U.S. NUCLEAR REGULATORY COMMISSION

REGION II

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| Docket No.: | 50-302 |
| License No.: | DPR-72 |
| Report No.: | 50-302/96-13 |
| Licensee: | Florida Power Corporation |
| Facility: | Crystal River 3 Plant |
| Location: | 15760 West Power Line Street<br>Crystal River, FL 34428-6708 |
| Date: | September 19 - October 9, 1996 |
| Inspectors: | B. Crowley, Lead Inspector<br>T. Cooper, Resident Inspector<br>L. Stratton, Security Inspector |
| Approved by: | A. F. Gibson, Director<br>Division of Reactor Safety |

Enclosure

## EXECUTIVE SUMMARY

Crystal River Nuclear Plant
NRC Inspection Report 50-302/96-13

A chronological Sequence of Events for previous 1A Emergency Diesel General (EGDG) cooling fan gear drive lube oil strainer problems and for the foreign material (penny) found in the strainer on September 19, 1996, was established by the inspectors. The Sequence of Events is documented in Attachment A to this report.

Overall, the licensee's response to the potential tampering event discovered on September 19, 1996, was satisfactory.

On September 19, 1996, the licensee identified that the lube oil strainer for the 1A EGDG cooling fan gear box had a coin (penny) under the strainer screen. The licensee's documented evaluation concluded that the penny most probably entered the strainer accidently when a mechanic, who carried the strainer screen in his pocket along with loose change, re-installed the strainer screen into the strainer body without inspecting it for foreign objects.

The practice of transporting small safety-related components, without any identification or protection, as was done with the strainer screen, is considered a poor work practice.

The inspectors concluded that site management appropriately pursued identification of the cause for the penny in the lube oil strainer.

Following extensive reviews by the licensee and independent verifications by NRC, the inspectors concluded no evidence of tampering had been identified.

The Corporate investigative staff adequately reviewed the event and other previous problems to ensure that any potential tampering events had been fully evaluated. They concluded that the penny most probably entered the strainer accidently and there was no evidence that suggests a pattern of tampering at the facility.

The licensee was able to successfully restore the EGDGs to operable status on September 20, 1996.

The inspectors concluded that tampering with EGDG-1A cooling fan gear box lube oil strainer could not be conclusively ruled out based on the existing evaluation documentation. However, as concluded by the licensee's investigation, the penny most likely entered the strainer by accident during installation of the strainer screen after removal for measurements on September 15, 1996.

The inspectors concluded that the licensee adequately evaluated other systems for signs of tampering and correctly concluded that no additional signs of tampering were evident.

The inspectors concluded that there was no evidence of additional potential tampering and that the licensee had adequately evaluated the plant problem reports and other documentation for additional examples of potential tampering.

The licensee appropriately identified actions to be taken to enhance detection of additional tampering.

The licensee was in compliance with the Physical Security Plan (PSP) with respect to fitness for duty, personnel access authorization, criminal history checks, and access control of vital areas. The licensee appropriately recorded the suspected tampering event in the Safeguards Event Log, as required by 10 CFR 73.71, "Reporting of Safeguards Events," Appendix G.

Attachment C contains information provided to Crystal River site management by NRC to assist in the licensee's response to the events. The attachment contains NRC Information Notice (IN) 83-27 concerning deliberate acts directed against plant equipment and internal NRC guidance for plant system check out following suspected sabotage.

Attachment D contains a graphical representation of the lube oil strainer and copies of photographs of the strainer screen as found on September 19 and as photographed on September 15 before re-installation into the strainer body.

Report Details

## O2 Operational Status of Facilities and Equipment

### O2.1 Potential Tampering Event

On September 19, 1996, the licensee found a coin (penny) under the strainer screen of the lube oil strainer for EGDG-1A cooling fan gear drive. The strainer had been removed from the Lube oil System as a complete assembly for the purpose of replacing with a strainer containing a larger mesh screen. The penny was under the inlet end of the screen covering the inlet bore of the strainer and appeared to block all flow through the strainer (See Attachment D, Figure 1 for a graphical representation of the strainer and the location of the penny). There had been a history of the strainer clogging and the licensee was in the process of replacing the complete strainer assembly since a larger mesh screen that would fit the installed strainer body was not available.

The licensee identified the event as potential tampering, declared an Unusual Event (UE), and initiated an immediate inspection for evidence of tampering of the entire 1A EGDG and associated systems, as well as other plant equipment. At the same time an investigation was initiated to try to determine if the penny in the lube oil strainer was in fact tampering.

