U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Reports No. 50-295/85042(DRP); 50-304/85043(DRP)

Docket Nos. 50-295; 50-304 Licenses No. DPR-39; DPR-48

Licensee: Commonwealth Edison Company
P. O. Box 767
Chicago, IL 60690

Facility Name: Zion Nuclear Power Station, Units 1 and 2

Inspection At: Zion, IL

Inspection Conducted: November 19, 1985 through January 3, 1986

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February 6, 1986
Date

Inspection Summary

Inspection on November 19, 1985 through January 3, 1986 Reports No. 50-295/85042(DRP); 50-304/85043(DRP))

Areas Inspected: Routine, unannounced resident inspection of loss of residual heat removal (RHR) capability; diesel generator; cold weather preparations; operational safety and engineered safety feature (ESF) system walkdown; surveillance; maintenance; and licensee event reports (LERs). The inspection involved a total of 411 inspector-hours onsite including 74 inspector-hours onsite during off-shifts.

Results: Of the seven areas inspected, no violations or deviations were identified in six areas. Two violations (failure to implement corrective action and inadequate procedures) and no deviations were identified in the remaining area. Paragraph 3 discusses these violations which were identified during followup of a loss of both RHR pumps.

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DETAILS

1. Persons Contacted

*G. Pliml, Station Manager
E. Fuerst, Superintendent, Production
*T. Rieck, Superintendent, Services
*W. Kurth, Assistant Station Superintendent, Operations
K. Kofron, Assistant Station Superintendent, Maintenance
L. Pruett, Unit 1 Operating Engineer
J. Gilmore, Unit 2 Operating Engineer
N. Valos, Rad Waste Operating Engineer
R. Budowle, Assistant Superintendent, Technical Services
M. Carnahan, Training Supervisor
*R Cascarano, Technical Staff Supervisor
A. Ockert, Assistant Technical Staff Supervisor
*C. Schultz, Regulatory Assurance Administrator
R. Aker, Station Health Physicist
*J. Ballard, Quality Control Supervisor
D. Kaley, Quality Control Engineer
*W. Stone, Quality Assurance Supervisor
D. McMenamin, Quality Assurance Engineer

*Indicates persons present at exit interview.

2. Summary of Operations

Unit 1

The unit operated at power levels up to 100% throughout the inspection period.

On December 4, 1985 the unit was placed in hot standby conditions for turbine shaft balancing due to excessive vibrations on the No. 4 turbine bearing. The generator was taken off the grid at 3:45 A.M. and reactor power reduced to less than 10%.

On December 6, 1985 at 1:00 A.M., Unit 1 tripped while in hot standby due to a steam flow/feed flow mismatch coincident with low steam generator level (25%). The trip resulted from a spurious activation of the steam flow/feed flow mismatch bistable while steam generator level was near 25%. Just prior to the trip the steam generator atmospheric relief valve opened to control the steam generator pressure and the level dropped to 25%. All other systems functioned normally. The spurious actuation was caused by instrument drift of steam flow transmitter 1FT-512. The transmitter could not be calibrated and was replaced.

At 3:30 P.M. on December 6, 1985 an Unusual Event was declared when the 1B accumulator was declared inoperable due to a leaking relief valve. The unit was in hot shutdown at the time. The relief valve was repaired and the Unusual Event was terminated at 2:00 A.M. on December 7, 1985. The unit was made critical at 6:30 A. M. on December 7, 1985 and upon successful completion of turbine shaft balancing, the unit was placed on the grid at 10:30 A.M. on December 8, 1985.

Unit 2

The unit remained shutdown for refueling and the ten year in service inspection. On December 14, 1985 the unit lost both trains of Residual Heat Removal (RHR) cooling. Paragraph 3 contains further detail on this event.

