April 28, 2006

Mr. Christopher M. Crane
President and Chief Nuclear Officer
Exelon Nuclear
Exelon Generation Company, LLC
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: BYRON STATION, UNITS 1 AND 2, NRC EVALUATION OF CHANGES, TESTS, OR EXPERIMENTS AND PERMANENT PLANT MODIFICATIONS BASELINE INSPECTION REPORT (IR) 05000454/2006006; 05000455/2006006 (DRS)

Dear Mr. Crane:

On March 24, 2006, the U.S. Nuclear Regulatory Commission (NRC) completed a combined baseline inspection of the Evaluation of Changes, Tests, or Experiments and Permanent Plant Modifications at the Byron Nuclear Power Station. The enclosed report documents the results of the inspection, which were discussed with Ms. M. Snow, and others of your staff at the completion of the inspection on March 24, 2006.

The inspectors examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations, and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel. Based on the results of the inspection, two NRC identified findings of very low safety significance were identified, which involved violations of NRC requirements. However, because these violations were of very low safety significance and because they were entered into your corrective action program, the NRC is treating the issues as Non-Cited Violations in accordance with Section VI.A.1 of the NRC's Enforcement Policy.

If you contest the subject or severity of a Non-Cited Violation, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with a copy to the Regional Administrator, U.S. Nuclear Regulatory Commission - Region III, 2443 Warrenville Road, Suite 210, Lisle, IL 60532-4352; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the Resident Inspector Office at the Byron Station.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

**/RA/**

David E. Hills, Chief
Engineering Branch 1
Division of Reactor Safety

Docket No. 50-454, 50-455
License Nos. NPF-37; NPF-66

Enclosure: Inspection Report 05000454/2006006; 05000455/2006006 (DRS)

cc w/encl: Site Vice President - Byron Station
Plant Manager - Byron Station
Regulatory Assurance Manager - Byron Station
Chief Operating Officer
Senior Vice President - Nuclear Services
Vice President - Mid-West Operations Support
Vice President - Licensing and Regulatory Affairs
Director Licensing
Manager Licensing - Braidwood and Byron
Senior Counsel, Nuclear
Document Control Desk - Licensing
Assistant Attorney General
Illinois Emergency Management Agency
State Liaison Officer, State of Illinois
State Liaison Officer, State of Wisconsin
Chairman, Illinois Commerce Commission
B. Quigley, Byron Station

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/RA/
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Engineering Branch 1
Division of Reactor Safety

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Enclosure: Inspection Report 05000454/2006006; 05000455/2006006 (DRS)

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Vice President - Licensing and Regulatory Affairs
Director Licensing
Manager Licensing - Braidwood and Byron
Senior Counsel, Nuclear
Document Control Desk - Licensing
Assistant Attorney General
Illinois Emergency Management Agency
State Liaison Officer, State of Illinois
State Liaison Officer, State of Wisconsin
Chairman, Illinois Commerce Commission
B. Quigley, Byron Station

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REGION III

| | |
|---|---|
| Docket No: | 50-454, 50-455 |
| License Nos.: | NPF-37; NPF-66 |
| Report No: | 05000454/2006006; 05000455/2006006 (DRS) |
| Licensee: | Exelon Generation Company, LLC |
| Facility: | Byron Station, Units 1 and 2 |
| Location: | 4448 N. German Church<br>Byron, IL 61010-9750 |
| Dates: | March 6, 2006 through March 24, 2006 |
| Inspectors: | R. Daley, Senior Reactor Inspector, Team Leader<br>A. Klett, Reactor Inspector |
| Approved by: | D. Hills, Chief<br>Engineering Branch 1<br>Division of Reactor Safety (DRS) |

Enclosure

## SUMMARY OF FINDINGS

IR 05000454/2006006; 05000455/2006006(DRS); 03/06/2006 - 03/24/2006; Byron Station; Evaluation of Changes, Tests, or Experiments (10 CFR 50.59) and Permanent Plant Modifications.

The inspection covered a two week announced baseline inspection on evaluations of changes, tests, or experiments and permanent plant modifications. The inspection was conducted by two regional based engineering inspectors. Two Green Non-Cited Violations (NCV) were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red), using Inspection Manual Chapter 0609, "Significance Determination Process (SDP)." Findings for which the SDP does not apply, may be Green, or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3; dated July 2000.