#### O2.1.1 Evaluation and Correction of Damaged Components

a. Inspection Scope

Review licensee's evaluation of the damaged components to determine if the as-found conditions represented potential tampering and determine if the damaged components were replaced or the damage corrected and the operability of the EGDGs satisfactorily demonstrated.

b. Observations and Findings

Following detection of the potential tampering, the licensee developed a plan for verifying that EGDG-1A was functional, that no further evidence of tampering existed, and that the EGDG could be proven to be operable. Prior to the detection, EGDG-1A had been declared inoperable, to allow maintenance on the component, due to concerns with degrading cooling fan gear drive lube oil pressures.

Operational History

During 1994, the licensee identified a decreasing trend in the 1A EGDG cooling fan gear box pump lube oil discharge pressures, even though the pressures remained above the administrative limits. The decision was made at that time to attempt to clean the oil in the gear box assembly. The gear box does not have an access port to allow cleaning. A small oil addition port at the top was opened and cleaning was attempted using a small tool through the port. The existing oil was drained from the gear box through the drain line, which is mounted on the side of the gear box. This drain line does not allow for complete draining of the gear box. Following the refilling of the gear box, the licensee noted that pressures were even lower and the strainer screen was fouling more rapidly. The licensee surmised that their attempts at

cleaning had merely stirred up debris that was trapped below the drain line. They drained and replaced the oil in the gear box a second time. Discharge pressure values returned to normal ranges. The licensee made the decision to replace the entire gear box assembly during the 10R refueling outage.

Following the replacement of the gear drive assembly in February 1996, the licensee had noted a trend of decreasing oil pressures during surveillance testing. During the performance of the EGDG-1A surveillance on September 11, 1996, the discharge pressure started at approximately 13 psi and dropped to approximately 8 psi. The administrative limits for the discharge pressure is between 14 and 29 psi. The licensee had determined, in response to Request for Engineering Assistance (REA) 91-1466 written for an unrelated problem and based on information obtained from the vendor, that 5 psi was the minimum discharge pressure for the system to remain functional. In response to this low gear box lube oil pressure, the licensee cleaned the screen and contacted the vendor. It was determined that the screen in place was a sheathed 40 mesh screen. Engineering determined that the metal sheathing reduced the flow area of the screen by about 1/2. While the vendor thought that this size screen would function acceptably in a system with clean oil, a 20 mesh unsheathed screen would be optimum for this application.

Conversations with the vendor revealed that each gear box assembly had a different strainer unit, procured commercial grade and dedicated to the assembly. Consequently, the licensee could not order a replacement screen without a detailed description of what was needed. On September 15, 1996, technicians from Mechanical Maintenance removed the screen from the strainer to allow the receipt inspection personnel in the warehouse to obtain measurements to order a replacement. The mechanic removed the screen, placed it in his pocket, and proceeded to the warehouse.

At the warehouse, the receipt inspectors took close-up photographs and detailed measurements of the screen, in an attempt to obtain the information to order replacement 20 mesh screens.

Based on licensee interviews, the maintenance technician stated that he then placed the screen in his pocket, which contained loose coins, and returned it to the plant. He proceeded, alone, to replace the screen in the strainer. On his first attempt, he placed the screen upside down in the strainer, but the retaining plug would not fit with the screen in this configuration. He reversed the screen and replaced the plug. The inspectors pointed out to the licensee that the practice of transporting safety-related components, without any identification or protection, is considered a poor work practice.

The licensee was unable to obtain a replacement 20 mesh screen, so the decision was made on September 18 to replace the entire strainer assembly, with a 20 mesh screen installed. Following the replacement, the maintenance technicians noticed the obstruction in the removed strainer.

Recovery

The inspectors verified by examining the Work Request (WR) and examining the system in the field that the strainer had been replaced prior to the licensee detecting the suspected tampering. It was while the maintenance technicians were examining the removed component that the potential tampering was identified.

The inspector accompanied plant personnel; two engineers, a Senior Reactor Operator (SRO) certified operations support person, and a security officer; on a field walkdown of EGDG-1A. The licensee personnel performed a detailed, intensive, examination of the EGDG; examining all accessible valves, electrical connections, linkages, freedom of travel in moving components, and appearances of lubricating oil and jacket cooling water.

