p = 0.039 psi.

As the cover tips, the required force (pressure) will continue to decrease until it is blown off.

This pressure differential would only reduce the available pressure drop for the surge line by about 2% and thus, has an insignificant impact.

The pressurizer manway is considered an acceptable vent after 108 hours assuming an initial RCS temperature of 140°F. The boiloff rate at 108 hours after shutdown is about 5.5 lbm/sec; 5.5 lbm/sec of 212°F steam blowing through the manway would have an impact momentum force of 18 lbf. There is sufficient force to blow the cover completely off. A cover weight of up to 18 lbf is considered acceptable. This would be a 3% reduction in the P available for the surge line.

Installation of this cover over the pressurizer manway opening as a safety precaution and to prevent foreign objects from entering the pressurizer is acceptable and has no impact on the consequences of a mid-loop loss of RHR accident provided the time since reactor shutdown has been >110 hours (consistent with OP-4F). RMP 30 requires the cover to be less than 18 lb. <u>(SER 89-072-02)</u>

41. <u>RMP 76</u>, (Minor), 4 kV Loss of Voltage Relaying & Auxiliary Feedwater Indication, Revision 2. <u>(Permanent)</u>

The revision added surveillance for undervoltage relay testing associated with nonvital bus (A01 and A02) stripping, including reactor coolant pump (RCP) breaker trip on bus undervoltage. Because of the consequences of actuation of bus stripping (including RCP breaker trip and reactor trip), the actuation signal is disabled during the course of the test by opening a knife switch in series with the actuation circuit.

<u>Summary of Safety Evaluation</u>: Prior to performing the test, the primary protection from loop low flow bistables is verified operable. The test itself will provide better reliability of the "RCP breaker trip from bus UV" signal, and thus, improve reliability of the backup protection for single-loop reactor coolant low flow trip. There is no effect on the total loss of flow analysis since the undervoltage reactor trip relays are not tested in this procedure.

The duration of the test is expected to be less than one hour during the month, and thus the surveillance is justified to improve reliability. When the knife switch is restored to operable status, the continuity of the circuit is again verified. The knife switch (cover) is also administratively controlled with red locks and independently verified.

Although the disabling is not directly indicated in the control room, operators are knowledgeable of the procedure in effect and the annunciation of 4 kV undervoltage alarms. Additionally they are informed by the procedure that the reactor trip signal from "RCP breaker trip on UV" is disabled during the procedure. These meet the intent of continuously indicating the disabling condition in the control room and keeping the operator aware of the ramifications of the inoperable condition. <u>(SER 90-079)</u>

42. RMP 78, (Minor), CC-719 Valve Operator Maintenance, Revision 1. (Permanent)

This safety evaluation amends SER 88-037 to incorporate operator maintenance on valve 2CC-719 by installation of a stem clamp. The original evaluation addressed only 1CC-719.

Summary of Safety Evaluation: Valve CC-719 is kept in the open position during normal operation. This valve provides an isolation for the component cooling water (CC) to containment. The valve does not receive an auto close signal and is not required to close for containment isolation. The component cooling water is supplied to the reactor coolant pumps and the excess letdown heat exchanger. During a cold shutdown or refueling shutdown with both reactor coolant pumps secured, CC-719 can be closed. The component cooling water system provides cooling for the residual heat removal system during a cold shutdown or refueling outage.

The design of the clamp is adequate to maintain the valve closed and not damage the valve stem. The weight of the stem clamp is less than the weight of the valve operator; therefore, the seismic stresses will be reduced.

Clamping this valve closed will not increase the probability of a loss of residual heat removal. Installation of the clamp does not affect the pressure boundary of the valve and the valve is not being used as an isolation valve; other valves exist for tagging components out of service to be worked on. Thus, the pressure-retaining boundary of the component cooling water system is not degraded. The clamp will not see any seismic loading because the valve is shut, vertically-oriented and the vertical "g" forces are not enough to overcome the weight of the components. The weight of the components was conservatively left out of the clamp load calculation.

The valve stem will not be supported horizontally with the motor operator removed during a seismic event. By engineering judgment, this is not considered a problem because the 1-1/2" diameter stem only extends about 12" above its support point in the valve gland.

It was assumed that the piping was designed as required to have a natural frequency above 30 Hz. Removal of the motor operator reduces the weight which would increase the natural frequency, so the above 30 Hz "g" loads can be used.

This valve is shown as an MOV in the P&ID figure in the FSAR. Thus, removal of the motor operator could be considered as a change to the facility as described in the FSAR.

It is recognized that the clamp does not exert a force on the valve stem to push the wedge into the seat. This fact is not considered to be a problem with respect to maintaining a leak-tight shutoff. The reason for this is because the valve will have been shut with the motor operator prior to installing the clamp and removing the motor operator. Thus, the valve disc will have been wedged into the seat with the normal closure force. The valve stem must have some travel prior to starting to move the disc. Also, from MOV testing, it has been noted that a considerable force is required to pull the disc out of the seat. Based on this, it is expected that the disc will remain wedged in the seat and will have the same leak-tightness with the clamp installed as it had with the motor operator installed. (SER 88-037-01)

43. RMP 84, (Minor), SI-370 Valve Operator Maintenance, Revision 1. (Permanent)

This safety evaluation amends SER 88-029 to incorporate operator maintenance on valve 2SI-870B by installation of a stem clamp. The original evaluation addressed only 1SI-870B.

Summary of Safety Evaluation: This safety evaluation amendment accomplishes corrective actions specified in the referenced NCR and amends SER 88-029 to incorporate operator maintenance on valve 2SI-870B. The amended safety evaluation follows.

Valve SI-870B is the suction isolation from the RWST for the "B" spray pump. This valve is open during normal operation. When a unit is in a cold shutdown, refueling outage or P14B is out of service, SI-870B can be closed. Via RMP 84, the valve is clamped in the closed position so the valve operator can be removed for maintenance.

The clamp has been designed not to damage the stem and to provide adequate force to keep the valve closed at system design pressures. The valve will only be clamped shut during a cold shutdown or refueling outage when operability of the spray system is not required. The fact that the valve is clamped closed does not pose a problem for the RWST. The seismic qualification of the system will not be adversely affected since the removal of the operator (200 lbs) and installation of the clamp (5 lbs) will reduce the system weight and the stresses on the system.

Additional seismic concerns are the possible effects of loading on the clamp and the unsupported valve stem with the motor operator removed. Since the valve is shut and mounted vertically, the clamp can only be loaded due to vertical down acceleration. Since the weight of the stem and disc was not subtracted out of the clamp force calculation, the vertical down "g" load would have to be greater than 1 g. Our SSE loadings are not that high, assuming the piping was designed as required with a natural frequency higher than 30 Hz. Removal of the motor operator weight would increase the natural frequency. The stem is unsupported in the horizontal direction above the gland with the motor operator off. By engineering judgment, the approximately 12" cantilevered, 1-1/8" diameter stem would not be a problem at our "g" loads.

Because the unit is in the cold shutdown or refueling shutdown condition, the spray system and RWST are not required for nuclear safety of the plant. The clamp is installed to keep the valve shut so it can be used as an isolation for the RWST for working on the out-of-service spray system. Maintaining the RWST as a possible source of boric acid for injection to meet TS 15.3.2.A is desirable, however. Since the pressure boundary is maintained and seismic capability is maintained, the RWST remains operable as a boric acid source.

This valve is shown as an MOV in the P&ID figure in the FSAR. Thus, removal of the motor operator could be considered as a change to the facility as described in the FSAR.

It is recognized that the clamp does not exert a force on the valve stem to push the wedge into the seat. This fact is not considered to be a problem with respect to maintaining a leak-tight shutoff. The reason for this is because the valve will have been shut with the motor operator prior to installing the clamp and removing the motor operator. Thus, the valve disc will have been wedged into the seat with the normal closure force. The valve stem must have some ravel prior to starting to move the disc. Also, from MOV testing, it has been noted that a considerable force is required to pull the disc out of the seat. Based on this, it is expected that the disc will remain wedged in the seat and will have the same leak-tightness with the clamp installed as it had with the motor operator installed. (SER 88-029-01)

44. RMP 85, (Minor), SW-2880 Valve Operator Maintenance, Revision 1. (Permanent)

The safety evaluation amends SER 88-036 to incorporate operator maintenance on valve 2SW-2880 by installing a stem clamp. The original evaluation addressed only 1SW-2880.

Summary of Safety Evaluation: Valve SW-2880 is normally open during operation. This valve supplies service water to the respective unit's turbine hall. The unit-specific valve would be required to close when safety injection is actuated on that unit and less than 4/6 service water pumps are running within 30 seconds. The affected unit in cold shutdown or in a refueling outage are prerequisites to operator removal and the valve stem being clamped open.

Since the safety injection system does not have to be operable during a cold shutdown or refueling outage this isolation feature does not have to be operable. The design of the stem clamp is adequate to hold the valve open without damaging the stem. Manual isolation valves are available should the turbine building service water need to be isolated for nonsafety-related reasons.

Clamping of this valve in the open position during cold shutdown or a refueling outage does not present an unreviewed safety concern. The valve stem clamp weighs less than the valve operator, therefore seismic stresses will be reduced. The seismic capability of the stem clamp was not addressed since failure of it has no nuclear safety consequences. By engineering judgment, seismic loading on the 1-3/16" diameter stem is not a problem.

The Technical Specifications require that two service water loop headers be operable. This is maintained with MOV-2880 clamped open since the seismic capability of the piping is maintained. The FSAR states that, "Motor-operated isolation valves are provided which are controlled remotely from the control room and which automatically isolate nonessential services in the event of a safeguards actuation signal." The previous discussion addressed this factor, however, the FSAR goes on to say, "The only portion of the system in a non-Class I structure is the piping in the turbine building to nonessential equipment. This portion of the system can be rapidly isolated by remotely-operated valves with redundant manual backup valves in the supply headers located in the Class I section of the control building."

With the motor operator removed from SW-2880 and the valve clamped open, the remote operation capability is lost. The probability of a failure of the piping downstream of this valve is not increased, only the time to isolate it would take longer, since a manual isolation valve would have to be used. The capability to remotely isolate the service water header would still be available to the operators to ensure adequate flow to the safeguards systems if required.

Because the redundant manual isolation valves are operable and the capability to remotely separate the service water headers remains, it is felt that the consequences of a failure of the turbine hall service water supply piping is not increased. (SER 88-036-01)

45. RMP 88, (Minor), CV-350 Valve Operator Maintenance, Revision 1. (Permanent)

The safety evaluation amends SER 88-038 to incorporate operator maintenance on valve 2CV-350 by installing a stem clamp. The original evaluation addressed only 1CV-350.

Summary of Safety Evaluation: Valve CV-350 is kept in the closed position during normal operation. The valve could be required to open in order to provide a path for emergency boration to bring the reactor to a cold shutdown condition. The use of this valve would only be needed in the event of an abnormal at power accident situation.

The required condition for stem clamping is cold shutdown or a refueling outage. With the unit in a cold shutdown condition, emergency boration is not required. The valve is clamped shut so 12% boric acid is not leaked into non-heat traced piping which would allow the boric acid to crystallize. The stem clamp is adequately designed to maintain the valve closed without damaging the stem. The weight of the stem clamp is less than the weight of the valve operator. Therefore, the seismic stresses will be reduced.

The valve is being clamped closed instead of isolating it so a path for boric acid injection from the boric acid storage tank remains available. Also, the boric acid recirculating pump and its flow path can remain in service. The pressure-retaining capability of the valve remains intact; thus, the piping on either side of the valve remains operable. A path is required to meet TS 15.3.2.A.

Leakage through the valve is not considered to be any more likely than with the motor operator on just prior to removing it. The valve will have been shut using the motor operator, which will have wedged the disc into the seat. The clamp will be installed prior to removing the operator; thus the established seal will not be disturbed. Even though the clamp will not exert a closing force on the valve, the seal is expected to be maintained based upon the fact that the stem must undergo some movement before it will start to move the disc. MOV testing has also shown that a considerable force is required to pull the disc out of the seat.

The clamp does not have to be seismic since failure of the clamp and opening of the valve has no nuclear safety consequences. By inspection, however, the clamp would be able to handle our seismic loads since it would only be subjected to loads from a vertical down acceleration. Assuming the piping was designed as required with a natural frequency above 30 Hz, the vertical "g" loads are not enough to offset the weight of the disc and stem. The natural frequency would increase with the removal of the motor operator weight. Seismic loading on the approximately 10" cantilevered 3/4" diameter stem is not considered a problem by engineering judgment.

With the unit in cold shutdown, removal of the motor does not affect any description in the FSAR. (SER 88-038-01)

46. RMP 150, (Minor), Installation & Removal of Purge Valve Component Bypass Lines, Units 1 & 2, Revision 0. (New Procedure)

Temporary jumpers were installed on the Unit 1 purge valves under TM 89-019. This was evaluated per SERs 89-090 and 89-090-01. This SER evaluates the same changes to both units' purge valves and reaches the same conclusion; that is, there will be no adverse effect on the purge supply and exhaust valves.

Summary of Safety Evaluation: Installation of a jumper around the cam-operated valve is necessary because the existing Unit 1 valves leak and the design of replacement valves and those currently installed on Unit 2 is such there is inherent leakage. Thus, the boot pressure will decay on a containment isolation or the loss of instrument air. The air pilot valve is also being jumpered out to further improve the leak tightness of the boot supply system.

The jumper will improve the sealing ability of the purge valves during a loss of instrument air by eliminating potential leaks in the boot air supply system. The cam-operated valve and the boot air pilot valve are in the control scheme for inflating and deflating the boot when the valve is manipulated. The jumper will be installed when the valve(s) are shut and they will not be operated with the jumper in place. This will be procedurally controlled by the RMP and applicable operating procedures including OP-3C, OP-9C, TS-35/36, IT-360/365, IT-380/385, OI-64, and WMTP 12.18, as appropriate. The jumper is intended to be in place whenever the unit is not in the cold or refueling shutdown mode except as allowed by TS 15.3.6.C.

When the jumper is removed, the valves will function as originally designed and will be able to close as required during refueling operations for containment closure for mid-loop operation. Loss of instrument air and the need to maintain boot pressure to seal against containment pressure for an extended period of time is not considered a part of the design requirements for these conditions.

When the jumper is installed, the sealing capability of the valve and boot supply system will be verified per TS-35(36) and IT-380(385).

When the jumper is removed, operability of the valve and control system will be verified by IT-360(365) and by RP-1C. (SER 89-020-02)

47. RMP 152, (Minor), Installation & Removal of Penetration 67 Foam Assembly for Steam Generator Eddy Current Cables, Revision 0. (New Procedure)

Summary of Safety Evaluation: The basis of the foam penetration is to provide a leakage limiting barrier for refueling operations for steam generator services cabling. The leakage is driven by HVAC-induced pressures only. The maximum static pressure the purge supply fans can provide is ~4" of water. There is no established criteria for leakage during this operating mode.

The intent was to provide a reasonable seal for the design configuration (e.g., limit leakage to cable sheathing for standard steam generator cabling). The leakage goes to the primary auxiliary building and would be monitored by the radiation monitoring system and filtered by the primary auxiliary building HVAC charcoal filters if a high airborne problem is detected.

Thus, the leakage criteria in RMP 152 could be relaxed from 10 lpm at 5 psig to a somewhat lower pressure value without having any impact on the public health and safety. This is in concert with the existing fuel handling accident analysis as it assumes the radgas released to containment is discharged to the atmosphere. However, it should be noted that the analysis also acknowledges that containment will be available to minimize the release (but does not credit this in the offsite dose calculation). The leakage to the primary auxiliary building is not a concern from a licensing standpoint as it would be much less than that which would be present during a fuel handling accident in the spent fuel pool area. Thus, a reduced leakage criteria of 10 lpm at .5 psig is acceptable. (SER 90-092)

48. RMP 168, (Minor) Unit 1(2), Calibration and Testing of Safety-Related Protective Relays Not Under Technical Specifications, Revision 0. (New Procedure)

The procedure performs routine annual calibration and testing of safety-related protective relaying not covered by Technical Specifications associated with 4 kV buses A05 and A06. It does not cover protective relaying associated with the emergency diesel generators.

Summary of Safety Evaluation: During performance of the calibration and testing, single relays are removed, calibrated and tested for equipment which remains in service and operable. For the phase and ground overcurrent relays associated with the 4 Kv supply breakers for the X13 and X14 station service transformers or the P15A or B safety injection pump motors, removal of one relay at a time is acceptable because the remaining three phase and ground overcurrent relays provide adequate protection for the load.

During calibration of the A05 (A06) bus differential relays, one phase differential protection relay will be removed at a time. When this is performed, protection will be provided by the A03 (A04) phase overcurrent relaying, the diesel generator G01 (G02) phase overcurrent relaying and the A05 (A06) bus load phase overcurrent relaying. Initial conditions are established to ensure that the A05/A06 buses are not tied together and the B03/B04 buses are not tied together. This will ensure that a single fault will not affect both trains of safeguard power.

Throughout the testing, all equipment will remain properly coordinated electrically to permit safe operation of the equipment under normal and short circuit conditions. (SER 90-096)

49. SMP 1042, Unit 1, (Minor), Reduce Spring Preload on PORV 1RC-430, Revision 0. (New Procedure)

Summary of Safety Ev tio. The work to be performed under SMP 1042 is sir ilar to the PORV spring adjust ormed under SMP 1007. SMP 1007 was evaluated by SER 89-066-02. This SE applies to SMP 1042 except that:

- The work will be controlled by SMP 1042, not a temporary modification. (A procedural temporary modification was used for the PORV spring adjustment in SMP 1007. The review of this temporary modification is valid for SMP 1042.
- Due to a change in the Technical Specifications since SMP 1007 was performed, SMP 1042 referenced the reactor coolant system temperature at which LTOP is required as 360°F, not 354°F. (SER 89-066-04)

50. SMP 1045, Unit 1, (Minor), Replace Flange & Reducer Downstream of Valve SW-144, Revision 0. (New Procedure)

The 8"x14" reducer downstream of SW-144 was eroded due to cavitation. Per TM 89-033, a second reducer was sandwiched over the top of the original and welded in place to provide replacement wall thickness while the line was in service. MWR 900299 was written to replace the reducer and flange with stainless steel components. The material substitution was authorized based upon a generic evaluation done for MR 87-158. SMP 1045 coordinates the evolution to replace the reducer and flange.

Summary of Safety Evaluation: The work requires the Unit 1 fan coolers to be out of service. Thus, the replacement was done during a refueling or cold shutdown. Other equipment was taken out of service as addressed in the SMP. This included the service building cooling coil, service building chiller, Unit 1 electrical equipment room cooler, auxiliary building cooling coil, SGBD analysis cabinet, and the gas analyzer sample cooler. Outside air can be recirculated as necessary in those areas where ventilation cooling coils are taken out of service. In regard to the gas analyzer sample cooler, the RETS-required sample from the gas decay tanks will not be affected since this sample is dry gas and no moisture needs to be condensed. Other administratively-required samples taken which do need the cooler can be rescheduled with forewarning given to Chemistry.

The replacement of the reducer downstream of SW-144 will result in open an unisolable 14" hole in service water overboard. The location at which the 14" line connects into the 20" overboard return header is at El. 34'4" south of the 20" flange (used for dam installation) east of C59. Thus, the level of the water in the service water overboard lines has to be lowered to an elevation below the north/south horizontal run of 20" pipe (in which the 20" dam flange is installed). To minimize effects on Unit 2 (at 100% power), the dam will be installed in the 20" header east of C59. This will also minimize the amount of water that will be able to return to the Unit 1 side of the return header from the CC heat exchangers (which tie in north of the dam) while the 14" line is cut. The return header level will be controlled via the butterfly valves (SW-146 and SW-104) at the entrance to the Units 1 and 2 circulating water system. Pressure indicators will be positioned at each valve location for monitoring head in the return headers. The flange at the dam will be kept slightly open to provide a vent path into the system to help ensure good head indication at SW-146 and SW-104.

To ensure that flooding does not occur in the PAB, personnel will be continuously stationed at the overboard valves, the flange to the dam, and in the area of the dam and 14" open line. The person in the area of the flange at the dam and 14" cut will be in radio contact with the people at the overboard valves to ensure that the valves are immediately opened in the event that the level rises causing leakage in the open system.

In addition, an inflatable pipe stopper will be installed in the 14" line when open to provide some protection against leakage if the level would suddenly rise. The stopper to be used is rated to hold back 4.8 psi. A second stopper is available as backup. To minimize the possible changes that could occur in the service water supply and return header, several things will be done to put the system in an "extreme" condition prior to opening the system. This includes running four service water pumps and opening the Unit 2 fan cooler return MOVs. This will help ensure that a signal which would result in starting of more than the normal two service water pumps and cycling open of the said MOVs does not result in a sudden overboard pressure increase. The "A" service water pump is tagged out of service for motor work which will reduce the starting potential to one.

The reducer replacement will be started and worked to completion (to the point of getting systems closed) to minimize the time that the system is open.

Considering the position of the supports on the 14" cooler return line relative to the 20" header and the fact that the fan coolers (Unit 1) are out of service, seismic impacts are not considered.

Installation of the new reducer results in SW-144 being relocated ~4" upstream of its present location. It appears that a slip-on flange was installed on the existing reducer when SW-144 was replaced with a flanged stainless steel valve some years ago. The new stainless steel reducer will be welded to a weld neck flange, thus resulting in the overall length of the reducer and flange being longer. This is not considered to have any adverse effects on the seismic capability of the piping. (SER 90-056)

51. SMP 1055, (Minor), Transition to New DC Control Power Alignment, Revision 0. (New Procedure)

SMP 1055 directs the method for switching DC control power for 4160 V and 480 V buses to the new normal lineup.

Summary of Safety Evaluation: Control power supplies to 1A01, 2A01, 1A04, 2A04, 1B01, and 2B01 will be momentarily interrupted while shifting from the present power supply to the new normal supply. During this switchover, the following protective relaying and automatic features for Unit 1 and Unit 2 will be lost:

A01, A04 - (1) RCP "A" breaker open on undervoltage (UV) and underfrequency (UF). These feed the reactor trip circuit with the RCP breaker contacts. (2) A01 UV reactor trip signal (fails to the trip condition, but need UV on A01 and A02 to trip the reactor). (3) AMSAC start circuitry for motor and turbine-driven auxiliary feed pumps will not start on main feed pump breaker opening due to bus UV. (4) 4 kV UV initiation of the turbine-driven auxiliary feed pump. (5) 4 kV UV trips for A01 (non-safety related). (6) 4 kV breaker control (A01 and A04) including overcurrent trip for A01 and A04 loads. (7) 4 kV fast bus transfer capability (A04 to A02).

B01 - (1) UV load shedding and indication. (2) 480 V breaker control (B01)

The features in question are expected to be out of commission for no more than about 1 minute. Control power will be disconnected from only one bus at a time. A procedure will be used to control the switchover, and will have a dedicated operator to minimize time delays.

The momentary loss of the listed protective relaying and automatic features is addressed in Technical Specification 15.3.0.D, which covers momentary loss of power to a component. Immediate action will be initiated to reenergize the components from the alternate source. During the interim, the operator will be sensitive to the capabilities which he has lost. (SER 89-134-06)

52. SMP 1058, Unit 2, (Minor), DC Transfer Switch Opening Force Measurement, Revision 0. (New Procedure)

SMP 1058 measures the force required to open the DC control power transfer knife switches on the 4160 V and 480 V buses for Unit 2. These switches select either a normal or alternate source of 125 V DC control power for the breakers on their respective buses. The measured force will be compared to an allowable force to determine the seismic adequacy of the switches.

Summary of Safety Evaluation: During the test, Unit 2 will be in a refueling shutdown condition. DC power to the switches (both the normal and alternate power) will be isolated while the switch associated with a particular bus is being tested. While the effect on the shutdown unit is minimal, some operability concerns for the operating unit (Unit 1) must be addressed.

Isolation of control power to the 2A05 bus and 2A06 bus will result in the inability of the diesel generator associated with that bus (G01 for 2A05; G02 for 2A06) to be automatically sequenced onto the bus in a postulated loss of offsite power scenario. The result is a loss of emergency power to safeguards buses 2A05 and 2B03 while they are being tested, and 2A06 and 2B04 while they are being tested (the procedure has these related buses being tested sequentially, 2A05 followed immediately by 2B03, and 2A06 followed immediately by 2B04). The expected time of inoperability, based on the scope of the work, is expected to be less than one hour.

The shutdown unit, while in a refueling shutdown condition, will be largely unaffected by the test. Both trains of RHR and CC are expected to be available. In the event of a loss of offsite power coincident with the testing of either of the safeguards buses, the opposite train may be selected.

The situation is more complicated for the operating unit due to the fact that service water pumps are "shared" between units, three being powered from Unit 1 safeguards buses and three being powered from Unit 2 safeguards buses. When buses 2A06 and 2B04 are being tested, there will be two SW pumps technically inoperable because diesel generator G02 will not be able to sequence onto the safeguards buses at 2A06. Similarly, when buses 2A05 and 2B03 are being tested, there will be one SW pump technically inoperable because diesel generator G01 will not be able to sequence onto the safeguards buses at 2A05. This may result in less than the minimum number of required pumps (four) per TS 15.3.3.D.1.a. Additionally, if one were to assume a single failure coincident with a loss of offsite power, and that failure is the G01 diesel during the testing of 2A06 and 2B04, a total of only one operable SW pump remains. (Note: From a safety perspective, only three of the six SW pumps are required to be operable during postulated accidents [FSAR 6.2.2 and 7.2.2]).

For these reasons, during testing of 2A06 and 2B04, diesel generator G02 will be declared out of service (it truly will be unavailable to the 2A06 bus) and a 7-day LCO will be entered per TS 15.3.7.B.1.e (similarly, during testing of 2A05 and 2B03, diesel generator G01 will be declared OOS). This LCO is conditional, based on the fact that the remaining diesel will be tested daily to ensure its operability and that the engineered safety features associated with this diesel shall be operable. This operability test will be performed prior to declaring the remaining diesel OOS. Also, the entering of a 24-hour LCO for having less than four SW pumps available (TS 15.3.3.D.2.a) is precluded by the provisions of TS 15.3.0.C which addresses the question of operability of a component when one of the component's power sources becomes inoperable.

An additional concern is the availability of AFW pump P38B, powered from bus 2B04. During testing of 2A06 and 2B04, as discussed above, emergency power will be unavailable to P38B. TS 15.3.4.C.2 stipulates a 7-day LCO for an OOS motor-driven feedwater pump. However, entering this LCO is also precluded by the provisions of TS 15.3.0.C. The governing, and only, LCO applicable during this test will be the 7-day LCO associated with declaring each of the diesels OOS. (SER 90-106)

53. SMP 1060, (Minor), Increasing the 2W1C1 Delivered Air Flow to Meet Design Requirements, Revision 9. (New Procedure)

During U2R15, RMP 31 was performed to verify the performance of the containment accident fan coolers. The testing identified a deficiency with the air flow rate delivered by the 2W1C1 accident fan. The accident fans are designed to deliver 38,500 cfm each, but the 2W1C1 fan was only delivering 37,476 cfm. A justification for continued operation was presented and accepted during MSSM 89-22. In order to resolve this issue, SMP 1060 was implemented to restore the performance of the 2W1C1 accident fan to its original design requirements.

Summary of Safety Evaluation: SMP 1060 controls the adjustment of the 2W1C1 fan blade pitch. The blade pitch is increased in small increments while monitoring the effect of each increase on fan air flow and motor amperage. The fan motor amperage is monitored to ensure that it does not exceed 80 amps without further evaluation. The value of 80amps was chosen as a ceiling since both the 2W1A1 and 2W1B1 fans are currently running at 80 amps (reference RMP 31, dated November 13, 1989). The 2W1C1 fan motor is currently running at 75 amps. All of the Unit 2 accident fans were tested and operated satisfactorily during the 1989 ILRT with a maximum motor amperage of 151 amps (2W1A1). The 2W1C1 fan motor amperage during the 1989 ILRT was 143 amps. These currents are well below the rated amperage for the containment accident fan motors of 176 amps.

SMP 1060 restores the 2W1C1 accident fan air flow to the original design value by adjusting the fan blade pitch. The procedure controls the adjustment to ensure that the fan motor will not be overloaded in a post-LOCA environment. (SER 90-105)

54. ST-4, (Major), Integrity, Revision 1. (Temporary)

Safety Evaluation Detail: Figure 1 and the status tree were temporarily changed due to new Technical Specification heatup and cooldown curves (Figure 15.3.1-1 and 15.3.1-2) as specified by Regulatory Guide 1.99, Revision 2. (SER 89-043-01)

ST-4, (Major), Integrity. Revision 2. (Permanent)

Safety Evaluation Detail: The Limit A curve was changed to a straight line at 285°F, which in turn, removes the Limit A table from Figure 1. Along with the wording change in the red path block of the integrity status tree from "pressure-temperature points in both cold legs to the right of Limit A" to "temperature in both cold legs greater than 285°F," the red path condition now exists between 0-285°F; the orange path between 285°F-315°F; the yellow path between 315°F-345°F; and the green path >345°F of both RCS cold leg temperatures. Due to the elimination of the Limit A curve, Figure 1 is no longer needed and thus, was deleted. (SER 89-043-02)

55. STPT 1.2, Unit 1, (Major), Reactor Trip OTΔT, Revision 4. (Permanent)
and
STPT 1.3, Unit 1, (Major), Reactor Trip OPΔT, Revision 4. (Permanent)

The setpoint change revises core full power ΔT for the Unit 1 white channels from 55.2°F to 54.5°F based upon reactor coolant system flow data measured on January 4, 1989. This setpoint change ensures that the calculated ΔTsp1 and ΔT sp2 are conservative in comparison to Technical Specifications.

Summary of Safety Evaluation: The proposed change was previously evaluated per SERs 88-141 and 88-141-01. The ΔT change to a channel-based ΔT will more accurately reflect the loop ΔT as sensed by the individual channels. The new ΔTs were selected based upon the lowest value of loop ΔT for each channel from U2C14. Flow test data for U2C15 shows that the channel ΔTs are higher than the previous cycle. Therefore, the actual ΔTs being greater than the ΔTs will provide an additional conservative margin to the Technical Specification setpoint. (SER 88-141)

The proposed change lowers the red channel ΔTo value from 56.1°F to 54.9°F. Based upon channel RCS flow measurements following the refueling outage, the UICI7 red channel ΔT is 55.2°T. This represents a reduction of -1.2°F from the previous cycle to the present time. With an indicated 53.2°F ΔT and a ΔTo of 56.1°F, the red ΔT setpoints are not less than the Technical Specification requirements.

The present Unit 1 red channel ΔT setpoints are based on a ΔTo that is greater than the actual loop ΔT as indicated by the red temperature channel. This results in the OTΔT trip being nonconservative in comparison to Technical Specification requirements. The change to the red ΔTo for STPT 1.2 and 1.3 results in the OPΔT and OTΔT setpoints for the red channel being lower than required by Technical Specifications. The setpoint change affects only the Unit 1 red instruments. (SER 88-141-01)

The evaluations performed for SER 88-141 and 88-141-01 are also applicable to changing the ΔTo for Unit 1 white channel. No additional evaluation is required. (SER 88-141-03).

56. STPT 1.2, Unit 1, (Major), Reactor Trip OTΔT, Revision 6. (Permanent)

The 1% setpoint conservatism on OTΔT channel was changed to 0.75°F and deletes ≤1.117 Tech Spec constants on K1 channel.

and

STPT 1.3, Unit 1, (Major), Reactor Trip OPΔT, Revision 6. (Permanent)

The ~1.75% setpoint conservatism on OPΔT channel was changed to 1.3125°F.

Summary of Safety Evaluation: The ΔTo setpoints for the OTΔT and OPΔT instrumentation are being lowered to more accurately reflect actual core full power ΔT and to ensure that the setpoints remain conservative in comparison to the Technical Specifications. The new ΔTo's were selected based upon full power ΔT data.

The instrumentation changes required to implement the ΔTo changes are within the design capabilities of the OTΔT and OPΔT instruments. The operation and reliability of the instruments will not be affected. (SER 88-141-04)

57. STPT 1.4, (Major), Revision 3, Pressurizer Pressure and Level. (Permanent).

The procedure involves lowering the existing high pressurizer water level reactor trip setpoint for 1&2LC-426A, 427A and 428A from 90% to 80%. This setpoint change was necessitated by the performance of the pressurizer level transmitters LT-426, LT-427 and LT-428. These transmitters are Foxboro Model N-E13DH differential transmitters installed under MR IC-259/260 as part of the post-TMI instrument upgrade program. Based on four years of operating experience, it is known that these transmitters have a tendency to drift between the annual calibrations. Every instrument calibration procedure performed since the new transmitters were installed has resulted in at least one of the transmitters being out of tolerance. Usually there is sufficient conservatism in the setpoint that the TS requirement is not exceeded. However, on one occasion one level channel was found to be nonconservative in comparison to Technical Specifications. To ensure that this does not happen again, the setpoint for the high pressurizer water level trip was lowered to increase the margin to TS.

Summary of Safety Evaluation: The TS for the high pressurizer water level trip is found in Section 15.2.3, "Limiting Safety System Setting, Protective Instrumentation," which requires that the high pressurizer water level reactor trip setpoint be set at <95% of span. According to the TS Basis, the high pressurizer water level reactor trip protects the pressurizer safety valves against water relief. The specified setpoint allows adequate operating instrument error and transient overshoot in level before the reactor trips.

The high pressurizer water level trip is discussed in several sections of the FSAR. Section 1.3.3, "Nuclear and Radiation Controls" (GDC 11-GDC 18) states, "Additional tripping functions such as high pressurizer water level trip ... are provided to backup the primary tripping functions for specific accident conditions and mechanical failures."

Section 4.1.5, "Cyclic Loads; Loss-of-Load Transient," states, "The loss-of-load transient is the most severe transient on the Reactor Coolant System. The transient applies to a step decrease in turbine load from full power occasioned by the loss-of-load without immediately initiating a reactor trip. The reactor and turbine eventually trip as a consequence of a high pressurizer level trip initiated by the reactor protection system." However, Section 14.1.9, "Loss of Electrical Load" states that core protection is provided by either the high nuclear flux trip or the pressurizer pressure trip depending on the plant conditions at the time the load is lost. It does not require the high pressurizer water level trip to show protection.