### A. Inspector-Identified and Self-Revealed Findings

**Cornerstone: Mitigating Systems**

Green. The inspectors identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," having very low safety significance for the licensee's failure to correctly translate the design basis into procedures. Specifically, the licensee failed to update operator rounds to verify the revised design basis minimum value for essential service water flow to the component cooling water (CC) heat exchangers. In addition, because the operator rounds were not revised, the design basis minimum flow value was not bounded by the emergency operating procedure used for establishing initial cold leg recirculation in the event of a loss of coolant accident (LOCA). This issue was entered into the licensee's corrective action program to revise the operator rounds.

The issue was more than minor because it was associated with the Mitigating System cornerstone attribute of "Design Control," and affected the cornerstone objective of ensuring the capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the failure to have operator rounds verify the design basis minimum service water flow or to have the emergency operating procedures ensure the minimum flow prior to establishing initial cold leg recirculation in the event of a LOCA could potentially have allowed the service water flow to be less than the required value to maintain the design heat load during post LOCA conditions. This finding was of very low safety significance because it screened out as Green using the SDP Phase 1 worksheet. Even though the licensee did not control their bounding design basis service water flow procedurally, the flow to the CC heat exchangers has historically been well above the bounding design basis flow. (Section 1R02.1.b.1)

Green. The inspectors identified a Non-Cited Violation of 10 CFR 50.48(a)(1) having very low safety significance for the licensee's failure to provide fire fighting systems of appropriate capacity and capability to minimize the adverse effects of fires on structures, systems, and components important to safety. Specifically, the licensee abandoned standpipes and manual hose stations located near safety-related equipment (essential service water makeup pumps) which reduced the fire suppression capacity and capability to protect such equipment. In addition, the site relied on a local fire department instead of the site fire brigade to manually suppress a fire that could have affected safety-related equipment. This issue was entered into the licensee's corrective action program, and compensatory measures were taken **to place dry chemical fire extinguishers in the vicinity of the fire area to take the place of the abandoned manual fire hose stations**.

This finding was considered more than minor because it was associated with the Mitigating System cornerstone attribute of "Protection Against External Factors," and affected the cornerstone objective of ensuring the availability of systems that respond to initiating events to prevent undesirable consequences. Specifically, removing the manual hose stations reduced the fire suppression capacity and capability for protecting the emergency service water cooling tower makeup pumps and their diesels in the event of a fire. **This finding was determined to be of very low safety significance (Green) based on a Phase 3 SDP evaluation.** (Section 1R17.1.b.1)

## B. Licensee-Identified Violations

No findings of significance were identified.

## REPORT DETAILS

### 1. REACTOR SAFETY

**Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity**

1R02 Evaluations of Changes, Tests, or Experiments (71111.02)

.1 Review of 10 CFR 50.59 Evaluations and Screenings

a. Inspection Scope

From March 6 through March 24, 2006, the inspectors reviewed six evaluations performed pursuant to 10 CFR 50.59. The inspectors confirmed that the evaluations were thorough and that prior NRC approval was obtained as appropriate. The inspectors also reviewed 13 screenings where licensee personnel had determined that a 10 CFR 50.59 evaluation was not necessary. In regard to the changes reviewed where no 10 CFR 50.59 evaluation was performed, the inspectors verified that the changes did not meet the threshold to require a 10 CFR 50.59 evaluation. The evaluations and screenings were chosen based on risk significance, safety significance, and complexity. The list of documents reviewed by the inspectors is included as an attachment to this report.

The inspectors used, in part, Nuclear Energy Institute (NEI) 96-07, "Guidelines for 10 CFR 50.59 Implementation," Revision 1, to determine acceptability of the completed evaluations and screenings. The NEI document was endorsed by the NRC in Regulatory Guide 1.187, "Guidance for Implementation of 10 CFR 50.59, Changes, Tests, and Experiments," dated November 2000. The inspectors also consulted Part 9900 of the NRC Inspection Manual, "10 CFR Guidance for 10 CFR 50.59, Changes, Tests, and Experiments."

b. Findings

b.1 Failure to Translate Design Basis Into Procedures for Service Water Flow to the CC Heat Exchangers

Introduction: The inspectors identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," having very low safety significance (Green) for the licensee's failure to correctly translate the design basis into procedures. Specifically, the licensee failed to procedurally ensure that required essential service water (SX) flows to the CC heat exchangers, which were established in design basis calculations, would be available during a design basis LOCA event. During a LOCA, this could have resulted in unanticipated operator actions to restore flow, or in the worst case, exceeding temperature limits for the CC heat exchanger.