3. Loss of Both Residual Heat Removal (RHR) Pumps

On December 14, 1985 at approximately 3:25 a.m., with Unit 2 in cold shutdown (mode 5) following core reload and the reactor coolant system (RCS) water level at the mid-plane of the hot leg nozzle for valve maintenance, both trains of the RHR system were lost. The event occurred when the RCS water level decreased to the point at which the B RHR pump became airbound. Operators initially felt that the problem was limited to the B RHR pump, because pump flow and motor current appeared to drop almost immediately to zero. Oscillations in these parameters normally associated with RHR pump cavitation were not observed. In order to restore RHR flow to the RCS, the operators started the A RHR pump which also gave indications of no flow and no motor current. RCS inventory was immediately increased using the B charging pump. Several other attempts to start the A RHR pump were unsuccessful, even after venting, until the RHR suction was switched from the RCS loop A to the refueling water storage tank (RWST) at about 4:20 a.m. The resultant gravity feed raised RCS water level significantly, and provided an immediate increase in RHR pump suction pressure as observed by the shift foreman in the RHR pump rooms. After about five minutes of gravity feed, indicated RCS level had increased from less than the 586' 6" elevation to approximately the 589' elevation and the RHR suction was switched back to RCS loop A. The B RHR pump was then successfully started, and RHR flow and motor current returned to normal. The A RHR pump was successfully started approximately 20 minutes later after waiting the required period to prevent exceeding the service rating for the motor on successive start attempts in a given period of time.

The licensee declared an Alert in accordance with EAL 12 of their Generating Stations Emergency Plan (GSEP) at 3:25 a.m. and terminated the event at 4:40 a.m. Some technical problems were experienced in notification of state and local agencies on the NARS line, and these problems will be examined in a future inspection by Region III emergency preparedness specialists.

a. Root Cause Analysis

(1) The licensee attributed the event to the following:

- limitations of the RCS level instrumentation
- operators not being aware of these limitations
- loss of RCS inventory due to normal system leakage

Each of these will be discussed in detail below.

(a) RCS Level Indication

There were two methods of RCS level indication in operation at the time of the event. One method was RCS level transmitters 2LT RC22A (wide range - 584' to 617' 4") and 2LT RC22B (narrow range - 584' to 592' 4") which sense level at the 584' elevation of RCS loop B, utilizing an existing tap for the loop stop valve flow permissive differential pressure transmitter (2FE 448). These level transmitters were installed in 1983 under modifications M-22-1(2)-81-11 and M-22-1-(2)-81-31. The second method was a temporary tygon tube made up between RCS loop D flow tap and the pressurizer vent.

The following concerns were identified:

(i) The tap for 1LT RC22A and B is at elevation 584'. Modifications M-22-1(2)-81-31 show the tap at 584' 6", as does the instrument maintenance (IM) procedure for calibrating these level transmitters. The elevation of the tap for RCS vessel level was measured following the December 14, 1985 event. It is not yet clear whether this condition contributed to the event.

(ii) Modifications M-22-1(2)-81-11&31, while showing the level tap (and therefore the minimum possible level which could be indicated) as 584' 6", were implemented using a strip chart which used 584' 0" as the minimum possible level which could be sensed by the instrument. This is an example of poor human factors considerations.

(iii) The tap at 584' 6" was selected even though operating procedures Maintenance Instructions (MI's) already specified the use of 584' 6" as a point at which operators controlled level for certain maintenance activities. This is another example of poor human factors considerations, which left no margin for observing levels below 584' 6". As noted above, it was fortuitously possible to read levels as low as 584' 0".

(iv) The tap selected is in close proximity to the RHR system return line, which may result in turbulence at half pipe conditions. The effects of this condition on level indication are not yet known. There may have been considerable turbulence at the level tap when at half pipe conditions.

(v) The tygon tube indication system is a temporary hookup which has a high point at 583' which has occasionally formed loop seals, resulting in false level indications.

(vi) There was a level deviation between the RCS vessel level indication system and tygon observed immediately following the event which persisted to varying degrees until the RCS was filled and vented. At least one SRO recalled that in the past, the recorder would not indicate levels below 584' 5", and procedural changes were written by him to a MI which permitted operating at 584' -0" to +4". He stated that the reason for selecting this level was that the vessel level indicating system would not indicate below this level, which was based on his personal experience and observation. The reason for the difference between vessel level indicators and tygon is not known, but is under investigation. Calibration sheets for the vessel level instruments have been reviewed by the station and by the NRC resident inspectors, and no abnormalities were noted with either the procedure or the results. It appeared possible that the vessel level recorders were indicating the actual level in the B RCS loop at the time of the event.