The description of the high pressurizer water level trip is found in Section 7.2.1, "Protective Systems Design Bases." The high pressurizer water level trip is provided as a backup to the high pressurizer pressure trip. The coincidence of two out of three high pressurizer water level signals trips the reactor. This trip is bypassed when three of the four power range channels and two of two turbine first stage pressure channels read below 10% power (P7). This section also states, "Finally, as shown in Section 14.1, the combination of trips on nuclear overpower, high pressurizer water level and high pressurizer pressure also serve to limit an excursion for any rate of reactivity insertion."

The only analysis in Section 14.1 that directly discusses the high pressurizer water level trip is Section 14.1.2, "Uncontrolled RCCA Withdrawal at Power." An uncontrolled RCCA withdrawal at power results in an increase in core heat flux. Since the heat extraction from the steam generator remains constant, there is a net increase in reactor coolant temperature. Unless terminated by manual or automatic action, this power mismatch and resultant coolant temperature rise would eventually result in DNB. Therefore, to prevent the possibility of damage to the cladding, the reactor protection system is designed to terminate any such transient with an adequate margin to DNB. The automatic features of the reactor protection system which prevent core damage in a rod withdrawal accident at power include the nuclear power range instrumentation overpower trip, OTΔT trip, OPΔT trip, and high pressure trip.

A high pressurizer water level trip, actuated from any two out-of-three level channels, is actuated at a fixed setpoint. This affords additional protection for RCCA withdrawal accidents.

The fixed setpoint for the high pressurizer water level trip is not specified in the FSAR. Lowering the setpoint to 80% does not require any changes to the descriptions found in the FSAR but it has an impact on the FSAR analysis. By altering the high pressurizer water level trip setpoint, it may be possible to change the order in which the various reactor trip signals will be received. This will not affect reactor protection but may change the conclusion of the RCCA withdrawal accident analysis.

Lowering the setpoint to 80% adds an additional margin of protection against a water relief from the pressurizer safety valves. It will also increase the margin for operating instrument error. However, it will reduce the margin provided for transient overshoot in level before the reactor trips. A high pressurizer water level trip of 80% is acceptable if it provides a sufficient pressurizer volume margin for transients.

Prior to unit full power operation, the full power Tavg was lowered to 570°F in order to reduce steam pressure to the turbine. As a result of lowering the full power temperature to 570°F, the pressurizer level control program was changed and normal full power pressurizer water level was lowered to 45.8%.

There was originally a margin of 11,320 lbm between the full power pressurizer water level (60%) and the high pressurizer water level trip (90%). If the high pressurizer water level trip is lowered to 80%, there exists a margin of 13,180 lbm between the full power pressurizer water level (45.8%) and the high pressurizer water level trip (80%). The 80% high pressurizer water level trip setpoint provides a greater margin for transients than originally specified. Therefore, the sequence of the reactor trips described in Section 14.1 of the FSAR will not be affected. Additionally, since the TS setpoint of <95% of span will be met a setpoint of 80% will provide the required reactor protection. (SER 90-003)

68. STPT 1.5, (Major), Reactor Coolant and 4160 Volt Setpoints, Revision 4. (Permanent)

The setpoint change establishes settings for reactor trip based upon loss of primary coolant flow through reactor coolant pump (RCP) breaker trip on undervoltage (UV). These settings specify TS 15.2.3.1.B(8)(b) for the required setpoint specification and reference STPT 21.1 for the actual UV setting.

Summary of Safety Evaluation: The time delay proposed for the setting is 7.0 seconds (which includes the time delay associated with the UV relays on detecting a total loss of voltage on the buses) as documented in the analysis for NCR N-89-117. Since these UV relays also actuate a portion of the auxiliary feedwater system, specifically 1(2)P29 steam supply valves MOV-2019 and 2020 through another time delay relay, the time delays are selected to ensure that all safety parameters are coordinated and will meet the accident analyses evaluations.

As presently listed in FSAR Table 7.2-1.8.b.2, the time delay associated with RCP breaker trip on UV is 15 seconds. However, by analysis described in NCR N-89-117, this long of a time delay is not justified. Therefore, the setting of 7.0 seconds (including time delay for bus relays on total loss of voltage) will yield a more conservative safety function, yet will not increase the probability of a reactor trip since the actuating devices will not be changed. The reactor trip on RCP breaker opening on UV is a backup to both the loss of (4 kV) voltage reactor trip (total loss of flow) and the partial loss of flow trip (for loss of one RCP) as implied from FSAR Sections 14.1.8 and 7.2.2. Therefore, the reduced time for the time delay will only improve protection for any active single failure of the primary trip functions. A change to the FSAR at Table 7.2-1 will be required when the setpoints are established by maintenance procedures.

Lowering the time to trip the reactor coolant pumps on bus undervoltage could result in reduced time of forced convective reactor coolant flow through the core. However, the lowered time is still well beyond the time to reach minimum DNBR, and the results of the loss of flow accident are unchanged. (SER 90-064)

69. STPT 3.1, Unit 1, (Major), P6, P7, P8, P9, and P10, Revision 3. (Permanent).

The setpoint changed Unit 1 full power first stage turbine pressure from 560 psig to 550 psig. This change ensures that the control functions which utilize first stage turbine pressure as an indication of turbine and/or reactor power properly reflect actual plant conditions.

Summary of Safety Evaluation: Turbine first stage pressure is used for determining the reactor coolant system reference temperature, the "at power" reactor trip unblock permissive (P7), turbine runback load limit reduction, rod control variable gains, auto rod withdrawal block and condenser steam dump arming.

Units 1 and 2 control systems were originally set up with a full load first stage turbine pressure of 550 psig. In September 1985, the Setpoint Document full power first stage turbine pressure for Unit 1 was changed to 560 psig to reflect actual plant parameters. Existing plant parameters and RESP 6.2, "Precision RCS Flow Measurement," data indicate that the Unit 1 full power first stage turbine pressure has changed again. Based on the RESP 6.2 data and calculations the actual full power first stage turbine pressure is 550 psig ±0.5 psi.

With a full power first stage pressure of 560 psig and an actual first stage pressure of 550 psig, the setpoints that utilize first stage pressure will all actuate at a value 2% higher than actually required. For example, the P7 permissive actuates at 9.16% power instead of 9% power and the steam dumps arm on a 10.2% power loss instead of 10% power. Additionally, this results in a lower than desired Tref. The most obvious indication of this is Tavg. Instead of controlling at a full power temperature of 570°F with rod control in automatic Unit 1 is maintaining approximately 569.7°F at 100% power.

The FSAR and the Technical Specifications do not directly address full power first stage turbine pressure values. The FSAR does state that the reactor coolant average temperature setpoint change is made as a function of turbine load as determined by first stage turbine pressure. TS 15.2.3.2.A states that the "at power" reactor trips (low pressurizer pressure, high pressurizer level and low reactor coolant flow for both loops shall be unblocked when power range nuclear flux 9% (±1%) of rated power, or turbine load 10% of full load turbine pressure.

Changing the setpoint and calculation value for first stage turbine pressure will not change either the FSAR or the Technical Specifications. It will provide for control functions based more closely on actual plant reference conditions. (SER 89-146)

70. STPT 21.1, (Major), Data Sheets, Sheet 37 and 42, Revision 1. (Permanent)

The setpoint change revises the overcurrent trip setpoint for safety injection pumps 1P15A&B from 7.0 sec to 7.3 sec to reflect relay manufacturers published curves.

Summary of Safety Evaluation: The increase in the time setting more accurately reflects the manufacturer's curves.

This setting change is conservative for operability in the fact that the overcurrent trip time is extended by 0.3 sec and the safety injection pump is given that much more time to start prior to tripping on overcurrent.

The FSAR mentions overcurrent tripping of safeguards pumps in Section 8.2.3, "Emergency Power, Loading Description." The FSAR states that if the safeguards pumps or fan motors (from the auto sequencing table) trip due to overcurrent, they can be reclosed from the control room. This feature is not changed. (SER 90-059)

DESIGN CHANGES

1. MR M-785-02, Fire Protection. The addendum provides a Halon automatic fire suppression system for the computer/instrument rack room.

   Summary of Safety Evaluation: The FSAR does not address fire protection requirements for the computer/instrument rack room. The new automatic fire suppression should be interlocked with the control room HVAC system. The final design of the fire suppression system has not been determined. The new system should be interlocked with the smoke removal system and with the return air damper from the computer room. This prevents exhausting the Halon before the fire is suppressed and from returning smoke and Halon to the air handling unit and discharging it to the control room. The return air damper should be capable of being reset from control panel C67. The Halon system should also discharge into the raised floor area to suppress any fire in the instrumentation and data cables. (SER 86-068)

2. MR M-815 (Common), Fuel Oil System. The modification changes the control circuitry for the heating boiler day tank fill valve to prevent accidental overflowing of the tanks. Rewiring will cause the fill valve to automatically close if either day tank is filled past its high alarm level. (The MR was approved during MSSM 82-08 on February 8, 1982.)

   Summary of Safety Evaluation: When one tank is filled over its high alarm level, the only way to open the fill valve to fill the other tank is to hold the control switch in the open position. Because of this and the high level alarm, the automatic shutoff will not be used as normal procedure when filling the tanks. The level will still be monitored locally by an operator while filling. To accommodate this, the local level indicator was replaced with a more accurate and easy to read pressure gauge.

   The modification does not affect the availability of fuel oil to the EDG day tanks. The control circuit still prevents filing the heating boiler day tanks if either of the EDG day tank's level is low.

   For a short time during installation, power was be isolated to the control circuit for CV-3923, which is used to fill the emergency fuel tank from the fuel oil storage tank. This valve could be opened manually if required. This did not violate TS 15.3.7.A.1.e because the 11,000 gallons of fuel oil required was available in the emergency fuel oil tank. It the emergency fuel oil tank had to be refilled during the installation, manual operation valve would accomplish this. Adequate time is available to ensure this is done during accident conditions. It was verified that the emergency fuel oil tank is full prior to installation. (SER 90-001)

3. MR 83-107 (Unit 1), Steam Generator Level Instrumentation. The modification alters the piping arrangement of the two wide range water level transmitters to provide additional redundancy.

   Summary of Safety Evaluation: Design and Installation requirements meet or exceed those for the existing wide range level piping. Connecting a wide range level transmitter to a narrow range level transmitter needs to be fully evaluated for possible effects on the safeguards (narrow range) channel;. The addition of the second wide range level transmitter to each steam generator was approved with the exception that it should not be tied in to a narrow range sensing line.

4. MR 85-056*A (Unit 1) & 85-057*A (Unit 2), Main Control Boards. MRs 85-056*A and 85-057*A replace the analog display for the subcooling meter with a digital display. The subcooling meter is part of the post-accident monitoring system required by NUREG-0737. There are two independent subcooling meter displays on each 1(2)C20.

The digital displays will be in the same locations as the analog displays. The signal inputs to the subcooling meter and the analog computation of subcooling are not altered by these modifications.

Summary of Safety Evaluation: The change to a digital display was reviewed for human factors and recommended by the control room design review committee. The display utilized red LED segments of the same size and type that are used in other control room displays and are easily read by an operator. The digital displays require 120 V AC, which the analog displays did not. One will be powered through a 10 ampere breaker from the white instrument bus and the other through a 10 ampere breaker from the yellow instrument bus. The digital displays require 6 V amperes power each, which is a negligible increase in load on each bus and is acceptable.

An analog meter will show the pointer "pegged" if the input signal goes outside of its normal range. A digital meter will not give the operator any such indication and will continue indicating normally and proportionally to other input when the input signal goes out of range. After this change to a digital meter, the operator must rely upon other means, such as his own knowledge of the range or the computer, to indicate when the signal goes outside its normal range of 50°F superheat to 200°F subcooling. It is judged that from a human factors viewpoint the net impact of this change is positive.

The digital displays were purchased as commercial grade equipment and they will be seismically qualified using SQUG methodology.

Installation of each unit's modification is planned during a refueling outage. As such, there are no TS limitations. If a modification is performed at power, only one meter shall be inoperable at a time in order to avoid entering Limiting Conditions for Operation (reference TS Table 15.3.5-5). (SER 90-041)

MR 85-056*A, Summary of Amended Safety Evaluation: The new digital subcooling meter display weighs ~2 lbs. The mounting plate for the new display is attached to the control board by four 1/4" diameter machine screws. Each screw has a net cross-sectional area of ~0.0318 sq in and the steel has a tensile strength of ~85,000 psi. Therefore, each screw can support ~2700 lbs. Four screws could support 10,800 lbs. The display weighs 2 lbs. Conservatively using peak accelerations of 3.15 g (2% damping) yields a worst case seismic load of <10 lbs. The new support design of the meter is more than adequate to withstand 10 lb loads in any direction under any conditions.

A formal calculation documenting the adequacy of the design will be completed at a later date and will be submitted as an amendment to this evaluation. All provisions of SER 90-041 and its conclusions remain valid. (SER 90-041-02)

MR 85-056*A (Unit 1) & 85-057*A (Unit 2), Summary of Amended Safety Evaluation: This amendment documents that a formal calculation evaluating the seismic adequacy of the design has been completed. This amendment is applicable to both MR 85-056*A and MR 85-057*A. Results of the calculation show that the new mounting configuration satisfies the requirements for Seismic Class II design. The calculation has been documented per Calculation N-90-036. All conclusions of previously approved safety evaluations remain valid. (SER 90-041-03)

5. MR 85-056*C (Unit 1) & 85-057*C (Unit 2), Main Control Boards. MRs 85-056*C and 85-057*C remove the "RCS gas vent header pressure hi" annunciator from 1(2)C20.

Summary of Safety Evaluation: The pressure in the RCS gas vent header is sensed by a pressure transmitter, displayed on an analog meter on 1(2)C20, sent to the plant computer, and alarmed on 1(2)C20. The design package detects solenoid valve leakage between the reactor coolant system and the header. Since there is no practical means of repairing the valves during power operation, the annunciator can remain in the alarm condition for an extended period of time resulting in a nuisance alarm. Having an alarm energized for an extended period of time is not desirable from an operational standpoint.

The operator can obtain the same information by viewing the analog panel meter. If combinations of valves leak enough to create a leak of safety significance, the leakage will be detected by inventory control measures. Consequently these solenoid valves, if they have a slow leak, would not be required until the following outage. It is concluded there is no safety significance associated with deleting this annunciator. (SER 90-041-01)

6. MR 85-213*D (Unit 1), AMSAC. MR 85-213*D revised AMSAC by using larger wire duct in IN16 to provide room for additional wires; adding a third computer input (ZAMSAC20) so the status of the P20 is recorded and alarmed on the enable/disable transition by the computer. This enables the operator to better determine when certain failures offer and will alert him to the failure; and adds a normally closed set of switch contacts to safety injection switch A-2 and wire them in series with the feedwater pump breaker switches.

Summary of Safety Evaluation: The new SI Switch A-2 contacts would be closed during normal operation and open during ORT 3 testing to isolate AMSAC during testing so a recorder will properly indicate breaker position. Since the new switch contacts are in series with the AMSAC input from the feedwater pump motor breakers, failure of the switch contacts to close would enable this part of the AMSAC input circuitry. The probability of switch failure is low.

The summary and conclusions of SER 89-055 remains valid with the addition of the above described design improvements. (SER 89-055-01)

7. MR 85-243*A (Common), Instrument Air. Design Package A installs a second instrument air header, including the filter/dryer dedicated to Unit 2 and replacement of compressors K2A&B with new 2-stage compressors.

Summary of Safety Evaluation: The system will be more reliable due to the flexibility available for isolating and cross-tying the headers. Tie-ins to the existing system were controlled and monitored by special maintenance procedures. Tie-ins to auxiliary feed pumps 2P28 and P38B were done during LCOs. The tie-ins to the existing system and the modifications to the existing piping does not affect the safe operation of the plant.

The modifications to the Unit 1 containment and main header were done during a refueling outage. Other modifications will be done during normal operations. The components that were not supplied by instrument air during the modifications were either (a) supplied by service air; or (b) not required for service. A loss of service air does not adversely affect plant safety because either the component fails to a safe position or the component has a backup supply. The service air used for temporary connections was the same as instrument air except that it will not be dried. Filters will be provided on the temporary lines. The tie-ins were made to the requirements of B31.1, meeting original plant design criteria.

The air dryer being replaced can be isolated from the system. Therefore, the replacement will not affect operation of the system. The compressors were replaced one at a time so instrument air was always available.

A cross-tie from service air to the new instrument air header was added. This addition makes a service air backup available to either header if it is isolated. (SER 87-011)

8. MR 85-243*B (Common), Instrument Air Upgrade. Design Package B addresses electrical changes, including replacement of compressors K2A&B; replacement of dryer Z31 and other instrumentation and control changes.

Summary of Safety Evaluation: Each replacement compressor increases the load on its power supply by ~25 amps. The compressors are locked out following an undervoltage trip so they will not be an initial load upon the emergency diesel generators. The compressors can be restarted manually if the operator determines that the diesel generator can supply the additional load.

The power supply to instrument air dryer Z31 has adequate capacity for the replacement dryer.

The control and indication changes provide increased reliability and allow operators to more effectively monitor the instrument air system.

The additional loads to the instrument buses from the control/indication circuits will be negligible and will be insignificant from a loading standpoint. Cable routing will be performed in accordance with Appendix R requirements as applicable.

Each of the new compressors replacing existing IA compressors K2A and K2B increases the load on its respective power supply by ~25 amps. The existing power supply cables and motor starters associated with the IA compressors are adequately sized to supply this increased load. Motor control centers 1B32 and 2B42, which supply compressors K2A&B, respectively, are fed from 480 V load centers 1B03 and 2B04, respectively. The limiting factors on the amount of current supplied by the load centers are transformers 1X13 and 2X14, which supply 1B03 and 2B04, respectively.

Two loading studies were performed to determine loading on transformers 1X13 and 2X14. The results indicated that these transformers could sometimes be operating at greater than rated capacity during normal plant operation and could also be overloaded during emergency operation. The amount of transformer loading indicated is probably higher than actual due to conservative assumptions. One such assumption is that all loads were assumed to operate continuously at 100% rated output. Many loads, such as charging pumps and battery chargers, operate at less than rated capacity.

Based upon observation and recorded data, transformers 1X13 and 2X14 are not being overloaded. Readings taken indicate that weekly maximum oil temperatures of the two transformers during normal plant operation range from 50-65°C. ANSI Standard C57.92, which covers loading of mineral-oil-immersed transformers, states the maximum oil temperature for normal life expectancy of the transformers at 100% rated load is ~75-80°C.

The new instrument air compressors increase load on the transformers by ~1.1%. Based upon the present operating condition and loading of the transformers, this increased load is acceptable. (SER 87-011-01)

9. MR 85-252*A (Unit 1). Auxiliary Feedwater System. MR 85-252*A eliminates the spring return left-to-center auto feature on the control switches for steam supply MOVs to turbine-driven AFW pump P29. MR 85-252 then provides for annunciation of the "Unit 1 AFWS Disabled" alarm whenever 1P29 steam supply MOV control switches are placed in the maintained close position.

Summary of Safety Evaluation: To provide annunciation for discharge valve AF-4022 and AF-4023 control switches, the present auto-open switch contact was removed from the AFW discharge MOV circuit. The contact then feeds an intermediate relay located in the P38A control circuit. Two sets of contacts off the intermediate relay replace the auto-open switch contact and provide alarm annunciation as soon as the control switch is taken out of the full pushed-in auto position.

To provide annunciation for steam supply valve 1MS-2019 and 1MS-2020 control switches, the 1MOV-2019/2020 low suction pressure circuit was reconfigured so a set of switch contacts feed an added alarm relay. Another set of contacts off the alarm relay provide alarm annunciation when the control switch is in the maintained close position.

The installation of additional relays does not substantially degrade reliability of the modified circuits. The added relays are of a type presently in use in QA applications. The relays have a good operating history and are Class 1E qualified. Mounting of all components was accomplished similar to other comparable components in order to maintain seismic qualification of the control boards. This modification does not introduce a single failure fault since separation of train related components and wiring is maintained. No other changes to the auxiliary feedwater system are made other than the above described changes in control circuitry within the main control boards.

Operability testing of valves, control switches and annunciation was conducted as part of the procedure controlling installation of circuit modifications. (SER 90-083A)

10. MR 85-253 (Unit 2). Auxiliary Feedwater System. MR 85-253 changed the annunciation provided by control switch logic for AFW pump P38B discharge MOVs. It eliminated the spring return left-to-center auto feature on the control switches for steam supply MOVs to turbine-driven AFW pump 2P29. In addition, the MR provided for annunciation of the "Unit 2 AFWS Disabled" alarm whenever 2P29 steam supply MOV control switches are placed in the maintained close position.

Summary of Safety Evaluation: To provide annunciation for discharge valve AF-4020 and AF-4021 control switches, the present auto-open switch contact was removed from the AFW discharge MOV circuit. This contact then feeds an intermediate relay located in the P-38B control circuit. Two sets of contacts off the intermediate relay replaces the auto-open switch contact and provide alarm annunciation as soon as the control switch is taken out of the full pushed-in auto position.

To provide annunciation for steam supply valve 2MS-2019 and 2MS-2020 control switches, the 2MOV-2019/2020 low suction pressure circuit was reconfigured so that a set of switch contacts will feed an added alarm relay. Another set of contacts off the alarm relay provide alarm annunciation when the control switch is in the maintained close position.

Installation of additional relays does not substantially degrade reliability of the modified control circuits. The added relays are of a type presently in use in QA applications. These relays have a good operating history and are Class 1E qualified. The new control switch for 2MOV-2019 and 2020 is also of a type presently in use. Mounting of all components was accomplished similar to other comparable components in order to maintain seismic qualification of the control boards. This modification does not introduce a single failure fault since separation of train-related components and wiring is maintained. No other changes to the auxiliary feedwater system were made other than the above described changes in control circuitry within the main control boards.

Operability testing of valves, control switches and annunciation conducted as part of the procedure controlling installation of circuit modifications. (SER 90-083B)

11. MR 87-182 (Units 1 & 2), Component Cooling System. The MR consists of adding drain valves to the component cooling pump casings to provide two drain valves for each pump casing. The additional drain valves minimize personnel exposure to chromated water during maintenance activities which require draining the pump.

Summary of Safety Evaluation: The component cooling system outside of containment is a "closed" system for containment integrity purposes (second isolation boundary). The additional valves do not adversely affect this function, nor do they adversely affect the operability of the component cooling system.

Each drain point currently exists. The drain plug was replaced with a Swagelok fitting and Whitey valve. Mechanical joints were used. The resulting configuration is seismic. The temperature and pressure rating of the new components meet or exceed original system design criteria. (SER 87-061)

12. MR 87-218*C (Unit 1), Reactor Coolant System. MR 87-218*C replaces the limit switches that were installed by MR 87-218*A with more appropriate limit switches for the application and installs a solenoid valve in the spray valves' air line to provide the operator a means to cause a Unit 1 spray valve to fail closed. The solenoid valve requires no air assistance for operation. The design package also includes wiring changes in the main control board.

Summary of Safety Evaluation: The cabling, controls, indicators, and override feature were addressed by SER 89-008 for the first two design packages of this MR.

The limit switches installed by MR 87-218*A were unnecessarily scoped QA due to a concern with a limit switch lock-up, disallowing a spray valve to fully close. The RC-431A&B spray valves are QA-Scope only because they provide a portion of the RCS pressure boundary; they provide no safety function. Limit switches and solenoid valves added to the valves are a concern only since they add weight to the valve supports which could affect the seismic qualification. Therefore, the new limit switches and solenoid valves will not be QA-Scope.

The seismic adequacy of the spray valves' mountings are under question by IN 89-028. The additional weight of bracket, limit switches, and solenoid valve (<25 lbs.) on the valve supports is negligible compared to the weight of the valve itself (~490 lbs), and is acceptable.

The installed limit switches have cast aluminum housings that weigh less than 8.4 oz and have less than 1/4 square foot of surface area each. The hydrogen generation (due to aluminum in containment) calculations were reviewed to evaluate the impact of adding these limit switches. This review concluded that the new limit switches pose no significant impact on the hydrogen generation.

Section 5.6.2 of the FSAR states the aluminum inventory listed in Table 5.6.2-2 reflects the determination to exclude as much as practicable the use of aluminum in containment. Due to the small amount of aluminum being installed inside containment and the large amount of effort required to use limit switches made of a non-aluminum material, it was concluded that it is not practicable to use non-aluminum limit switches. (SER 89-008-01)

13. MR 87-219 (Unit 2), Main Control Boards. The modification installs limit switches on the pressurizer spray valves and indicating lamps on 2C04 for control room position indication. In addition, a solenoid valve is installed in the spray valves' air line and a selector switch mounted on 2C04 to provide the control operator a means to cause a Unit 2 spray valve to fail closed.

Summary of Safety Evaluation: Section 4.2.2 of the FSAR states the spray valves limit pressure during load transients and that they can be manually operated from the control room. This remained unchanged.

Section 7.7.3 of the FSAR states control stations on the main control boards are packaged in a modular concept and are grouped according to function to minimize operator error. It also states the vertical section of the control boards incorporates instrumentation, trend records and annunciator panels and that the console section contains control devices and indicating lights. These concepts were employed except indicating lamps are located on the lower vertical section of 2C04 just above the spray valve controllers. This is consistent with the intent of minimizing operator error and packaging control stations in a modular concept.

The spray valves are QA-Scope but not environmentally qualified. To prevent a limit switch lockup from not allowing the valves to fully close or fully open the switches are QA-Scope.

The solenoid valves are fail open; and non-QA. To avoid inadvertent spray valve closure, the solenoid valves fail open on loss of power. Power is supplied by a non-safety related bus (2Y05) so the station batteries or diesel generators are not unnecessarily loaded.

Going to "override shut" on the selector switch is similar to going to manual closed on the controller when the controller or the positioner works. Going to override shut on the spray valve solenoid valve causes the valve to shut but not provide a manual closed signal to controller PC-431H or PC-431C. It is therefore possible that when the override shut signal is removed, a wound-up controller could provide a full open signal to a closed spray valve.

The only time the override should be used is when the manual control station cannot shut a spray valve. This circumstance can only be detected after making such an attempt. Thus, the manual control station should be sending the valve a full closed signal when the override is used. Administrative controls can be used to ensure a bumpless transfer if the spray valve controller is not in manual shut when the override is changed from closed to auto. No automatic feature changes. There is an insignificant impact upon the seismic qualification of the spray valve in view of similar applications. (SER 88-108)

14. MR 87-227 (Common), Electric Generator/EDG. MR 87-227 modifies the main generator base adjust control switch and the emergency diesel generator (EDG) voltage regulator and governor control switches so the "raise" function is on the right and the "lower" function is on the left. Also included are the minimum and maximum excitation lamps, which are located directly above the base adjust controls. Lamp wiring was

exchanged so the minimum excitation lamp is oriented to the left of the maximum excitation lamp.

The null meters for each unit were rewired so null meter motion follow the motion of the modified base adjust switch. Rewiring of the meters to match the drawings returns the circuits to original design.

Summary of Safety Evaluation: Control switch changes involve the exchange of two wires at each switch and the installation of new nameplates. Indication lamp changes involve exchanging one wire from each lamp and exchanging the lamp labels. Double verification was performed to verify leads as they are lifted and reterminated. Continuity checks will be used to verify proper switch operation and the integrity of the reterminated leads. There are no seismic or Appendix R requirements. There are no system functional changes. (SER 90-048)

15. MR 87-231 (Unit 1), Main Control Boards. The modification replaces the four SI spray ready/spray active and containment isolation status light panels in main control board C01 with panels that: (1) Have larger windows, allowing larger, more readable text. (2) Utilize the CHAMPS database equipment numbering system. (3) Have windows functionally grouped for pattern recognition. (4) Operate on the on/off/push-to-test sequence rather than the dim/bright concept currently in use.

Summary of Safety Evaluation: The new panels enhance the operator's ability to determine SI system and containment isolation status by presenting the same information as the existing panels in a more clear format. The most significant improvement is that it is easier to tell which windows are on and which are off.

The new panels are larger than the existing panels and, require larger cutouts in the control board. The mounting of the new status light panels was analyzed to ensure that a seismic event will not cause the panels to become dislodged. Control board C01 has been evaluated with regard to the new cutouts and panel patches required for this modification.

The status light panels provide a secondary indication of the position of SI and containment isolation valves. This indication is provided from a set of contacts on the valve position switch. The contacts driving the status light panels are not in the valve control circuitry and are considered to be performing a nonsafety-related function. The new status light panels merely replace the existing panels; they do not connect in any way to the valve control circuitry. Therefore, the new panels do not have any effect on the startup or operation of any component or system important to safety.

The maximum load associated with the replacement status panels is 184 VA per train or 1.54 amps on each of the 120 V AC instrument buses which provide the power supply. This determination is documented in calculation Impell 89-007. This load is present on instrument buses 1Y03 and 1Y04 only when all status lights are on. Normal load is approximately one-half of this value since approximately half of the windows will be off at any time.

The existing maximum load associated with the status panels removed is 86 VA per train or 0.72 amps on each of the 120 V AC instrument buses 1Y03 and 1Y04. Again, this load is present only when all the status lights are on. Normal load will be approximately 3/4 of the maximum load or 0.54 amps (half of the status lights are on [bright status] and half in the dim state).

The actual load added to instrument buses 1Y03 and 1Y04 is. ~0.23 amps during normal operation and 0.82 amps at conditions which would result in all lights being on. Based upon observations of the existing loading of instrument buses 1Y03 and 1Y04 and the inverters which supply them, this load addition is insignificant.

The four replacement status panels are supplied from two 120/24 V AC control transformers located in C01. The control transformers and thus, the status panels, are isolated from safety-related loads supplied by 1Y03 and 1Y04 by a series of three devices: (1) a 3 amp fuse located in C01; (2) a 6 or 10 amp molded-case circuit breaker in C01 (MOB); and (3) the branch circuit breaker in 1Y03 or 1Y04 which supplies C01. Proper coordination of the 3 amp fuse with the 6 or 10 amp MOB is addressed in calculation Impell 89-007. Proper coordination of the 6 or 10 amp MOB with the branch breaker in 1Y03 and 1Y04 is original plant design and is assumed to be adequate. This isolation is the same as the status panels presently in C01. (SER 89-046-02)

16. MR 87-235 (Common), Fire Protection. The modification enables operators at C01 to remotely silence alarms on D400, master fire alarm panel, a capability which already exists at the D400 panel.

Summary of Safety Evaluation: The modification does not affect the ability of D400 to detect or respond to alarms. The modification allows operators to silence an existing alarm, enabling them to receive subsequent alarms while the initial alarm condition still exists.

The addition of a pushbutton switch and LEDs to panel C900 in C01 has no impact upon the seismic qualification of C01. The modification does not change the operation of panel D400, therefore there are no Appendix R impacts from the modification. (SER 90-115)

17. MR 88-008 (Unit 1), Main Control Boards. MR 88-008 rearranges the nuclear instrumentation (NIS) meters on 1(2)C04, respectively, in order to resolve HED #350. The rearrangement involves removing the meters from the control board and remounting them in the existing NIS cutouts using the existing components. Some main control board (MCB) internal wires between the meters and risers were replaced due to inadequate lengths.

Summary of Safety Evaluation: Each meter is electrically isolated from its associated input or protection channel via an isolation amplifier. This configuration allows meter rearrangement without taking any associated protection channels out of service.

FSAR Section 7.4.1 states that "startup rate indication for the source and intermediate range channels is provided on the main control boards." Section 7.4.3 also specifically states that there are source range count rate, intermediate range current, power range % power, power range delta flux, and post-accident NIS meters on the main control boards. While these FSAR statements will not hold true during the modification installation process, their intent will be met by having all these meters mounted on the control boards before and after the modification work is performed.

The work was done while the associated reactor was shut down for refueling so no power range or intermediate range indication was needed. All associated protection channels remained operable. The audible count rate was available both in the control room and containment. Visual and audible annunciation of any abnormal increase in core activity were available in the control room as well as audible annunciation in containment.

TS 15.3.8.3 states that, "Core subcritical neutron flux shall be continuously monitored by at least two neutron monitors, each with continuous visual indication in the control room and one with audible indication in the containment available whenever core geometry is being changed. When core geometry is not being changed, at least one neutron flux monitor shall be in service." The meters were rearranged when fuel movement was not in progress.

FSAR Section 7.4.2, under "Protection Philosophy," states, "Separation of redundant protective channels is maintained from the neutron sensor with its associated cables to the signal conditioning equipment in the control room with its associated output wiring, indicating or recording devices, and protective devices." The isolated output signal cables from the signal conditioning equipment to the NIS meters on the MCB do not meet this criteria nor do they need to since the outputs are isolated. The new wiring also does not meet this criteria as the existing wiring paths were used. Therefore, the above statement on separation of redundant channels were changed to clarify the actual wiring configuration such that wiring separation is not required for non-protective portions of the circuitry.

FSAR Section 7.4.2, "Equipment Design Basis," states that for the wide range detection channel, "all electrical equipment is seismically supported." The seismic support configuration is not degraded by this modification. The meters were remounted using the same hardware. Making the post-accident meters' mounting plate flush with the rest of the control board increased the control board strength by filling an existing hole.

FSAR Sections 14.1.1 and 14.2.1 analyze an uncontrolled RCCA withdrawal from a subcritical condition and fuel handling accidents, respectively. The NIS monitors reactivity and provides protective inputs under abnormal conditions. Since these protective features are not affected due to isolation via isolation amplifiers, neither of the analyses is affected. (SER 89-113)

18. MR 88-022 (Common), Miscellaneous. The modification provides permanent power supplies for frisker stations and installs five (5) shielded frisking booths in the primary auxiliary building. The frisking booths are located near the spent fuel pit, in both unit's El. 66' fan rooms, in the central of El. 44', and in the El. 8' fan room. A spare frame, without shielding, was provided for use during infrequent jobs, such as blowdown evaporator outages or steam generator replacement or sleeving projects.

Summary of Safety Evaluation: The location of the semi-portable frisking booths is such that safety-related or seismic category structures or equipment will not be affected or else the booths will be permanently attached (not portable) and installed seismically.

Other issues that shall be addressed in the design and installation of the frisking booths and stations include: Effects upon ingress/egress and personnel evacuation routes shall be minimized, existing equipment accessibility shall be maintained to the maximum extent possible; and the lowest local background levels will be sought for frisker booth and station location.

Permanent power shall be supplied from grounded non-vital power supplies. There are no adverse effects upon any vital or instrumentation buses. Transformer and circuit loading was considered and determined to be satisfactory.

The final design minimizes required maintenance. Materials selected are compatible with existing plant components, background radiation levels within the booths are acceptably low, and the auxiliary building's combustible loading is not increased. Appendix R compliance was addressed and the resulting configuration does not impact our Appendix R commitments. (SER 88-026)

19. MR 88-037 (Unit 1), Reactor Coolant System. MR 88-037 installs thermocouples on the shells of the steam generators and provides local readout capability.