Description: 10 CFR 50.59 screening, 6E-04-0115, "Revise Updated Final Safety Analysis Report (UFSAR) Table 9.2-11 (DRP 10-071)," evaluated an activity in June 2004 which revised UFSAR Table 9.2-11 to reflect the increase of the lower limit for SX flow through the CC heat exchangers from 5000 gallons per minute (gpm) to 5400 gpm. The basis for the increase in flow was described in calculation BYR2000-014, "Byron/Braidwood Uprate Project - Post LOCA Component Cooling Water System Temperature Analysis." This calculation evaluated the effects on the CC system temperature from a five percent power uprate for both units. Higher core power levels increased the CC heat loads for power operation, residual heat removal (RHR) cooldown, and post accident cooling. The calculation also determined the required SX flow (5400 gpm) at 100 °F to maintain the design heat load during post LOCA conditions.

Calculation BYR99-010, "Documentation of the Basis of the Emergency Operating Procedure (EOP) Setpoints" established the basis for the 6000 gpm minimum SX flow to the CC heat exchangers. This calculation stated, "A 5400 gpm flow rate will remove the post LOCA heat load at power uprate conditions. At this minimum flow rate, the CC temperature will exceed the 120 °F limit briefly during the initial recirculation phase. However, it will not exceed 130 °F, which is acceptable to the components being cooled. The margin between the 6000 gpm setpoint and 5400 gpm limit provides 600 gpm margin for addressing instrument uncertainty for this function."

The inspectors discovered that SX flow to the CC heat exchangers could only be verified by local indication during daily operator rounds; however, the operator rounds did not reflect the new minimum SX flow of 5400 gpm. Instead, the operators were verifying a minimum flow of 5000 gpm. In addition, the operator rounds also did not take into account instrument uncertainty of the flow meter. Consequently, a reading of 5000 gpm would have been acceptable per the operator rounds; however, the actual flow could have been as much as 600 gpm less. The actual flow in this worst case would have been almost a 1000 gpm below the design basis minimum value for SX flow.

In the event of a LOCA, the licensee's emergency operating procedure, 2BEP ES-1.3, "Transfer to Cold Leg Recirculation," would be entered after the reactor water storage tank level reached the low-low level switchover point. This procedure provided the necessary instructions for transferring the emergency core cooling system and containment spray system to the recirculation mode. The procedure also established CC flow to the RHR heat exchangers; however, this flow was not verified until after operation in the recirculation mode had been established. Because the operator rounds did not verify that SX flow to the CC heat exchangers was greater than 6000 gpm, the potential existed for the flow to be approximately 1000 gpm less than the design basis minimum value required for the initial recirculation phase, as established in the station's calculations. Insufficient SX flow to the CC heat exchanger could have resulted in unanticipated operator actions to restore flow, or in the worst case, exceeding temperature limits for the CC heat exchanger for an extended period of time.

The licensee entered this issue into the station's corrective action program as Issue Report 463574. The licensee's corrective action was to update the operator rounds to verify 6000 gpm on the SX flow to CC heat exchanger flow meter to ensure that the design basis minimum flow of 5400 gpm would be present.

<u>Analysis</u>: The inspectors determined that the failure to correctly translate the revised minimum SX flow to CC heat exchangers into procedures was a performance deficiency warranting a significance evaluation. This finding was considered more than minor in accordance with Inspection Manual Chapter (IMC) 0612, "Power Reactor Inspection

Reports" because it was associated with the Mitigating System Cornerstone attribute of "Design Control" and affected the cornerstone objective of ensuring the capability of systems needed to respond to initiating events to prevent undesirable consequences. Specifically, the failure to have operator rounds verify the design basis minimum or to have the EOPs ensure the minimum flow prior to establishing initial cold leg recirculation in the event of a LOCA could potentially have allowed the SX flow to be less than the required value to maintain the design heat load during post LOCA conditions.

