ENCLOSURE 1

REVISED PAGES FOR NRC INSPECTION REPORT 50-397/96-24

The inspectors identified additional concerns regarding the closing safety classification of the ECCS pump discharge check valves and keepfill pumps. It appeared that these components may be required to operate for accident mitigation. Per Chapter 15 of the FSAR, the ECCSs are required to automatically inject in response to loss of coolant accidents [(LOCAs), upon receipt of a low reactor water level signal]. Although each ECCS is equipped with automatic injection valves that cycle open and closed to maintain water level during the event (with the pump running continuously), it is not a Chapter 15 requirement to operate the systems in this manner. Furthermore, plant operators indicated that, if sufficient time was available between injections, the ECCS pumps would be secured to minimize wear on the pumps. The system logic would subsequently be reset to align the systems for auto initiation on a low level signal. The failure of a pump discharge check valve to close or the failure of the keepfill pump to operate (when the ECCS pump is secured) could render the ECCS train inoperable. Therefore, it appeared that the licensee was relying on these components to help mitigate the consequences of LOCAs (by maintaining the ECCSs operable).

The NRC's final concern dealt with the potential system response during a loss of offsite power concurrent with a LOCA. When the loss of offsite power occurs, the ECCSs could be de-energized for several seconds (at least 10) before power is restored to the pumps. If the ECCS pump discharge check valves did not remain relatively leak tight the ECCSs could loose fill. When the pumps were re-energized the piping could be subjected to a water hammer. Additionally, the ultimate injection time could exceed 27 seconds.

Although the closing functions of the check valves were not within the scope of the IST program, the inspectors noted that this function was inadvertently being tested during ECCS IST. After securing an ECCS pump, operators were required to verify that the low system header pressure alarm clears. The failure of the alarm to clear would be an indicator that the ECCS pump discharge check valve did not close. Although this test adequately demonstrated check valve closure, it did not demonstrate that the valve leakage was within acceptable limits.

The inspectors were working with NRR and the licensee regarding the safety classification of this system. This item will remain open pending final resolution.

E8.2 <u>(Open) Unresolved Item 50-397/9617-01</u>: **Deferral of Reactor Feedwater (RFW) Pump trip test:** This item pertained to the licensee's deferral of one test associated with the RRC and RFW systems. The licensee had originally planned to trip one RFW pump from 100 percent reactor power to verify proper operation of RFW and RRC scram avoidance capabilities. All testing, with the exception of the RFW pump trip test, was completed on October 15, 1996.

Per the FSAR, the RRC system was designed with a recirculation runback feature. The control circuit reduced reactor recirculation system flow in the event of a RFW pump trip from power levels as high as 100 percent. The intent of the runback was to decrease reactor power to within the capacity of the remaining RFW pump, thus avoiding a scram on low reactor water level. The inspectors noted that this design

feature had been tested during preoperational testing in 1984. Additionally, via the FSAR, the licensee was committed to NRC Regulatory Guide 1.68, "Preoperational and Initial Startup Test Programs for Water-Cooled Power Reactors," which included the performance of a RFW pump trip test during the initial startup testing program.

Successful accomplishment of this design feature would require appropriate system response from both the RRC and RFW systems (both of which were modified substantially during Refueling Outage R11). When compared to the system response in 1984, the new RFW control system appeared to be as responsive as the old system. However, the runback rate of the new RRC system was reduced significantly (RRC loop flow) when compared to the old system. This reduction in RRC system responsiveness raised the question of the potential impact on the scram avoidance capability.

General Electric had performed an analysis (prior to the setpoint change) and determined that an acceptable setting for the RRC runback rate was between 3 and 15 percent. However, the inspectors considered the analysis to be of limited value. Specifically, the analysis stipulated that maintaining the scram avoidance capability was highly dependent on the assumptions for the RFW system control system settings, RFW flow capability, and the level control system settings. Engineering did not perform additional analysis to ensure that the noted settings were compatible with the RRC runback rate that was selected.

At the close of this inspection period, the inspectors were concerned because the licensee had not performed the subject feedwater pump trip test, had not performed appropriate analysis which demonstrated that the loss of scram avoidance capability did not occur, and did not have a documented safety evaluation which provided the bases for the determination that a change to the facility (RRC flow "runback rate") did not involve an unreviewed safety question. In response to the inspector's concerns the licensee initiated steps to perform an engineering analysis of the current feedwater and RRC system settings to ensure that a loss of scram avoidance capability did not occur. This item will remain open pending further NRC review of that analysis.