Summary of Safety Evaluation: The attachment of the thermocouples is via high temperature epoxy cement and the steam generator shell is carbon steel. This arrangement has no deleterious effects on the shell metal or its ability to retain secondary system pressure. In addition, the conduit was seismically installed and is mostly located inside the steam generator shield wall. Due to its location and small physical size, there are no postulated failure modes which may cause any impact on safety-related equipment. (SER 89-075)

20. MR 88-045 (Unit 1), Plant Shielding. This is an addendum to SER 89-112, which discussed the use of portable shielding racks in the regenerative HX cubicle. Subsequent to that evaluation, it was decided to store the lead blankets and racks inside containment to minimize time and effort that would be required to install the shielding each outage.

Summary of Safety Evaluation: The racks have a paint coating qualified to withstand post-accident atmospheres. The racks were secured to a nonsafety-related structure (stairway) during power operations. The stairway is assumed to be Seismic Class 2. Securing of the racks to the stairway was done with chains or heavy straps, and was administratively controlled. The small load of the empty racks secured to the stairway is not a significant concern. Therefore, storing the racks in this location will not affect/impact any safety systems.

The lead blankets will be kept in a closed storage container (gang box) made of stainless steel. Storing the lead in this container does not exceed the floor's live loading limit. The container is anchored in place (using QA anchorage), to prevent it from affecting/impacting any safety systems.

The storage of the blankets inside containment is acceptable from a fire loading standpoint. The blankets are good up to 225°F for extended periods of time. Accident conditions would result in temperatures in excess of this, but only for short duration. The container is located in an area where it is not subject to high energy piping failures. The storage container is covered to prevent/minimize direct contact between the lead blankets and containment spray. It is also vented so even a severe pressure spike may, at worst, cause only minimal buckling/damage. These factors ensure that the lead blankets (and all material associated with them) is contained, will remain at this location and will in no way affect the containment recirculation sump.

This equipment decreases the free volume of containment by 25-30'. This is insignificant compared to the 1 million ft of volume presently in containment. (SER 89-112-01)

21. MR 88-070 (Unit 1) & 88-071 (Unit 2), Main Control Boards. MRs 88-070 & 88-071 rearrange SG level controls and steam and feedwater controls and recorders by moving one recorder from the front of 1(2)C03 to the back and rearranging other controllers and another recorder on the front of 1(2)C03 to provide a symmetrical pattern.

A review of the original modification determined that a safety evaluation was not required because no changes to circuit diagrams or circuit functions was involved. This change was determined to be cosmetic only and involved no safety significance.

Summary of Safety Evaluation: In the new arrangement, a control board path is used to fill the space between a one unit-wide Foxboro support shelf and a two unit-wide Foxboro support shelf. The more narrow shelf holds a controller and the wider shelf can hold either two controllers or one recorder. The patch supports one side of each shelf. The control board patch is attached to the control board with four 1/4" diameter machine screws.

Each controller weighs ~11 lbs. A one-wide support shelf weighs ~8 lbs. A two-wide support shelf weighs ~15 lbs. Total weight for three controllers and two shelves is 56 lbs.

Each screw has a net cross-sectional area of ~0.0318 square inches and the steel used in a Grade 5 screw has a tensile strength of ~85,000 psi. Therefore, each screw can support ~2700 lbs. The controllers and shelves weigh 56 pounds.

Conservatively using peak accelerations of 3.15 g (2% damping) yields worst case seismic loads of <200 lbs. The total mass of the shelf configuration is decreasing, which indicates that the existing seismic qualification of the board for global considerations is conservative. Therefore, only the patch must be addressed.

Since the patch is made from 3/16" thick stainless steel material, which for the given loads and dimensions acts as a rigid structure by judgment, the design adequately withstands designed earthquake loadings. (SER 90-068)

After the original evaluation was performed, a question was raised regarding the continued adequacy of the main control boards as a result of this modification. The original evaluation was amended per SER 90-068 to address seismic concerns associated with the modification.

***Summary of Amended Safety Evaluation: A formal calculation evaluating the seismic adequacy of the design was completed. Results of the calculation show that the new mounting configuration satisfies the requirements for Seismic Class II design. The calculation was documented per Calculation N-90-037. All conclusions of the previously approved safety evaluation remain valid. (SER 90-068-01)

22. MR 88-094*B (Unit 2), Secondary Chemistry. MR 88-094*B made the tie-ins and line routings for batch tank water and chemical injection for the new Unit 2 hydrazine and morpholine chemical injection skid. The tie-ins were made and root valves installed during the 1989 Unit 2 outage. The line routings to the new chemical injection skid were made after the skid was installed. A separate design package and associates safety evaluation was prepared for placing the new hydrazine and morpholine chemical injection skid into service.

Summary of Safety Evaluation: The batch tanks' water supply is provided by gravity feed from the condensate storage tanks (CSTs). A 1" line was connected to an existing 6" line which was valved into the CSTs by normally locked open valves. The new components to be installed met the design pressure and temperature ratings of the line class which was tied into. The new 1" line was supported in accordance with Power Piping Code USAS B31.1-1967. A liquid penetrant examination of the welds up to the new root valve were performed along with an initial service leak check. The leak tightness of the remainder of the new 1" line was assured by a post installation leak check at design pressure.

The point of chemical injection into the condensate system from the new chemical injection skid is unchanged from its existing position at the condensate pump discharge header. A tie-in was made and a new root valve installed in the existing 3/8" injection tubing upstream of existing root valve CS-21. In addition, a new in-line valve was installed upstream of this new root valve to facilitate the removal of the existing hydrazine system once the new chemical injection skid has been functionally tested and accepted. The new components were installed to meet the design pressure and temperature ratings of the line class which was affected. The new 3/8" injection tubing was supported at least every 6'-6" per standard plant practice. A post-installation leak check at design pressure was performed on all of the newly installed components. (SER 89-103)

MR 88-093*B (Unit 1) & TM 90-013 (Unit 1), Chemical Injection System. This design package makes the tie-ins and line routings for batch tank water and chemical injection for the Unit 1 hydrazine and morpholine chemical injection skid. TM 90-013 installs a temporary Unit 1 hydrazine injection system for use when the chemical injection tie-in were made with the unit at power.

SER 89-103 was approved and was accomplished in Unit 2 via MR 88-094*B. This report amends the original safety evaluation report to address Unit 1 considerations.

Summary of Safety Evaluation: The batch tank water line was installed during the U1R17 1990 outage. The safety evaluation done in SER 89-103 for the Unit 2 batch tank water line installation applies directly to the Unit 1 installation.

The installation of the chemical injection line for Unit 1 is identical to the Unit 2 installation except that the installation was made with the unit at power. The safety evaluation done in SER 89-103 applies and is supplemented by the following discussions.

To install the chemical injection tie-in at power, hydrazine injection from the hydrazine addition system was isolated. A temporary Unit 1 hydrazine injection system was connected to the Unit 1 condensate sampling connection via TM 90-013. The TM was installed, tested and operated via IWP 88-093*B-03. The temporary injection system provides hydrazine to the Unit 1 condensate system while the hydrazine addition system was isolated from Unit 1 to make the tie-in. The temporary hydrazine injection point into the Unit 1 condensate system was within 2' of the permanent hydrazine injection point and therefore the temporary change in injection point was not expected to affect water chemistry.

Condensate sample flow to the secondary sample panel was isolated while the temporary injection system was used so hydrazine was not lost to the sampling system. PBNP 8.4.1, "Secondary Water Chemistry Monitoring Program," lists Action Levels 1 and 2 for oxygen concentration in the condensate system. However, the temporary isolation of the condensate sample flow was considered justified.

The temporary hydrazine injection system meets the design criteria of Power Piping Code ANSI B31.1-1967 which meets original design criteria of the condensate system. The temporary injection system was functionally tested before hydrazine from the hydrazine addition system was isolated to Unit 1. Having hydrazine at this location does not present any unacceptable safety or fire hazards.

In addition, this amended report noted that a post-installation leak check at nominal operating pressure or greater was to be performed on the newly installed chemical injection lines for both the Unit 1 and Unit 2 lines instead of a leak check at design pressure as stated in SER 89-103. Since the leak tests are not procedurally or B31.1 required, the change in leak test pressure was acceptable. (SER 89-103-01)

MR 88-093*C (Unit 1) & 88-094*C (Unit 2), Chemical Injection System. The design packages make the final electrical connections and testing of the Unit 1 and Unit 2 hydrazine and morpholine chemical injection systems.

Summary of Safety Evaluation: The modifications do not change the chemical addition point into the condensate system, nor do they change any secondary system water chemistry action levels. Therefore, corrosion rates of the steam generator tubes will not be negatively impacted by this change.

A malfunction of the hydrazine controller would be detected by the residual hydrazine, oxygen or pH analyzers. The abnormal levels would cause secondary sample panel alarms which would bring in the control room secondary sample panel alarm. With the problem in hydrazine feed rate identified, the pumps could be placed in manual operation if necessary to repair or adjust the controller.

The feedwater flow signal is obtained by connecting to the existing I/I converter connected to the steam generator A feedwater flow loop which provides a signal to the hydrazine pumps in the existing hydrazine addition system. The I/I converter provides isolation to protect the feedwater flow signal loop. During installation the "A" steam generator main feedwater control was placed in manual for a short time while the old feedwater flow signal was disconnected and the new cable was terminated.

The Unit 1 system is supplied with power from 480 V power panel PP-3, while the Unit 2 system is powered from 480 V power panel PP-8. The load analysis performed in the final design showed that the additional loads being placed on the power panels is acceptable. These power panels are not supplied by the emergency diesel generators.

The fluid handling components of the system are compatible with the chemical concentrations which will be used. The pressure and temperature ratings of these components meet the system design ratings. The system design and construction was in accordance with the B31.1 Power Piping Code.

In order to prevent contaminants from entering the condensate and feedwater systems, the system fluid handling components were thoroughly flushed with batch tank water before injection into the condensate system takes place. The batch tanks were equipped with gasketed covers to preclude debris from entering the tank. The chemical injection pump suction lines connect to the side of the batch tanks instead of the bottom to allow any debris entering the batch tanks to settle out on the tank bottom instead of entering the pump suction line. The chemical injection pump suction lines contained Y-strainers which will filter out any particles which do get into the suction lines.

Shutoff valves and tubing lines are connected to the suction line Y-strainers and the pump discharge lines to allow flushing of the Y-strainers or venting of the pumps when necessary. These tubing connections along with the injection pump relief valve discharge tubing lines are routed to a funnel at the side of the skid. The tank drain header is also routed to this funnel. The funnel is routed to a turbine hall sump drain. This path of discharge is slightly different than that previously used, however both routings end up going to the retention pond in which the chemical concentrations are diluted before proceeding into the lake.

Hydrazine spills are addressed in AOP-12A. At the skid sites, the floor sloping and nearby turbine hall sump drain allow the chemicals to be contained within the plant boundaries. A service water hose connection is available within ~20' of each skid and could be used to wash down any spill. A subsoil drain manway exists just east of the Unit 1 skid location. The floor is sloped such that a spill of chemicals would not naturally flow toward the manway. However, if a catastrophic tank failure occurred, a portion of the initial slug of liquid could flow to the manway. In order to guard against this unlikely event, the manway opening was sealed just below the manway cover. The seal was designed such that it could be temporarily removed if access to the manway is ever required.

The systems do not present an unacceptable increase in fire loading. The highest concentrations of the chemicals which will be present at the skid locations are 35% hydrazine and 40% morpholine. In these concentrations these chemicals do not burn, are not considered flammable; and therefore need not be kept in fire proof storage cabinets. If hydrazine spills are wiped up with rags, the system operating procedure instructs the worker to rinse the rags thoroughly with water after their use to ensure that the rags do not present a fire hazard as they dry out. (SER 89-103-02)

ECRs PB-90-019/020 to MRs 88-093*B/094*B, Chemical Injection System. ECRs PB-90-019 and PB-90-020 made changes to MRs 88-093*B and 88-094*B. The ECRs do not change the conclusions of SER 89-103 and 89-103-01 for the safety aspects of these modifications. The ECRs, however, made minor changes to the evaluation summaries. The 1" batch tank water fill line could be installed at any time since the new tie-in point is downstream of an existing drain valve. The 1" tie-in point is now from a 10" line instead of a 6" line. NDE was not required for the root connection since this connection already exists.

Summary of Safety Evaluation: SER 89-103-02 is not affected by the ECRs. (SER 89-103-03)

23. MR 88-118 (Unit 1), Primary Plant Instrumentation. The MR breaks up the string of 6 indicators (4 pressurizer level, RV dual level and pressurizer relief tank [PRT] level) by moving the PRT level indicator (LT-442) over a few inches to the space that was previously occupied by an LTOP key switch and indicating light. The RV dual level indicator (LI-447/447A) was then moved to the position LI-442 was in. The indicators were mounted in the same manner as existing and the electrical connections are similar to existing; thereby the design and function of the instruments was not changed.

Summary of Safety Evaluation: To minimize the potential for installation impacts on plant operation, the work was done during a refueling outage. Since the PRT level and the RV level indication were not available for a short time while the indicators were being moved, the work plan minimized the time the indication was unavailable, and identified the specific plant conditions required.

The indication was removed from service while the cavity was flooded and the reactor vessel head was removed. RV level indication is not required during this time. PRT level indication is not essential for the short period of time the indicator was being moved because discharge into the PRT could be observed by monitoring the PRT temperature and pressure indicators.

No additional weight was being added to the control boards and no structural supports were cut so the seismic rating of 1(2)C04 was not affected. (SER 89-121)

24. MR 88-156A*B (Common) Main Control Boards. The MR rem... two trend recorders in 1(2)C03 per unit, add... CRT in 1(2)C03 per unit and one ...acter display in 1(2)C04 per unit.

Summary of Safety Ev... ...e trend recorders were controlled via the plant computer. These computer outputs were placed on existing hard-wired trend recorders in the Unit 1(2) ASIP. The hard-wired parameters removed from the ASIP to accommodate the computer outputs may be placed on the trend recorders.

The CRT installed in 1(2)C03 in place of the removed trend recorder is controlled by both the SAS and PPCS keyboards; making it useful during normal plant operation as well as emergency situations. The 1x20 character display is an addition to the one that already exists in 1(2)C04.

The items involve no change to the plant functionality. The bus load changes are insignificant.

All devices were mounted Seismic Class 2 and all control board modifications maintain the seismic response that existed prior to this change. (SER 89-122)

25. MR 88-151 (Unit 1), Feedwater System. The MR installs circuits to trip the condensate pumps by energizing their respective lockout relays and trip the heater drain tank pumps by paralleling the pump stop contacts on their control switches upon a containment high pressure signal. Tripping these pumps ensure that main feedwater flow is terminated.

Summary of Safety Evaluation: Termination of feedwater flow in the event of a steam line break inside containment and a stuck open feedwater regulating valve is required to resolve LER 266/88-008. The containment high pressure signal which actuates at or below 6 psig was chosen as the initiating signal. Tripping off the motors for the condensate pumps and heater drain tank pumps was chosen as the method of interrupting feedwater flow.

The initiating signal is mechanized as two out of three logic by using additional contacts on existing safety injection relays and switches. The circuit used for safety injection is not interrupted or altered.

The circuit was installed to respond to a double-ended steam line break inside containment which results in a rapid increase in containment pressure. Per calculation N88-041, the containment high pressure actuation point is reached within 2 seconds after the double-ended break. For a smaller steam line break inside containment or a loss-of-coolant accident, it is possible that safety injection would have been actuated by another initiating signal and reset before containment pressure reaches the high set-point. In this situation the condensate and heater drain tank pumps would not be tripped by this circuit. Under these circumstances, motor operated valves on the discharge of the main feedwater pumps would have closed, thereby stopping feedwater flow and the control room operators would have had time to analyze the accident situation and take appropriate actions. In any case, the condensate and heater drain tank pumps will be operable following a safety injection reset.

Either tripping the heater drain tank pump motors or tripping closed a valve in their common discharge line could have been used to interrupt the water flow from the heater drain tank. Tripping the pumps was chosen to eliminate the time delay associated with the valve closing. This results in a lower peak pressure during the postulated accident.

If this circuitry is actuated, it is expected that the secondary system will be stressed. When water flow through the tubes of No. 4 feedwater heaters is stopped, the water in the tubes is expected to flash into steam, pressurize the system and force open the safety valves. Although this is not a desirable situation, it is no worse than what happens during a loss of AC power incident. (SER 89-125-01)

26. MR 88-164 (Unit 1), Reactor Coolant System. The MR replaces PT-420, the original reactor coolant system wide range pressure transmitter. PT-420 is a 0-3000 psig pressure transmitter with an accuracy of ±15 psi. PT-420 is used in the overpressurization mitigation system (OMS). When the OMS is actuated, PT-420 provides a signal to bistable PC-420C to open PORV-430 when RCS pressure increases 415 psig. The TS requirement is for actuation 425 psig. Therefore, it is possible to violate TS with PT-420 in calibration. To eliminate this possibility, PT-420 was replaced with a narrow range 0-1000 psig ±2.5 psi Rosemount pressure transmitter.

Summary of Safety Evaluation: The pressure transmitter was qualified and suitable for this application. It met or exceeded all design ratings and characteristics of the originally installed transmitter with the exception of maximum overpressure. However, the transmitter has a maximum allowable overpressure of 7500 psig, which is sufficient for use in this application. Additionally, the transmitter was seismically qualified in accordance with the SQUG guidelines.

The transmitter is completely compatible with the power supply and instrument loop for PT-420. Therefore, the replacement of PT-420 will not increase the likelihood of a spurious actuation or the failure of the OMS.

Since PT-420 will no longer be a wide range pressure channel, it was removed from the RCS wide range pressure recorder, PR-420 was replaced by PT-420C, which is one of the three EQ wide range pressure transmitters. Since PT-420 and PT-420C share the same sensing location, there will be no change in RCS pressure information indicated on PR-420.

A digital display was added to the control board to provide indication of PT-420. This adds 5 pounds to the control board. This will not affect the seismic characteristics of the control room. The replacement of PT-420 will not adversely affect the operation of the overpressurization mitigation system. (SER 89-111)

27. MR 88-169 (Unit 2), Electric Generator. The modification added a redundant vapor extractor on the generator bearing drain tank. This redundancy more positively prevents the possible buildup of hydrogen gas in the drain tank or bearing pedestals.

Summary of Safety Evaluation: The physical characteristics and performance requirements of the new vapor extractor closely match those of the existing extractor.

The new extractor has a more reliable drive train design than the existing unit. The inlet and outlet of the new extractor was tied into the existing system per the applicable piping specification and B31.1-1967. The new extractor shares instrumentation and control board indicating lights with the existing extractor, which are needed for proper operation of the system. Power is obtained from the same motor control center 2B41 that powers the existing extractor, but since only one extractor will be in service at a time, it does not change the overall load on the motor control center. The change does not affect the functionality of the system, but provides added reliability and availability. (SER 90-020)

28. MR 88-173 (Unit 1), Feedwater System. MR 88-173 changes 1SV-466B and 1SV-476B from a "universal" 3-way valve to a "normally closed" 3-way valve. This change is to ensure the reliable operation of these valves.

Summary of Safety Evaluation: A universal 3-way valve can have pressure supplied at either port #2 or port #3. Port #1 is connected to the "load." A normally closed 3-way valve has port #1 connected to the "load," port #2 connected to the supply air, and port #3 vented to atmosphere. The deenergized condition is for port #1 aligned to port #3.

The function of the "B" solenoid valves is not specifically described in the FSAR. Chapter 7.3 refers to an override signal closing the feedwater valve when the average coolant temperature is below a given temperature or when the respective steam generator level rises to a given value or upon a safety injection signal. Chapter 10.2 refers to the same signals closing the feedwater control valves.

Changing the "B" solenoid valve from a universal 3-way valve to a normally closed 3-way valve does not change the override signals indicated in the FSAR.

The tubing changes to 1SV-466D and 1SV-276D assure the valves are installed in accordance with the original design. The function of these valves will not be changed. The ability of these valves to close the feedwater control valves was verified by acceptance testing. The solenoid valves and the feedwater control valves were tested.

The "slugging" feature provided by 1SV-466A and 1SV-476A is described in Chapter 10.2 of the FSAR. The MFRV slugging is for operational considerations only. There are no safety-related functions associated with the slugging. The primary concern is to maintain the inventory of water in the steam generator using hot feedwater and to keep the steam generator water level in the narrow range level. The 5 second opening time for the slugging of the MFRV is not critical and time can be increased as required. If increased, the closing temperature should be lowered to maintain the amount of water entering the steam generator. (SER 89-021)

29. MR 88-175*C (Unit 1), Steam Generators. The modification provides lockable, shielded storage containers for diaphragms on each containment El. 10' platform. These diaphragms are normally in contact with reactor coolant and are highly contaminated. Typical dose rates for a diaphragm are 10 R/hr gamma contact; 100 R/hr beta contact; 1 R/hr gamma at 18", and 7 R/hr beta at 18".

Summary of Safety Evaluation: Design requirements of the shielded storage containers were that each container be capable of storing two diaphragms and the plastic bags used for contamination control; the container's shielding decrease the dose rate from the two diaphragms to <1000 mr/hr at 18" (the calculated dose rate from the container is equivalent to the normal containment El. 10' platform general area dose rate); the container be a seismically-mounted, poured-lead shield, with the lead contained in stainless steel; and the stainless steel container does not require the use of post-DBA qualified paint. These design requirements assure that the container does not introduce any new hazards to the plant.

The lockable, shielded storage containers for the steam generator primary manway diaphragms meet the requirements of NRC Information Notice 88-079. (SER 89-120)

30. MR 88-184*B, Fire Protection System. MR 88-184*B removed the existing Cardox carbon dioxide control system and installed a new suppression actuation system for the fire protection for the gas turbine G05 building. The new suppression system provides automatic electrical supervision of the heat detector circuit, the power circuit, and the suppression actuation circuit per NFPA requirements. An auxiliary relay was installed to provide alarm functions and to activate the automatic shutdown functions of the G05 controls. Tripping G05 removes the primary heat source in the building and stops the fuel oil pumps.

Summary of Safety Evaluation: The existing Cardox system is shown in Figure 9.6-3 of the FSAR. The entire system was removed. The heat detectors were rewired to allow electric supervision per NFPA requirements. The heat detectors were monitored through a new zone input module in D411. The output of the new input module provides a contact to Zone 1 of C140, local control panel for FP-3707. C140 electrically trips FP-3707. This allows water to flow into the sprinkler piping.

The "Technical Evaluation of Inadvertent Suppression System Actuation at PBNP" indicates that the suppression system for the G05 building is carbon dioxide. The modification changes this evaluation. The probability of inadvertent actuation is greatly reduced by requiring independent operation of both a closed automatic sprinkler head and operation of FP-3707. The equipment in the G05 building is not safe shutdown related. (SER 89-091)

MR 88-184-01 (Common), Fire Protection System. The addendum provides sprinkler protection on the gas turbine building north and east exterior walls.

Summary of Safety Evaluation: The 1&2X04 transformers are not located a sufficient distance from the gas turbine building to satisfy NFPA codes. The sprinklers are closed head and the piping is galvanized for outdoor installation. The piping was pitched back to the supply header so existing drain provisions are adequate. The system is required to prevent the propagation of fire between the X04 transformers and equipment in the gas turbine building. Heat detectors at the X04 transformers or in the gas turbine building trips the deluge valve, allowing water to enter the system. Heat from a fire actuates the nozzles as necessary. Thus, no additional alarm of initiating devices is required. Flow calculations show that the system water supply is adequate for the wall spray sprinkler flow plus either the gas turbine sprinkler system flow or the X04 transformer sprinkler system flow. (SER 89-091-02)

31. MR 88-188 (Common), Various Systems. MR 88-188 involves three different motor-operated valve (MOV) betterment changes. The three changes consist of: (1) Installing 4-rotor limit switches to allow for the complete separation of position indicators and torque switch bypasses. This increases the accuracy of position indication light, while eliminating the occurrence of premature tripping of torque switches due to inertia during startup of the operator; (2) Installing T-drains to Limitorque operators to provide a reliable and qualified way to remove damaging foreign liquids from limit switch compartments; and (3) Providing overload indication to the control room.

Summary of Safety Evaluation: The operating time and characteristics for any and all of the valves does not change with the introduction of the new 4-rotor limit switch. This change enhances MOV position indication and torque switch bypass operation only. The function and operation of interlocks remains the same. The 4-rotor limit switch is a standard Limitorque-supplied component.

The T-drain is both EQ and QA for MOV operators. Existing weep hole drains were not qualified in some locations and they provide a direct path to the internals of the operators. These plugs were replaced. The parts, the T-drain and pipe plug add no extra weight and are seismically qualified in the MOV.

Overload indication in the control room is discussed in FSAR Section 7.5.2. This modification makes the few non-overload indicating MOVs consistent with the FSAR. The ground wire of the open and closed light was moved to the positive terminal of the overload relay so both indication lamps are deenergized on MOV overload. The overload relay contacts are adequate for the additional current of the indication lamps. All wiring changes were made in the motor control center.

EQ or QA parts were required. No new penetrations were made; there were no additional loading of conduit or cable trays. There are no Appendix R considerations associated with these changes. (SER 90-039)

32. MR 89-016*B. Fire Protection System. MR 89-016*B changes the location of an isolation in the service building to accommodate the service building renovation.

Summary of Safety Evaluation: The change only impacts the fire protection system in an administrative area. The piping system pressure boundary meets or exceeds original design criteria. There are no impacts on safety-related systems or equipment.

The installation removes a significant amount of the Unit 1 turbine building and primary auxiliary building fire suppression equipment for the duration of the installation. The installation minimized the amount of time that the affected systems are isolated. (SER 90-107)

33. MR 89-017 (Unit 1). Electric Generator. The MR removes the 32% generator power relays and will replace that circuit with a new circuit which trips the generator lockout relays when the generator output breaker opens at any power level. The new circuit can be defeated during startup using the turbine trip-to-lockout switch.

Summary of Safety Evaluation: The lockout relays (86-TG01 and 86-X01) will be tripped when the generator output breaker opens at any generator power level, instead of tripping only at power levels above 32%. The reason for the existing circuit is to prevent damage to motors from overspeed resulting from turbine overspeed upon loss of electrical load. To lower the setpoint, as the new circuit will (to 0% effectively), would further reduce the amount of overspeed, and therefore, would be more conservative.

The probability of the new circuit malfunctioning is not greater. Loss of power to the auxiliary relay in the circuit will not prevent the circuit from tripping the lockout relay. Two redundant trains were used to increase reliability.

There are no sections of the FSAR or Technical Specifications which refer specifically to the 32% generator power relays. Adequate train separation will be maintained. Seismic adequate of main control board C02 will be maintained. The MR does not impact the turbine-generator overspeed analyses since the change is below the load level in which an overspeed event can be achieved.

This MR results in a change in operating philosophy in that the turbine trips to lockout switch will be placed in defeat before the generator breaker is opened for turbine overspeed testing. This prevents turbine trip events from causing a lockout. This would result in a reverse power trip if a turbine trip occurred while the generator breaker was shut. This is not a significant reduction in protection as the trips defeated have a 60 sec time delay and the reverse power is similar. There are no safety concerns in view of low power level and the non-safeguards status of the turbine trip feature. (SER 89-119)

34. MR 89-023*A*B*Addendum 01, Reactor Coolant System. The purpose of Addendum 1 is to: (1) Install a new reactor coolant system (RCS) reduced inventory level channel (LT-447A) that is basically identical to existing level channel LT-447. This new level channel was added in response to NRC Generic Letter 88-17. (2) Replace the instrument manifold for LT-447 with Whitey valves to make the valving configuration for LT-447 the same as LT-447A.

Summary of Safety Evaluation: LT-447A uses the same connection as LT-447 for the variable leg. The reference leg for LT-447A is independent from the reference leg for LT-447 in that a single valve is not capable of isolating both reference legs. The new reference leg taps into the pressurizer steam space sample line between manual valve SC-950 and containment isolation valve SC-951 just downstream of SC-950 in the upper pressurizer cubicle. Welded connections were used up to the first normally closed (during power operation) valve. New tubing with Swagelok fittings run to LT-447A.

In order that a pressurizer steam space sample is not inadvertently taken when LT-447A is in use, which could cause a perturbation in the level indication, a new in-line valve was installed between the reference leg tie-in point and valve SC-951. This in-line valve is procedurally controlled so it is shut when LT-447A is in use and normally open when LT-447A is not in use. Since pressurizer steam space samples are not periodically required or taken, there is not a concern in isolating this sample line during the periods of time when LT-447A is needed. In addition, this new in-line valve provides a test boundary for performing ORT 37 (seat leakage test on SC-951) such that valve SC-950 and the new reference leg root valve will not have to be shut to perform the procedure.

Swagelok fittings were used throughout the installation after the first normally closed valve. This portion of the line does not experience severe thermal transients. Welded fittings were used in line portions that may experience severe operational thermal transients. The acceptability of Swagelok fittings is based on their use in the variable leg of LT-447 and in the pressurizer steam space sample line where Swagelok fittings exist outside of the pressurizer cubicle both upstream and at valve 1SC-951. The newly installed fittings were hydrostatically tested/leak checked at 2500 psig before returning the affected lines to service.

Review of FSAR Section 9.4.2 revealed the incorrect statement that socket-welded joints are used throughout the sampling system except at sample vessels, sample panels and sample sinks. This statement in the FSAR was modified to include the appropriate use of Swagelok fittings. There is not a safety concern with using Swagelok fittings in 3/8" diameter lines connected to the RCS that do not experience severe operational thermal cycling.

Swagelok fittings have been proven to be highly reliable by their extensive use throughout the plant. As stated in FSAR Section 14.3, the rupture of a 3/8" line in the RCS can be accommodated for by the charging pumps; thereby allowing an orderly shutdown. More specifically, the FSAR states that typically one charging pump can accommodate for a 3/8" diameter hole in the RCS. The resultant radioactive impurities contained in the discharged coolant would be confined to the containment.

The refueling cavity was flooded before isolating LT-447. Since LT-447 is only required during reduced inventory conditions, isolation of LT-447 did not violate its availability requirements. A post-installation leak check of all newly installed fittings at 2500 psig was performed. The variable legs of LT-447 and LT-447A was filled and vented, and the reference legs were drained after installation acceptance so the level channels were prepared to return to service.

The new level transmitter, power supply and alarm bistable are of the same model or type as existing level channel LT-447. The level indicator is a dual input indicator which will display the level for both LT-447 and LT-447A, and is used in other applications on the control board. The new instrument channel (LT-447A) is powered from the red instrument bus, while the existing channel (LT-447) is powered by the yellow instrument bus. Separation of the channels, in accordance with IEEE-384, was maintained to the extent possible.

The changes made do not add any new failure modes or channel functions (besides the redundant level indication channel) that did not exist in level channel LT-447. The additional level channel provides added assurance that RCS level indication will remain available during reduced inventory conditions. (SER 89-054)

35. MR 89-023 (Unit 1), 89-024 (Unit 2), Reactor Coolant System. An increase in scope for these MRs was made to accomplish the following: (1) relocation of the reactor vessel flange leakoff line manual valve (RC-522); (2) addition of a drain valve in this line; and (3) elimination of the tie-together line between the reactor vessel flange leakoff line and LT-447s variable leg drain valve.

Summary of Safety Evaluation: The evaluation documented in SER 89-054 applies in its entirety except as revised or supplemented herein. Manual valve RC-522, which is the final valve to the RCDT from the RV flange leakoff line, was simply moved upstream 15' to alleviate ALARA concerns. In addition, the 3/8" tubing line between the RV flange leakoff line and manual valves RC-522A, 523 and 525 which allowed the RV flange leakoff line to be drained through LT-447s variable leg drain valve (RC-525A) were eliminated, and a 3/8" drain valve will be added to the RV flange leakoff line downstream of temperature element TE-418. The addition of this drain valve allows the drainage of the RV flange leakoff line to be visually verified without affecting LT-447 or LT-447A, and it also allows a procedure to be simplified (RP-1B), thus reducing the chance of valve mispositioning. These installations involve 3/8" Swagelok fittings and are QA and seismic. An MWR was used to control work and a post-installation leak check performed as practical to 2500 psig. Since the modified portion of the RV flange leakoff line was downstream of temperature element TE-419, this change does not significantly impact indication of RV flange leakage.

The alarm bistable being used in level channel 2LT-447A is the same model which was installed in level channels 1LT-447 and 1LT-447A, and which will be installed in level channel 2LT-447 via MR 89-010.

A small manometer-type loop seal exists in the reference leg for LT-447A at the reference leg tie-in point at the top of the pressurizer. The existence of this loop seal is justified based upon the administrative controls applied to the use of this level channel.

The reference leg is initially blown down with nitrogen in OP-4D, "Draining the Reactor Coolant System." A signoff step in OP-4D verifies a positive outflow of nitrogen at the transmitter's reference leg drain valve. After the initial blowdown, if the pressurizer is flooded up offscale high, it will again be required to drain down using OP-4D. A precaution was placed in OP-4D which states that the reference leg may not be self-draining since a small inverted manometer and a very long run of small diameter tubing are present.

The level indication from LT-447A was cross-checked against the indications from LT-447 and the Tygon hose/local level indicator (when available), and recorded. If a deviation of 3" or more is noted, action will be taken. If the reference leg was sloped completely downward, any water entering the line would still affect the level indication, and, after initial blowdown of the line, the upward sloping tie-in may, in fact, preclude water from entering the line. (SER 89-054-01)

36. MR 89-029 (Unit 1), Reactor Protection. The modification removes the delta flux function {f(ΔI)} from the overpower ΔT setpoint (OPDT) for all four protection channels of each unit. The end result of the modification(s) is that the OPDT will only vary as a function of Tavg, f(Tavg), and then only when Tavg is >573.9°F. The modification consists of rewiring [illegible] signal cables for the OPDT summer, the ΔI current source, the f(ΔI) high current selector and the overtemperature ΔT (OTDT) compensator. Following the modification, the f(ΔI) signal will only be input into the OTDT compensator. The f(I) signal to the OPDT summer will be replaced with a constant 10 ma input from the I current source. This 10 ma input corresponds to f(ΔI)=0. This input to the summer is necessary to maintain the proper relationship between the f(Tavg) input to the OPDT summer and summer output following the removal of the f(ΔI) signal.