In accordance with IMC 0609, Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations," Attachment 1, the inspectors performed an SDP Phase 1 screening. The finding screened as having very low significance (Green) using IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for the At-Power Situations," because the inspectors answered "no" to all five questions under the Mitigating Systems Cornerstone column of the Phase 1 worksheet. Even though the licensee did not control their bounding design basis service water flow procedurally, the flow to the CC heat exchangers has historically been well above the bounding design basis flow.

Enforcement: 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires that measures be established to assure that the design basis is correctly translated into procedures. The station's calculations established the minimum SX flow to the CC heat exchangers at 5400 gpm. Contrary to 10 CFR Part 50, Appendix B, Criterion III, the licensee failed to procedurally ensure that required essential service water flows to the CC heat exchangers, which were established in design basis calculations, would be available during a design basis LOCA event. Since this finding is of very low safety significance and was entered into the licensee's corrective action program (Issue Report 463574), it is considered an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy. (NCV 05000454/2006006-01; 05000455/2006006-01 (DRS))

1R17 Permanent Plant Modifications (71111.17B)

.1 Review of Permanent Plant Modifications

a. Inspection Scope

From March 6 through March 24, 2006, the inspectors reviewed six permanent plant modifications that had been installed in the plant during the last two years. The modifications were chosen based upon risk significance, safety significance, and complexity. As per inspection procedure 71111.17B, one modification was chosen that affected the barrier integrity cornerstone. The inspectors reviewed the modifications to verify that the completed design changes were in accordance with the specified design requirements and the licensing bases and to confirm that the changes did not adversely affect any systems' safety function. Design and post-modification testing aspects were verified to ensure the functionality of the modification, its associated system, and any support systems. The inspectors also verified that the modifications performed did not place the plant in an increased risk configuration.

The inspectors also used applicable industry standards to evaluate acceptability of the modifications. The list of modifications and other documents reviewed by the inspectors is included as an attachment to this report.

b. Findings

b.1 Reduction of Fire Suppression Capacity and Capability

Introduction: The inspectors identified a Non-Cited Violation of 10 CFR 50.48(a)(1) having very low safety significance (Green) for the licensee's failure to provide fire fighting systems of appropriate capacity and capability to minimize the adverse effects of fires on structures, systems, and components important to safety. Specifically, the licensee abandoned standpipes and manual hose stations located near safety-related equipment which reduced the fire suppression capacity and capability to protect such equipment. In addition, the site relied on a local fire department instead of the site fire brigade to extinguish a fire that could affect safety-related equipment.

Description: Modification EC 351113, "Abandonment of Fire Protection Ring Header," dated August 2005, abandoned in-place the fire protection water ring header in the River Screen House (RSH). The RSH contains safety-related SX Cooling Tower Makeup Pumps and their respective diesel fuel oil storage tanks. The reason for the modification was to prevent main control room alarms that were being caused by a leak in the fire protection header line. The modification disabled the alarms and installed positive isolation (blank plate) between the circulation water supply header and the fire protection ring header. The modification also resulted in the abandonment of standpipes and six manual hose stations in the RSH.

The inspectors questioned the adequacy of abandoning the manual hose stations since this modification adversely affected the fire suppression capacity and capability for equipment important to safety (SX Makeup Pumps). However, when evaluating the change, the licensee determined that the change did not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire. Furthermore, the evaluation stated that the hose stations were not the primary means of suppression protecting safety-related equipment (a localized carbon dioxide ($CO_2$) system was provided), portable fire extinguishers were available, and the local fire department would have the primary responsibility for suppressing the fire using their own equipment.

Based upon the licensee's Fire Protection Report (FPR), the inspectors determined that the licensee's conclusion that the level of protection for the safety-related equipment in the area would not be diminished was not adequate. The station's FPR, Section 3.0, Guidelines of Branch Technical Position (BTP) CMEB 9.5-1 listed the station's fire protection program requirements. BTP CMEB 9.5-1, Section 3.1.c.(1) stated NRC's position on the fire suppression system design basis, "Total reliance should not be placed on a single fire suppression system. Appropriate backup fire suppression capability should be provided." The station's response was, "Comply. Backup fire suppression equipment is provided in the form of manual hose stations and portable fire extinguishers at or near where automatic fire suppression systems are installed as well as at other locations throughout the plant." BTP CMEB 9.5-1, Section 3.7.k stated NRC's position on guidelines for specific plant areas, specifically for safety-related pumps, "Hose stations and portable extinguishers should be readily accessible [for pump houses and rooms housing redundant safety-related pump trains]." Again, the licensee reaffirmed their compliance with this portion of the BTP.