E8.3 Electrical Breakers Not Seismically Qualified in the Test/Disconnect Position

On November 22, 1996, licensee engineers demonstrated good performance in identifying that WNP-2 had been in an unanalyzed condition. A spare electrical circuit breaker in the safety-related 4160 volt (E-SM-8) switchgear was stored in the "racked out" position and this particular configuration was not addressed by the seismic analysis. The breaker could have affected the operation of adjacent breakers during a seismic event. In response to the finding, the licensee made a 1-hour phone notification to the NRC. As an immediate corrective measure, the spare breaker was removed and placed in an approved enclosure. Additionally, other safety-related breaker enclosures were inspected and no other problems were identified. The resident inspectors will perform additional followup to this issue in response to the pending Licensee Event Report.

ATTACHMENT

Supplemental Information

PARTIAL LIST OF PERSONS CONTACTED

Licensee

P. Bemis, Vice President for Nuclear Operations
L. Fernandez, Licensing Manager
A. Langdon, Acting Operations Manager
J. Muth, Quality Support Supervisor
B. Pfitzer, Licensing Engineer
G. Smith, Plant General Manager
J. Swailes, Engineering Director
D. Swank, Regulatory Affairs Manager
R. Webring, Vice President Operations Support

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 61726:	Surveillance Observations
IP 62703:	Maintenance Observations
IP 71707:	Plant Operations
IP 92903:	Followup - Engineering
IP 92904:	Followup - Plant Support
TI 2515/134:	Licensee Onshift Dose Assessment Capabilities

ITEMS OPENED AND CLOSED

Opened

50-397/9624-01	URI	Incorrect HPCS instrument installation
50-397/9624-02	URI	Failure to review calculations for power uprate
50-397/9624-03	URI	Failure to write PERs

Discussed

50-397/9621-01	IFI	RHR keepfill pump failure
50-397/9617-01	URI	Feedwater pump trip test deferral

ENCLOSURE 2

REVISIONS INDICATED

The inspectors identified additional concerns regarding the closing safety classification of the ECCS pump discharge check valves and keepfill pumps. It appeared that these components may be required to operate for accident mitigation. Per Chapter 15 of the FSAR, the ECCSs are required to automatically inject in response to loss of coolant accidents [(LOCAs), upon receipt of a low reactor water level signal]. Although each ECCS is equipped with automatic injection valves that cycle open and closed to maintain water level during the event (with the pump running continuously), it is not a Chapter 15 requirement to operate the systems in this manner. Furthermore, plant operators indicated that, if sufficient time was available between injections, the ECCS pumps would be secured to minimize wear on the pumps. The system logic would subsequently be reset to align the systems for auto initiation on a low level signal. The failure of a pump discharge check valve to close or the failure of the keepfill pump to operate (when the ECCS pump is secured) could render the ECCS train inoperable. Therefore, it appeared that the licensee was relying on these components to help mitigate the consequences of LOCAs (by maintaining the ECCSs operable).

The NRC's final concern dealt with the potential system response during a loss of offsite power concurrent with a LOCA. When the loss of offsite power occurs, the ECCSs could be de-energized for several seconds (at least 10) before power is restored to the pumps. If the ECCS pump discharge check valves did not remain relatively leak tight the ECCSs could loose fill. When the pumps were re-energized the piping could be subjected to a water hammer. Additionally, the ultimate injection time could exceed 27 seconds.

Although the closing functions of the check valves were not within the scope of the IST program, the inspectors noted that this function was inadvertently being tested during ECCS IST. After securing an ECCS pump, operators were required to verify that the low system header pressure alarm clears. The failure of the alarm to clear would be an indicator that the ECCS pump discharge check valve did not close. Although this test adequately demonstrated check valve closure, it did not demonstrate that the valve leakage was within acceptable limits.

The inspectors were working with NRR and the licensee regarding the safety classification of this system. This item will remain open pending final resolution.