Summary of Safety Evaluation: The elimination of the f(ΔI) input to OPDT is necessary in order to utilize the full delta flux operating envelope requested under Technical Specification Change Request #127. The acceptability of removing the f(ΔI) term from the OPDT setpoint with respect to plant/reactor operation and safety was addressed in the TS change submittal. This safety evaluation report will address only the physical changes to plant hardware required to eliminate the f(ΔI) function.

This modification has a small effect on plant hardware because there is an increase in the load on the ΔI current source and a corresponding decrease in the load on the f(ΔI) high current selector. This load change is associated with adding the OPDT summer to the ΔI current source loop. The input resistance of the OPDT summer is 100 ohms. This will result in a total load on the I current source of 200 ohms. The I current source is designed to provide an output of 10-50 ma into an output load of up to 600 ohms. Likewise, the load on the f(ΔI) high current selector will be reduced to 100 ohms. Following the modification, the ΔI current sources and the f(ΔI) high current selectors will still be operated within their capabilities. (SER 89-110)

37. MR 89-034*A, Circulating Water System. MR 89-034*A installs a weldolet in the 3" section of the Unit 2 LP trap header. The weldolet will contain an isolation valve with a nipple and cap. This will serve as a future tie-in point for radwaste steam trap drains.

Summary of Safety Evaluation: MR 89-034*A is designed to meet B31.1-1967. It is designed to 1085 psig, similar to the upgrade modification to the LP trap header. This is a much greater design pressure than the original LP trap header. The modification uses stainless steel to guard against the effects of erosion/corrosion in the steam/water environment.

A worst case failure of this modification is a catastrophic failure, which would essentially result in a "hole" in the LP trap header. The probability of this occurring is extremely unlikely. The consequences of this failure are limited by the consequences of any other catastrophic failure of the LP trap header. These consequences are limited because the accident analyses do not take credit for the condenser being available. In a steam generator tube rupture, the steam to the condenser is isolated very quickly. (SER 90-087)

38. MR 89-046*A (Common), Building & Structures. MR 89-046*A installs a removable support just inside the vital switchgear room to turbine hall doors. The support provides a bearing surface for the doors to aid in their ability to survive a design basis flood. Ensuring that the doors do not fail ensures the operability of the vital switchgear during a design basis flood.

Summary of Safety Evaluation: The support was Hilti-bolted to the floor and the wall using flush-mounted Hilti bolt expansion inserts. The support was not attached to the doors, thus not affecting the doors' fire rating. Miscellaneous changes to the door's hardware to resolve support interferences were performed in accordance with acceptable fire door practices.

The support was designed to withstand 4' of flooding in the turbine hall. The support is not seismically analyzed, however, it would withstand a seismic event in view of its flooding load capabilities. Combining seismic and flooding is not considered credible. The installation is just inside the door and could not impact the vital switchgear in the event of a catastrophic failure. The installation has no significant impact on any system or structure that could cause an accident or is required to mitigate an accident. (SER 90-067)

39. MR 89-052 (Unit 1), Safety Injection System. MR 89-052 welds a threaded pipe stub into the valve body of safety injection accumulator nitrogen fill vent valve, HCV-957. The threaded connection allows the volumetrics tester to be directly connected to the valve for testing.

Summary of Safety Evaluation: HCV-957 is a remote operated valve which serves as a containment isolation valve (CIV) and as a relief valve protecting the piping between inside containment CIVs 834A and 834B and outside containment CIV 846 from overpressurization from the nitrogen supply connected downstream of CIV 846. There is a remote possibility that the isolating components of HCV-957 could be damaged when welding in the pipe stub due to excessive heating. To decrease the possibility of damage, the welding was done with the valve open to lessen the amount of heat buildup. Since the valve was open while welding in the pipe stub, the installation was done with the plant in the cold or refueling shutdown condition at which time containment integrity is not required. Prior to returning HCV-957 to service, HCV-957 was leak tested and stroked to ensure the operability of the valve was not affected by the modification.

The addition of the threaded pipe stub to HCV-957 has a negligible affect on its relieving capacity since the pipe stub's inside diameter is the same diameter as the valve's inlet piping. It is not considered possible that the installation work could affect the setpoint of HCV-957. Therefore, stroke testing of the valve was considered adequate to ensure that the valve operator is free to move and will open at its setpoint if required.

To prevent inadvertent capping or plugging of HCV-957, a step was added to ORT 32 and CL-7A which verifies that the pipe stub has not been capped or plugged. In addition, a placard stating that HCV-957 is a relief valve and is not to be capped or plugged, except during testing, was hung from the valve. Also, the text was modified to ensure that the nitrogen spoolpiece is removed or the nitrogen 12-packs are disconnected prior to capping the relief valve. Based on these controls, the probability of the relief port being inadvertently blocked is considered acceptably low.

Since the welded-in pipe stub does not breach the pressure boundary, no pressure testing is required. During test performance, any leakage from the threaded pipe stub would add to the leakage measured through the valve, which is conservative. The threaded pipe stub is made of stainless steel to preclude rusting of the pipe threads. Since the pipe stub is open to atmosphere and is a free end, the slight difference in thermal expansion coefficients of the two steels is not a concern.

The placard and pipe stub add ~0.7 pounds to the valve which is considered to be an insignificant weight addition to the seismically-supported valve and is within small bore piping seismic guidelines. (SER 89-128)

40. MR 89-056 (Common), Lifting Devices. MR 89-056 provides a generic lifting pad eye for lifting plant equipment such as valve operators and internals.

Summary of Safety Evaluation: This equipment is not specifically addressed in the FSAR, the lifting pad eye will be used to facilitate maintenance practices that were considered as part of the design of the plant. The lifting pad eye was designed to support a 1000 lb load. 1000 lbs does not constitute a heavy load. A specific seismic evaluation was not done because the system must be out of service when the lifting pad eye is being used. When the lifting pad eye is unloaded it will have sufficient strength to prevent dislocation during a seismic event. (SER 90-032)

MR 89-056*A, addressed the design of two new pad eyes that are for increased loads.

Summary of Safety Evaluation: The original safety evaluation addressed a lifting pad eye designed to support a 1000 lb load. This addendum addresses a Type A lifting pad eye designed for a 1000 lb load; a Type B lifting pad eye designed for a 5000 lb load; and a Type C lifting pad eye designed for a 3000 lb load. A specific seismic evaluation was not done because the system must be out of service when the lifting pad eye is being used. When the lifting pad eye is unloaded it will have more than enough strength to prevent dislocation during a seismic event.

The lifting pad eyes and the addition of the approved loading will not adversely affect the integrity of any poured concrete wall in the plant.

The lifting pad eyes will be used for maintenance of components that are in systems which are out of service, so the impact upon the plant is negligible. (SER 90-032-01)

41. MR 89-081 (Common), Hydrogen Monitoring System. MR 89-081 adds jumpers in C174 and C175 to connect the existing white and yellow hydrogen monitor power loss alarm contacts to the existing hydrogen monitor trouble alarms on 1C20.

Summary of Safety Evaluation: Each monitor contains power loss contacts which are operated by normally energized relays. This change does not affect either of the monitors or any portion of the indication circuits. Redundancy between the monitors will be maintained. Only the alarm circuit is affected; the original alarm inputs remain.

There are no seismic or Appendix R concerns. QARs for the SIS wire were recorded. Post-installation testing verified that both alarm inputs actuate the respective 1C20 annunciator. The monitors were calibrated prior to returning the units to service. (SER 90-023)

42. MR 89-086 (Unit 1), Feedwater System. MR 89-086 replaces the Unit 1 "B" main feed pump suction elbow support strut clevis and pin.

Summary of Safety Evaluation: Replacement of this support clevis does not affect the functionality of this system. The material was standard support grade material, and is larger than the existing support clevis and pin. With larger bearing areas, stresses in this member are lowered. The design also incorporates cap screws and can be used to take free play out of the joint to minimize future wear problems.

This support is not within the NRC IEB 79-14 seismic piping supports boundary; and therefore, was not qualified as such. Standard construction techniques were used to verify the adequacy of the base welds to ensure the support will not fail during operation. (SER 90-040)

43. MR 89-092 (Unit 2), Refueling Cavity. The MR installs a permanent set of brackets on the wall of the lower refueling cavity of each unit. The brackets hold an all-fiberglass ladder, which will be used in the lower cavity. The ladder will be attached to the brackets when not in use. This includes during at-power operation as well as during periods of refueling shutdown when the cavity is flooded.

Summary of Safety Evaluation: The ladder was modified to remove all aluminum and other materials which are not desirable in the borated cavity water or in a post-LOCA containment environment. The only remaining materials are: Stainless steel (small amounts on the ladder and the entire bracket); fiberglass (the ladder, including rungs); and natural rubber (the new ladder feet). The fiberglass and the natural rubber were analyzed for leachable chlorides and fluorides. Based upon these analyses, the materials will not have an adverse effect on the cavity water or on the reactor coolant system.

The total weight of the ladder is 30 pounds. It is being rigidly held to the cavity wall using 3/8" flat stock. In the event of a design basis accident, the ladder will not break loose and become a missile hazard. Even if it would break loose, its physical location is in the bottom of the lower cavity, which negates missile concern. Since fiberglass is heavier than water, it will not float in the event that the cavity was flooded up from containment spray or RCS break flow (there is a drain). The ladder will remain in the lower cavity.

The only accident which this installation could affect is a fuel handling accident. Due to the small size of the installation, and its significant distance from any fuel motion path, it was concluded that the modification will not increase the probability of a fuel handling accident. The installation was performed with QA welds and by qualified welders. The installation was evaluated for its seismic performance. (SER 89-145)

44. MR 89-096 (Unit 1), Main Control Boards. MR 89-096 rearranges the low pressure heater dump reset buttons on the vertical section of main control board 1C03.

Summary of Safety Evaluation: This modification does not change the mounting configuration of the reset buttons. Following reinstallation, the reset buttons were tested to ensure correct operation. No system functional changes occurred. Each valve was cycled by using the reset button and a terminal strip slider.

The modification is not safety-related. The MR adversely impacted the seismic capability of the main control boards as no cutting or changes in mounting details are involved. Electrical separation was not required. (SER 90-014)

45. MR 89-098 (Unit 1) & 89-099 (Unit 2), Containment Spray System. MRs 89-098/099 install pressure taps and gauges on the suction of the containment spray pumps. These gauges were installed to facilitate inservice testing. The tap will be located on the suction line to the containment spray pump and will consist of a tap, isolation valve, fittings and gauge.

Summary of Safety Evaluation: The FSAR describes the containment spray system in Section 6.4 Appendix C and in 14.3.4. The eductor is discussed in Section 6.4.2. The pressure gauges will only be used for testing. When the system is in service, the pressure gauge will be isolated from the suction of the containment spray pumps. Thus the new tap and gauge have no affect on the safety function of the containment spray system as described in the FSAR.

The new gauge and tap were installed to the requirements of the original code and system piping design requirements. The configuration was evaluated and will not affect the seismic qualification of suction piping. (SER 90-024)

46. MR 89-122 (Common), Fire Protection System. MR 89-122 installs a pressure gauge on the electric fire pump auto start pressure sensing line.

Summary of Safety Evaluation: The fire water system itself is not safety-related, but provide fire protection to equipment that is safety-related. Therefore, there is no postulated scenario which could result in this modification creating an accident which has been described in the FSAR or any accident which has not been described in the FSAR.

The only postulated failure of the proposed modification is a rupture of the new tubing or the gauge. The consequences of this failure would be the same as the consequences of a failure in the existing pressure sensing line. Such a failure would result in a 3/8" hole in the fire water system, which would have an insignificant impact on the ability of the fire water system to provide fire protection to safety-related equipment. If the failure occurred during a normal operating period, the "sensed" pressure would drop and the electric fire pump would automatically start. This would be quickly detected by the operating crew. Therefore, the consequences of a failure of the proposed modification would not be increased beyond the consequences of a failure of the existing system.

The tubing run for the new gauge is very short. The tubing used is well in excess of the design pressure of the fire water system and is compatible with the existing tubing. The new gauge is extremely light weight and even if it did come loose it would not be likely to cause any damage to adjacent tubing. (SER 90-013)

47. MR 89-123 (Unit 1), Safety Injection System. MR 89-123 replaces the accumulator level nitrogen equalization line from 3/8" tubing to 1/2" tubing and increases the slope of horizontal runs. This is done to facilitate proper drainage of this line should water accumulate in it.

Summary of Safety Evaluation: The tubing and fittings have temperature and pressure ratings far in excess of the design requirements of this system. Stainless steel material was used for all tubing and fittings.

The larger diameter tubing (same wall thickness) provides more bending strength than the original tubing, with an insignificant change in weight. Valves in the tubing run will still be within 6" of a support. The change does not affect the seismic qualification of the tubing run.

The change does not affect the functionality of this system, but in fact, should make it more reliable. No control functions are included with the instrumentation. (SER 89-117)

48. MR 89-125 (Unit 1), Service Water System. The modification removes four (4) unnumbered pressure gauges from the service water system's Unit 1 accident fan cooler return lines. There are no similar pressure gauges on the service water lines servicing Unit 2. After the pressure gauges were removed, a pipe cap was placed on the existing pipe nipple which is welded into the downstream side of each valve.

Summary of Safety Evaluation: The modification has no negative impact on the service water lines since the changes are downstream of existing root valves which are normally closed. Therefore, flow in the lines will not be affected. In addition, the root valves, which are manual containment isolation valves, are not affected by the change. The seismic integrity of the service water system is not negatively impacted since weight is actually being removed by the modification. (SER 90-065)

49. MR 89-126 (Common), Various Systems. The original filter elements used in the reactor coolant filters (1&2F1) and the reactor coolant pump seal injection filters (1&2F39A&B) were of a tubular wound wool fiber design. No controlling documents were discovered which controlled changes to the filters in the mid-1970s. NCRs N-89-034 and N-89-167 were issued against this deficiency, and this was issued to document the acceptability of the modifications made to various filter internals and to update appropriate documentation systems in response to the referenced NCRs.

Summary of Safety Evaluation: Benefits obtained from the media change include: (1) simplified filter changes, which minimizes the spread of radioactive contamination and lowers personnel radiation exposure, (2) lower cost per filter change; and (3) higher filter media differential pressure capacity.

The operation of the filters is not adversely affected from the media change as there is no change in the particulate filtration rating of the filter media; the weight of the filter unit is less with the pleated cartridge filter media, and there is no appreciable change in the filter's center of gravity. Thus, the filters' seismic evaluations are not adversely affected.

The description of the reactor coolant filters, as found in Section 9.2 of the FSAR, is affected by this modification. This section states that "disposable synthetic filter elements are used" in the reactor coolant filters. A more accurate description of the post-modification reactor filters would be that "disposable filter elements are used." The FSAR description of the reactor coolant pump seal injection filter is not affected by this change.

Catastrophic failure of the filter(s) could cause equipment damage and possible failure. Failure of a seal injection filter could allow particulate matter to be injected into and damage the RCP seals. Failure of a reactor coolant filter could allow particulate matter into the suction of the charging pumps. The postulated failures are no different than the original filters. The filter elements are encapsulated in a fine stainless steel mesh screen. Thus, failure of a filter element would only allow small-sized particulate matter to migrate downstream (less than 1/64"). Although this would result in equipment damage, the damage should be seen as an accelerated wear versus catastrophic failure. The filter media used has withstood the service conditions over the many years of application. Thus, filter degradation in this manner is not expected. Normal equipment performance monitoring should identify filter or downstream equipment problems prior to catastrophic failure. (SER 90-011)

50. MR 89-128 (Common). Emergency Diesel Generators. MR 89-128A&B installs isolation valves and test tees on several instrument lines to the G01 and G02 control panels (C64, C65).

Summary of Safety Evaluation: A calculation was performed to determine the maximum allowable span of 1/4" tubing with a 2 1/4" Whitey valve located anywhere in the span. The resultant maximum 5' span was included in the work plan. Because of the seismic acceptability, the probability of failure is not significant. In addition, a worst case failure of the valves or tees would have no different impacts on diesel operability than a postulated failure of the existing tubing. (SER 89-101)

51. MR 89-139 (Unit 1). Nitrogen System. MR 89-139 replaces components in the nitrogen gas backup system to 1RC-430 and 1RC-431C. The change was made to improve the opening time of the power-operated relief valves (PORVs) for low temperature overpressure protection (LTOP) considerations to meet the Westinghouse criteria. The MR (1) replaces existing Asco 3-way solenoid valve admitting air/nitrogen to the PORVs with a solenoid having a higher Cv and the same electrical characteristics; (2) replaces the existing 3/8" nitrogen backup tubing from the nitrogen regulator valves with 1/2" stainless steel; (3) replaces existing 3/8" flexible hose between solenoid and valve operator with new 1/2" hose. This change required drilling into the operator cover and welding a 1/2" fitting to the cover; and (4) installs a 2-stage regulator in lieu of the existing Smith regulator for consistency between Unit 1 and Unit 2.

Summary of Safety Evaluation: The solenoids were secured to the existing supports using 1/4" bolts with double nuts. The solenoids were delivered with footings for this purpose. The method has been evaluated and is adequate to meet seismic considerations. The splices to the existing plant wiring are environmentally qualified. The new solenoids are approximately the same weight as the existing model and do not affect the overall valve seismic design. The higher Cv reduces head loss in the nitrogen backup tubing, thereby decreasing the opening time.

It was determined that the existing 3/8" tubing causes too much head loss to meet the acceptance criteria. Therefore, the 1/2" tubing was installed on Unit 1 without intermediate testing of opening times. The 1/2" stainless steel tubing is adequate for the design conditions; was seismically mounted; and was leak tested prior to operation of the system.

The tubing was supported using the seismic tubing support guidelines. Since there are several bends in the tubing between the wall-mounted regulators and check valves and the solenoids mounted on the PORVs, there is no concern related to movement of the PORV (RCS) or thermal expansion of the tubing.

The existing flexible hose between the valve operator and solenoid discharge port was replaced. The new flexible hose is adequate for the design pressure, has a wire wrapping to protect it from inadvertent damage during operation and is consistent with the original valve manufacturer's design. Installation of the new hose required drilling a new hole on the operator cover and welding a Swagelok fitting into the cover. The bottom of the fitting was ground smooth with the inner surface of the cover to prevent interference with valve operation. The weld was a minimum 3/16" and was tested with liquid penetrant prior to operation.

The hose weighs slightly more than the existing hose because it is larger; however, in view of the total weight of the PORV assembly, it is insignificant from the standpoint of affecting the valve seismic response.

The 2-second opening time criteria is based upon a consideration of RCS volume, LTOP relief valve pressure setting and mass inputs associated with the activation of one safety injection pump. The analysis was reviewed using site-specific inputs.

A concern was raised during the modification process regarding the need to establish a lower setpoint for the opening of the PORVs. This concern was that the valve would open too quickly and would induce water hammer into the PORV discharge piping or that would damage the valve. It was concluded that the only criteria for opening time is the 0.7 seconds established by the manufacturer for protection of their valve. The water hammer concern is with the relief valve discharge piping. This piping is non-QA and non-seismic. The potential for water hammer damage in this line affecting the PORVs or upstream piping is minimal in view of the discharge piping and support configuration just downstream of the valves.

Calculation PB 89-036 was performed to quantify the percent improvement in opening time associated with system pressure under the seat. The results presented different percentages based upon the nitrogen regulator set pressure. The values ranged from ~16% for a 100 psig nitrogen supply to ~24% for an 85 psig nitrogen supply. Based upon experience gained during the Unit 2 installation (nitrogen supply left at 100 psig) and engineering judgment, the factor for pressure-assisted operation was applied at 15%. (SER 90-021)

52. MR 89-142 (Unit 1), Buildings & Structures. MR 89-142 adds shielding around the regenerative heat exchanger cubicle to eliminate the high radiation area that currently extends into the hallway outside the cubicle. Temporary shielding in the form of vinyl covered lead blankets was placed around the letdown line and around the gap above the door during outages.

Summary of Safety Evaluation: No lead comes in contact with the stainless steel piping. Temporary shielding will be in place only during outages and will be administratively controlled.

Permanent shielding was added to the cubicle door. The original design does not appear to have been installed in accordance with design control requirements. Thus, no documentation regarding material qualification or structural analysis is available. These modifications simply add four more 1/8" lead sheets (for a total of 3/4" thickness) to the existing frame.

The movable door is supported by 4 industrial grade trolleys trapped in a steel track. The track is welded approximately every foot to a standard 4" channel embedded in concrete. Similar channels have been rated for greater than 2000 lbs/ft. The movable door will weigh ~800 lbs. The load per trolley is well within the load rating for similar industrial grade design trolleys.

The fixed door section weighs ~1000 lbs. It is supported by the track on the movable door side (middle of assembly) and is continuously supported on the vertical edge by attachment to an angle welded to another channel embedment.

Both doors were analyzed to ensure that they will remain in place during a seismic event. Even if the door(s) should fail and possibly impact the regenerative heat exchanger, it is outside the containment isolation boundary and is isolable from the RCS. (SER 90-045)

53. MR 89-150 (Common). Buildings. The extension building garage was remodeled into a drug screening facility. The drug screening facility provides services for the licensee collection requirements of 10 CFR 26, Fitness-For-Duty Program, and normal plant first aid and medical screening requirements. A new single bay garage was added immediately north of the extension building.

The existing electrical service to the extension building was not large enough to adequately supply the heating and air conditioning for the addition and remodeled area. The power is supplied from either 1B01 or 2B02, with no preference to either source. Accordingly, ECR PB-89-108 added a 100 amp panelboard for the remodeled area.

Summary of Safety Evaluation: The station distribution system is discussed in FSAR Section 8.2.2. The panelboard is supplied from a 480 to 120/208 volt, 30 kVA transformer, which is fed from a manual transfer switch and fused disconnects which will allow the panelboard to be supplied from 1B01 or 2B02. 1B01-3B and 2B02-43D were upgraded to accommodate the load. 1B01 and 2B02 are non-safeguards equipment distribution buses. These buses are stripped during accident conditions and do not load the vital safeguards buses, the emergency diesel, the instrument buses, or the DC battery system.

The maximum power required at any given time for the heating and air conditioning unit is less than 50 amps at 208 V AC (18 kVA). This adds 22 amps to the load center (1B01 or 2B02). The overcurrent setpoints for the load center breakers were changed from 225 amps to at least 240 amps (250 amps max is preferred for reliable load center operation and compliance with NEC Article 310). The additional load is nominal when considering the existing 480 V bus loading and diversity factors of the connected loads. Note that the existing 300 MCM supply cable ampacity is sufficient for the added load and increased overcurrent trip setting.

The added load on breakers 1B01-3B/2B02-43D does not degrade the performance of existing 480 V loads. The 22 amps added to either of the 480 V breakers represents less than 10% of the existing breaker trip setting of 225 amps. By taking into account the proposed breaker trip setting increase and by assuming marginal diversity factors of connected loads, the continuous operation of the 480 V loads is reasonably ensured. (SER 89-149)

54. MR 89-169 (Unit 1). Condensate System. MR 89-169 provides a method by which the hinge pin bonnet leakage problems on 1CS-466AA and 1CV-476AA can be stopped by seal welding a disc to the valve body so the as-built configuration does not rely on the carbon steel gasket for sealing.

Summary of Safety Evaluation: The bonnet area exposed to the internal pressure (design pressure) of the valve is increased due to the location of the seal weld. The cover thickness and bolt stress requirements due to pressure forces over this area are Code acceptable.

The bonnet is offset away from the valve body due to the addition of the seal-welded disc and there will be some added weight due to the disc. The additional stresses incurred with respect to seismic loads are considered to be negligible.

The valve internals are still assembled as originally built, thus not changing its operation. The seal-welded disc provides the pressure boundary, although the metal gasket is still installed under the hinge pin shoulder.

Failure of the hinge pin bonnet to hold the pin in place due to stud or bonnet failure could result in the valve being inoperable. This is not considered a reasonable failure mode based upon stress values calculated and the potential is no greater than for the original design.

Failure of the seal weld to be leak tight would be no different than the failure of the metal gasket. (SER 90-038)

55. MR 89-175 (Common), Service Water System. MR 89-175 installs seismic floor supports on the discharge pipe of SW-4401 (G02) and SW-4404 (G01). These are the relief valves on the service water line downstream of the EDG glycol coolers (reference NCR N-89-158).

Summary of Safety Evaluation: The modification upgrades the support of these lines and brings them to the standards of the Bechtel "Small Bore Piping Guidelines" and B31.1-1967. If the installation failed in the worst possible way, the consequences of the failure would only bring the system back to its current configuration. Therefore, the consequences of the failure are bound by the present analyses. (SER 90-047)

56. MR 89-180 (Unit 1) & 89-181 (Unit 2), Instrument Air System. MRs 89-180/181 disconnect the instrument air (IA) lines from the containment personnel hatches and plug the 1" diameter hatch penetrations with pipe plugs. The modification prevents the possibility of overpressurizing a hatch as required by ASME Section VIII or masking the TS 15.4.4 leak test results of a hatch. This modification carries out the corrective actions for NCR N-89-296.

Summary of Safety Evaluation: The IA line was disconnected from the personnel hatch, cut back as far as possible without affecting the IA branches to any other equipment and capped. Both sides of the 1" hatch penetration was plugged with pipe plugs to ensure that a leak tight seal is obtained.

Removal of the IA lines to the personnel hatches and the installation of tubing caps on the severed IA lines eliminates several possible leakage paths from the IA headers (i.e., 4 valves and several soldered joints). All safety-related equipment supplied with IA is designed to "fail-safe" upon a loss of IA or has a backup source. This change does not affect any of this equipment. Since the installation of the tubing caps on the IA lines meets original design criteria found in Bechtel line class information and Power Piping Code ANSI B31.1-1967, the probability of a loss of IA pressure due to this change is not increased.

The pipe plug material is in accordance with original design criteria as found on the personnel hatch drawings. To test the pressure integrity of the personnel hatch after the pipe plugs are installed, Technical Specification test TS-10 was performed. Removal of the IA connection does not negatively impact the hatch design parameters (seismic, pressure, temperature, etc.).

The installation of the modification temporarily opened a penetration in the personnel hatch between the inner and outer doors. The installation work procedure required that the plant be in the cold shutdown or refueling shutdown condition and that the inner door be operable when refueling operations are in progress. During the Unit 2 installation, the containment purge supply and exhaust valves were inoperable. Therefore, the Unit 2 installation also required that refueling operations are not in progress.

TS 15.7.3 requires that either purge exhaust SPING RE-305 be operable or else grab samples be taken and analyzed once per 12 hours if effluent releases continue while radiation monitor RE-212 is disabled. In addition, TS 15.3.8 requires that SPING RE-305 be operable if refueling operations are in progress. The installation work plan ensured that these requirements are met. (SER 90-031)

57. MR 89-183 (Common). Waste Gas System. The modification removes the travel stops on the waste gas decay tank discharge isolation valves (WG-1617, 1618, 1619, 1620). The mispositioning of these stops resulted in the valves being open when the indicators showed closed. This led to inadvertent release of waste gas decay tank contents.

Summary of Safety Evaluation: The manufacturer recommends the use of travel stops when the process stream temperature is >170°F to avoid diaphragm damage. The process stream temperature which these valves see is 80°F per the FSAR. Therefore, the travel stops could be removed without affecting the operation or integrity of the valve. (SER 90-030)

58. MR 89-191*A (Unit 1). Residual Heat Removal System. Modification 89-191*A addresses the reconfiguration of the Unit 1 residual heat removal (AC-601R-2) relief valve 861C discharge. The relief valve discharge was installed to connect to the El. 21' floor drain system (during initial relief valve installation via modification M-46). These drains then discharged into the Sump A. This design package decouples the relief valve discharge from the containment floor drain system; removes a section of the old relief valve discharge line to ensure adequate seismic clearance; and installs a temporary plug on the floor drain piping in the line.

Summary of Safety Evaluation: This change was performed due to seismic qualification requirements for the relief valve and inlet piping configuration. The FSAR describes valve 861C in Section 6.2.2, "System Design and Operation - Safety Injection System;" Section 4.2.3, "Pressure Relief Devices;" and Section 9.3.2, "System Design and Operation - Auxiliary Coolant." Reconfiguration of the discharge of RH-861C does not alter any of its overpressurization protection capabilities as described in the FSAR.

The fluid that could be discharged will not affect adversely the El. 8' of containment. This area normally serves as a collection point for discharged fluid in its role as Sump B. The fluid will drain via the El. 8' floor drains into the Sump A. The current configuration drains discharge to Sump A. The equipment in this area that is important to safety is post-LOCA qualified up to 10' above the floor of the containment. The discharge of this valve would not empty any more inventory than is postulated in LOCA evaluations. Thus, the change is bounded by the existing LOCA accident evaluations. The discharge line will not aim directly at any safety-related equipment.

The discharge from this relief valve would not directly be considered a LOCA unless the residual heat removal system was required. The relief valve can be isolated from the reactor coolant system, at which point cooldown could be accomplished by the use of the steam generators or by use of containment sump recirculation.

The changing of the relief discharge to the El. 8' floor of containment from the drain line causes a personnel safety concern; however, Design Package B addresses this concern.

The installation was done to the requirements of B31.1, to the original Westinghouse design requirements and the requirements of Modification M-46. The entire revised configuration, including the 10" AC-601R-2 residual heat removal piping, was reviewed for design loadings including pressure, deadweight, seismic and relief valve discharge. (SER 89-138-01)

MR 89-191*B (Unit 1), Residual Heat Removal System. This evaluation is a continuation of SERs 89-138 and 89-138-01. Those evaluations addressed the reconfiguration of the RHR relief valve 861C for MRs 89-191*A and 89-179*A and B. This continuation addressed the additional details from MR 89-191*B. The existing relief valve anchor was replaced by two piping support guides. This change was based on piping stress analysis to bring the piping in compliance with Code requirements.

Summary of Safety Evaluation: The floor drain line that the 861C relief valve was previously tied into was capped off. This replaced a temporary pipe plug added by MR 89-191*A. The functional changes were discussed in the other evaluations.

A shield was added, for personnel protection, that directs discharge from the relief valve onto the floor of containment. This same shield design was installed on Unit 2. The shield has no functional impact on the operation of the relief valve or any other plant system, structure or component. (SER 89-138-02)

59. MR 90-002 (Unit 1) & 90-003 (Unit 2), Feedwater Heaters, Vents and Drains. MRs 90-002/003 add a drain line to the piping section between the heater drain tank pumps {1(2)P27A, B, C} discharge isolation valves (151, 157 and 163) and the heater drain tank discharge check valves. The drains minimize the potential for personnel burn injuries.

Summary of Safety Evaluation: Although this equipment is not discussed in the text of the FSAR, it is shown in Figure 10.2-4A of the feedwater drains. The addition of these drain taps does not affect any of the conclusions reached in the FSAR. The taps comply with the requirements of B31.1 and the original piping system design requirements. This was a non-seismic, non-QA installation. (SER 90-027)

60. MR 90-033 (Unit 2), Waste Gas System. MR 90-033 installs two check valves in the hydrogen line to the Unit 2 VCT, two check valves in the nitrogen line to the Unit 2 VCT, and rearranges the layout of the Unit 2 VCT gas makeup system to reduce congestion. This MR provides double-valve isolation between radioactive gas systems (cryogenic and VCT cover gas), and the hydrogen and nitrogen gas systems.

Summary of Safety Evaluation: Per Appendix A of the FSAR, the VCT and its associated piping are Seismic Class I. The nitrogen, hydrogen and cryogenics gas systems are Seismic Class III. Appendix A also states that "The interface between a Class I system and a lower class system is a normally closed valve or a valve which is capable of remote operation from the control room." For the VCT gas makeup system, a normally closed valve would be impractical and a remotely-operated valve is not supplied.

Regulatory Guide 1.29 describes the interface as "The system boundary includes those portions of the system required to accomplish the specified safety function and connecting piping up to and including the first valve (including safety or relief valve) that is normally closed or is capable of automatic closure when the safety action is required." For the VCT gas makeup system, the safety function that would be required is the isolation of the piping leading to the VCT to prevent the release of fission gases from the VCT to the auxiliary building.

The VCT gas makeup line check valve (2CV-263) constitutes the separation between the Seismic Class 1 and Class 3 piping. All portions of this modification were installed in the Seismic Class 3 portions of the Unit 2 VCT gas makeup system piping. In addition, Seismic Class 2 over 1 criteria was applied in the design.

All material specified is compatible with the existing arrangement and the design basis as recorded in the FSAR. All tubing and tubing components are specified in accordance with Westinghouse Pipe Class 151R and Stone & Webster Piping Standard IC-N8.

Failure of the VCT gas makeup piping is bounded by the safety analysis for a VCT rupture (FSAR Section 14.2.3). This modification does not increase the likelihood of a rupture of the VCT gas makeup system piping. (SER 90-082)

61. MR 90-052 (Units 1 & 2), Safety-Related Piping Supports. NRC IE Bulletin 79-14 was issued to direct licensees to verify that seismic analyses were applicable to as-built plants. Piping line walks of the as-built condition were performed to verify the applicability of the as-built analyses. Where the applicability could not be established, new piping analyses were performed to document the acceptability of the as-built condition. Because of the magnitude of the discovered discrepancies, over 1000 piping support upgrades were required. The upgrade effort was completed before the end of 1983.

In 1988, selected portions of the service water inside containment were reinspected. Again, significant discrepancies were discovered. Acceptability of the post-79-14 analyses was initiated via a sampling program that included piping line walks, calculation checks and a review of the mechanical correction documentation. As a result of this sampling program and a reanalysis of the RHR systems outside containment (due to an error in the thermal evaluations), MR 90-052 was initiated. This modification corrects the inadequacies found in the piping supports.

The supports of Design Package A affected were divided into three categories.

- Category A includes those supports whose upgrades are minor and have no potential impact in the operability of the RHR system. Upgrades of this sort include shimming, spring can replacement and minor structural upgrades.

- Category B supports include those supports associated with the B train of the Unit 1 RHR system and require grinding, welding, and/or the addition of some structural members. A worst case problem during the installation of these upgrades could potentially affect the operability of the B train of this system. In order to be conservative, meet the requirements of TS 15.3.1.A.3, and minimize any potential hazards, all Category B supports were modified either during the time of reactor core unload or when the reactor vessel head was removed and the reactor cavity is flooded.

- Category C supports are those supports which lie on common lines for which there is no separation of trains. The restrictions identified for Category B supports are also valid. As an added precaution these supports were modified only when the core is unloaded.

Design Package A: This design package and IWP upgraded the RHR Unit 1 piping supports which have been shown to be inadequate to meet Code compliance (ANSI B31.1).

Design Package C: This design package controls the upgrades of the piping supports that are located in the AFW room. JG-4-H31 is an anchor located at the tee which joins the service water and the condensate storage tank water to supply the water to the Unit 1 steam-driven AFP, 1P29. Since the unit was shut down for refueling at the time of modification, there was no TS or operational concerns.