The inspectors were also concerned that the station depended on the local fire department instead of the site's fire brigade to extinguish a fire that could affect safety-related equipment. BTP CMEB 9.5-1, Section 3.3.b stated the NRC's position on fire brigades, "A site fire brigade trained and equipped for fire fighting should be established to ensure adequate manual fire fighting capability for all areas of the plant containing structures, systems, or components important to safety." The licensee's response was that the station complied with this section.

Based upon the licensee's repsonse to the BTP, as contained in the Byron FPR, the inspectors determined that the hose stations and fire brigade were critical fire protection features to protect the safety related equipment in the RSH. Consequently, the inspectors concluded that relying on an offsite fire department in addition to abandoning the manual hose stations reduced the fire suppression capacity and capability for protecting the SX cooling tower makeup pumps and their diesels, therefore adversely impacting on equipment important to safety. The licensee entered this issue into the station's corrective action program as Issue Report 469894. **The licensee's interim compensatory measures were to place dry chemical fire extinguishers at the RSH and to send a non-licensed operator to the RSH upon receipt of a fire detector or suppression actuation alarm.**

Analysis: The inspectors determined that the failure to provide fire fighting systems of appropriate capacity and capability to minimize the adverse effects of fires on structures, systems, and components important to safety was a performance deficiency warranting a significance evaluation. This finding was considered more than minor in accordance with IMC 0612, "Power Reactor Inspection Reports" because it was associated with the Mitigating System cornerstone attribute of "Protection Against External Factors," and affected the cornerstone objective of ensuring the availability of systems that respond to initiating events to prevent undesirable consequences. Abandoning the manual hose stations reduced the fire suppression capacity and capability for protecting the SX cooling tower makeup pumps and their diesels, therefore having an adverse impact on equipment important to safety. The manual hose stations would have been needed when the concentration of the localized $CO_2$ suppression dissipated in the event of a fire. The loss of the SX cooling tower makeup pumps could have resulted in the degradation of the safe shutdown function to provide essential mechanical support for hot standby.

In accordance with IMC 0609, Appendix A, the inspectors performed an SDP Phase 1 screening and determined that the finding degraded the Fire protection (FP) portion of the Mitigating Systems Cornerstone. Therefore, screening under IMC 0609. Appendix F, "Fire Protection Significance Determination Process," was required. The finding was determined to affect the element of "Fixed Fire Protection Systems" in accordance with Table 1.1-1 in Appendix F. **The finding was assigned a high degradation rating in accordance with Step 1.2 and Attachment 2 of Appendix F because the water-based suppression system was nonfunctional. The finding was also assigned a duration factor of 1.0 since the degradation occurred for more than 30 days. Since the finding affected the River Screen House, a fire area fire frequency of 2E-2 (the generic fire frequency for an intake structure) was assigned to the finding. The change in core damage frequency (CDF) was determined to be 2E-2 (duration factor times the fire frequency); therefore, additional risk screening was required.**

The RIII Senior Reactor Analyst (SRA) performed a phase 3 Significance Determination for this finding. The inspectors and the SRA determined that the scenario of concern for a fire in the RSH with no manual suppression capability was a large fire which would affect both SX makeup pumps. This fire was assumed to result in a plant transient. The two diesel driven SX Pumps in the RSH were determined to be the ignition sources which could potentially ignite the fuel stored adjacent to the diesel. The fire frequency for two diesel generators based on IMC Manual Chapter 0609, Appendix F, Attachment 1 was 1.1E-2/yr. This diesel generator fire frequency was used for the diesel driven SX Pumps. Because the finding involved the manual suppression system, no credit for suppression of the fire before it involved both trains of SX makeup was considered. Each diesel driven SX Pump has a localized automatic carbon dioxide suppression system which would likely be effective in suppressing smaller fires. However, the carbon dioxide suppression was not explicitly credited in the significance determination. The SRA calculated a conditional core damage probability using the NRC's Standardized Plant Analysis Risk (SPAR) model for Byron assuming that the fire results in a transient and affects both trains of SX makeup. The risk model includes the deep well pumps which can perform the same function as the SX makeup pumps and are unaffected by the fire. The calculated conditional core damage probability was 6.7E-5. As a result, the delta CDF for this finding was calculated to be approximately 7.5E-7. Because this estimate is below 1.0E-6, this finding was characterized as having very low safety significance (Green).