E8.2 ~~(Closed)~~(Open) Unresolved Item 50-397/9617-01: **Deferral of Reactor Feedwater (RFW) Pump trip test:** This item pertained to the licensee's deferral of one test associated with the RRC and RFW systems. The licensee had originally planned to trip one RFW pump from 100 percent reactor power to verify proper operation of RFW and RRC scram avoidance capabilities. All testing, with the exception of the RFW pump trip test, was completed on October 15, 1996.

Per the FSAR, the RRC system was designed with a recirculation runback feature. The control circuit reduced reactor recirculation system flow in the event of a RFW pump trip from power levels as high as 100 percent. The intent of the runback was to decrease reactor power to within the capacity of the remaining RFW pump, thus avoiding a scram on low reactor water level. The inspectors noted that this design

feature had been tested during preoperational testing in 1984. Additionally, via the FSAR, the licensee was committed to NRC Regulatory Guide 1.68, "Preoperational and Initial Startup Test Programs for Water-Cooled Power Reactors," which included the performance of a RFW pump trip test during the initial startup testing program.

Successful accomplishment of this design feature would require appropriate system response from both the RRC and RFW systems (both of which were modified substantially during Refueling Outage R11). ~~The RRC system modification involved a change in the original recirculation system flow control valve rate of approximately 7 percent per second to the new adjustable speed drive system rate of approximately 4.8 percent per second, raising a question of potential impact on system scram avoidance capability.~~

~~The inspectors questioned the relationship between recirculation flow control valve rate and the adjustable speed drive rate, and the engineering analysis that the licensee had performed to determine that testing could be deferred or not performed. General Electric had performed an analysis (prior to the setpoint change), and determined that an acceptable setting for adjustable speed drive runback rate was between 3 and 15 percent per second. The inspector's review indicated that differences in system component response characteristics (between the old flow control valve and the new adjustable speed drive pump) resulted in relatively minor change in actual system flow rates. In fact, the new system actually resulted in a slightly higher recirculation flow rate change, which would improve scram avoidance margin. Accordingly, the inspectors concluded that the original design intent had been maintained and deferral of the testing was acceptable.~~

~~This item is closed.~~ When compared to the system response in 1984, the new RFW control system appeared to be as responsive as the old system. However, the runback rate of the new RRC system was reduced significantly (RRC loop flow) when compared to the old system. This reduction in RRC system responsiveness raised the question of the potential impact on the scram avoidance capability.

General Electric had performed an analysis (prior to the setpoint change) and determined that an acceptable setting for the RRC runback rate was between 3 and 15 percent. However, the inspectors considered the analysis to be of limited value. Specifically, the analysis stipulated that maintaining the scram avoidance capability was highly dependent on the assumptions for the RFW system control system settings, RFW flow capability, and the level control system settings. Engineering did not perform additional analysis to ensure that the noted settings were compatible with the RRC runback rate that was selected.

At the close of this inspection period, the inspectors were concerned because the licensee had not performed the subject feedwater pump trip test, had not performed appropriate analysis which demonstrated that the loss of scram avoidance capability did not occur, and did not have a documented safety evaluation which provided the bases for the determination that a change to the facility (RRC flow "runback rate") did not involve an unreviewed safety question. In response to the inspector's

concerns the licensee initiated steps to perform an engineering analysis of the current feedwater and RRC system settings to ensure that a loss of scram avoidance capability did not occur. This item will remain open pending further NRC review of that analysis.

E8.3 Electrical Breakers Not Seismically Qualified in the Test/Disconnect Position

On November 22, 1996, licensee engineers demonstrated good performance in identifying that WNP-2 had been in an unanalyzed condition. A spare electrical circuit breaker in the safety-related 4160 volt (E-SM-8) switchgear was stored in the "racked out" position and this particular configuration was not addressed by the seismic analysis. The breaker could have affected the operation of adjacent breakers during a seismic event. In response to the finding, the licensee made a 1-hour phone notification to the NRC. As an immediate corrective measure, the spare breaker was removed and placed in an approved enclosure. Additionally, other safety-related breaker enclosures were inspected and no other problems were identified. The resident inspectors will perform additional followup to this issue in response to the pending Licensee Event Report.

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~~Closed~~

~~50-397/9617-01 URI feedwater pump trip test deferral~~

Discussed

50-397/9621-01	IFI	RHR keepfill pump failure
50-397/9617-01	URI	Feedwater pump trip test deferral