(b) <u>Operator Knowledge</u>

(i) Of approximately nine operators or senior operators interviewed after the event, all but one felt that the chart recorder would indicate properly over the full span. While their comments appear to be consistent with the equipment design, they conflict with both the elevation of the level tap in the modification packages and the IM calibration procedure, and appear to fail to reflect the previous experience with level not going below 584' 5" as described in (a)(vi) above.

(ii) No operators were aware of the 6" offset described in (a)(i) above. This condition was determined during the licensee's review of the event in question. This does not appear to have contributed to the event.

(c) Inventory Loss

After draining to the RCS hot leg mid-plane on December 10, 1985, there were only normal system losses due to leakage and sampling except for a divert of unknown duration on December 11, 1985 at about 4:00 p.m.. Estimates of nominal leak rates which could account for this event range from 0.25 to 0.55 gpm.

(2) Investigation by Region III and resident inspectors has revealed the following additional contributors:

- Problems with procedures

- Inadequate corrective action for previous events

(a) Procedures

(i) Station procedures did not require cross checking control board indication with tygon indication while in this condition. Several supervisors indicated that the non-licensed operators generally check the tygon about once per shift on an informal basis. These checks, if performed, were not logged. The procedure in use at the time fo the event, MI-6, "Filling and Draining the Refueling Cavity and Fuel Transfer Canal", required tygon level to be verified to agree with the vessel level recorder at step 6.34, the step at which the tygon indication was put in service, but no other checks were specified.

(ii) MI-6, step 6.34 required verifying tygon to agree with vessel level recorder, but no tolerance was specified.

(iii) MI-6 contained no caution as to the minimum value which the RCS vessel level indication system could indicate. Other MI's did contain this type of caution (MI-1, MI-1B, and MI-1F) stating that the "Refueling vessel level recorders will not indicate below 584' 5". Tygon level indication should be used exclusively if level is to be held at or below 584' 5"." These cautions were established due to operating experience or erroneous understanding of the elevation of the vessel level tap, or both.

(b) Inadequate Corrective Actions for Previous Events

The licensee had a similar event (loss of RHR due to RCS inventory loss) in 1983, and has had several other loss-of-RHR events in the last several years, including one in 1984, which were due to other causes. In addition, there has been one NRC bulletin, IEB 80-12, and one IE Information Notice 80-20 which pertain to this type of event. The licensee has also received INPO SOER 85-4, dated August 28, 1985, which summarizes the experience of the industry over the past several years for loss of decay heat removal events. The following observations were noted:

(i) Deviation Report (DVR) 22-2-83-36, dated March 14, 1983, reports a loss of RHR event which was attributed to the inability of the vessel level recorders to indicate below 584' 5", and to the formation of a loop seal at the 587' elevation in the tygon indicating system. The DVR states that the "operators were informed that the temporary vessel level indicator would not read below 584' 5"." This correction was inadequate, since operators generally felt that the vessel level indication system would provide valid indication down to the 584' level as described in a(1)(b)(i) above.

(ii) In their response to IEB 80-12, the licensee stated, "Zion Station has analyzed its procedures for adequacy of responding to RHR loss events. This review identified areas needing further clarification of modification. As a result of this review, the necessary procedure changes have been initiated and will be implemented by September 12, 1980." It appears that this action was not completed until after the September 14, 1984 loss of RHR event, when AOP-20 was written. It does not appear that this condition contributed significantly to the event on December 14, 1985.

(iii) In LER 84-31-01, which documents the September 14, 1984, loss of RHR event, the licensee states, "A modification will be considered for a completely hard piped system relieving to the PRT.' This modification to the tygon level indicating system has yet to be installed.

b. Event Significance

Because the event occurred approximately 100 days after shutdown, there was a small decay heat load. The licensee has calculated that the time to boiling for the event described above is four hours 43 minutes. If the event had occurred ten days after shutdown instead of 100, the time would have been one hour four minutes. In the case of the event, decay heat removal was available from the refueling water storage tank (RWST) which could deliver borated water by gravity feed and by both centrifugal charging pumps. In the latter case, one or more steam generators would likely have been available for decay heat removal.