The remaining supports are JB-2-H21, JB-2-H22 and HB-19-S619. These supports are all located on a branch of the service water supply to the Unit 2 turbine hall.

The upgrades involved with these supports involve no grinding or welding of the piping pressure boundaries, but only the addition of structural members to bring the supports into Code compliance. Therefore, there were no operational or regulatory impacts as a result of this design package.

Design Package D: The supports involved in this design package were associated with the condensate storage tank and the AFW mini-recirc piping.

The piping is sufficiently isolated from the AFW system as to have no impact on the AFW operation and is not required to be seismic in the areas where the supports are being upgraded. No grinding or welding of the piping pressure boundary was required and there are no operational or regulatory concerns with these upgrades.

Design Package E: The piping anchor CH-151R-4-H50 was upgraded and the existing Sch 10 elbow was replaced with a Sch 40 elbow. This piping is on the CVCS volume control tank bypass line to the holdup tanks downstream of 3-way valve 1LCV-112A. This line is required during operation to prevent overfilling of the VCT.

Replacement of this line during cold shutdown has no impact on the accident analyses, safety margins or operability since this part of the system is not required during cold shutdown.

Summary of Safety Evaluation: In Design Packages A, C and E some of the supports were temporarily removed to facilitate the piping support upgrades. Control of these temporary conditions was identified in the individual IWPs and will document the required temporary support values and directions. This is acceptable because the time of required temporary support was very short, the failure of any of the temporary supports could not pose an operability problem, and the purpose of these temporary supports was to minimize the deadweight deflections that would occur during the time that the permanent supports were not in service. The use of temporary supports via the MR installation procedures was considered adequate and does not pose an unresolved safety question.

Installation of these upgrades brings the piping supports into Code compliance, thereby allowing the affected systems to function as required during all design basis events. Installation of the upgrades during the planned time periods shall not result in Limiting Conditions of Operation, Technical Specification violations or operational concerns. (SER 90-029)

MR 90-052*B, Residual Heat Removal System. The RHR piping supports outside containment were improved to meet Code allowables. The modification included the temporary removal of some of the existing piping supports to facilitate the required changes.

Summary of Safety Evaluation: During the time of the modification of the individual supports, temporary supports were in place to prevent the support system from being compromised. Control of these temporary supports resided in the Installation Work Plan (IWP) and this adequately documented the requirements for temporary supports.

Installation of these upgrades brings the piping supports into Code compliance, thereby allowing the RHR system to function as required during all design basis events. Installation of the upgrades during the planned time periods shall not result in Limiting

Conditions of Operation, Technical Specification violations or operational concerns. (SER 90-029-01)

62. MR 90-056*A (Unit 2). Containment Ventilation. The MR installs temperature instrumentation for 2HX-15D, the lowest containment fan cooler (CFC), for monitoring heat transfer performance of the heat exchangers. This monitoring of the performance of containment fan coolers is in response to Generic Letter 89-13, "Service Water System Problems Affecting Safety-related Equipment."

Summary of Safety Evaluation: Thermocouples were installed at the inlet and the outlet of the containment fan cooler coils with local indication to be used for monitoring. The thermocouples are attached to the structure containing the cooling coils. If the thermocouples break, the mass of the thermocouples will not impact the operation of the fans. RTDs were installed in the service water lines for monitoring, which also have local indication. If the RTD thermowells broke off in the system, they would be trapped at the bottom of the first vertical riser in the system and would not impact the flow in the pipe. The diameter of the thermocouples is 1/2" and they are 4.5" long. The pipes are 8" diameter so the flow is not impacted by the installation of the RTDs.

Installation of the instrumentation does not affect the ability of the containment fan coolers to perform their safety-related function of removing heat from containment. Rather, the instrumentation will be used to verify the capability of the CFCs. The instrumentation will not increase the probability of a malfunction of the containment fan coolers. The thermocouples will not affect the air flow in the coolers and therefore the heat transfer capability. The RTDs will not affect the service water flow to the CFCs.

The installation of instrumentation does not affect the operation of the CFCs. The mass of the thermocouples will not affect the operation of the coolers or fans. (SER 90-114)

63. MR 90-075*B*C (Unit 2). Circulating Water System. DP*B involves drilling additional holes in the longest of the four bypass steam dump lines in each condenser to increase the steam dump distribution header flow area and thus reduce steam velocity. The reduction in steam velocity will reduce erosion of tubes near the bottom of the bundle. The volume of steam passing through the pipe is controlled by the steam bypass valves upon system pressure signal. The flow volume is also limited by the pipe size as documented in the FSAR, so the additional holes do not significantly alter the operation of the bypass steam dump. This design package also does not affect the seismic qualification of the bypass steam dumps or the condenser (Seismic Class III per Appendix A of the FSAR).

DP*C reverses the modulating sequence of the condenser steam dump valves so the longest operating time will be assigned to the physically longest condenser steam dump diffusers. This effort removes the erosion source from the immediately affected area. Reversing the sequence was achieved by exchanging respective I/I repeaters inside rack 1(2)C107.

DP*C rearranges the condenser valve position indication lamps on the front of 1(2)C03. The alphanumeric sequence was sacrificed in favor of maintaining the display consistent with operator expectations. Lamp rearrangement meets the mirror imaging and display integration requirements of our control room design document.

Summary of Safety Evaluation: Concern for increased probability for a condenser tube rupture was considered. The additional holes drilled in the bypass steam dump pipe are of the same diameter, spacing, and pattern as the original Westinghouse design. Therefore, stress remains evenly distributed per unit length of pipe.

The "blow-open" features of the condenser steam dump system will not be affected by this modification. Seismic qualifications of the main control boards will not be affected, and there are no Appendix R concerns since all rewiring efforts will occur within the control boards.

The safety concerns from an FSAR accident analysis viewpoint are not applicable because the condenser is not safety-related, and its heat removal characteristics are not taken credit for in the FSAR. The system will not change as it is described in the FSAR. (SER 90-088)

64. MR 90-077 (Unit 2), Auxiliary Feedwater System. MR 90-077 provides a simple method of checking to see if the drain line in the 1(2)P29 auxiliary feedwater pump exhaust line is clear. By adding a tee/valve assembly to the drain line of the exhaust line, the test demonstrates that the line is clear before cold, fast start testing of the steam-driven auxiliary feedwater pump turbine.

Summary of Safety Evaluation: The tee was used for connecting a water source to the drain line for flushing purposes. The valve was used for isolating the drain line during testing. A seismic support was added to the drain so it meets Seismic Class 1 ratings for small bore piping. The function of the auxiliary feedwater system was not altered. (SER 90-091)

65. MR 90-108 (Unit 2), Electrical Distribution System. MR 90-108 installs 3 test points and 2 test switches in the undervoltage circuit for each of the 2A01 and 2A02 buses. This was done so the time delay relays used for stripping the buses can be timed. The timing of these relays is required in response to NCR N-89-117.

Summary of Safety Evaluation: For each of the buses, one test switch prevents the bus stripping relays from energizing. This allows testing of the undervoltage relays while the unit is at power. The other test switch was installed in the trip circuit for the station service transformer breakers. This allows testing the stripping of the bus during a refueling outage, since the station service transformer breakers are the only breakers on the A01 and A02 buses that will be closed.

The test points are used to verify contact operation and coil integrity during testing. They also verify that the knife switches properly close upon completion of the testing. The test points were added to the existing undervoltage test panel on each of the buses. The cutouts required for the test points were small and the mass of the test points is negligible and will have no structural impacts on the bus.

A 10-pole Flexitest switch was installed on each of the buses next to the existing test panel. The test switch assembly requires a 2.3x5.4" cutout and weighs 1.75 pounds. These switches are used elsewhere on the 4160 V switchgear and the mounting of the new switches was similar to the existing switches. No. 14 or No. 16 AWG SIS wire will be used to connect the switches and test points. The A01 and A02 buses are Seismic Class 3 structures.

Caution will be taken during the periodic testing to prevent shorting or grounding of the test points. During normal operation, the test points will be covered by the existing test panel cover and will have no effect on the circuit operation. Also, the test switches, while closed, will not affect the circuit operation. During the periodic testing, after each test switch operation, it was verified that the knife switch closes properly. Therefore, if a test switch failed open, it would be detected before it would affect the bus stripping operation. Knife switch failure would have no effect on auxiliary feedwater initiation.

Since work was done to the station service transformer breaker trip circuit, it too was opened. A temporary jumper was installed to allow closing the tie breakers in on a live bus. Double verification was used to verify that the jumper was properly installed and removed. Section 8.2-4 of the FSAR describes these tie breakers stating that they utilize a dead bus transfer scheme, because no synchronization ability has been provided. Since the two 480 V buses were supplied from the same source, no synchronization was required and the tie breakers could be closed in on a live bus. (See also NCR N-90-187 for further details on this issue.) (SER 90-089)

66. MR 90-111 (Unit 2), Auxiliary Feedwater System. The MR reroutes the portion of cable ZC2NA012D which runs between 2A01 and 2A02, so it is not in conduit that contains a cable for the opposite train. The previous configuration was a nonconformance as documented in NCR N-90-058. Cable 2NA012D was pulled out of conduit 2DA-1 and rerouted through 2DA-2.

Summary of Safety Evaluation: In order to make room for the additional cable in 2DA-2, an existing annunciator cable (2K0228C) was rerouted through 2DA-1. The annunciator cable is not safety-related and therefore could be moved to the other conduit. The cable is used for the "Unit 2 common critical control power failure" annunciator on C02. In order to ease the installation and limit the amount of time that the annunciator is out of service, cable 2K0228C, which is 3/C #10 AWG, was replaced with a 2-conductor #12 cable. No. 12 AWG wire is acceptable for use in annunciator circuits. The added resistance in the circuit was small because the length of cable replaced was small (<20'), and does not affect the operation of the annunciator.

The resulting configuration decreases the percent fill of the conduits below that allowed by NEC Chapter 9 Table 31. The overall combustible loading was decreased.

The auxiliary feedwater system is described in Section 10.2 of the FSAR. This modification did not change the operation of the system. The reliability of the system is increased because the potential of a single failure affecting both trains of the control circuitry for the turbine-driven auxiliary feedwater pump is being eliminated.

A 72-hour LCO was initiated and the turbine-driven AFP declared out of service per TS 15.3.4.2. Technical Specifications require that the associated turbine driven AFP along with its essential instrumentation be operable for single unit operation. This change was done to meet the original design criteria and does not affect the design basis. No system functional changes occurred. (SER 90-036)

67. MR 90-131 (Unit 1), Reactor Coolant System. The incore thermocouple for location A-7 (1TE-00001) was found to be leaking at its electrical connector. The connector was cut off, and a 1/8" stainless steel Swagelok cap was added to seal the 1/8" stainless steel MI cable sheath.

Summary of Safety Evaluation: When the electrical connector is removed, the A7 thermocouple will no longer be usable for indication purposes; therefore, its input was removed from the PPCS scan. Removing the signal will not affect the ability to meet TS Table 15.3.5-5 requirements to have four operable thermocouples per core quadrant.

The existing electrical connectors are seismic components. The electrical connector was replaced with a lighter Swagelok cap, thereby reducing the stresses which would be generated in the stalk during a seismic event.

The electrical connectors are also environmentally qualified. Since removing the connector will make the A-7 thermocouple non-functional, EQ requirements are not applicable.

Calculation P-88-016, performed for MR 88-047, demonstrates that the thermocouple sheath can be expected to withstand internal pressure in excess of the reactor coolant system's safety valve setpoint. If a leak developed, it would not exceed the capacity of a single charging pump (FSAR 14.3.1). (SER 90-057)

An amendment to the original SER was issued to address the use of a Swagelok plug in lieu of the 1/8" Swagelok cap described in the original evaluation. During installation of the 1/8" Swagelok cap used to seal incore thermocouple A7, it was determined that a Swagelok plug should be used since the cap could not be installed.

***Summary of Amended Safety Evaluation: The Swagelok plug is an acceptable RCS pressure boundary since it provides a seal with an existing Swage fitting and the stub thermocouple sheath. With the exception of this change, the conclusions of SER 90-057 remain valid. (SER 90-057-01)

68. MR 90-153 (Unit 2), Main Steam System. MR 90-153 eliminates the potential of having a failure of a contact block affect both trains in the main steam isolation valve (MSIV) manual initiation circuit.

Summary of Safety Evaluation: Failure of a contact plunger to be depressed is a single failure that would affect the entire switch because it would prevent the switch actuator from turning. This failure would affect the opening of the MSIVs, which is not a safety-related function. Also, this failure would be immediately detected since the operator would not be able to turn the switch.

The other type of failure is the failure of a contact plunger to reset once it is released. A contact failing to reset will also affect those contacts mounted directly behind it, but will not affect those contacts on the other side of the switch. Because of this, the contacts were rearranged so the A train contacts are on one side and the B train contacts are on the other side.

The MSIV manual control switches are 2-position maintained switches with no automatic return operation. The switch actuator is of a simple design and failure of this type of actuator seems unlikely. Because of the simple design and the reliability of these switches in the past, train-specific switches are not necessary.

The modification has no system functional effect on the MSIVs as described in FSAR Section 10.2.2 or their control circuit as described in Section 7.2.2. The requirements of manual actuation of safety-related systems, per Section 7.2.1, are being maintained. The change has no impact on the automatic main steam isolation circuitry. (SER 90-080)

69. MR 90-158 (Unit 2), Snubbers/Supports. The modification extends the pressure sensing line of the hydraulic fluid reservoir of the snubber for the Unit 2 "B" steam generator.

Summary of Safety Evaluation: The line was extended to an area of a lower dose rate than its current location. The extension line was designed to match the original line specifications and used materials acceptable for use in containment. (SER 90-111)

70. MR 90-162 (Unit 2). Fuel Transfer System. The MR provides shielding of the fuel transfer tube to prevent the streaming of gamma rays through the expansion crack between containment and the fuel transfer tube canal structure.

Summary of Safety Evaluation: The final design involved installation of lead bricks overlapping the expansion joint between the fuel transfer canal structure and containment, inside the canal structure. Thirty lead bricks, 2"x4"x8", were vertically stacked. The bricks were seismically supported.

The gamma ray scatter from the fuel transfer tube will be reduced with lead sheets stacked on the fuel transfer penetration tube. Twenty 1/8" layers (accumulated thickness of 2.5") were strapped individually with 0.75" wide, 0.030" thick stainless steel bands on each end. The last layer was secured with straps positioned every 3".

Fuel handling accidents were evaluated in Section 14.2 of the FSAR to ensure that no hazards are created. The probability of a failure of the fuel transfer tube due to the installation of lead shielding is not increased. This was verified by evaluating the seismic response of the installation. (SER 90-077)

71. MR 90-167 (Unit 2). Fuel Transfer System. MR 90-167 installs a handrail to the Unit 2 manipulator crane motor platform (MCMP) along with a gateway to access the platform from the manipulator crane controls platform (MCCP).

Summary of Safety Evaluation: General Design Criterion 2 requires that systems important to safety shall be designed to withstand the effects of earthquakes. Appendix A of the FSAR indicates the manipulator is Seismic Class 3. The addition of a handrail does not alter this seismic classification. Since the main danger is that the handrail could fall off the manipulator into the reactor vessel during fuel handling, the handrail was considered "important to safety". An analysis was done to verify that the handrail will not fall off of the manipulator into the refueling cavity during a seismic event.

Fuel handling accidents are evaluated in Section 14.2.1 of the FSAR to ensure that no hazards are created. The possibility of a fuel handling incident is very remote because of the many administrative controls and physical limitations imposed on fuel handling operations. All refueling operations are conducted in accordance with prescribed procedures under direct surveillance of a supervisor technically trained in nuclear safety.

Rupture of one complete outer row of fuel elements in a withdrawn assembly is assumed as a conservative limit for evaluating the environmental consequences of a fuel handling incident. Even in the unlikely event that the handrail should fall and strike one or more fuel assemblies, there is very little chance that more than the equivalent of one complete outer row of fuel elements could be ruptured. The postulated accident would be within the accident evaluated in the FSAR Section 14.2.1. (SER 90-076)

72. MR 90-169 (Unit 2). Reactor Coolant System. MR 90-169 removes the second-off isolation valve (RC-500C) from the reactor vessel level indication system (RVLIS) reference leg and replace it with tubing. The valve, which is located in the refueling cavity, is not used for operation or maintenance of the RVLIS and is not required by Power Piping Code ANSI B31.1-1967.

Summary of Safety Evaluation: The modification was installed during a refueling outage when operability of the RVLIS is not required. The valve was replaced with stainless steel tubing and fittings of the same type as those already existing in the RVLIS reference leg. The tubing and fittings have pressure and temperature ratings in excess of the design ratings of the RCS. The new components will be seismically supported.

The new components were checked for leaks in accordance with TS 15.4.3 requirements during the post-refueling pressure test of the RCS.

An RCS leak can still be isolated via the first-off isolation valve from the reactor vessel head. If a leak in the RVLIS reference leg occurs, it will be within the capacity of the charging system. RCS leakage would be detected and could cause a unit shutdown in accordance with the Technical Specifications for reactor coolant leakage and RVLIS operability. (SER 90-103)

73. MR 90-172, Instrument Air System. MR 90-172 revises the location of test vent valve IA-371. IA-371 is the vent on the boot seal side of the check valve in the instrument air line to purge supply valve 2VNPSE-3244. IA-371 was originally installed under MR 89-049 (reference SER 89-060). MR 90-172 also plugs the existing tee which supplies IA-371.

Summary of Safety Evaluation: The new location of IA-371 is in the pressure boundary of the boot seal. This installation was seismically mounted to assure it does not adversely affect the boot seal during a seismic event. All materials met or exceeded the original specification for the system. (SER 90-070)

74. MR 90-190 (Unit 2), Electrical Distribution System. MR 90-190 removes the Train B circuits from 2C150 by installing separate relays in the main control board. Where the existing relay was not also providing a Train A circuit function, the relay was relocated to the main control board. Where the existing relay provided a Train A circuit function, a second relay was installed in the main control board and the coil connected in parallel with the existing relay. Rewiring in the control board was done to assure train separation. The three affected circuits were: (1) 2P11B component cooling (CC) pump - relay provides an automatic start of the relay on low CC header pressure; (2) 2RC-427 RCS letdown isolation valve - relays close the valve on low pressurizer level; and (3) 2RC-430 pressurizer PORV - relays open the valve on high pressurizer pressure.

Summary of Safety Evaluation: Upon completion of the MR, the circuits are functionally the same as prior to it. Equipment location and arrangement was changed to provide train separation. The coil portion of the circuit, which is not train or safety-related, was changed in some cases to have 2 relay coils in parallel.

The installation was procedurally controlled and was done during a cold shutdown of Unit 2. The portions of the circuits to be modified were isolated by opening sliders in the main control board. This allowed the circuits to remain operable except for the specific control functions listed above. The 2P11B CC pump was designated as the running pump and therefore the loss of its autostart feature would have no effect on plant operability. Also the low temperature overpressure control function for 2RC-430 was not defeated except briefly during testing.

TS 15.3.15.A operability requirements were evaluated to work on the pressurizer PORV 2RC-430 high pressurizer pressure relay. The proposed work on CC pump 2P11B did not affect the pump operability concerns of TS 15.3.3.C, "Component Cooling System." The work on the three circuits brings the plant back into conformance with the instrumentation and protection circuit descriptions of FSAR Chapter 7, although the specific circuits are not described in the FSAR. (SER 90-108)

75. MR 90-192*A (Unit 2). Safeguards System. MR 90-192 eliminates electrical separation conflicts in the safeguards racks. Design Package A covers containment isolation valve circuits; 2V313, RCP seal water return; 2V3047, containment IA isolation valve; 2V3048, containment IA isolation valve; 2CV-3200A, R211/212 isolation valve; 2V508, reactor makeup water CI valve; 2V371, letdown line isolation; 2V769, excess letdown HX CC outlet; 2V846, SI accumulator T34A & B nitrogen supply CI valve; 2V2083, steam generator A sample isolation; 2V2084, steam generator B sample isolation; 2V5958, steam generator blowdown isolation; 2V5959, steam generator blowdown isolation; 2V966A, primary system sampling; 2V966B, primary system sampling; and 2V966C, primary system sampling.

Summary of Safety Evaluation: The primary approach involved using spare contacts on existing CI relays in the safeguards racks to supply auxiliary CI relays in the main control board. Wiring in the main control board was done in a manner to provide for electrical separation between circuits. The modified CI valve circuits are functionally the same as the original circuits. That is, either train of containment isolation actuation will cause the valve to close.

The circuit change for valves 2V313 and 2V371 was different. Although these were originally single isolation valves, a modification added redundant valves 2V313A and 2V371A. Since there are redundant valves to 2V313 and 2V371, there was no reason for these valves to receive CI signals from both safeguards trains. Therefore, the opposite train CI interlock was removed from these valve circuits to match the design for all other redundant containment isolation valve circuits.

The addition of the new auxiliary racks added one additional component to the actuation circuitry which could potentially fail. However, it was felt that the probability of this is remote. With these particular circuits, multiple failures would be required to block the CI function. Use of auxiliary relays is a typical design method which is used for other safety-related functions such as stripping the battery chargers on SI.

The MR was installed during cold shutdown with the primary system not solid and no fuel motion. To maintain instrument air to containment, work on valve 2V3047 did not begin until work on valve 2V3048 was complete. The circuit for 2CV3200A was not affected until most of the other changes were completed to minimize the outage of RE-211/212 and the associated containment vent valves 2V3243 and 2V3244. The RE-211/212 system is not required when the unit is in cold shutdown and no fuel motion is in progress. (SER 90-109)

An ECR added DC power failure alarm relays to the new auxiliary containment isolation relay circuits. The coil of these alarm relays is connected in series with a resistor across the DC power supply for these circuits and is normally energized. Contacts from these relays were added to an existing annunciator circuit, "Unit 2 Safeguard DC Control Power Failure." Although these alarm relays do not perform a safety-related function, they are part of a safety-related circuit which performs a containment isolation function. Therefore, they may not fail in a manner which could disable this safety function.

The relay type and design is identical to those installed in many other safety-related circuits. Examples include the safety injection pumps and emergency diesel generator output breakers. The only way that this alarm relay could defeat the safety function would be for it to short out the DC supply. Since the design incorporates a 1500 ohm resistor in series with the coil, this would require shorting between two nonadjacent terminals on the relay base. The relay base is of rugged construction with terminals rated for 1250 V. Therefore, this is not considered a credible failure mode.

The new alarm relays were mounted on the same steel plate as the containment isolation auxiliary relays. Seismic mounting of the relay bases was justified using SQUG methodology. The relays are mounted below the containment isolation auxiliary relays so they could not fall on safety-related equipment. If the alarm relays did fall out, the associated annunciator would alarm.

There is no credible failure mechanism associated with the alarm relays which could disable the safety function of these circuits. Also, these relays improve the reliability of these circuits by providing an alarm if the power supply is interrupted. (SER 90-109-01)

76. MR 90-209 (Common), Fuel Oil System. The modification provides seismic support of the fuel oil transfer piping in the control building. Five new supports were added to the transfer piping, along with modifications to four other supports, to bring the piping into Code compliance for pipe stress and support loads.

Summary of Safety Evaluation: The piping was analyzed for operability and was found to be within operability criteria for piping and supports. The piping was also reanalyzed with a new support configuration consistent with these changes. The new analyses show that the piping will fall within Code allowables. The modification provides an installation consistent with safety analysis report requirements and ensures availability of the fuel from the emergency tank to the diesel generators. (SER 90-099)

77. MR 90-226*A (Unit 2), Chemical & Volume Control System. The modification replaces volume control tank level transmitter 2LT-141.

Summary of Safety Evaluation: Although the control and alarm functions of this level instrument loop are described in the FSAR, no specifics are given to describe the level transmitter. The modification does not affect the control function or alarms in any manner.

The modification does not result in an increased probability of a volume control tank rupture or alter the conclusions of the volume control tank rupture analysis found in Section 14.2.3 of the FSAR. There are no net additional loads on the 2DY02/DYOPB inverters or on the D06 station battery.

The transmitters are not QA-Scope and are not Seismic Class 1. The transmitters are not environmentally qualified, and Appendix R design considerations are not required. Existing 2LT-112 and 2LT-114 separation was not changed. (SER 90-112)

78. MR 90-230 (Unit 2), Containment Spray System. This modification provides a new support configuration for the Unit 2 auxiliary spray piping to bring the piping and supports into code compliance for normal operating, seismic, and thermal stratification conditions. Two new support designs were installed and two existing supports were removed. The piping was analyzed with the new support configuration. The new analyses show that the piping and supports will fall within code allowables for both pipe stress and support loads.

Summary of Safety Evaluation: The modification provides an installation consistent with the requirements in the FSAR, and ensures availability of the auxiliary spray line to perform its intended function. (SER 90-113)

TEMPORARY MODIFICATIONS

1. TM 90-004 (Unit 1), Radiation Monitoring System. The temporary modification adds Chr...ex 10PTV1 heat tape to RE-211/RE-212 piping in the Unit 1 personnel hatch. Th... ...ply for the heat tape was taken off the supply to the hatch testing pump, P77B. Th... pump is supplied by emergency lighting Panel 31-E.

   Summary of Safety Evaluation: Using a maximum of 60' of heat tape the largest additional load would be 10.5 W/ft (60 ft) 1/120 V = 5.3 amps.

   FSAR Section 8.2.3, Emergency Power, and Table 8.2.1 describe loading on emergency diesel generator G01. An estimated load for emergency lighting is 50 kW. Minimal load was added by installation of the heat tape supplied through breaker 31-E-03. The current draw of 1.3 amps for pump P77B is intermittent. The heat tape is self-regulated so the maximum current draw would be 5.3 amps (0.6 kW). In warmer conditions this load would decrease. Potential damage due to fault conditions as a result of failure of the heat tape system would be protected via the 20 amp supply breaker, 31-E-03.

   From FSAR Table 8.2.1, following a LOCA the estimated injection phase loading on the diesel generator is 2529 kW for 30 minutes. The diesels are capable of supplying 2850 kW continuous. This results in a margin of 321 kW. The estimated recirculation phase load is 2706 kW. This results in a margin of 144 kW. The installation of heat tape will decrease both margins by 0.6 kW but the decrease will not reduce operability of the diesel generators. (SER 90-006)

2. TM 90-007, 125 V DC System. The temporary modification replaces the existing breaker on D11-25, a Westinghouse HFA-2070 with thermal only trip, with a Westinghouse Type HFB-3070.

   Summary of Safety Evaluation: The installed breaker was inadequate because its thermal trip element might not react quickly enough to isolate a fault from D11 or the DC bus. The thermal/magnetic trip element in HFB type breakers has an instantaneous rating, which adequately isolates faults. Therefore, the non-safety related load was isolated from the safety-related DC bus.

   HFB series breakers are electrically equivalent to HFA series. The HFB series has the required thermal-magnetic trip. The replacement breaker is a 3-phase model, which is adequate for use in 2 pole DC applications. The center pole of the replacement breaker will remain disconnected.

   D11 is rated as Seismic Class 1. HFB breakers require an adapter kit to fit the space vacated by the HFA breaker. The adapter kit consists of copper conductors which are slightly longer (about 3/8 ") than original, and mounting Z-plates which are of slightly different width, to accommodate the difference in size between HFB and HFA breakers. The HFB weighs about 1721 g, while the HFA weighs about 1745 g. Since the mass of the breakers is slightly reduced, the location of the center of mass is essentially the same, the mounting hardware is essentially the same, and the mounting method is the same, the replacement HFB breaker is seismically acceptable for use in D11. (SER 90-010)

3. TM 90-010 (Unit 2), Feedwater System. TM 90-010 temporarily repairs support EB-9-2H11 on the Unit 2 "B" main feed line such that the saddle is removed and replaced with shim plates. The saddle was found broken free from the pipe; thus, its load-carrying capacity was reduced.

Summary of Safety Evaluation: To avoid welding to the feed line while it is pressurized, the pipe was lifted ~1/4" to enable removal of the saddle and insertion of shim plates and an abrasion plate. The line was lifted using rigging and attachment points with load carrying capacity equal to or greater than the design load. The rigging was installed within 2-3' of the support location to minimize any support relocation effects on the system. The original saddle was for 3" insulation so the shimming was 3" thick, including abrasion protection plate.

The shim plates were not welded to the pipe so axial movement is still allowed. The abrasion shield was strapped to the pipe to keep it stationary. The shim plates are wide enough so any north to south movement will not result in the pipe falling off the shim stock.

This section of line is Seismic Class 3 but needs to be intact for support of the nearby class change to Class 1 at the main feed check valves. The temporary restoration of support EB-9-2H11 restores its load carrying capability to design condition, thus maintaining the adequacy of the Class 1 piping.

While EB-9-2H11 was repaired, the temporary support was located as close as reasonably possible to the existing support. It utilized embeds in the overhead as similar supports. Several of these are attached to embeds in the floor with similar loading values. Although the embed load is typically limited to 1000 lb/ft, the existing installation shows greater capability. It utilized I-beams and rigging capable of carrying the design load of 558 lb gravity + 2035 lb SSE.

The temporary beam welded to the embeds was left in place for use during the permanent repair. This was considered acceptable since it was not located above any safety-related components and added an insignificant weight to the seismic structure. (SER 90-018)

4. TM 90-016 (Common), Building & Structures. The TM removed some of the ceiling tiles in the computer and control rooms.

Summary of Safety Evaluation: The TM has a short-term effect upon the control room. The decor was restored by a permanent modification which installed registers, grills and/or open tiles in place of the removed tiles. The replacements for the removed tiles were selected to minimize ventilation noise. Removal of these tiles will not affect fire barriers. (SER 90-028)

5. TM 90-017 (MWR 901059), Feedwater System. Support EB-9-2H16 on the Unit 2 "A" main feed line was modified so the saddle was removed and replaced with shim plate. The saddle was found to be broken free from the pipe, and thus, its load-carrying capacity was reduced.

Summary of Safety Evaluation: The pipe has an abrasion shield installed to protect it. The shim plate was welded to the support. Axial movement of the pipe was not restrained since movement between the abrasion shield and shim plate can still occur. The length of the shim plate was long enough to prevent the pipe from dropping off the shim if side-to-side movement occurs. The thickness of the shim will be sized to provide the 1/16" gap at the top of the pipe.

The section of affected piping is Seismic Class 3 but needs to be intact for support of the nearby class change to Class 1 at the main feed check valves. The temporary restoration of support EB-9-2H16 restores its load carrying capability to design conditions, thus maintaining the adequacy of the Class 1 piping.

While EB-09-2H16 was repaired, the temporary support was located as reasonably as possible to the existing support. It utilized embeds in the overhead as do similar supports. Loads on these supports are similar in value to that at EB-9-2H16. Although loading on embeds is typically limited to 1000 lbs, existing installation in these areas show higher capability. The temporary support location was upstream of EB-9-2H16. The temporary support utilized I-beams and tie rods capable of carrying the design load of support EB-09-2H16. The I-beam was left in place for later use to restore EB-09-2H16 to original configuration. Failure of the temporary support during use would result in a total deflection of 3" at EB-9-2H16. (SER 90-025)

6. TM 90-020 (Unit 1), Reactor Coolant System. The TM blocked one power-operated relief valve (PORV) open during the containment integrated leak rate test (CILRT).

Summary of Safety Evaluation: SER 89-144 previously evaluated TM [illegible]-043, which blocked both Unit 2 PORVs open during a CILRT. Blocking one PORV open rather than both does not affect SER 89-144 conclusions. Therefore, SER 89-144 also applies when one PORV is blocked open.

Blocking one PORV open is considered adequate because the design basis looked at a single PORV opening assuming a worst case transient of a single high pressure safety injection pump discharging to the reactor coolant system while the system is solid. One SI pump is procedurally tagged out by OP-3C, "Hot Shutdown to Cold Shutdown." A redundant valve is not required because physically blocking provides a positive means of venting the RCS to the pressurizer relief tank and satisfies TS 15.3.15.4. (SER 89-144-01)

7. TM 90-023 (Unit 1), Component Cooling System. The temporary modification provides an interim corrective action to address NCR 90-089. Cables ZA1B10AC and ZB1B23BC both run through Riser 82 into rack 1C158. These two cables form part of the circuit which automatically starts the component cooling (CC) water pumps on low pressure. Simultaneous failure of these cables could result in the automatic start function being defeated and the possible loss of all control power to the breakers feeding the CC pumps.

The permanent solution to the problem is to reroute one of the cables through a new conduit to 1C158, bypassing Riser 82. This conduit was run to meet the separation criteria. As a temporary measure to place the system into a conservative position, the use of 1P11B as the normal running pump and the opening of sliders in 1C03 to cable ZB1B23BC (cable ZB1B23BC provides the auto start signal to 1P11B) was accomplished by the TM.

Summary of Safety Evaluation: This configuration allowed the manual and automatic start circuit of 1P11A to remain operational and still allows the manual operation of 1P11B. The operation of the associated control room annunciator, "component cooling discharge pressure low" remained unchanged. The opened sliders to cable ZB1B23BC prevent a fault from affecting both circuits by isolating this cable from the circuit.

The disconnecting of cable ZB1B23BC prevents a single failure involving Riser 82 to result in the loss of the control power of both CC pump breakers. No additional single failure could cause this loss of control power. (SER 90-037A)

8. <u>TM 90-024 (Unit 2)</u>. Component Cooling System. The temporary modification provides an interim corrective action to address NCR 90-089. Cables ZC2B34AD and ZD2B28BD both run though Riser 92 into rack 2C158. These two cables form part of the circuit which automatically starts the component cooling (CC) water pumps on low pressure. Simultaneous failure of these cables could result in the automatic start function being defeated and the possible loss of all control power to the breakers feeding the component cooling water pumps.

The permanent solution to this problem is to reroute one of the cables through a new conduit to 2C158, bypassing Riser 92. This conduit was run to meet the separation criteria. As a temporary measure to put the system into a conservative position, the use of 2P11B as the normal running pump and the opening of sliders in 2C03 to cable ZD2B28BD (cable ZD2B28BD provides the auto start signal to 2P11B) was accomplished by the TM.

<u>Summary of Safety Evaluation</u>: This configuration allowed the manual and automatic start circuit of 2P11A to remain operational and still allows the manual operation of 2P11B.

The operation of the associated control room annunciator "component cooling discharge pressure low" remains unchanged. The opened sliders to cable ZD2B28BD would also prevent a fault from affecting both circuits by isolating this cable from the circuit.