Enforcement: 10 CFR 50.48(a)(1) stated, "Each operating nuclear power plant must have a fire protection plan that satisfies Criterion 3 of Appendix A to this part." 10 CFR Part 50, Appendix A, Criterion 3, "Fire Protection," stated, "Fire detection and fighting systems of appropriate capacity and capability shall be provided and designed to minimize the adverse effects of fires on structures, systems, and components important to safety." Contrary to this requirement, the licensee failed to provide fire fighting systems of appropriate capacity and capability to minimize the adverse effects of fires on structures, systems, and components important to safety. Specifically, the licensee abandoned standpipes and manual hose stations located near safety-related equipment which reduced the fire suppression capacity and capability to protect such equipment. In addition, the site relied on a local fire department instead of the site fire brigade to extinguish a fire that could affect safety-related equipment. Since this finding is of very low safety significance and was entered into the licensee's corrective action program, it is considered an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy. (NCV 05000454/2006006-02; 05000455/2006006-02 (DRS))

## 4. OTHER ACTIVITIES (OA)

### 4OA2 Identification and Resolution of Problems

.1 Routine Review of Condition Reports

a. Inspection Scope

From March 6 through March 24, 2006, the inspectors reviewed five Corrective Action Process documents that identified or were related to 10 CFR 50.59 evaluations and permanent plant modifications. The inspectors reviewed these documents to evaluate the effectiveness of corrective actions related to permanent plant modifications and evaluations for changes, tests, or experiments issues. In addition, corrective action documents written on issues identified during the inspection were reviewed to verify adequate problem identification and incorporation of the problems into the corrective action system. The specific corrective action documents that were sampled and reviewed by the team are listed in the attachment to this report.

b. Findings

No findings of significance were identified.

## 4. OTHER ACTIVITIES

4OA6 Meetings

.1 Exit Meeting

The inspectors presented the inspection results to Ms. M. Snow and others of the licensee's staff, on March 24, 2006. Licensee personnel acknowledged the inspection results presented. Licensee personnel were asked to identify any documents, materials, or information provided during the inspection that were considered proprietary. No proprietary information was identified.

ATTACHMENT: SUPPLEMENTAL INFORMATION

## SUPPLEMENTAL INFORMATION

## KEY POINTS OF CONTACT

Licensee

E.Blondin, Mechanical/Structural Design Manager
T. Fluck, Regulatory Assurance Specialist
J. Langan, Regulatory Compliance
V. Naschansky, Electrical/Iand C Design Manager
W. Perchazzi, Engineering Response Manager
R. Randels, Sr. Manager Design Engineering

Nuclear Regulatory Commission

B. Bartlett, Senior Resident Inspector
R. NG, Resident Inspector
D. Hills, EB1 Branch Chief

## ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

None.

Opened and Closed

| | | |
|---|---|---|
| 05000454/2006006-01; 05000455/2006006-01 | NCV | Failure to Translate Design Basis Into Procedures for Service Water Flow to the CC Heat Exchangers |
| 05000454/2006006-02; 05000455/2006006-02 | NCV | Reduction of Fire Suppression Capacity and Capability |

Discussed

None.

## LIST OF DOCUMENTS REVIEWED

The following is a list of licensee documents reviewed during the inspection, including documents prepared by others for the licensee. Inclusion on this list does not imply that NRC inspectors reviewed the documents in their entirety, but rather, that selected sections or portions of the documents were evaluated as part of the overall inspection effort. Inclusion of a document in this list does not imply NRC acceptance of the document, unless specifically stated in the inspection report.