PRA studies point out that loss of decay heat removal events are significant contributors to overall risk to the public. This appears to be due to the limits of operator action in identifying and mitigating the event. For this event, operators identified the loss of RHR pump A almost immediately and took adequate action to restore RHR.

c. Corrective Actions

The licensee performed the monthly surveillance test PT-2J, "Residual Heat Removal Pump Tests" on December 15, 1985 and both RHR pumps were within 10% of their head curves and had acceptable motor bearing vibration readings. There did not appear to be significant degradation in either of these parameters. The licensee contacted the manufacturer, Ingersoll-Rand, and determined that cavitation of these pumps for brief periods of time should not damage them, and that the first indications of any pump degradation would be observed in the pump head curve and vibration measurements.

In addition, the licensee issued Standing Order #280 to the operating shifts which:

(1) Informed operators of level indication system problems,

(2) Stated the level below which the RCS level should not be allowed to decrease to avoid exceeding the limits of the level indication system, and

(3) Stated the conditions under which tygon level should be used to provide backup to the vessel level indication system.

The licensee will also determine whether modifications to the vessel level and tygon indication systems will be needed, and has initiated that process. Procedures used during this event will also be reviewed to determine which changes will be necessary.

The licensee has not completed their investigation into the root cause of this event, and, as a result, corrective actions listed above may be subject to change.

10 CFR 50, Appendix B, Criterion XVI, requires that measures shall be established to assure that conditions adverse to quality are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. On March 14, 1983, a condition adverse to quality, a loss of decay heat removal event, occurred on Unit 2, and the licensee failed to assure that corrective action was taken to preclude repetition as shown by the loss of decay heat removal event on December 14, 1985 on Unit 1. This is considered a violation (295/85042-01; 304/85043-01).

10 CFR 50, Appendix B, Criterion V, requires that activities affecting quality shall be prescribed by documented procedures of a type appropriate to the circumstances. It further requires that procedures shall include appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished. Procedure MI-6, "Filling and Draining the Refueling Cavity and Fuel Transfer Canal" was inappropriate to the circumstances in that it failed to provide periodic checks between reactor vessel level indicating system recorders and tygon level indication while the reactor coolant system loop was in the partially drained condition. In addition, Procedure MI-6 was inappropriate to the circumstances in that it failed to contain a caution stating that the refueling vessel level recorders will <u>not</u> indicate below 584' 5", and that tygon level indication should be used exclusively if level is to be held at or below 584' 5", which correctly appeared in similar procedures. Furthermore, Procedure MI-6, step 6.34, failed to include appropriate quantitative or qualitative acceptance criteria for determining that the comparison between reactor vessel level indicating system recorders and tygon level was satisfactorily accomplished. These three examples are considered a single violation (295/85042-02; 304/85043-02).

Two violations and no deviations were identified.

4. Diesel Generators

On November 24, 1985, the 0 (common) diesel generator (DG) output breaker failed to automatically close during a surveillance test. At the time, Unit 1 was operating at full power, and Unit 2 was in cold shutdown. The output breaker was replaced with a spare, a surveillance test was successfully performed, and the 0 DG was declared operable.

The licensee's investigation determined that a linkage arm in the closing mechanism had been installed incorrectly. The breaker had been disassembled for preventive maintenance in October of 1984, during which the linkage arm was removed and reinstalled by plant maintenance personnel under the supervision of a vendor technical representative. The breaker (which was a spare breaker at that time) was installed in the 0 DG output breaker cubicle in July 1985, and since that time has passed several surveillance tests.

The licensee determined that other breakers had been subject to the same preventive maintenance, and, at the request of the NRC, inspected all similar breakers used in safety related applications for both units. The inspections were able to be performed without disassembling the breakers, and did not involve taking safety related equipment out of service. No other breakers were found with the above mentioned linkage arm incorrectly installed.

The licensee has not conclusively determined the root cause of the failure of the breaker to close or the reason the linkage arm was incorrectly installed. Investigation into these matters by the licensee continues. The linkage arm may have contributed to the failure, but the licensee is currently planning to conduct testing to determine whether this was actually the case. The licensee is also investigating the tolerances for the components of the closing mechanism to see if there was excessive movement allowed on the shaft to which the linkage arm was connected, causing the breaker to fail. This will remain an Open Item pending completion of the licensee's investigation (295/85042-03).