The disconnecting of cable ZD2B28BD prevents a single [illegible] involving Riser 92 to result in the loss of the control power of both CC pump breakers. No additional single failure could cause this loss of control power. <u>(SER 90-037B)</u>

9. <u>TM 90-027 (Unit 1)</u>. Nitrogen System. TM 90-027 provides high pressure nitrogen (160-180 psig) to the reactor vessel (RV) inspection PaR device. The PaR device electrical lines are pressurized with this nitrogen to ensure they remain dry while the PaR device is on the RV.

<u>Summary of Safety Evaluation</u>: A nitrogen 12-pack with attached pressure regulator and relief valve was connected to the existing Swagelok fitting at the truck fill connection upstream of valve 1-837C in the Unit 1 containment facade. A 1/4" ID hose was connected to the existing Swagelok fitting at the isolation valve test connection (IVTC) at valve 1-1425 on El. 21' in the containment. The hose provided nitrogen to the PaR device. An air compressor is connected to the nitrogen supply line to the PaR on El. 66' in Unit 1 containment as a backup to the nitrogen system. This compressor automatically starts if nitrogen pressure gets too low, thereby assuring that the electrical lines remain dry. This also ensured that no refueling cavity water can be siphoned or drawn back into the nitrogen system.

The portion of the nitrogen system piping being used was between the truck fill connection and the IVTC. This piping is normally used to pressurize the Unit 1 safety injection (SI) accumulators. Since Unit 1 was in cold shutdown, the accumulators were not required. The accumulators were isolated from this piping to prevent their undesired pressurization. Additionally, this piping was isolated from the Unit 2 nitrogen piping used to pressurize the Unit 2 accumulators and had no effect on their operation. This piping was also isolated from the alternate nitrogen supply to the waste disposal system, and did not affect it.

A relief valve set at ~220 psig was connected to the piping upstream of the truck fill connection to prevent overpressurization of this piping and the hose being used.

This part of the nitrogen system is normally isolated from the Unit 2 SI accumulators and the waste disposal system. Therefore, this temporary modification could affect neither of those portions. The temporary modification was removed prior to repressurizing the Unit 1 SI accumulators and prior to Unit 1 startup when the accumulators are required per TS 15.3.3.A. (SER 90-044)

10. TM 90-028 (Unit 2), Main Steam System. TM 90-028 removed the limit switches from the valve body on MS-2017, "B" steam generator main steam isolation valve. Removal of the limit switches results in loss of valve position signals in the control room and the loss of a turbine trip signal generated from the valve disc leaving its open position.

One reason given for the installation of the trip signal is to prevent wipe-in closure due to an actuator loss of air pressure or the failure of an air solenoid. Both of these problems appear to have been remedied through the years. MWR 8202 modified the valves to open further giving more allowance for a diminished air pressure. Modification E-201 was installed in 1983 to replace the air solenoids with a more reliable model. These two changes eliminated the wipe-in problem that was the justification for MR E-47. In addition, a larger operator was installed on 2MS-2017; thus this valve is the least likely valve to be swept closed at full power.

A second reason in the FSAR for the trip relays was to prevent increased steam flows in the steam line of the MSIV which did not immediately wipe-in. The closure of the MSIV with the increased steam flow could result in a challenge to the main steam safeties. The atmospheric dump valves are sometimes unreliable at the full load steam conditions and should not be depended to open when required. This would result in one or more main steam safety valves lifting. This is within the design of the main steam system.

Summary of Safety Evaluation: The turbine trip signal upon an MSIV leaving its full open position was added in 197? under MR E-47. This modification and its intent is described on Pages 10.2-17 and 18 of the FSAR. The MSIV turbine trip signal is also described on Page 7.2-31 of the FSAR. No protective function is attributed to the trip signal in this section.

Based on the descriptions as given in the FSAR, the defeat of the turbine trip signal on the closing of MS-2017 does not result in an unreviewed safety question.

Loss of the valve position indication in the control room should not hamper normal operations of the unit. A verification of valve position is required in the event that certain EOPs are entered. If an EOP would be entered that required valve position verification, this step would have to be fulfilled by a visual observation.

Loss of the valve position indication does not result in an unreviewed safety question. The main requirement for the indication is during an event requiring the use of the applicable EOP. The intent of the EOP step can be satisfied by other means of verification. (SER 90-055)

11. TM 90-029 (Common), 13.8 kV Electrical System. TM 90-029 removed relays 62BF/H10, 62BF/H20 and 62BF/H30 from their cases in panels C221, C222 and C223. This eliminated the potential for misoperation causing a bus lockout.

The 62BF breaker failure relays on the 13.8 kV system provide a backup level of protection. They were added to the 13.8 kV system design to cover the potential significant consequences of a failure of the primary protection. 62BF/H30 was installed to provide backup protection for a cable fault between the H03 and H06 switchgear. This would normally trip the 2-87/X03 relays which would trip lock out relay 2-86/X03.

2-86/X03 will trip breakers H52-06, H52-30, and circuit switcher F89-152. It will also apply an auto-close signal to bus tie breakers H52-21 and H52-31. This automatic bus crosstie function was the reason for adding the breaker failure relay backup protection. If the H52-30 breaker failed to trip, the auto-close of the tie breakers would connect the fault to the opposite unit's high voltage station auxiliary transformer. The overcurrent relays on this transformer would cause a 1-86/X03 lockout.

Thus, if H52-30 failed to trip, one fault could cause the loss of all offsite power for both units. 62BF/H30 protects against this by initiating a timing sequence whenever an auto trip signal is applied to H52-30. If current is still flowing through H52-30 after 160 ms, 62BF/H30 will trip lockout relay 86/H03. 86/H03 will trip all the breakers on the H03 bus including bus tie breaker H52-31. Since the overcurrent relays on the 1X03 transformer would take about 1.5 seconds to trip, loss of the opposite units high voltage station auxiliary transformer is avoided. Function of the other 62BF relays is similar. There are 58 SBF-1 breaker failure relays installed in the WE system. Several actual misoperations have occurred over the last few years. An investigation has attributed these misoperations to DC control circuit transients. Modification kits have been ordered to eliminate the problem. Misoperation of these relays in the PBNP 13.8 kV system would cause a lockout of the associated switchgear bus. For the H02 or H03 bus, this would cause a loss of offsite power to Unit 1 or Unit 2 and would result in an auto start of both diesels.

Summary of Safety Evaluation: It is believed that the potential for the misoperation to occur is much greater than the possibility of a cable fault combined with a failure of a breaker to trip. Although this relay was added as part of the 13.8 kV system upgrade, the potential for a breaker failure causing loss of all offsite power existed prior to this modification. PBNP operated for 18 years without this backup level of protective relaying.

As specified in FSAR Section 8.2.2 for the original 13.8 kV system (with bus tie breakers H52-02 and 03), the closing of the bus tie breakers into a common fault was prevented by trip and lockout interlocks in the breaker control circuits. This was true for a cable fault between the X03 and X04 transformers. However, for a fault on the secondary side of an X03 transformer, or on the bus duct between the X03 transformer and the H52-05/06 breaker to trip, the condition could be established for a loss of all offsite power to both units as described above. This would occur with the auto closure of the H52-02 and 03 bus tie breakers on the X03 lockout signal. Therefore, removal of the 62BF relays places the units in a condition where a cable fault, with a breaker failure, could lead to loss of all offsite power, where previously an X03 transformer or bus duct fault, with a breaker failure, could have resulted in a loss of all offsite power. These two probabilities of fault with failure are considered equivalent. Therefore, there is no increase in the potential for an accident situation leading to a loss of all offsite power. (SER 90-050)

12. TM 90-034 (Common), Cranes. A debris catcher was installed on the primary auxiliary building (PAB) crane bridge to catch small particles of debris which are falling from the roof. This debris was generated by the PAB reroofing work. Debris from this project entered the roof through small holes in the metal decking. These holes were made during original construction and are randomly located. The debris caused a concern in the area of the spent fuel pool (SFP).

Summary of Safety Evaluation: Assembly and disassembly of the debris cover can be done away from the SFP so there is no concern from falling parts of the cover or debris that the cover has caught. The cover was designed to the same type of safety margin as the crane. The cover is close to the roof and can catch all of the larger particles. The cover (and crane) can be moved to stay centered under the roof work. Work on the roof was done in Sections 8'-0" wide. The crane is 26'-0" wide and covers a large area on both sides of the work.

The cover was made of a Unistrut frame covered by a tarp. The frame consisted of a Unistrut spanning from one bridge girder to the other on 6'-0" centers attached to the Unistrut, which was laid next to the trolley rails. The attachment of the spanning pieces of Unistrut to the pieces next to the rails was sufficiently rigid so racking of the frame was not possible. Since the frame was located between the trolley rails, movement of the cover was limited and it could not fall down. The weight of the cover was <1750 pounds and is not defined as a heavy load.

A fire-retardant, reinforced tarp with grommets was installed around the perimeter at about 4'-0" center-to-center. The tarp was sufficiently large enough to span from bridge girder to bridge girder and was attached to the crane with nylon rope to each bridge girder walkway at a minimum of 5'-0" center-to-center. Each rope had sufficient strength to hold the entire tarp. Other small areas (such as the gap between the walkways and bridge girders) were covered with fire retardant plastic sheets and installed such that they could not fall from the crane. (SER 89-118-01)

13. TM 90-038 (Unit 1), Buildings & Structures. Camera and lighting was installed in Unit 1 containment to visually monitor the weld on control rod drive mechanism (CRDM) I3.

Summary of Safety Evaluation: The camera, lights and associated cabling were securely mounted to the handrail on the north side of the cavity. The brackets are seismically adequate and will not come loose from the railing. The mass of the devices is small so if they did fall, they would not cause damage.

The light fixtures and the pivot device for the camera bracket is partially made out of aluminum. The total additional temporary weight of aluminum is less than 1 pound. This is small compared to the 163.5 lb contingency factor listed in Table 5.6.2-2 of the FSAR. (SER 90-072)

14. TM 90-043 (Unit 2), 480 V Electrical Distribution System. TM 90-043 disconnected backup pressurizer group 2T1B from its electrical supply on 2B02 so temporary power to a Westinghouse induction heating unit could be supplied through the vacated breaker.

Summary of Safety Evaluation: TS 15.3.1.A.6 requires that 100 kW of heaters be available during steady-state power operations. At least one bank of heaters shall be supplied from an emergency bus. The 2T1B group of heaters which was disconnected supplies 200 kW of heating power; the remaining groups supply 800 kW. Heater groups 2T1C, 2T1D and 2T1E are powered from emergency buses 2B03 and 2B04.

Prior to removing heater group 2T1B from service, it was verified that at least 100 kW of heaters were available and that at least one bank of heaters was supplied from the emergency bus. Following restoration, double verification ensured that the portions of the control circuit which were disturbed were restored. The breaker for group 2T1B was manually shut from 2C04 and ammeter checks on downstream load cable confirm that the load was restored. (SER 90-075)

15. <u>TM 90-046 (Unit 2)</u>. Shielding. The temporary modification placed a water-filled "shadow" shield in the upper cavity. The shield dimensions of 4.5'x6.5'x8" reduce the gamma exposure rate by 35%. The shield was located in the northwest corner of the upper cavity and was in place only during reactor vessel head dressing and undressing.

<u>Summary of Safety Evaluation</u>: The effects that the shield could have upon boron dilution were evaluated. The shield holds a volume of 19.5 ft^3 of water. If this entire volume emptied into the reactor vessel after the head was removed, the dilution would be insignificant (maximum 20 ppm). Since the shield was away from the reactor vessel and vessel water level is 1'+ below the flange, there was virtually no chance of mixing.

There was no piping or equipment in the northwest corner that could be impacted by the shield. The chance of water entering the vessel from a ruptured shield is nearly impossible because the cavity is sloped away from the vessel and the vessel flange extends above the cavity floor. <u>(SER 90-074)</u>

16. <u>TM 90-054 (Common)</u>. Service Water System. MOV SW-2818 provided isolation of service water (SW) to the cable spreading room air conditioning.

<u>Summary of Safety Evaluation</u>: SW-2819 can be left in the open position for valve operator maintenance since the SW flow to the heat exchangers is controlled by the temperature control valves TCV-2818A and TCV-2818B mounted downstream of MOV SW-2818. The power supply for SW-2818 is from safeguards power MCC B21 (which is stripped on a safety injection (SI) signal or a loss of AC power), the valve control logic receives no automatic closure signals on an SI initiation. A manual valve SW-338 is available for isolation if required.

MOV SW-2819 provides isolation of service water (SW) to the control room air conditioning. SW-2819 can be left in the open position for valve operator maintenance since the SW flow to the heat exchangers is controlled by the temperature control valves TCV-2819A and TCV-2819B mounted downstream of MOV SW-2819. The power supply for SW-2819 is from nonsafeguards power MCC B22, the valve control logic receives no automatic closure signals on an SI initiation. Manual valves SW-340 and SW-341 are available for isolation if required.

These valve operators can be removed during any plant conditions since valve closure is not required by design during an SI initiation or a loss of all AC power. Manual valves are available and accessible if isolation is desired.

These valves are installed in SW piping that is Seismic Class 1. Removal of the valve operator from the valve reduces the valve's mass, raising the valves natural frequency and reducing the seismic stresses. The seismic loading on the unsupported stem will not cause the stem to yield.

The stem clamp was adequately designed to maintain the valve in the open position. The stem clamp was placed on the valve stem so the clamp was tight against the packing gland follower. A piece of brass shim stock was placed between the stem clamp and the valve stem. <u>(SER 90-078)</u>

MISCELLANEOUS EVALUATIONS

1. EWR # EIE 89097, Revised Control Power Alignment for 4160 V and 480 V Buses. The evaluation documented considerations pertaining to selection of control power supplies for 4160 V and 480 V buses. There was a concern that upon a loss of a DC bus, no automatic bus transfer for A01 and A02 could occur, resulting in undesirable conditions for turbine bearing lubrication. The AC lube oil pumps receive power via A02, and the DC pump receives power from the battery which normally supplies DC control power to A02. Loss of a DC bus and turbine trip would result in no electric lube oil pump running in the affected unit.

   Summary of Safety Evaluation: Control power to 1(2)A02 should be from a different source than that supplying the associated DC lube oil pump. The new arrangement ensures that loss of D01 (D02) will not result in loss of lube oil to the turbine. Additionally, to ensure that a loss of D01 or D02 does not result in a complete loss of control power for the non-vital and switching buses, the control power supplies were split. To ensure that following loss of D01 or DO2, at least one pair of non-vital and switching buses would have control power, and the associated fast bus transfer would work correctly.

   Safeguards buses should have control power supplies split to maintain train separation. This does not represent a change from the present normal lineup. 480 V buses should receive control power from the same source as its 4160 V supplying bus. This ensures that control power is available for the energized 480 V buses following fast bus transfer.

   DC power for RCP UF trip (device 812) is hard wired to D16 (D18) from D01 (DO2). DC power for RCP UF trip (device 811) is selected with the choice of control power for that bus. The logic of RCP UF trip is such that 1 of 2 UF signals from A01 and A02 each are needed to cause a reactor trip. TS require that a minimum of one UF channel per bus be operating, or else maintain the unit in hot shutdown. As a worst case, consider when control power to A01 or AO2 is selected to the same DC bus as that supplying the hard wired UF trip channel (as is normally the case), a single failure resulting in the loss of both UF channels would be the result of losing a battery, DC bus or D11 (D13). These would all result in reactor trip. To restore the lost UF channel, in any event, the alternate control power supply would be selected. It is not a violation of Technical Specifications to align control power as suggested.

   Battery loading is unaffected by the change in control power lineup. Before and after the change, D11 and D13 each supply ten 4160 V and 480 V bus switchgear normal control power circuits.

   After considering the applicable criteria for 4160 V and 480 V bus control power lineup, the most reliable lineup was selected. This lineup addressed the concerns of turbine lube oil pump operability and correct operation of fast bus transfer, and ensured that at least one set of vital, non-vital and switching buses are available following loss of a battery of DC bus. (SER 89-134-04)

2. FSAR Section 10.2-1. The proposed change to the FSAR increased the value listed in Table 10.2-1 for the steam generator upper pH guideline from 9.3 to 9.4 s.u. Several minor changes were also included in the change to FSAR Table 10.2-1, including temperature for measurements of pH and conductivity. The inclusion of this temperature is to clarify that the listed values are for measurements taken at 25°C and not at system temperatures.

   Summary of Safety Evaluation: The chemical agents used to control pH, i.e., ammonia and morpholine, were added to the list of control parameters. However, no normal values are listed for these parameters since the governing parameter is the pH resulting from their addition. The reference to micromhos (µmhos) for conductivity was changed to micro-siemens (µS); the accepted nomenclature for the unit of electrical conductance. The upper pH guideline change is based on the vendor recommended guidelines. (SER 90-052)

3. FSAR 11.1.2, Nitrogen Gas System. FSAR Chapter 11 Section 11.1.2, "System Design and Operation," Pages 11.1-6 and 11.1-7, which describe the nitrogen gas system were changed in June of 1989. The change was made to accurately describe the mode of operation for this system. This description was not accurate in previous versions as documented in NCR 89-156.

   Summary of Safety Evaluation: This change describes the high pressure and low pressure nitrogen system. The change states the low pressure system can be supplied by the high pressure system through pressure control valves. It also states the low pressure system is the primary supply of cover gas in various tanks.

   The change to Page 11.1-16 on the nitrogen manifold was made to clarify its use in relationship to the low pressure system as described on Pages 11.1-6 and 11.1-7. This does not change system operation for nitrogen gas.

   The high pressure nitrogen 12-packs are normally isolated. They are primarily used for charging the SI accumulators, which is a manual operation. There are no automatic functions associated with the high pressure nitrogen system nor is there any safeguards equipment which requires automatic or a continuous supply of high pressure nitrogen. (SER 90-009)

4. MWR 901077, Non-installation of SG Safety Valve Header Heat Tracing. MWR 901077 removed the insulation and heat tracing from the Unit 1 A steam generator safety valve header for ISI inspections. The MWR was also scoped to reinstall the insulation and heat tracing after the inspections are complete. This safety evaluation reviews the safety impacts of leaving the heat tracing off the safety valve header.

   Summary of Safety Evaluation: The purpose of heat tracing on the main steam lines is not precisely known. Several scenarios are possible. One of the best explanations appears to be to assist in starting up the plant from a "cold iron" condition in extremely cold weather. For example, a steam generator may be in wet layup, including the main steam header, a pre-startup hydrostatic test of the steam generators may need to be performed. Either of these situations would require that the main steam lines be filled up to the MSIVs with water. If this would be done with facade and pipe temperatures below 0°F, it is possible that some freezing may be seen on the surface of the inside of the pipe. Another possible explanation for the existence of heat tracing on these lines is a desire to keep the pipe warm for pressurizing (i.e., brittle fracture concerns). In any of these cases, there are other options available.

   Most of the scenarios within reasonable possibility deal with subcritical conditions and other non-accident conditions. Because of this, failure of safety-related systems which can be postulated are limited to the main steam system during periods when the steam generator is not in service. The results of such a failure would be well- bounded by the steam line break accident which is analyzed in the FSAR. During an actual accident condition, the main steam lines would be drained and depressurized before the temperatures in the steam piping would approach the freezing point. Therefore, removing the heat tracing on the main steam line has no impact on an accident condition.

The FSAR and licensing basis documents were reviewed. Figures 10.2-1 and 10.2-1A were updated accordingly. (SER 90-060)

5. MWR 901918-901925, MWR 902159-902166, Main Steam Safety Valve Ring Settings. Ring settings on the main steam safety valves (MSSVs) were changed to assure full discharge capability. The new ring settings increase SV blowdown. SV blowdown is the pressure at which the safety valve reseats. Previous analyses assumed that the MSSVs open and reseat at the setpoint pressure. This evaluation determines the effect of the new ring settings, and the resulting increase in SV blowdown.

The ring settings were changed per MWRs 901918 through 901925 for 1MS-2005 through 1MS-2008 and 1MS-2010 through 1MS-2013. This safety evaluation also applied to changes for the corresponding Unit 2 MSSVs per MWRs 902159 through 902166. A JCO remained in effect for Unit 2 until changing of the ring settings was accomplished during U2R16.

Summary of Safety Evaluation: The primary function of the MSSVs is to limit pressure on the secondary side of the steam generators to less than the system design pressure. Changing the ring settings assures the valve's ability to perform its primary function. Fullscale testing of the valves found ring settings that provide the design flow rate at the valve's pressure setpoint as described in FSAR Sections 10.3.2 and 15.3.4.

A second function of the MSSVs is to back up the power-operated relief valves and the automatic steam dump control system to maintain RCS temperature at hot shutdown conditions following a plant shutdown. The pressure on the secondary side of the steam generator corresponds to a saturation temperature which determines the temperature of the reactor coolant system (assuming two-phase thermal equilibrium conditions). Increased blowdown of the MSSVs reduces secondary side pressure which decreases the temperature of the reactor coolant system.

The minimum average coolant temperature when the reactor is in the hot shutdown condition is 540°F. MSSVs should reseat at or above the saturation pressure corresponding to 540°F. The pressure associated with saturated water at 540°F is 963 psia. Blowdown of up to 12.6% reseats the MSSV with the lowest pressure setpoint (1085 psig) at or above 963 psia and maintains the RCS in hot shutdown conditions.

Several accidents analyzed in the FSAR include a description of the MSSVs. MSSV performance is important in an uncontrolled RCCA withdrawal at power accident when the reactivity insertion rate is small. A small insertion rate produces a slower change in reactor power and RCS temperature. The slower change reduces the effectiveness of the overtemperature ΔT trip. RCS temperature rises slowly and the MSSV setpoint can be reached prior to reactor trip. When the MSSV setpoint is reached, the steam release further slows the RCS temperature rise and reactor trip is further delayed. A delay in reactor trip reduces the minimum departure from nucleate boiling ratio reached during the accident. Reactor power and RCS temperature continue to increase until a protective trip is reached. Increased blowdown of the MSSVs does not change the results of this accident since reseat of the valve is not considered.

Analysis of the excessive load increase accident is done with the LOFTRAN computer code which models the MSSVs. However, performance of the MSSV model in the analysis is not important. Steam load is set to 10% greater than rated load and the computer code calculates a new equilibrium condition for the plant. Blowdown of the MSSV has no impact on the results of the accident.

Loss of external electrical load depends on MSSVs to limit secondary pressure and cool the plant. No credit is taken for operation of the steam dump system or the power operated relief valves on the steam line. Increased blowdown does not change the total amount of steam released from the steam generator, but it does change the timing of the release. A change in the timing of the release may impact dose calculations for the accident. Dose calculations are not reported in the PBNP FSAR and are not part of the design basis for a loss of external electrical load at PBNP.

In a loss of normal feedwater accident, the MSSVs remove heat from the system after the turbine is tripped. Changing the ring settings assures that full relief capacity is available. Increased blowdown of the valves will not adversely impact the plant during a loss of normal feedwater accident.

MSSVs cool the plant during a loss of all AC power. Changing the ring settings assures that full relief capacity is available. Increased blowdown of the valves will not adversely impact the plant during a loss of normal feedwater accident.

Calculated doses from a steam generator tube rupture increase slightly with increased MSSV blowdown. Offsite doses to the thyroid increase 35% from 0.55 to 0.75 Rem. Offsite doses to the whole body increase 3% from 0.117 to 0.121 Rem. Higher doses are the result of an increased break flow rate caused by earlier SI actuation, lower steam generator pressure, and a higher break flow fluid density due to lower reactor coolant system temperatures. Dose calculations are based on a typical Westinghouse plant using Westinghouse's FSAR analysis methods performed with both accident initiated and pre-accident iodine spikes. Westinghouse FSAR analysis methods provide the most conservative estimate of the impact of increased blowdown.

The increased doses from a steam generator tube rupture are much less than allowed by 10 CFR 100. Standard Review Plan 15.6.3, "Radiological Consequences of Steam Generator Tube Failure" states that the calculated doses for an accident initiated iodine spike should not exceed 10% of the 10 CFR 100 limits. The calculated dose of 0.75 Rem is much less than 30.0 Rem to the thyroid and the calculated dose of 0.121 Rem is much less than 2.5 Rem to the whole body.

Blowdown of the MSSVs can be increased to as much as 12.6% without reducing the margin of safety. (SER 90-051)

Operation of the main turbine electro-hydraulic (EH) system in manual. Operation of the EH system in manual was necessitated by a circuit card failure which precluded automatic operation.

Summary of Safety Evaluation: The EH system is described in Section 10 of the FSAR, "Steam and Power Conversion System." The FSAR states that the EH system controls the turbine stop valves so they are either in the wide open or closed position. The governor valves are positioned in response to an electrical signal from the main governor controller. Additionally, these valves are tripped by the turbine protective devices. Features of the EH system listed in the FSAR are the governor valve controller, load limit controller, auxiliary controller, speed controller, load controller, operators panel on the RTG control board, high pressure hydraulic fluid pumping unit, and turbine protective devices, including function limit trips, automatic load runback upon receipt of a dropped rod signal and extraction line nonreturn valves closing signal.

The actual operation of the EH system is not specified. Operation of the EH system in manual will not alter the FSAR description of the system.

Operation with the EH system in manual results in two significant changes to plant operations. First, the automatic features associated with the main governor controller will not be functional. All turbine speed/load changes must be affected by the control operator. Since the FSAR or the Technical Specifications do not state that the EH system is operated in automatic during normal power operations, operating the system in manual does not require a safety evaluation for its effect on turbine control.

The second difference associated with operating the EH system in manual is that the turbine load reference runbacks are not operable in manual. These runbacks are described in the FSAR and therefore require a safety evaluation.

The functional description of the automatic turbine load runbacks is found in FSAR Section 7.2. An automatic turbine load runback is initiated by a signal from a dropped rod assembly as indicated by either a rapid decrease in nuclear flux or by the rod bottom bistables. Load runbacks are also initiated by an approach to an overpower or overtemperature condition. This will prevent high power operation which might lead to a minimum DNB ratio less than 1.30.

The turbine runback acts by: (a) Reduction of the load reference setpoint of the turbine EH controller by a preset amount. This is accomplished by reducing the setpoint at a constant rate for a preset time; and (b) Reduction of the turbine load limit to a preset value. The load limit (a clamp on the voltage signal controlling the turbine control valve position) is reduced until turbine thermal load, as sensed by either of two turbine impulse channels, is below a preset value.

Load reference turbine runbacks affected by being in the manual mode are 1/4 NIS Train A channels senses a rod dropped; 2/4 overtemperature ΔT (OTΔT) channels sense an overtemperature condition; and 2/4 overpower ΔT (OPΔT) channels sense an overpower condition.

Load limit turbine runbacks are not affected by being in the manual mode and any signal from a rod bottom bistable, or 1/4 NIS Train B channels senses a dropped rod. Operation with the EH system in manual eliminates the OTΔT and the OPΔT runbacks and removes the redundancy provided for an NIS dropped rod signal.

FSAR Sections 7.2 and 7.3, "Control Systems Design," describe the dropped rod protection provided for the core. RCCA withdrawal is prevented and turbine runback is initiated by a dropped RCC assembly signal to provide additional core protection. Two independent and diverse systems are provided to sense a dropped rod, a system which senses a sudden reduction in out-of-core neutron flux and a rod bottom position detection system. Both systems initiate protective action in the form of a turbine load cutback and blocking of automatic rod withdrawal. This action compensates for possible adverse core power distributions and permits an orderly retrieval of the dropped RCC. The turbine runback and rod withdrawal stop are control system actions versus protection system actions. The purpose of these actions is to prevent exceeding design fuel limits, but they are not relied upon or required to assure safety.

Section 14.1.3, "Rod Cluster Control Assembly Drop," states that a rod drop signal from any rod position indication or from one or more of the four power range channels initiates reduction of the turbine load by a preset adjustable amount. The turbine runback is achieved by acting upon the turbine load limit and on the turbine load reference. The analysis assumes that a turbine runback occurs, however, core protection is provided by the OTΔT trip. Since operation in manual does not prevent load limit runbacks, the RCCA drop analysis is still valid.

Based on the FSAR description of the dropped rod protection power operation without the redundant dropped rod load reference, turbine runback will not result in an unreviewed safety question.

Section 1.6.4 of the FSAR, "Systems for Reactor Control During Xenon Instabilities," discusses the need for a turbine runback to maintain axial power within limits. The reactor control strategy during xenon instabilities is based on the difference in output between the top and bottom sections of the long ion chambers. If the operator allows axial power imbalance to exceed operating limits, various levels of protection are invoked automatically. These include generation of alarms, turbine power cutback, blocking of control rod withdrawal and reactor trip. This section only refers to the OTΔT turbine runback.

An OTΔT turbine runback is initiated when the core ΔT is greater than the ΔT rod stop setpoint where the ΔT rod stop setpoint is equal to ΔTsp1 minus a setpoint bias. The turbine runback is continued until the core ΔT is equal to or less than the ΔT rod stop setpoint. This function serves to maintain an essentially constant margin to trip and gives the operator the opportunity to adjust the rods to reshape the core flux profile before a reactor trip occurs.

The OTΔT turbine runback is included in one of the safety analysis found in FSAR Section 14.1.4, "Chemical and Volume Control System Malfunction." For a dilution at power prior to reaching the reactor protection trip the operator will have received an alarm on OTΔT and a turbine runback. Protection is provided by the OTΔT trip. Therefore, as in the case of excessive axial power offset, the OTΔT turbine runback is provided to allow the operator time to correct the problem prior to receiving a reactor trip.

The OTΔT alarms are still functional with the EH system in manual and will provide operator notification of a problem which if left uncorrected will result in an OTΔT trip. Since the OTΔT turbine runback is not required to show core protection, operation without the runback does not result in an unreviewed safety question.

The OPΔT turbine runback is mentioned in Section 7.2 of the FSAR along with the OPΔT trip. The FSAR states that there is an OPΔT turbine runback. No reason for the runback was given in the FSAR or the Technical Specifications and the runback is not included in any of the safety analyses found in the FSAR.

Since no specific requirements for the OPΔT turbine runback are given, it was concluded that the function of the OPΔT runback is to provide the operator the time to correct the overpower condition prior to receiving the OPΔT reactor trip. As such it serves no protective feature and operation without the OPΔT turbine runback will not result in an unreviewed safety question. (SER 90-015)

6. U1C17 EOL Coastdown. This safety evaluation report addressed the U1C17 end-of-life Tavg coastdown.

   Summary of Safety Evaluation: Technical evaluations of the systems affected by the Tavg coastdown remained valid for the Unit 1 coastdown. All evaluations are applicable to Unit 1 with the following clarifications.

   Part 2 of the Tavg coastdown 570°F to 555°F section states that the OPΔT setpoint will not be affected by the Tavg coastdown since Tavg must exceed 574.2°F before the setpoint decreases. Due to a recent TS change, the reduction in OPΔT occurs at 573.9°F. Likewise, following the installation of the stretch resistors the reduction in the

OPΔT setpoint will occur at 558.9°F not 559.2°F as stated in Part 2 of the Tavg coastdown 555°F to shutdown section.

Part 2 of the Tavg coastdown 555°F to shutdown section states that following the installation of the stretch resistors, the overtemperature setpoints will be conservatively reduced by ~12.3°F. However, due to core changes and an increase in the TS, Tavg gain constant from 0.015 to 0.020, the OTΔT setpoints will be ~16.4°F conservative.

SER 88-100 stated that the end-of-life Tavg coastdown occurs in two parts for instrumentation and control purposes; coastdown from 570°F to 555°F, and from 555°F to shutdown. It also stated that 555°F is the point at which full power Tcold goes out of range low. This is not accurate for each cycle. The full power Tcold is dependent upon the core full power ΔT. Since core full power ΔT varies slightly from cycle to cycle, Tcold will also vary. Additionally, the reactor may not be at 100% power when 555°F is reached. The actual power level also varies from cycle to cycle. As a result, the Tcold at a 555°F Tavg is not a set value.

Tcold instrumentation is no longer able to accurately generate a signal that is proportional to Tcold was considered. SER 88-100 stated that with the normal range resistors installed this occurred at ~527°F and with the stretch resistors installed at ~512°F. During the U1C16 coastdown, Tcold approached 512°F. SER 88-100-01 was approved to allow Tcold to decrease to 510°F for the U1C16 coastdown.

The dual current sources used for Tcold (and also Thot) are Foxboro Model 66/T dual current sources. These dual currents sources are capable of generating a 0 to 10 V output in proportion to the temperature of the associated RTD. The range resistors are selected such that a 2 to 10 V output corresponds to the temperature range of interest. Normally, this corresponds to a temperature range of 540°F to 615°F. With the stretch resistors installed, the range changes to 525°F to 600°F. The output of the dual current source is input into a Dana amplifier. The amplifier specifications state that it can generate a 0 to 10 V output based on a 0 to 10 V input.

Although the calibration range for the temperature loops is 2 to 10 V, the dual current sources are calibrated at 0 V. Additionally, the procedure which installs the stretch resistors performs a check of the amplifiers for a dual current source output of 0 V. Data from previous coastdowns indicates that the amplifiers are capable of proper operation at the dual current source null point. Therefore, the 2 to 10 V range is not specified for the proper operation of the dual current sources or the amplifiers.

The outputs of the Thot and Tcold amplifiers are electrically combined to create a Tavg signal and a ΔT signal. The Tavg signal has a range of 540°F to 615°F (525°F to 600°F with the stretch resistors installed) which corresponds to 2 to 10 V. The ΔT signal has a range of 0 to 75°F which corresponds to 0 to 8 V. It is at this point that the 2 to 10 V or 0 to 8 V becomes critical for proper loop operation. Therefore, Tcold could decrease to any value within the capability of the dual current source and amplifier as long as the generated Tavg and ΔT are within the required voltage range.

Additionally, the instrumentation must be capable of monitoring a temperature excursion that would require actuation of the reactor protection system. Specifically, the instrumentation must be capable of generating a ΔT signal for the overtemperature and overpower ΔT circuitry.

For the OTΔT trip there are two areas of concern. First at what temperature the Tcold instrumentation will no longer be able to decrease in a transient to generate the ΔT required for the OTΔT trip and at what point the TS OTΔT setpoint increases above the range of the measured core ΔT circuitry. The more limiting factor is the point at which the TS OTΔT setpoint increases above the range of the measured core ΔT circuitry. This occurs (assuming static conditions) at a Tavg of approximately 561.3°F. In other words, the OTΔT trip is inherently limited whenever Tavg is below 561.3°F until temperatures rise and the OTΔT setpoint decreases below 75°F. This is not a concern from a protection standpoint because as shown on Figure 14-1 of the FSAR at temperatures below ~570°F the OPΔT setpoint is more limiting.