IR02 Evaluation of Changes, Tests, or Experiments (71111.02)

10 CFR 50.59 Screenings

6E-04-0008; Revision to TRM Appendix O, "Safety Function Determination Program," and 0BOL 7.10/0BwOL 3.7.10; Revision 0

6E-04-0058; Revise TS Bases B 3.3.6, "Containment Ventilation Isolation Instrumentation," to clarfiy Operability requirements; Revision 0

6E-04-0071; Change the Existing Instantaneous (i.e., Magnetic) Trip Settings for Five new HFP Series Breakers; Revision 1

6E-04-0078; Revise DEHC Turbine Control Software Input Parameter SPDBMINS from 2 RPM to 3 RPM to Make DEHC Response Occur at 1 RPM Lower Speed During Reduced Turbine Speed/Reduced Grid Frequency Conditions; Revision 0

6E-04-0115; Revise UFSAR Table 9.2-11 (DRP 10-071); Revision 0

6E-05-0031; UFSAR Change for Clarification of Expected Voltage Ranges for the Switchyard; Revision 0

6E-05-0037; Technical Requirements Manual (TRM) Appendix P, "Containment Leakage Rate Testing Program" - TRM Change Request 05-001; Revision 0

6E-05-0072; Change the Existing Instantaneous (i.e., Magnetic) Trip Setting For new HFP Sereis Breakers for 2AP24E-A4; Revision 0

6E-05-0121; EC 356794, Revise 1FIS-WO026 1A Containment Chiller Outlet Low Flow Switch Setpoint; Revision 0

6E-05-0157; Clarify UFSAR Section 0.2.5.2.2 Fuel Consumption Rate for SX Makeup Pump Engine Drive (DRP 11-048); Revision 0

6D-05-0161; Revise TRM and Associated Implementating Procedures in Support of Byron TS Amendment No. 143; Revision 0

6E-05-0172; Clarify References to RWST Internal Pressure in the ECCS and CS Pumps NPSH Analysis; Revision 0

6E-05-0178; Change the Existing Instantaneous Trip Setting Phase Over Current Relays for the 1A/B, 2A/B SX Pumps; Revision 0
10 CFR Part 50.59 Evaluations

6G-04-0001; TRM Change 04-001,TRM Section 3.9.a, Decay Time; Revision 0

6G-04-0002; Containment Floor Drain Sump Flow/Level Instrument Modification (EC 337255); Revision 1

6G-04-0003; DEH Replacement (EC 343598); Revision 0

6G-04-0006; Installation of Temporary Pumps for Draining the “A” SX Suction Piping; Revision 1

6G-04-0009; Byron Unit 1 Power Ascension DEHC Testing - SPP 04-012 (Section 6) Procedure 1BGP 100-3; Revision 0

6G-05-0004; TRM Change 05-015, TRM Section 3.9.a, “Decay Time”; Revision 0

IR17 Permanent Plant Modifications (71111.17B)

Modifications

EC 079657; Removal of 2SX101A AF MTR DRVN Cooling SOV. Also Replace 2SX2102 and 2SX2103A With Stainless Steel Valves; dated October 24, 2005

EC 341175; Add Time Delay Relays For the Halon System in the Upper Spreading Room; dated April 28, 2004

EC 345659; Revise Primary Containment Chiller Condenser Controller Setpoint from 5 psig to 10 psig Due to ACE 173147-11; Revision 1

EC 346797; Revise 1PR11J Low Gas Monitor Setpoint (1RE-PR011B) to Detect 1 GPM RCS Leak Rate Based on Current RCS Activity Level with Failed Fuel; Revision 0

EC 349293; Revise Setpoint for the Pressurizer Safety Valves; Revision 0

EC 349891; Defeat Interlock Function of Containment Rad Monitor 1PR011J; Revision 0

EC 351113; Abandonment of “FP” Ring Header; dated August 25, 2005

Other Documents Reviewed During Inspection

Corrective Action Program Documents Generated As a Result of Inspection

AR 00461308; Design Basis SGTR Operator Acceptance Criteria Challenge; dated February 28, 2006

AR 00463574; 2006 NRC Mod and 50.59 Inspection - OPS Rounds Not Updated; dated March 8, 2006

AR 00469079; NRC Mod Inspection - UFSAR Section 9.2.5.2.2 Wording; dated March 21, 2006

AR 00469894; Abandonment of RSH FP Header and Hose Stations; dated March 23, 2006

Corrective Action Program Documents Reviewed During the Inspection

AR 00229458; Couldn't Perform Surv Due to Tech Spec Compliance Issues; dated June 17, 2004