On December 4, 1985, Unit 1 was shut down for turbine shaft balancing. As required by the licensee's procedure, the 1A DG was started prior to removing the main generator from the grid. The 1A DG was later secured due to small rapid oscillations in load, voltage, frequency, and reactive load (VARS). The licensee felt that these oscillations did not render the DG inoperable, since the oscillations were not large enough to reset the DG output breaker permissive, which depends on sufficient output voltage and proper frequency.

An investigation into the root cause of the oscillations was initiated, and the licensee determined that the oscillations were most likely caused by a dirty rheostat on the engine panel voltage regulator. Because the rheostat was exercised during the surveillance, the surface dirt was removed, and the problem did not repeat. The 1A DG has successfully passed all surveillance tests since the oscillations were observed.

No violations or deviations were identified. One Open Item was identified.

5. Cold Weather Preparation

The inspector verified that the surveillance procedure TSGP-43,"Cold Weather Preparation Program" was technically adequate and sufficient in scope to provide coverage to appropriate equipment. The inspector reviewed the surveillance completed in November 1985 for completeness and proper supervisory review. For portions of the surveillance which could not be completed due to modifications or equipment out of service, acceptable compensatory measures were documented and verified to be in place. The inspectors also verified by personal observation the correct implementation of portions of the surveillance.

No violations or deviations were identified.

6. Operational Safety Verification and Engineered Safety Features System Walkdown

The inspectors observed control room operations, reviewed applicable logs and conducted discussions with control room operators from November 19, 1985 through January 3, 1986. During these discussions and observations, the inspectors ascertained that the operators were alert, fully cognizant of plant conditions, attentive to changes in those conditions, and took prompt action when appropriate. The inspectors verified the operability of selected emergency systems, reviewed tagout records and verified proper return to service of affected components. Tours of the auxiliary and turbine buildings were conducted to observe plant equipment conditions, including potential fire hazards, fluid leaks, and excessive vibrations and to verify that maintenance requests had been initiated for equipment in need of maintenance.

The inspectors verified by observation and direct interview that the physical security activities were being implemented in accordance with the station security plan.

The inspectors observed plant housekeeping/cleanliness conditions and verified implementation of radiation protection controls. From November 19, 1985, to January 3, 1986, the inspectors walked down the accessible portions of the component cooling, auxiliary feedwater, service water, and residual heat removal systems to verify operability. The inspectors also witnessed portions of the radioactive waste system controls associated with radwaste shipments and barreling.

These reviews and observations were conducted to verify that facility operations were in conformance with the requirements established under Technical Specifications, 10 CFR and administrative procedures.

No violations or deviations were identified.

7. Monthly Surveillance Observation

The inspector observed Technical Specifications required surveillance testing on the centrifugal charging system, power operated valves, service water systems and safety injection boric acid flow transmitter. The inspector verified that testing was performed in accordance with adequate procedures, that test instrumentation was calibrated, that limiting conditions for operation were met, that removal and restoration of the affected components were accomplished, and that test results conformed with Technical Specifications and procedure requirements and were reviewed by personnel other than the individual directing the test. The inspector further verified that any deficiencies identified during the testing were properly reviewed and resolved by appropriate management personnel.

The inspector also witnessed portions of the following test activities:

PT-8B Monthly Check Sheet For Component Cooling and Service Water Pumps Functional Tests.

PT-20 Centrifugal Charging System Power Operated Valve Tests.

No violations or deviations were identified.

8. Monthly Maintenance Observation

Station maintenance activities on safety related systems and components listed below were observed or reviewed to ascertain whether they were conducted in accordance with approved procedures, regulatory guides industry codes or standards and in conformance with Technical Specifications.

The following items were considered during this review: the limiting conditions for operation were met while components or systems were removed from service; approvals were obtained prior to initiating the work; activities were accomplished using approved procedures and were inspected as applicable; functional testing and/or calibrations were performed prior to returning components or systems to service; quality control records were maintained; activities were accomplished by qualified personnel; parts and materials used were properly certified; radiological controls were implemented; and fire prevention controls were implemented.

Work requests were reviewed to determine status of outstanding jobs and to assure that priority is assigned to safety related equipment maintenance which may affect system performance.

The following maintenance activities were observed or reviewed:

1C Service Water Pump

Following completion of maintenance on the 1C service water pump the inspector verified that this system had been returned to service properly.