Therefore, if during the coastdown, the Tcold instrumentation is capable of generating the necessary decrease in Tcold until Tavg decreases below 561.3°F then coastdown will not affect the protection afforded by the OTΔT trip. The Tcold instrumentation will be capable of developing the required ΔT until ~98.6% power (assuming a transient which results in equal and opposite changes in Thot and Tcold). At this power level during the coastdown Tavg will be ~559.6°F. Therefore, the Tcold instrumentation will be operable for all temperatures where the OTΔT trip is not limited. Once the stretch resistors are installed the OTΔT trip setpoint becomes more conservative. Additionally, once the stretch resistors are installed the range of core temperatures that provide protection also increases due to the decrease in T' from 573.9°F to 558.9°F. After the stretch resistors are installed, Tavg can decrease to 546.3°F before the OTΔT trip setpoint increases above 75°F. Therefore, installing the stretch resistors will provide a greater range of core protection from DNB during the coastdown.

Because the TS OPΔT setpoint decreases due to a Tavg increase and then only when Tavg is above T' (573.9°F normally, 558.9°F in stretch), the concern of the OPΔT setpoint increasing above 75°F does not exist. The only concern therefore in determining the operability of the Tcold instrumentation and the OPΔT trip circuit is whether or not it will be possible for Tcold to decrease to a temperature required to generate the TS OPΔT setpoint before going offscale low.

The Tcold instrumentation will be capable of developing the required ΔT until ~95.6% power with the normal range resistors installed and ~86.7% power with the stretch resistors installed (assuming a transient which results in equal and opposite changes in Thot and Tcold). At a power level of 95.6% power during the coastdown, Tavg will be ~551.44°F. Since the stretch resistors are procedurally installed before Tavg decrease below 555°F, it will always be possible to generate a TS OPΔT trip during the coastdown while the normal range resistors are installed. The 86.7% power level at which it may not be possible to generate the TS OPΔT trip occurs prior to the projected end of the coastdown. If credit is taken for the conservatism found in the calibration of the OPΔT summers and bistables which results in the actual trip setpoint being a 1.3125°F below the TS, setpoint an OPΔT trip can be generated until the projected end of the coastdown. Sufficient margin should exist to account for differences between the projected and actual coastdown.

In cases where Tavg is below T' (573.9°F normally, 558.9°F in stretch), the OPΔT trip function is a backup to the NIS overpower trip. Since Tavg is less than T' during coastdown, the primary trip function for an overpower accident will be the NIS trip. If, in conjunction with the overpower condition Tavg increased above T', the OPΔT trip setpoint would be reduced. As a result of the increased Tavg and the reduced setpoint, the problems associated with the Tcold instrumentation going offscale low would no longer exist. Additionally, the OPΔT runback will still be present during coastdown.

The potential for diluting safety injection flow were reviewed for applicability to the end-of-life Tavg coastdown. Unit 1 is within its design basis for shutdown margin during normal operations (specifically that margin required by the steam-line break analysis). Coastdown is less limiting than normal power operations for two reasons. A lower Tavg yields a less negative moderator temperature coefficient, leading to a smaller reactivity addition upon shutdown. Additionally, a lower Tavg yields a lower secondary steam pressure, which results in a lower initial mass release rate and therefore a reduced cooldown rate. Therefore, the potential for diluting safety injection flow is not a limiting concern.

With the clarifications stated above, previous evaluations are applicable to the U1C17 coastdown. (SER 88-100-02)

7. U1C17 Burnup Extension: SER 89-071 states that the U1C17 burnup is limited to 9,480 MWD/MTU plus a 1000 MWD/MTU power coastdown. The 9,480 MWD/MTU burnup was the prediction of the U1C17 lifetime. The U1C17 reload safety evaluation states that the Cycle 17 burnup is limited to end-of-full-power-capability (EOFPC) plus 1,000 MWD/MTU power coastdown. EOFPC is defined as all rods out and a boron concentration of 10 ppm.

From the U1C17 boron letdown curve data, it was estimated that actual EOFPC would be about 9,200 MWD/MTU. It was also estimated that the EOFPC plus 1,000 MWD/MTU burnup limit could be exceeded during U1C17. Therefore, a safety evaluation was performed for an additional 500 MWD/MTU cycle burnup.

Summary of Safety Evaluation: There are no unreviewed safety questions identified as a result of the U1C17 extended operation. These conclusions were based on (a) Cycle 17 burnup not exceeding 10,700 MWD/MTU; (b) coastdown is achieved by power reduction and the Tavg program for rod control, pressurizer level and steam dump systems are not changed; (c) there is adherence to plant operating limitations; and (d) the safety aspects on the reactor internals of utilizing PPSAs are acceptable.

The assumptions regarding coastdown being achieved by power reduction and Tavg program changes for the noted systems are not specifically true for U1C17; however, the U1C17 Tavg coastdown and the change in Tavg program were previously evaluated. (SER 89-071-02)

8. U1C18 Reload Core: The Unit 1 Cycle 18 reload contains 16 fresh Region 20A upgraded Optimized Fuel Assemblies (OFA) at 4.0 w/o, 12 fresh Region 20B upgraded OFA at 4.2 w/o, 1 fresh Region 20C upgraded OFA at 2.6 w/o, 12 Region 19A upgraded OFA, 15 Region 19B upgraded OFA, 12 Region 18A OFA, 16 Region 18B OFA, 16 Region 17B OFA, 12 Region 16, 4 Region 14, 1 Region 11A and 4 Unit 2, Region 8 standard fuel assemblies. The Cycle 18 core is the second reload containing a full region of upgraded OFA fuel for PBNP Unit 1.

Summary of Safety Evaluation: For the Cycle 18 core, all the licensing basis accidents were reviewed which potentially could be affected by the reload core design. The Westinghouse evaluation mainly used the analyses reported in WCAP-11872. The evaluations have been performed using methodology, models and procedures which the NRC staff has reviewed and approved.

The core design was performed assuming the reactor coolant system can be operated at a pressure of either 2000 or 2250 psia. As a result of the Cycle 18 evaluation, it was concluded that the Cycle 18 design does not cause previously acceptable safety limits to be exceeded, provided that the Cycle 17 burnup is 10,514 MWD/MTU; Cycle 18 burnup is limited to the EOFPC which is defined as the burnup of fuel when all rods are

... hot full power and the RCS boron concentration reaches 10 ppm plus ... /MTU power coastdown; and there is adherence to the plant operating ... itations given in the Technical Specifications.

Region 19B assembly U21 was damaged during handling. A replacement assembly was fabricated with 2.6 w/o U-235. The new assembly, identified as V29, is designated as a Region 20C assembly. Use of this replacement assembly does not constitute an unreviewed safety questions.

The mechanical and thermal-hydraulic designs for the U1C18 reload core are similar to those previously reviewed and accepted reload designs containing OFA fuel. This core was designed to operate under nominal design parameters and approved Technical Specifications. For postulated accidents presented in the FSAR which could be affected for the reload core, reevaluation has demonstrated that the results of the postulated events are within allowable limits. The reload core meets the current Fq(Z)xP limit of 2.5 and the current FΔH limit of 1.70.

A new all rods out position change from 225 to 228 steps was evaluated and determined to be acceptable.

No additional TS changes are required beyond those already covering upgraded OFA transition cores. No special environmental considerations are involved. (SER 90-05...)

9. U1C18 Reactor Coolant System Debris. The following items were not accounted for during U1R17: (a) Fragments of a small (1.5" length) cotter pin. (b) A metal knob, about 1.25" diameter, 0.375" thick, with a 0.625 threaded stud of ~0.25" diameter protruding from one end. The approximate mass is 26.9 grams. (c) A fiber washer for Item 2; approximate mass 0.46 g.

Summary of Safety Evaluation: Safety evaluations for the control rod guide tube flexure and split pin failures address the concerns for loose parts in the reactor coolant system. The items listed above are considered to be less significant than the split pin parts, which were previously shown to not constitute an unreviewed safety question. (SER 90-063)

10. U1C18 Secondary Source Substitution. During the U1R17 refueling operations, one of the secondary sources (SS-8) used in U1C17 could not be removed from its fuel assembly. A replacement secondary source (SS-6) was selected from the secondary sources that had been discharged from previous cycles. SS-6 was last used during U1C7, which ended on October 5, 1979. SS-6 is the earlier type of secondary source having 12 burnable poison rods, in addition to the normal 4 secondary source rods. SS-6 was placed in fuel assembly P17 in core location J2 for U1C18. Secondary source SS-7 was placed in fuel assembly T08 in core location F11.

Summary of Safety Evaluation: TS 15.5.3.A.5 and FSAR Section 3.2.3 state that the secondary sources are used to provide a required minimum count rate during startup operations. The secondary sources used in the PBNP reactor cores are comprised of a mixture of antimony and beryllium. These secondary sources emit neutrons of ~25 keV. The reactions these sources rely on are: (1) The antimony-123 absorbs a neutron and becomes antimony-124, (2) antimony-124 decays to tellurium-124 and in the process emits gamma rays, the half life of Sb-124 is about 60 days, and (3) approximately one out of each one million Sb-124 gamma rays interact with the beryllium-9 in the sources to cause a photoneutron reaction.

When neutron irradiation of these secondary sources ceases, the Sb-124 decays. Therefore, the sources produce fewer neutrons as time passes after they have been discharged. Secondary source SS-6 has been discharged for more than 10 years. SS-6 probably does not emit enough neutrons to be detectable at the source range detectors, even with subcritical neutron multiplication in the reactor core. This is not a safety concern as long as adequate neutron count rate is verified during fuel motion using procedure RP-1C, "Refueling," as required.

Adequate count rate at startup is assured by having an adequate count rate during refueling, because the source range count rate increases as the RCS temperature is increased and as the boron concentration is decreased. Therefore, the proposed source geometry does not pose an unreviewed safety question for refueling operations, as long as adequate neutron count rate is verified. (SER 90-054-01)

11. Amended Safety Evaluation for U1R17 Steam Generator PIP Repair. The process of plug-in-plug (PIP) repair of steam generator mechanical plugs was addressed in SER 89-124. Although our safety evaluation of that process did not indicate the evaluation was specific to Unit 2, the Westinghouse supporting documentation, SECL 89-1051 addressed the mechanical analysis for the repair specifically for the Unit 2 steam generators.

A question was subsequently raised whether the original evaluation was also applicable to PIP repairs performed on Unit 1 steam generator mechanical plugs.

Summary of Safety Evaluation: Although a 10 CFR 50.59 review is not required, one is considered appropriate due to industry concerns regarding mechanical plug failure. The vendor confirmed that the PIPs supplied for installation into Unit 1 were fabricated in accordance with the same drawing as those fabricated for Unit 2, with the material and design being the same.

Therefore, the conclusions of SER 89-124 remain valid in their entirety for extension of the steam generator PIP mechanical plug repair process for Unit 1 and extends this applicability to that unit. (SER 89-124-01)

12. EOL Tavg Coastdown. This report addresses the operation of PBNP Unit 1 or 2 during the EOL Tavg coastdown. EOL Tavg coastdown is a change in the plants operation to allow the core's lifetime to be extended by reducing the reference temperature. The Tavg coastdown also includes rescaling the bypass manifold temperature instrumentation loops to allow the reactor coolant system temperatures to decrease below what would normally be considered as the minimum temperature.

SERs 88-100, 88-100-01 and 88-100-02 were prepared for previous Tavg coastdowns. It was originally intended that SER 88-100, which was specifically written for the U2C14 coastdown, would support all future coastdowns as long as the coastdown procedure remained the same. However, during review of SER 88-100 for subsequent coastdowns, it was determined that there was a need to enhance the evaluation, particularly concerning the operability of the ΔT-related trips. SER 88-100-01 and 88-100-02 were prepared for U1C16 and 17, respectively, to address these additional concerns.

Summary of Safety Evaluation: SER 88-100 covers the effects of the coastdown for the following areas: nuclear instrumentation, pressurizer level, rod speed control and steam dump systems, reactor coolant flow trip, LOCA and non-LOCA safety analysis, pressurizer filling transients, steam line break analysis, core design limits, piping supports, SG tube vibration, and NSSS design transients. The conclusions of SER 88-100 for these areas is applicable to future coastdowns.

SER 88-100-01 was specifically approved for only the U1C16 coastdown, and authorized a reduction in Tcold to 510°F during the coastdown. This evaluation is not applicable to future coastdowns.

SER 88-100-02 corrected a portion of the OTΔT and OPΔT trip evaluation found in SER 88-100 due to changes in the Technical Specification formulas for the trip setpoints. These changes are applicable to both units and evaluation of the effects of these changes performed for U1C17 coastdown are valid for both units.

SER 88-100-02 addressed a concern associated with the potential for diluting safety injection flow. The evaluation concluded that coastdown is less limiting then normal power operation. This conclusion is also applicable to future Tavg coastdowns.

As stated in SER 88-100-02, when considering the operability of the temperature instrumentation during coastdown, the issue is whether or not it will be possible to generate an OTΔT trip and/or OPΔT trip prior to the actual core ΔT exceeding the Technical Specification setpoints.

It was assumed that the full power core ΔT (ΔT_0) used in the calibration of the OTΔT and OPΔT instrumentation is within the range of 53.5°F to 56.5°F. This range encompasses all past and present $\Delta T'_0$s and should cover future adjustments. As shown in the supporting calculations the limiting temperatures are associated with the higher ΔT_0.

For the OTΔT trip, the area of concern is at what point the OTΔT trip setpoint increases above 75°F, where 75°F is the maximum core ΔT that can be monitored by the ΔT instrumentation. Assuming that primary pressure is maintained within the normal band, the OTΔT trip setpoint will increase during the coastdown as a function of the decrease in Tavg. As shown in the supporting calculations, when Tavg decreases below ~563.2°F during normal power operations and below ~548.2°F after the "stretch" resistors are installed, it will no longer be possible to generate an OTΔT trip prior to exceeding the Technical Specification setpoint. However, during an overtemperature transient as core temperatures rise, the OTΔT trip will be restored when the setpoint decreases below 75°F. This inherent circuit limitation of the OTΔT trip is not a concern from a reactor protection standpoint because as shown on FSAR Figure 14-1 at temperatures below ~570°F the OPΔT setpoint is more limiting. Additionally, after the "stretch" resistors are installed the temperature ranges where the OTΔT trip is effective will be expanded by 15°F, which provides additional core protection during the coastdown.

Because the OPΔT trip setpoint is not affected by a decrease in Tavg, assuming that Tavg is below T' (573.9°F normally, 558.9°F after the "stretch" resistors are installed) the OPΔT trip is not limited by the ΔT circuit. It is however limited by the Tcold circuit. During an overpower transient, it is possible that Tcold will decrease off scale low and that an OPΔT trip signal will not be generated prior to exceeding the Technical Specification OPΔT setpoint. This point will be reached when Tavg has decreased to ~550.7°F during normal power operation. Since the "stretch" resistors are procedurally installed prior to decreasing Tavg below 555°F, it will be possible to generate an OPΔT trip during the coastdown while the normal range resistors are installed. After the "stretch" resistors are installed, the point where an OPΔT trip would not be generated prior to exceeding the Technical Specification setpoint decreases to 535.7°F. Therefore, as long as Tavg is not allowed to decrease below 535.7°F during the coastdown, it will be possible to generate an OPΔT trip prior to exceeding the Technical Specification setpoint. Since a Tavg of 535.7°F is the lowest allowable temperature, a minimum coastdown Tavg of 537°F was established to provide a sufficient margin to the Technical Specification setpoint.

In concert with the additional evaluations stated above, SER 88-100 and SER 88-100-02 are applicable to future end-of-life Tavg coastdowns provided that the OTΔT and OPΔT instrumentation calibration ΔT_0's are ≤56.5°F and Tavg remains ≥537°F during the coastdown. (SER 88-103-03)

13. U2C17 Reload Core. The U2C17 reload contains 12 fresh Region 19A upgraded Optimized Fuel Assemblies (OFA) at 3.8 w/o, 16 fresh Region 19B upgraded OFA at 4.2 w/o, 12 Region 18A upgraded OFA, 16 Region 18B upgraded OFA, 12 Region 17A OFA, 16 Region 17B OFA, 8 Region 16A OFA, 16 Region 16B, 8 Region 15 OFA, 4 Region 12B (previously irradiated in Unit 1, Cycle 13) and 1 Region 11A (previously irradiated in Unit 1, Cycle 11) standard fuel assemblies.

Summary of Safety Evaluation: The core design was performed assuming the reactor coolant system can be operated at a pressure of either 2000 or 2250 psia. As a result of the Cycle 17 evaluation, it is concluded that the U2C17 design does not cause previously acceptable safety limits to be exceeded, provided that (a) Cycle 16 design burnup was between 9,900 and 10,900 MWD/MTU (actual burnup was ~10,777 MWD/MTU); (b) Cycle 17 burnup is limited to the end-of-full-power-capability (EOFPC); and (c) there is adherence to the plant operating limitations given in the Technical Specifications and the total peaking factor (Fq) is administratively limited to 2.43.

The mechanical and thermal-hydraulic designs for the U2C17 reload core are similar to those of previously reviewed and accepted reload designs containing OFA fuel. This core is designed to operate under nominal design parameters and approved Technical Specifications. For those postulated accidents presented in the FSAR which could be affected by the reload core, reevaluation has demonstrated that the results of the postulated events are within allowable limits. The reload core meets the current Fq(Z)xP limit of 2.5 and the current FΔH limit of 1.70. Additionally, the reload core meets the more restrictive administrative limit on FqxP of 2.43. The administrative limit on FqxP has been temporarily established because of an error that was discovered in the decay heat model used for the large break LOCA analysis calculation performed by Westinghouse. This error was reported in LER 90-007-00. A new all rods out position change from 225 to 228 steps was evaluated and determined to be acceptable. No TS changes are required beyond those already covering upgraded OFA transition cores. The administrative limit on Fq will be maintained at 2.43 until sufficient analysis have been performed to return the limits to those stated in TS 15.3.10.B.1.a. No special environmental considerations are involved. (SER 90-100)

14. Shredding & Compaction of Dry Activated Waste (DAW) in the Steam Generator Storage Facility (SGSF) South Bay. SER 89-088 previously addressed storage of low-level radioactive waste in the south bay of the SGSF. The SER was approved with the understanding that two additional concerns needed to be addressed: (1) Storage of dry activated waste (DAW) in its present drummed form in the steam generator storage facility; and (2) ramifications of treating the steam generator storage facility as an effluent release path to the environment.

Summary of Safety Evaluation: The radiological analysis supporting SER 89-088 is based on the compaction and storage of DAW in a higher density rectangular "bale" configuration. The density of the shredded and compacted waste will be greater than that presently achieved with drummed waste. Consequently, the waste cannot be stored as efficiently in drums as in rectangular containers, both from a waste density and a geometrical perspective (historical drummed waste volume during 1978 through 1982 concluded that the SGSF south bay held the capacity for 3 years' production of drummed waste). Therefore, from a radiological standpoint, the analysis conservatively bounds the case of storage of drummed waste in the facility.

Due to the proposed shredding and compaction of DAW in the SGSF south bay, the creation of a new effluent release point in the form of particulate activity must be assumed.

The south bay is presently fitted with a HEPA-filtered ventilation duct on the south wall of the facility. This vent is meant to serve the purpose of pressure equalization between the south bay and the environment (A similar HEPA-filtered vent serves this purpose in the north bay) while at the same time providing radioactive particulate removal. However, due to installation of the rolling panel door (with integral personal access door) and without any forced ventilation, the south bay cannot be treated as an air tight structure, and air pressure buildup within cannot be assumed to exhaust entirely through the HEPA filter. Therefore, at the present time a release to the bay must be considered a release to the environment.

PBNP initiated MR 89-187 to upgrade the SGSF south bay. The modification is proposed to install additional lighting, heating, ventilation, ventilation radiation monitoring, shield walls and a 10-ton crane. The ventilation system is proposed to serve to exhaust facility air through a HEPA-filtered, radiation-monitored vent path. The modification is presently in its planning stage. While the negative-pressure and continuous monitoring capabilities of this modification are attractive and ideal, they do not exist now. The question becomes whether or not interim measures can be taken to control and monitor the potential airborne particulate effluent.

Applicable sections of the FSAR, RETS, 10 CFR 50.36a, 10 CFR 50 Appendix A GDC 60, 63 and 64, Appendix I; 10 CFR 20, 10 CFR 190, NUREG-0472 and NUREG-0133 were reviewed. Adhering to the controls imposed by RETS assures compliance with these regulations and guidelines.

A comparison of the SGSF site with the drumming area was performed. The basis of this evaluation is to draw a comparison between the present monitored effluent discharge path from the drumming equipment area and the proposed discharge path in the SGSF. The RETS stipulate, among other items, the controls and limits associated with the drumming area discharge path. If the same controls can be imposed on the proposed release point at the SGSF, the design is safe from a radiological release viewpoint.

Effluent particulate sampling with auxiliary sample equipment, on a continuous basis, is an acceptable alternative to on-line monitoring.

Additionally, particulate releases must be quantified. Therefore, in-house determination of alpha activity, and off-site analysis for strontium must be recorded.

Air samples taken in the SGSF south bay have indicated the presence of radon/radon daughters. This naturally occurring radiation source must be accounted for.

Use of the monitor during operations will entail selecting an alarm setpoint which may vary depending on the indoor radon concentration in the SGSF. The variation in radon concentration has been shown to change based on the time of year, the weather conditions, and even the time of day. To account for these variations, the sampler shall be run for the time duration identified in the pre-operational testing prior to starting radwaste activities in the SGSF. After running the sampler for the specified time period, the count rate due to the presence of radon daughters will be established. Using this count rate as the background count rate the minimum detectable count rate (or lower limit of detection) can be established based on a formula similar to that found in HPIP 5.50. The alarm setpoint shall then be established at a level equal to the sum of the background count rate plus the minimum detectable count rate.

Radwaste activities (not only operation of the MSCS, but any handling of radwaste) in the SGSF shall be terminated upon receipt of an alarm. This serves to protect the workers in the facility and to eliminate the SGSF as a radioactive release point. If the air inside the facility is being monitored to detect and control airborne radioactivity to less than detectable levels, then releases to the outside environment will also be maintained below detectable levels.

Receipt of an alarm should prompt HP to investigate whether the source is due to radwaste activities or due to natural fluctuations in the radon levels.

In order to assess the environmental impact of a release from the SGSF, it is necessary to obtain a credible source term. Next, the concentrations at the site boundary and the equivalent curie releases must be related to the RETS limits under plausible release scenarios. Finally, a monitor setpoint must be determined in order to assure that the RETS limits are not exceeded.

An analysis to determine postulated atmospheric isotopic radionuclide composition in the SGSF atmosphere was conducted. Based on the resulting concentrations of Co-60, Cs-137, and Ni-63 which are either greater than the 10 CFR 20 Table 1 MPC or greater than 25% of the MPC, the south bay would be classified as an airborne radioactivity area under the conditions postulated for this scenario. Therefore, monitoring should be provided for discharges into the SGSF south bay during the operation of the shredder/compactor.

A calculation was performed to examine the approach to RETS release limits. Under the specified assumptions, the criterion of maintaining radionuclide concentrations at the site boundary at or below the general population MPCs are accomplished. Even at an order of magnitude less efficient HEPA filtration (99% vs 99.9%) the radionuclide concentrations at the site boundary would be at least two orders of magnitude lower than the applicable MPC_a value.

Equivalent Curie (EQCI) Release Limits were also examined. The calculated EQCI indicate that I-129 releases from the SGSF south bay would be an insignificant fraction of the atmospheric I-131 EQCI release limit and that the other particulate would constitute ~1% of the Co-60 EQCI release limit. Because the EQCI release limits are based on the RETS dose limits, the calculated EQCI releases from the SGSF approximate the corresponding fractional doses expected from these releases. Based upon the conservative assumptions used in these calculations, releases from the SGSF south bay should have a minimal impact upon the environment.

Although releases to the SGSF south bay have a minimal environmental impact, all measurable releases within the SGSF should be included in the PBNP monthly release to the environment.

On an interim basis, (until completion of MR 89-187 which is proposed to provide a forced-air, HEPA-filtered, on-line radiation monitored ventilation system), use of the MSCS, with reasonable assurance of meeting all regulations and guidance associated with the control and monitoring of radiological effluents, is acceptable, if accompanied by continuous area monitoring of the SGSF air space for beta particulate. This monitoring shall also be required at any time facility activities have the potential for creating an airborne particulate hazard, e.g., radwaste handling prior to compaction. (SER 89-088-01)

SPEEDs

1. SPEED 89-081, Purge Supply & Exhaust System. SPEED 89-081 replaces a Numatics Model 2PC3-1 valve with a Numatics Model 01MA3-1 valve.

Summary of Safety Evaluation: The new valve is slightly thinner; thus it is lighter in weight. The new valve has a Cv of 0.30, while the Cv of the old valve is not known. The stroke required to open on the new valve is 0.11", compared to 0.22" on the old valve. The full travel range on the new valve is 0.22", compared to 0.31" on the old valve. Travel range can be accommodated by the adjustable actuator button on the purge supply and exhaust valve shaft.

These valves are actuated by an arm (~1' length) pivoting at the purge supply and exhaust valve shaft. The motion of the arm will result in the actuating motion being an arc. The valves are designed for a straight axial push. Since the stroke length is short and the arc is slight, this is considered acceptable.

In regard to the smaller stroke required to achieve full opening of the valve, the required leak-tightness of the purge supply and exhaust valve indicates sufficient tight tolerances such that a shorter stroke is accommodated. Thus, an 01MA3-1 valve that would not operate due to insufficient deflection should be attributed to misadjusted travel stops on the butterfly, T-ring problems, etc., rendering an inflated T-ring useless.

Substitution of an 01MA3-1 valve for a 2PC3-1 valve does not result in a degradation of the function of the purge supply and exhaust valve. Vendor data indicates an ambient temperature of +40°F to 200°F for the 01MA3-1 valve. The valve has Buna N O-rings, which would have been the case in the 2PC3-1 valve. Some typical Buna N compounds are rated for 1000 hours of service at 250°F. The service life increases with decreasing temperature and decreases with increasing temperature. Temperature extremes cause the O-ring compound to take a compression set. This is also true for radiation exposure. Nitrile is the second to lowest value for compression set after exposure to 10^7 rads, Buna N is a poor choice for extended high temperature service in regard to compression set.

For normal containment conditions, Buna N is sufficient. For accident conditions in containment, the short duration of extreme temperatures (286°F), Buna N will be sufficient.

Although valve operating ambient temperature range is 40-200°F, Buna N is suitable to -20°F; also to 286°F for short durations. This valve does not operate during an accident; thus all the O-rings are in static service so the compression set will not have a significant impact. The compound is also good for -40°F for short durations when the valve is not stroked.

Per EQ summary sheets, the solenoid valves for the purge supply and exhaust system are exposed to 4×10^6 rads. Buna N nitrile functions as satisfactorily as ethylene propylene at radiation levels up to 10^7 rads. Buna N is, therefore, acceptable.

To ensure that the O-ring compound have a known resistance to radiation, they will be replaced with O-rings of compound N741-75. Its fluid compatibilities are equivalent to that of standard Buna N O-rings. The typical O-ring used is a Precision Rubber Compound 8317 (902-6) durometer 70, Buna N. The N741 O-ring is durometer 75 and is considered to have a negligible effect for static applications (size dash -011).

The original valve (2PC3-1) is of poppet design and should have zero leakage when new. The 01MA3-1 valve is a "spool and sleeve" design, which will have some inherent leakage. The spool and sleeve is a precision matched set to minimize leakage. An acceptable leak rate was verified by testing. These valves do not see a lot of cycling and should not be subject to wear problems.

The 2PC3-1 and 01MA3-1 valves are observed to be non-magnetic. Thus, assuming both are aluminum, the impact on the aluminum content in containment remains unchanged.

The 01MA3-1 valve body is aluminum and thus would be subject to attack by sodium hydroxide. At the time that spray is occurring, the purge supply and exhaust valves would be shut, with their boots inflated. They would remain this way and thus, the valve would not have to stroke. Chemical attack on the valve body would have a negligible effect on the operation of the valve. If sodium hydroxide entered the valve body via vent paths and was in liquid form for extended periods, a possible degradation of the aluminum sealing areas around the sleeve assembly barrel could take place. Measures were taken to keep out the droplets of "spray" with sodium hydroxide.

After subsequent bench leak rate testing of ten 01MA3-1 valves it was determined that the inherent leakage that these valves exhibit would result in the failure of the leak rate/drop test on the purge supply and exhaust valves. As a result, a procedure was written to bypass these valves for times when containment integrity is needed.

The 01MA3-1 valves are adequate for use during refueling when the purge supply and exhaust valves are required for containment closure during mid-loop operation and fuel movement. Control of their use at these times shall be via procedure. For this application, it will not be necessary to shield the valve vents from sodium hydroxide or replace the O-rings with those of a known compound. (SER 90-090)

2. SPEED 89-094, Foxboro H-Line Refurbishment Substitutions. SPEED 89-094 addresses replacement of several internal components in the Foxboro H-Line instruments. The replacement parts were installed during the October 1989 phase of the Foxboro refurbishment project. The replacement components were analyzed, approved and tested.

   Summary of Safety Evaluation: The replacement of internal components was evaluated during the early stages of the refurbishment project and documented in SER 88-104. Although this evaluation specifically addresses the replacement of potentiometers and capacitors, its conclusion is also applicable to the replacement of other types of internal components in the Foxboro H-Line instruments. The conclusions contained in SER 88-104 remain valid for this evolution. (SER 88-104-01)

3. SPEED 89-101, dated October 30, 1989. SPEED 89-101 evaluated the use of a Whitey severe service union bonnet valve with optional Grafoil packing and stainless steel handle as a replacement for a Westinghouse Type 3/8-T58 valve in shutoff applications.

   Summary of Safety Evaluation: SPEED 85-01 previously evaluated an acceptable substitute for the Westinghouse Type 3/8-T58 valve. The valve evaluated in SPEED 85-01 had a regulating stem tip and is an acceptable substitute for the Westinghouse valve in regulating and shutoff applications. However, the replacement valve evaluated in this SPEED was considered a better valve for repetitive shutoff applications since its stem tip does not rotate on the seating surface, thus preventing galling of the valve seat.

The new valve replaces Westinghouse 3/8-T58 valves in shutoff applications when the Westinghouse valve is beyond repair. These valves are used in Westinghouse Class 2505 applications which include the sampling and waste disposal systems.

The valve substitution changes the flow coefficient factor of the valve from 1.2 to 0.86. This change slightly reduces the maximum flow rate which is not considered significant for the applications in which the valve is used.

The overall length of the replacement valve is less by 5/16". This change may require a slight change in tubing configuration to allow installation of the replacement valve. The magnitude of this change is not considered to require a detailed review for each individual case. There are several other dimensional changes which will not change the performance capability of the valve or cause working restraints.

The valve material is changed from Type 304 to Type 316 stainless steel and the valve packing is changed from graphited asbestos to Grafoil. No change in performance is expected due to these material changes. Type 316 stainless steel is specified for use in the Westinghouse 2505 line class. Grafoil packing is currently used successfully in the primary system.

The pressure and temperature ratings of the replacement valve are higher than the ratings of the original valve. The basic design of the compression type fittings are unchanged. The Westinghouse 2505 line class requirements state the Swagelok fitting end connections are acceptable. The reliability of the valve is expected to remain the same.

The weights of the original and replacement valves are approximately equal; therefore, the seismic integrity of the affected tubing line remains relatively unchanged. Since the dimensions and geometry of the two valves are similar, the seismic integrity of the replacement valve is considered to be equal to the original valve.

The replacement valve was manufactured to the B31.1 Power Piping codes as applicable. Since the valve is used in applications where it forms part of the reactor coolant pressure boundary, failure of a valve could result in a loss-of-coolant accident (LOCA). Since the valve is only 3/8" in diameter, the maximum possible leakage that could occur if the valve failed is within the makeup capability of the charging pumps and therefore is not as significant a safety concern as a larger break would be. However, the use of the replacement valve should not increase the probability of failure since the new valve has been determined as an acceptable substitute as documented in SPEED 89-101. (SER 90-017)

4. SPEED 90-010, Primary Plant Instrumentation. The SPEED replaces the source range detectors to improve the reliability and availability of the detectors by extending their operational lifetime. The originally installed detectors have a history of premature failure. This results in frequent plant operation with only one operable source range channel. The replacement detector has several design changes and improvements which should lengthen detector lifetime.

Summary of Safety Evaluation: The source range channels are provided as part of the nuclear instrumentation system which monitors the neutron flux from a completely shutdown condition to 120% of full power. The nuclear instrumentation system utilizes three discrete protection and indication ranges. Each range of instrumentation (source, intermediate and power) provides the necessary overpower reactor trip protection required during operation in that range. The overlap of instrument ranges provides reliable continuous protection from source to intermediate and low-power ranges. The lowest range is the source range which covers the bottom six decades of leakage neutron flux.

Two independent source range channels are provided. Each channel receives pulse-type signals from a proportional counter. The signal is a random count rate proportional to leakage neutron flux. The proportionality is determined by the detector's sensitivity. According to the FSAR, the source range detectors have a nominal thermal neutron sensitivity of ten counts per neutron per centimeter per second (cps/nv). The detector assemblies are surrounded by high density polyethylene which acts as a moderator-insulator and are contained in watertight, corrosion resistant steel enclosures.

This description applies both to the original detectors and the replacement detectors. The major difference between the two detectors is that the new detector is less sensitive. The original detector has a thermal neutron sensitivity of 13 cps/nv while the replacement detector has a sensitivity of 11 cps/nv. Since the detector sensitivity determines how much of a given neutron flux level is measured by the detector, the replacement detector will indicate approximately 85% of the leakage neutron flux when compared to the original detector. However, when compared to the proportional counter as described in the FSAR, the replacement detector will indicate a higher level. Additionally, based on testing and operational experience, the replacement detector will provide sufficient overlap with the intermediate range channels. Therefore, the replacement detector will provide the source range monitoring capabilities as described in the FSAR.