AR 00239280; RWST Vent/Vacuum Breaker Design Basis Issues; dated July 27, 2004

AR 00252639; Incorrect Reference in TRM Appendix P; dated September 14, 2003

AR 00253948; Design Document Deficiencies With DEH Modification Documents; dated September 17, 2004

AR 00299453; SSDand PC - Basis For SX System Testing Not Captured; dated February 9, 2005

AR 00304065; Potential Impact on B1R13 1AP21E Transformer EQ Change Out; dated February 21, 2005

AR 00315944; Issues Raised During 1B AF Pump Testing; dated March 22, 2005

AR 00332643; Inconsistent ASME Code Revisions Used for Pzr Safety Vlv; dated May 4, 2005

Calculations

BYR98-185; Essential Service Water Makeup Pump Diesel Oil Storage Tank Minimum Level; Revision 00

BYR99-010; Documentation of the Basis of the Emergency Operating Procedure (EOP) Setpoints; Revision 1

BYR2000-007/BRW-00-0010-M; Byron/Braidwood Uprate Project - Spent Fuel Pool Temperature Analysis; Revision 0

BYR2000-014; Byron/Braidwood Uprate Project - Post LOCA Component Cooling Water System Temperature Analysis; Revision 1

CQD-040092; Demonstrating Functionality of Non-Safety Related Vacuum Relief Device on RWST; Revision 0

Drawings

M-33 Sheet 68A; Instrument Installation Details 2LE-PC002 and 2LE-PC0003; Revision A

M-33 Sheet 72; Installation Detail Reactor Cavity Sump Level Probe; Revision F

M-118 Sheet 4; Diagram of Containment Chilled Water System - WO; Revision P

Procedures

BAR 1-2-C5; CC HX Outlet Temp High Alarm No.: 1-2-C5; Revision 1

BAR 1-2-D5; CC Pump Suct Temp High Alarm No.: 1-2-D5; Revision 1

2BEP ES-1.3; Transfer to Cold Leg Recirculation Unit 2; Revision 105

Miscellaneous Documents

Byron Station Plant Review Report 04-012; Revision to TS Bases Section B 3.3.6, "Containment Ventilation Isolation Instrumentation"; dated March 10, 2004

Byron Station Plant Review Report 05-006; Revision to TRM Appendix P; dated March 24, 2005

CAE-01-049, CCE-01-049; Westinghouse Letter Regarding Westinghouse Input to CCW Issue; dated April 18, 2001

Instruction Bulletin No. 78805; 36000 Series Tank Level Indicating Transmitters; Revision F

00813-0100-4235; Model 1152 Alphaline® Nuclear Pressure Transmitter; Revision AA

License Amendment Submittal dated June 27, 2003; Request for a License Amendment to Revise the Pressurizer Safety Valves Lift Settings; dated June 27, 2003

SER dated January 14, 2005; Reactor Coolant Leakage Detection Instrumentation; dated January 14, 2005

SER dated May 26, 2005; Hydrogen Recombiners and Hydrogen Monitors; dated May 26, 2005

## LIST OF ACRONYMS USED

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|---|---|
| ADAMS | Agency-Wide Document Access and Management System |
| ASME | American Society of Mechanical Engineers |
| BTP | Branch Technical Position |
| CFR | Code of Federal Regulations |
| CC | Component Cooling Water |
| CDF | Core Damage Frequency |
| $CO_2$ | Carbon Dioxide |
| DRP | Division of Reactor Projects |
| DRS | Division of Reactor Safety |
| EC | Engineering Change |
| EOP | Emergency Operating Procedure |
| FP | Fire Protection |
| FPR | Fire Protection Report |
| IMC | Inspection Manual Chapter |
| IR | Inspection Report |
| LOCA | Loss of Coolant Accident |
| MCC | Motor Control Center |
| NCV | Non-Cited Violation |
| NEI | Nuclear Energy Institute |
| NRC | Nuclear Regulatory Commission |
| PARS | Publicly Available Records |
| PRA | Probabilistic Risk Assessment |
| RHR | Residual Heat Removal |
| RSH | River Screen House |
| SDP | Significance Determination Process |
| SPAR | Standardized Plant Analysis Risk |
| SRA | Senior Risk Analyst |
| SX | Essential Service Water |
| UFSAR | Updated Final Safety Analysis Report |