No violations or deviations were identified.

9. Licensee Event Reports (LER) Followup

Through direct observations, discussions with licensee personnel, and review of records, the following event reports were reviewed to determine that reportability requirements were fulfilled, immediate corrective action was accomplished, and corrective action to prevent recurrence had been accomplished in accordance with Technical Specifications. The LERs listed below are considered closed:

UNIT 1	DESCRIPTION
85-36	Miscellaneous Vent Stack Monitor Inoperable During Unit 2 Containment Purge
85-37	Failure of Lake Discharge Tank Isolation Valve to Close on Hi-Rad Alarm
85-38	Missed ASME Code Class Piping for 10 Year ISI Hydrostatic Test
85-38-01	Missed ASME Code Class Piping for 10 Year ISI Hydrostatic Test
85-39	Closing of Service Water Cross-Tie Valve With Service Water Pump Out of Service
85-42	Auto-Start of Penetration Pressure Air Compressors
85-45	Auto-Start of Penetration Pressure Air Compressors

LER No.

Unit 2	Description
85-18-01	Inadequate Documentation for Environmentally Qualified Valve Motor Operator Wiring
85-20	Inadvertent Closure of Containment Isolation Valves During Testing of Safeguards
85-21	Inadvertent Trip of Unit 2 Purge Due to Spurious 2RIA-PR40 Hi-Rad Alarm
85-22	Hi-Rad Alarm on Fuel Handling Accident Rad Monitor Causing Inadvertent Trip of Containment Purge
85-23	Procedure Deficiency in Electrical Test Causes Closure of Containment Isolation Valves
85-24	Component Cooling Pump Restart After Being Manually Tripped
85-25	Steam Generator Level Transmitters Drifting Out of Tolerance
85-26	Improperly Installed Check Valves in RCFC Motor Heat Exchanger Housing Drains
85-27	Inadvertent Trip of Unit 2 Purge

Regarding LER 295/85-36, "Miscellaneous Vent Stack Monitor Inoperable During Unit 2 Containment Purge," this item is considered a licensee identified violation for which no citation will be given. (295/85042-04).

Regarding LER 295/85-39, "Closing of Service Water Cross-Tie Valve with Service Water Pump Out of Service," this LER is considered closed. However, an Unresolved Item was opened in Report 295/85036 pending determination of the reportability of the event.

Regarding LER 304/85-27, "Inadvertent Trip of Unit 2 Purge," the LER will be closed. However, an Open Item will be issued pending revision to procedure RP1350-8, "Out of Service Surveillance for Radiation Monitors" (304/85043-03).

Regarding LER 304/85-18-01, "Inadequate Documentation for Environmentally Qualified Valve Motor Operator Wiring," this LER is closed. However, an Unresolved Item was opened in Report 304/85032-01, and documented in a Part 21 report.

Regarding LER 304/85-26, "Improperly Installed Check Valves in RCFC Motor Heat Exchanger Housing Drains," this LER is closed. However, an Unresolved Item will be issued pending further evaluation of the safety significance of the event (304/85043-04).

Regarding LER 295/85-37 "Failure of Lake Discharge Tank Isolation Valve to Close on High Radiation Alarm", this LER is considered closed. However, an Open item will be issued pending the investigation of the operability of the solenoid operator associated with the Lake Discharge Tank Radiation Monitor (295/85042-05).

No violations or deviations were identified. One licensee identified violation, one Unresolved Item, and two Open Items were identified.

10. Open Items

Open Items are matters which have been discussed with the licensee which will be reviewed further by the inspector and which involve some action on the part of the NRC or licensee or both. Three Open Items disclosed during this inspection are discussed in paragraphs 4 and 9.

11. Unresolved Items

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items, violations or deviations. One Unresolved Item disclosed during this inspection is discussed in Paragraph 9.

12. Exit Interview

The inspectors met with licensee representatives (denoted in Paragraph 1) throughout the inspection period and at the conclusion of the inspection on January 3, 1986 to summarize the scope and findings of the inspection activities. The licensee acknowledged the inspectors' comments. The inspector also discussed the likely informational content of the inspection report with regard to documents or processes reviewed by the inspector during the inspection. The licensee did not identify any such documents or processes as proprietary.