The TS requirement associated with the source range channels is for the source range high flux reactor trip. Technical Specifications require that the source range high flux reactor trip setpoint be set within the range of the instrumentation. The basis for the TS states that the source range high flux reactor trip prevents a startup accident from subcritical conditions from proceeding into the power range. Any setpoint in its range would prevent an excursion from proceeding to the point at which significant power is generated. Since the sensitivity of the replacement detector is close to the nominal 10 cps/nv stated in the FSAR, any reactor trip setpoint within the capability of the replacement detectors meets the requirements of the Technical Specification and meets the intent of the Technical Specification basis. (SER 90-053)

5. SPEED 90-017, Velan Check Valve Hanger Brackets. SPEED 90-017 changes the hanger bracket bolting in Velan 1500 psig check valves from ASTM A-193 B6 (410) to ASTM A-193 B8 (304) material. The hanger bracket holds the check valve clapper hinge pins in place. This bolting is internal to the valve. This change is being made in response to NRC Bulletin 89-02, which identified intergranular stress corrosion cracking (IGSCC) failures in certain ASTM A-193 B6 applications. The ASTM A-193 B8 material recommended is Type 304 stainless steel.

Summary of Safety Evaluation: The new bolting material must be of adequate strength and resistance to IGSCC in the application environment. The B8 bolting material is not as strong as the B6 bolting material. This does not affect the design parameters of the subject valves as the B8 bolting material is adequate. The bolting only fastens the hanger brackets to the valve body/seat assembly. The hanger brackets support the hinge pin for the valve clapper arm. There are negligible operating and thermal loads on these bolts. The primary load is from installation torquing to ~18 ksi. Material yield is 30 ksi minimum.

ASTM A-193 B8 bolting should be adequately resistant to IGSCC in our application. The applications include safety injection (SI) pump discharge checks, low head SI core deluge line first and second-off checks and CVCS charging line check valves. The conditions range from ambient to reactor coolant system temperature; RCS fluid to stagnant refueling water storage tank fluid. Radiation damage to the valve components is not a concern in view of valve locations.

For IGSCC to be a concern, it is believed that tensile stresses must be present in excess of yield; chemical contaminants need to be present and Type 304 stainless steel needs to be sensitized. In this bolting application there are high localized stresses considering stress concentration factors; a chemically controlled environment (except for saturated oxygen conditions for the refueling water storage tank fluids); and standard Type 304 stainless steel bolting. The bolting, per ASTM A-193, is carbide solution treated following forging prior to final machining.

Thus, the bolting should not be sensitized and IGSCC should not occur. To verify that the machining process did not sensitize the material, samples were taken of each heat and the grain structure inspected. The material was not sensitized.

To verify the acceptability of this material application, the vendor was contacted. The vendor approves the use of this material as long as it is not sensitized. EPRI was concerned that with anticipated stress levels, discrepancies in material production could result in bolting being very susceptible to IGSCC. This material application is thus similar to the previous problem identified in NRC Bulletin 89-02 in that the material/application results in an "unforgiving" material if errors are made in the manufacturing process.

Although there are better material choices than ASTM A-193 B8, it is adequate for a power cycle in view of QA involvement to ensure appropriate vendor practices. Also, a post-machining grain structure inspection of each material heat was performed to ensure no material sensitization had occurred.

ASTM A-193 B8 is not recommended for long-term service because of the potential for failure if sensitization occurs. Instead, ASTM A-564 Type 630 (17-4 PH), similar to the material used for the Anchor-Darling valves (reference SPEED 89-024) is recommended. As an alternative, the original material may be reused if inspected per NRC Bulletin 89-02, or ASTM A-193 B6X material may be used (same as original with hardness limits). (SER 90-046)

6. SPEED 90-018, Primary & Auxiliary Valves. SPEED 90-018 substitutes either a Velan Part No. 8959-110-013 or 8959-110N440 for a 8959-2-35. These part numbers are for a wedge (disc) in a Velan 10" 1500 lb gate valve. These valves are in the low head safety injection system.

Summary of Safety Evaluation: FSAR Section 6.2, Safety Injection System, states that the disc (wedge) is to be made of ASTM A182 F316, or A351 CR 8M or CF8; that the discs (wedges) will be liquid penetrant inspected; and that the seating surfaces are hard faced (Stellite #6 or equivalent) to prevent galling and reduce wear. Therefore, the description of the disc in the FSAR will remain unchanged.

The substitution of the new wedge for the original wedge is acceptable based upon a certification that the new part "... is acceptable for the intended use and will not affect form, fit or function." This changed the wedge material from the original A 351 CF8 Stellite #6 to SA 182 F-316 Stellite #6.

The substitution of the 8959-110-013 wedge for the original 8959-2-35 wedge represents a change in material from the original A 351 CF8 Stellite #6 to SA 182 F-316 Stellite #6. This is the same change that was documented above as being acceptable by the valve manufacturer. There are some dimensional differences between the 8959-2-5 and the 89-110-013; however, these are within the finishing tolerance provided by the manufactu er. (SER 90-049)

7. SPEED 90-025, Primary Pla strumentation. SPEED 90-025 replaces resistors in the Foxboro H-Line bistables. R tors R14 and R64 in the control switch circuit of the bistables will be upgraded fro 100 ohm; 1/2 watt resistors to 100 ohms; and 1 watt resistors. The resistors are upgraded due to an increased frequency of bistable failure associated with the failure of these resistors.

The failure mechanism is heat degradation of the resistor coupled with component age resulting in resistor cracking. These resistors provide a feedback voltage to the bistable's differential amplifier which triggers a silicon control switch, which in turn controls the bistable output. When the bistable output is energized, this feedback resistor has a load of ~0.4 watts or ~80% of its rated load. Due to the fail-safe design of the reactor protection and safeguards systems, the bistable outputs are normally energized. Therefore, the normal state of these resistors is to be at 80% of their rated load. As a result of almost 20 years of operation in this mode, these resistors have become brittle and are susceptible to cracking.

Summary of Safety Evaluation: This evaluation addresses continued operation of the bistables until the resistors are replaced. If the heat degradation progresses, enough of the resistor will open which turns off the silicon control switch and deenergizes the bistable output. Operation of the bistables until the resistors are replaced is acceptable since the failure of these resistors results in the protective or control action.

The exception to this is the containment spray bistables which energize for circuit actuation. However, since the containment pressure bistables are normally deenergized, the resistor load is less and these bistables should not be susceptible to this failure mechanism. Additionally, the operability of the containment spray bistables is verified monthly.

Replacement of these resistors with 100 ohm 1 watt resistors upgrades the power rating of R14 and R64 which should make these resistors less susceptible to failure due to being continuously loaded at 0.4 watts. This improves the reliability of the bistables. (SER 90-058)

8. SPEED 90-042, Boric Acid Flow Transmitter Replacement. SPEED 90-042 documents acceptability of changing out boric acid flow transmitter 2FT-110 with a spare of a later model. The newer model is the same type of flow transmitter in that both are magnetic type. The newer model has some slightly different electronics which results in a slightly different power load (less than 2 watts different). Physically the newer model is much smaller. It is about 5-1/2" shorter and weighs 17 pounds less. To accommodate the size difference, a short spoolpiece was used.

Summary of Safety Evaluation: The differences in the two units are not significant. The Seismic Class 1 rating of the boric acid piping is not affected. The unit will actually have higher temperature/pressure limitations than the existing unit. The transmitter will operate in the same manner as the existing one and has the same accuracy. (SER 90-071)

9. SPEED 90-064, Emergency Diesel Generators. The SPEED replaces emergency diesel generator Graham-White Model 812-6 air start solenoid valve with a Model 712-065 solenoid valve.

Summary of Safety Evaluation: FSAR. The electric air start solenoid will perform in the same manner as described in the FSAR. The addition of the manual override will not increase the probability of failure of the solenoid valve due to the design features of the manual override. This air start solenoid valve with a manual override is used as a standard on EMD diesels used in nuclear plants. No known manual override failures have occurred.

Manual override design features include: (1) The plunger can only be inserted from the inside of the valve, this prevents the plunger from ejecting. (2) The plunger and O-ring seal will only be exposed to air pressure when the valve is open, therefore the plunger O-ring is not in the air start supply boundary so leakage will not effect the air start supply. (3) Catastrophic failure of the plunger O-ring will not cause a complete loss of downstream line pressure since the air pressure causes the plunger to seat against the valve body limiting air leakage by mechanical blockage. Previous testing has shown that only 40 psi is required to engage the air starter pinions and initiate an air start. By inspection, the plunger with no O-ring seal can block enough air flow to allow a start to occur. (SER 90-118)

10. SPEED 90-066. The SPEED replaces the main feedwater regulating valve stem lock bars.

Summary of Safety Evaluation: Whenever a reactor trip occurs with a Tavg above 553°F, the main feedwater control valves move to the fully open position to increase the feedwater flow to the steam generators to reduce reactor coolant temperature to the no-load Tave value. The valves remain fully open until either one of the following conditions occurs, at which time the respective valve, or valves, fully close: Abnormally high steam generator level; safety injection signal; or Tavg error signal (between measured Tavg and the no load Tref) reduces to a preset level. Either a high generator level or a safety injection signal will close the feedwater valves. Closing the MFRVs is part of a redundant action to isolate the main feedwater lines to prevent overcooling the RCS and minimize containment pressure in the event of a main steam line break. Replacement of the stem lock bar with the new stem locking device does not change the existing MFRV function or controls. The new locking device will reduce the probability of the stem from turning into or out of the actuator. The design of the new locking device provides positive locking of the stem to the actuator.

Torque that had caused the stem to rotate will not cause a torsional failure of the stem. The manufacturer stated that the design will not adversely affect the performance or torsional fatigue life of the stem.

The plug/stem rotational moment is positively transferred to the actuator/bonnet connection. Existing fit and clamping forces are expected to provide sufficient friction to prevent any rotation. An anti-rotation rib is provided to prevent any possible rotation of the actuator on the bonnet.

This change does not alter the failure mode of the MFRVs (1&2CV-466 and 1&2CV-476). The valve operator will still fail closed on loss of instrument air. The valve closing times were not changed. (SER 90-102)

11. <u>SPEED 90-067</u>, Service Air System. The SPEED replaces service air containment isolation valve SA-27.

<u>Summary of Safety Evaluation</u>: The new valve used to replace the original inside containment isolation valve (CIV) for the service air header for the containment loops does not affect the system in an adverse way. The new valve meets the original piping class specifications for the service air system (OB-1), and meets the performance criteria for containment accident conditions.

The new valve does not negatively impact the seismic capabilities of the piping system (basically the same design and lighter in weight) and is seismically equivalent to the original valve. <u>(SER 90-101)</u>

12. <u>SPEED 90-070</u>, Auxiliary Feedwater/Safety Injection Systems. The SPEED replaces the original bearings (MRC 7409-DU) for the auxiliary feedwater and safety injection pumps with MRC 7409-PDU bearings.

<u>Summary of Safety Evaluation</u>: The parts list for P38A&B and P29 (auxiliary feedwater pumps) specify an MRC 7409-DB bearing or equal and an MRC 7409-DB bearing for P15A&B. SPEED 86-03 established the equivalency between an MRC 7409-DB and an MRC 7409-DU. This SPEED establishes the equivalency between MRC 7409-DU and an MRC 7409-PDU, which means the bearing is acceptable for use in P15A&B, P29 and P38A&B.

Since the load capability is greater than the original and the dimensional fits remain the same, there is no impact on the performance or construction of the pump. In view of the sensitivity of the equipment affected, Section XI inservice testing continues to verify the operability of the pump. <u>(SER 90-117)</u>

NONCONFORMANCE REPORTS

1. NCR N-89-267. MWRs 884024 and 891519 removed the root isolation valves for the Unit 1 4A and 5A feedwater heater sample points. The main piping runs were replaced with stainless steel. The work was accomplished via approved work plans and spare parts equivalency documents. It was believed at the time of the work that these valves existed without representation on plant drawings and there was no apparent need for the valves. It was subsequently discovered that these valves were depicted on plant drawings as 1SAX-2429 and 1SAX-2430, even though the valves were not marked or labeled.

   Summary of Safety Evaluation: Removal of valves at sample points 1SAX-2429 and 1SAX-2430 does not result in effects detrimental to nuclear safety-related equipment. The valves were removed after it was thought they had no use and were thought to not appear on plant drawings. This was done during replacement of a piping run from carbon to stainless steel. The valves will not be reinstalled. It was determined that the sample points are not being used nor are they needed because there are other available sample points. (SER 90-019)

2. NCR N-90-062. A potential single failure mode was identified in the 480 V AC bus tie breaker from B03 to B04. A hypothetical "DC+" short to the control circuit on the (+) side of the "X" relay could cause the relay to pick up, in turn energizing the "CC" (closing coil) relay causing the breaker to close. The solution to this problem was removal of the control power fuses to this circuit (placing them in the off position), disabling this single failure from operating the breaker.

   Summary of Safety Evaluation: Installation and removal of the control power fuses was added as procedural steps in routine maintenance procedures. Additionally, an operating instruction was revised to further describe normal operation and authorized use of the B03-B04 bus tie breakers.

   A concern was whether the presence of an undetected ground on the circuit could provide another path which could energize relays with a "DC+" short to the control circuit. The W battery chargers have ground detection capable of detecting grounds of 500 ohms or less. Assuming a ground present on the bus of 500 ohms (undetected) coincident with the "DC+" short to the control circuit, current may flow in the circuit. The "X" relay (based on of sampling of direct measurements) has a coil resistance of approximately 1500 ohms (maximum). This 1500 ohms in series with the 500 ohm ground may not provide enough current limiting resistance to prevent the "X" coil from operating. Thus for the purpose of analysis it was assumed that this relay operates, closing its "X" contacts and providing a current path to the "CC" closing coil.

   This series arrangement of the 1500 ohm "X" coil in parallel with the "CC" coil and 500 ohm ground provides adequate current limiting resistance to prevent the "CC" relay from operating. The "CC" current for operation is ~32 amperes which at 125 V DC the coil resistance calculates to about 4 ohms. The addition of the 500 ohms to the "CC" circuit will limit the current to ~0.25 amperes and the relay will not operate, thus the breaker will not operate. No additional single failure could provide both "DC+" and "DC-" across the "CC/X" coil parallel circuit with the DC control power fuses removed. (SER 90-035)

3. NCR N-90-157. Testing disclosed that both Unit 1 RHR pumps develop less than the 95% of design head limit listed in ASME Section XI Subsection IWP. The Unit 1 Train "B" pump develops less than 89%. Therefore, an operability concern existed with the emergency core cooling system (ECCS) while operating on containment sump recirculation. The evaluation establishes the NPSH requirements of the containment

spray pumps by determining a conservative containment sump temperature at the time of switchover from injection to recirculation (for containment saturation temperature up to 250°F).

The major concern is providing adequate net positive suction head (NPSH) to the containment spray and SI pumps. When both the CS and SI pumps are running, the CS pump is limited when it comes to NPSH for two reasons. The absolute pressure at the suction of the SI pump is higher than at the CS pumps. Additionally, the NPSH required by the SI pump is less than that of the CS pump.

Summary of Safety Evaluation: Calculation N-90-045 was performed in order to determine the amount of cooling required for the RHR heat exchangers to maintain adequate NPSH for the CS pumps during containment sump recirculation. The calculation was based on a uniform degradation of the manufacturer's pump curve by 20% of the design head of the pump (280 ft water) in order to provide some margin in the calculation.

In this calculation, it was determined that while on high head sump recirculation with containment spray, only one train operable, and RCS pressure = 0 psig, a containment pressure of 50 psig is required to maintain adequate NPSH to the CS pump. This assumed that the flow control valves in the core deluge lines had failed open due to loss of instrument air. If instrument air is available to these valves and they are completely shut, the CS pumps could not be operated at containment pressure <50 psig if the high-head SI pumps are running. If the high head SI pumps are secured (using low head recirculation), it was determined that adequate NPSH is available for the CS pumps only if containment pressure is >10 psig. It should be noted that the above containment pressure requirements do not include instrument error.

For two-train operation of high head recirculation, SI pump flow rate is less than that for a single train. This results in a lower flow rate through the common line feeding the CS and SI pumps, and therefore, less head loss. CS pump suction pressure will be higher, and thus less cooling of the sump fluid will be required by the RHR heat exchanger. This combined with the fact that more cooling will be available by the RHR heat exchanger with two trains of safeguards operable, means that the single train case is more limiting (two trains of ECCS cannot be operated with only one train of safeguards operable). The single train calculations bound the two-train case.

From a radiological perspective, containment spray is not required to operate while on sump recirculation to satisfy 10 CFR 100 (offsite dose) requirements, since most of the iodine released to the containment atmosphere has been scrubbed during the first 20 minutes of the injection phase (see calculation N-90-068, Part 100 Evaluation for NCR N-90-157).

The evaluation of NCR N-89-275 showed that sodium hydroxide addition was not required following the injection phase and could be secured. Lastly, in Section 6.4.2 of the FSAR it states that after the injection phase, it is expected that containment spray would not be required. The fan cooler units are sufficient to reduce containment pressure once on recirculation. (SER 90-120)

4. NCR N-90-187, Electrical Distribution System. NCR N-90-187 dealt with lack of electrical separation of control power cables for the B03/B01 and B04/B02 bus tie breakers, the dc control power fuses for these breakers have been removed to prevent inadvertent closure of the breakers. The NCR described a condition where both trains of tie breaker control circuit cables are routed in common raceways. With a single fault in these raceways, both breakers (A and B trains) may close inadvertently as a +dc source may be supplied (by another common faulted supply or cable) to the "x" coil of the breakers.

Under the conditions of a total loss of offsite power to the station, safeguards actuation in the accident unit and shutdown of the other unit, the diesel generators will provide power to both units. If the single postulated failure (on the shutdown unit) occurs simultaneously or subsequent to the accident, the diesels will each carry a full train of safeguards, a shutdown unit train and an inadvertently loaded B01 or B02 bus. Thus, overload of both diesels could be postulated under these conditions with the single failure.

Summary of Safety Evaluation: Placing the breaker control power fuses in off for each of these breakers removed the common mode single failure potential.

The use of one of these breakers, with its control power fuses installed, is acceptable and will not pose a common mode single failure potential. However, prior to installing the control power fuses with the breaker open, the opposite train diesel must be verified operable to ensure that a single failure in the control circuit of the breaker will not potentially place the only operable diesel in an unanalyzed condition. When the breaker is closed, train independent safety grade tripping is available, and if both tripping and closing (due to the fault) signals are present, the breaker will open and mechanically lock itself out preventing reclosure.

Both breakers (B03/B01 and B04/B02 ties) must be shut on a unit, then additional compensatory action will be required to ensure that the single failure potential is removed (e.g., disconnecting control circuit cables in one or both breaker closing circuits by a temporary modification).

Leaving the breakers racked in with dc control power fuses removed is an acceptable condition to ensure no common mode single failure could occur. The condition of having an undetected ground on both breaker control circuits, accompanied with an undetected dc ground fault, and the single failure occurring in the common cable trays is bounded by the analysis of SER 90-035 (single failure potential of B03/B04 bus tie breakers) which showed that the breakers would not operate.

Until permanent rerouting of control power cables can be accomplished, operation of these breakers will be under administrative control through use of operator aids, operating instructions and/or routine maintenance procedures. (SER 90-093)

V. NUMBER OF PERSONNEL AND PERSON-REM BY WORK GROUP AND JOB FUNCTION

Job Group Station Employees	Number of Personnel Greater Than 100 mrem	Total rem for Job Group	Work Function and Total Person-rem					
			Reactor Operations & Surveillance	Routine Maintenance	Inspections	Special Maintenance	Waste Processing	Refueling
Operations	58	35.750	14.180	-------	17.750	-------	0.800	3.020
Maintenance	48	81.890	-------	42.090	2.860	8.290	-------	28.650
Chemistry & Health Physics	40	35.480	30.840	-------	-------	-------	4.640	-------
Instrumentation & Control	14	4.220	-------	2.210	0.030	-------	-------	1.980
Technical Services	3	0.820	0.500	-------	0.040	-------	-------	0.280
Administration & Engineering, Regulatory Services	13	4.760	0.260	-------	4.500	-------	-------	-------
Utility Employees	34	36.770	1.750	16.510	4.010	3.070	-------	11.430
Contractor Workers & Others	219	148.480	0.840	-------	35.370	109.380	2.890	-------
GRAND TOTALS	429	348.170	48.370	60.810	64.560	120.740	8.330	45.360

POINT BEACH NUCLEAR PLANT CALENDAR YEAR 1990	
Whole Body Exposure Range (rem)	Total
No Measurable Exposure	383
Less than 0.100	186
0.100 to 0.250	86
0.250 to 0.500	100
0.500 to 0.750	66
0.750 to 1.000	44
1.000 to 2.000	101
2.000 to 3.000	34
3.000 to 4.000	0
4.000 +	0
GRAND TOTAL	1,000

279 individuals were monitored exempt from the provisions of 10 CFR 20. This report meets the requirements of 10 CFR 20.407(a)(i).

VI. STEAM GENERATOR EDDY CURRENT TESTING

UNIT 1

Plug Repair: Plug repair was performed on all three plugs in both legs of the "B" steam generator to address an industry wide concern with Alloy 600 plugs which may be susceptible to IGASCC. A total of six PIPs were installed between both legs of the steam generator.

PU = Tube Plug PIP			PS = Sleeve Plug PIP	
Row	Column	PIP Type	Repair ID No.	Date Repaired
1	1	PU	3	04/09/90
2	1	PU	4	04/09/90
43	40	PU	5	04/09/90
Total number of plugs repaired this outage: 6				

UNIT 2

Unit 2 was shut down for Refueling 16 on October 6, 1990. Eddy current examination of the steam generator tubes began on October 10 and was completed on October 23, 1990, using the digital multi-frequency eddy current system. Inspection results in the "A" steam generator hot leg showed four tubes degraded ≥40%, five tubes with an undefined signal, and 40 tubes with axial indications in the tubesheet area. All of these tubes were plugged. One tube, which was not degraded, was inadvertently plugged due to a communication error and the decision was made to install a plug in the opposite tube end.

In the "B" steam generator, a total of 19 tubes showed indications ≥40%, 16 tubes with undefined signals, and 32 tubes with axial indications in the tubesheet area. All of these tubes were plugged.

The 800 psid leak test revealed seven tubes and three plugs in the "A" steam generator and one tube and six plugs in the "B" steam generator were damp or dripping.

800 psid Leak Check

Prior to eddy current inspection, 800 psig secondary-to-primary leak checks were performed in both legs of both steam generators. Remote video equipment was utilized to inspect for leakage at the primary tubesheet face. The results of the leak test were:

	A	B
Tubes with evidence of potential leakage <1 drop/minute	6	1
Mechanical plugs with evidence of potential leakage <1 drop/minute	0	2
Mechanical plugs which were damp only (no drips noted)	0	4
Explosive plugs which were damp only (no drips noted)	2	0
Explosive plugs with confirmed leakage 55 drops/minute	1	0
Sleeved tubes with evidence of potential leakage <1 drop/minute	1	0

All signs of leakage observed during the leak test, with the exception of the leaking explosive plug, could be either condensation or very minor weepage. Active tubes showing any signs of dampness were eddy current tested. The one explosive plug that was actively leaking at 55 drops/minutes ("A" SG HL R43C35) was machined out, and a weld plug was installed in its place. All but on of the mechanical plugs noted were of heat 3513 and were previously repaired via the PIP process. The remaining mechanical plug, heat 85C4, was damp only. All inactive tubes that showed potential evidence of leakage will be monitored during future leak tests.

Eddy Current Inspection Scope

Eddy current exams began immediately following the leak checks. The program addressed the following items.

- An approximate 20% full-length inspection of all inservice tubes. (Technical Specifications required a 3% sample including tubes sleeved at one end only.)
- Previously degraded tubes which have not been repaired.
- All hot leg unsleeved tubes not included in the full-length sample were inspected to the first support plate, looking particularly for tubesheet crevice corrosion.
- A 20% sample of cold leg sleeved tubes.
- A sample of cold leg tubes susceptible to wastage and pitting was inspected to the first support plate.
- A 1026 tube "B" cold leg first support expansion required per Technical Specification 15.4.2.A.2.b, Table 15.4.2-1, including those which had reportable indications but were unsleevable due to channelhead restrictions.

The number of tubes inspected and the extent of the inspections are as follows:

"A" Steam Generator		
	Number of Tubes from	
Extent of Inspection	Hot Leg	Cold Leg
Full Length	279	
#6 TSP Cold Leg	43	43
Sleeve Top Cold Leg		24
Sleeve Top Hot Leg	279	279
#1 TSP	1229	244
Total	1830	590

"B" Steam Generator		
Extent of Inspection	Number of Tubes from Hot Leg	Cold Leg
Full Length		294
#6 TSP Cold Leg	43	43
Sleeve Top Cold Leg		156
Sleeve Top Hot Leg	282	126
#1 TSP	1340	1538
Total	1665	2157

"A" Steam Generator Tubes Exceeding the Plugging Limit

On October 20, 1990, review and verification of all eddy current data for tubes with reportable indications was completed. Four tubes in the "A" steam generator were found with degradation ≥40% (Technical Specification Limit 15.4.2.A.5). An additional 45 tubes were found to have non-quantifiable indications which, through experience, required repair. The following is a list of the affected tubes.

Plugged Tubes:

MAI - Multiple Axial Indication
ATE - Above Tube End
ATS - Above Tubesheet
SQR - Squirrel Indication
SAI - Single Axial Indication
HL - Hot Leg
CL - Cold Leg

TUBE	DEFECT	LOCATION
R 2C 6	MAI	6.4" ATE HL
R 2C11	MAI	4.2" ATE HL
R18C12	SQR	4.2" ATE HL
R19C15	MAI	5.9" ATE HL
R35C23	MAI	8.2" ATE HL
R35C26	MAI	4.8" ATE HL
R34C30	SAI	6.3" ATE HL
R40C30	MAI	5.4" ATE HL
R35C32	MAI	2.3" ATE HL
R33C33	SAI	6.5" ATE HL
R40C34	MAI	4.8" ATE HL
R41C35	SQR	2.8" ATE HL
R33C36	MAI	2.3" ATE HL

TUBE	DEFECT	LOCATION
R32C36	76%	10.5" ATE HL
R33C37	SAI	7.1" ATE HL
R44C39	SAI	At #2 TSP HL
R39C40	MAI	5.7" ATE HL
R43C41	MAI	5.8" ATE HL
R41C42	MAI	2.9" ATE HL
R37C42	MAI	2.5" ATE HL
R44C42	MAI	3.0" ATE HL
R33C48	46%	0.3" ATS HL
R44C49	MAI	4.1" ATE HL
R34C52	MAI	3.4" ATE HL
R42C52	MAI	4.9" ATE HL
R41C53	MAI	4.4" ATE HL
R35C53	MAI	11.7" ATE HL
R36C54	SAI	4.1" ATE HL
R43C54	MAI	4.3" ATE HL
R40C55	MAI	4.3" ATE HL
R37C56	MAI	2.4" ATE HL
R40C56	MAI	5.9" ATE HL
R39C56	MAI	3.5" ATE HL
R41C60	MAI	6.5" ATE HL
R40C60	Plugged in Error	
R35C61	SAI	15.1" ATE HL
R33C65	SQR	3.1" ATE HL
R35C66	MAI	4.9" ATE HL
R36C66	SAI	20.3" ATE HL
R40C67	80%	3.6" ATE HL
R37C67	84%	2.8" ATE HL
R33C67	MAI	3.5" ATE HL
R32C68	MAI	5.5" ATE HL
R 5C75	MAI	6.5" ATE HL
R 5C76	SQR	10.6" ATE HL

TUBE	DEFECT	LOCATION
R10C78	SAI	11.6" ATE HL
R 6C78	MAI	6.1" ATE HL
R12C80	MAI	9.9" ATE HL
R20C85	MAI	3.9" ATE HL
R14C85	SQR	6.0" ATE HL

"B" Steam Generator Tubes Exceeding the Plugging Limit

In the "B" steam generator 19 tubes were found with degradation ≥40% (Technical Specification Limit 15.4.2.A.5). An additional 48 tubes were found to have non-quantifiable indications which, through experience, required repair. The following is a list of the affected tubes.

TUBE	DEFECT	LOCATION
R 6C 2	MAI	4.2" ATE HL
R 6C 3	90%	2.6" ATE HL
R10C 3	47%	At #1 TSP CL
R 1C 3	SQR	3.2" ATE HL
R 7C 4	SQR	4.3" ATE HL
R16C 6	MAI	9.5" ATE HL
R 7C 6	96%	2.5" ATE HL
R17C 6	SAI	6.3" ATE HL
R 7C 7	MAI	2.9" ATE HL
R 1C 7	SQR	3.6" ATE HL
R20C 8	MAI	9.5" ATE HL
R15C 8	78%	8.87 ATE HL
R17C 8	SQR	3.8" ATE HL
R22C 9	MAI	5.2" ATE HL
R22C10	60%	4.8" ATE HL
R 6C10	83%	2.8" ATE HL
R17C11	MAI	11.3" ATE HL
R13C12	SAI	10.2" ATE HL
R22C12	51%	At #1 TSP CL
R19C13	MAI	1.9" ATE HL
R C13	63%	3.4" ATE HL

TUBE	DEFECT	LOCATION
R22C13	MAI	5.9" ATE HL
R37C22	40%	At #1 TSP CL
R36C23	46%	At #1 TSP CL
R36C26	SAI	5.1" ATE HL
R22C32	45%	At #1 TSP CL
R39C32	MAI	7.7" ATE HL
R 2C56	44%	At #1 TSP CL
R42C63	47%	0.5" ATS HL
R36C64	MAI	7.8" ATE HL
R33C65	SAI	5.0" ATE HL
R 1C66	MAI	4.6" ATE HL
R39C66	SAI	6.7" ATE HL
R36C71	MAI	4.8" ATE HL
R23C72	90%	7.0" ATE HL
R 1C74	MAI	3.7" ATE HL
R23C74	SQR	7.7" ATE HL
R 5C76	SQR	11.1" ATE HL
R 1C77	MAI	4.2" ATE HL
R24C77	MAI	4.8" ATE HL
R24C78	SQR	5.7" ATE HL
R24C19	SAI	7.1" ATE HL
R24C81	SQR	4.8" ATE HL
R27C81	SAI	7.4" ATE HL
R17C81	MAI	6.6" ATE HL
R22C82	SQR	3.5" ATE HL
R19C82	89%	3.2" ATE HL
R 8C82	SQR	2.8" ATE HL
R24C83	93%	2.6" ATE HL
R23C83	SQR	4.5" ATE HL
R22C83	MAI	3.6" ATE HL
R27C83	40%	1.7" ATS HL
R13C84	MAI	3.2" ATE HL

TUBE	DEFECT	LOCATION
R19C84	96%	2.9" ATE HL
R 6C84	SQR	5.7" ATE HL
R 8C84	SQR	2.6" ATE HL
R23C84	SQR	3.7" ATE HL
R17C84	SQR	4.4" ATE HL
R11C84	SQR	4.5" ATE HL
R 6C86	MAI	5.8" ATE HL
R17C86	MAI	9.0" ATE HL
R13C86	MAI	3.9" ATE HL
R17C87	MAI	7.8" ATE HL
R 6C87	MAI	8.4" ATE HL
R 8C87	92%	2.9" ATE HL
R 8C89	MAI	1.9" ATE HL
R 2C90	SQR	3.2" ATE HL

The previous year's examination was compared to this year's data to determine growth rates and/or trending. The results are as follows:

- The majority of recent cold leg problems have been addressed by the recent sleeving programs. The "A" steam generator cold leg problems are less active than the "B" steam generator. The average increase in wall loss is approximately 4-7% per year.

- Previously identified hot leg indications in both steam generators have exhibited growth rates under 10%. However, several indications which have not been previously identified, yet exceed the plugging limit, continue to emerge.

Cold Leg Wastage and Pitting

Due to the preventive sleeving programs undertaken during recent Unit 2 outages, the magnitude of the wastage problem has significantly decreased. Although the problems with wastage persist, pitting has yet to become a problem with these steam generators. In the "A" steam generator, 29 tubes showed signs of wastage and in the "B" steam generator, 41 tubes had this type of indication.

Tubesheet Crevice Corrosion

Forty-one tubes were found in the unsleeved region of the "A" steam generator hot leg with tubesheet crevice corrosion indications. In the "B" steam generator, 47 tubes displayed this type of problem. All of these tubes, regardless of wall loss, were taken out of service via plugging.

Probe Restrictions

Numerous tubes in both steam generators are considered to be restricted due to various forms of tubesheet or tube support plate denting. In the "A" steam generator, 67 tubes would not pass a 0.720" diameter probe, 15 of these would not pass a 0.700" diameter probe; and 3 of these would not pass a 0.680" diameter probe. (The 3 tubes were inspected with a 0.650" diameter probe.) In the "B" steam generator, 18 tubes would not pass a 0.720" diameter probe. All of these passed a 0.700" diameter probe.

RPC Inspections

In order to qualify bobbin coil data which showed hot leg distorted indications, rotating pancake coil inspections were performed on 56 tubes in the "A" steam generator and 40 tubes in the "B" steam generator. Forty tubes required plugging in the "A" steam generator, and 31 in the "B" steam generator as a result of the rotating pancake coil testing.

Sludge Lancing

The total weight of sludge removed from the "A" steam generator was 289 pounds. An additional 219 pounds were removed from the "B" steam generator. Post-cleaning checks were performed on both steam generators to verify the effectiveness of the cleaning.

Preventive Maintenance

Wisconsin Electric continues to monitor tube integrity in both legs of both steam generators. In order to augment the eddy current exams, secondary tube bundle exams have been performed to assess possible fouling conditions attributable to previous secondary plant heat exchanger materials and general operating conditions. These exams allow us the opportunity to better tailor the eddy current exam to the existing conditions in the steam generator and to provide early warning of any deteriorating conditions on the secondary side of the tubing.

Results of the testing and repair of the Unit 2 steam generator were transmitted to the NRC via LER 301/90-003-00.

VII. REACTOR COOLANT SYSTEM RELIEF VALVE CHALLENGES

Overpressure Protection During Normal Pressure and Temperature Operation

There were no challenges to the Unit 1 or Unit 2 reactor coolant system power-operated relief valve or safety valves at normal operating pressure and temperature in 1990.

Overpressure Protection During Low Temperature and Pressure Operation

There was a single actuation of the primary system low temperature overpressure (LTOP) mitigation channel during Unit 1 operations in 1990. On May 12, 1990, operators caused a minor, instantaneous pressure transient in the reactor coolant system during the routine fill of the "A" safety injection accumulator. The least conservative pressure channel indicated a spike of 410 psig. The NRC Region III office was notified via the emergency notification system (ENS).

There were no challenges to Unit 2 power-operated relief valves during low temperature and low pressure operation in 1990.

VIII. REACTOR COOLANT ACTIVITY ANALYSIS

There were no indications during operation of Unit 1 and Unit 2 in 1990 where reactor coolant activity exceeded that allowed by Technical Specifications.