One lubricating oil drain valve was found out-of-position, in the open position, but this was on a line that was capped and no leakage was observed from the cap. The licensee documented the discrepancy in a Problem Report (PR) and returned the valve to its correct position.

Following the completion of the walk-down, on September 19, 1996, operations performed Security Procedure (SP)-354A, Monthly Functional Test of the Emergency Diesel Generator EGDG-1A. The inspectors witnessed the performance of the surveillance test. The normal range of discharge pressures for the gear box pump is 14 to 29 psi. During the performance of the EGDG-1A surveillance, the cooling fan gear box lube oil pressure at the beginning of the four hour test was approximately 23.5 psi. After the oil had heated, the discharge pressure had decreased to approximately 21 psi, where it remained for the duration of the four hour surveillance.

On September 20, 1996, a walk-down on EGDG-1B was performed by Engineering personnel, Training Instructors, Operations personnel, and Security personnel. No discrepancies were identified. The inspectors observed the performance of licensee procedure, SP-354B, Monthly Functional Test of the Emergency Diesel Generator EGDG-1B. Acceptable gear box pump discharge pressures, consistent with the values expected on EGDG-1B, were obtained.

After full load conditions were reached, during the run of the EGDG, a high jacket coolant alarm was received on the diesel control panel. Local investigation revealed the engine outlet temperature was 178°F, using infra-red instrumentation. The high coolant temperature setpoint is supposed to be 195°F. Engineering monitored the temperatures and determined that the performance of the EGDG was acceptable. The alarm setpoint was calibrated to proper levels following completion of the surveillance. WR NU 0337921 was initiated to investigate the alarm set point.

Based on the EGDG walk-downs, the successful completion of the surveillance testing, and the investigation conclusions that there did not appear to be any other tampering on the EGDGs, the EGDGs were declared operable on September 20, 1996.

Examination of the Removed Strainer

On September 20, 1996, the licensee conducted a test in the site receipt inspection facilities, where approximately 5 psi of oil pressure was applied to the strainer that had been removed, to determine if, with the penny in place, the strainer would have passed any oil flow. The licensee monitored the strainer for approximately 20 minutes. There was no observed leakage past the obstruction.

The licensee removed the screen element from the strainer and examined it, comparing the results to the documented results of the September 15, 1996 inspection. There were marked differences in the observed dimensions and the uniformity of the measurements on September 20, 1996. In addition, distortions at the ends of the screen and damage to the screen mesh were present on September 20 that were not present on September 15, as shown in Figure 2. The licensee has determined, based on these observations, that the penny was not present in the strainer prior to the examination on September 15, 1996. The inspectors observed the licensee taking the measurements of the damaged screen and compared the screen to photographs taken of the screen on September 15, 1996. Licensee interviews with additional mechanics revealed that one of the mechanics had noted the deformation of the screen on September 17, 1996, during maintenance, but had concluded that this was normal.

The licensee has concluded that, based on the pictorial evidence and interviews, the penny entered the strainer between September 15 and September 17, 1996, and most likely on September 15 when the mechanic re-installed the screen after carrying it in his pocket with loose coins. When the screen was removed from the strainer body on September 20, the licensee demonstrated that a penny would fit inside the screen and sometimes would hang up in the screen when it was turned upside down. If the penny was in the screen at the time the mechanic tried to re-install it upside down, it could have fallen out into the oil in the bottom of the strainer body and not have been noticed by the mechanic.

c. Conclusions

The licensee was able to successfully restore the EGDGs to operable status on September 20, 1996. Testing and examinations conducted by the licensee resulted in a high probability that the penny had not been in the system during any previous testing. As concluded in the licensee's investigation report, the penny most likely entered the strainer by accident on September 15, 1996, during re-installation of the screen after removal for measurements and transporting in the mechanics pocket, which contained loose change.

The practice of transporting small safety-related components, without any identification or protection, as was done with the strainer screen, is considered a poor work practice.

O2.1.2 Evaluation of Plant Systems for Additional Tampering

a. Inspection Scope

Verify plant safety systems have been sufficiently evaluated for potential tampering to assure they can perform their intended functions.

b. Observations and Findings

In response to the penny found in the EGDG gear drive lube oil strainer, the licensee performed an inspection of additional systems, including all safety related systems and non-safety related systems that could have an impact on the safe operation of the plant, to assure that the systems were intact, with no signs of potential tampering. The Operations and Engineering departments conducted independent walk-downs of the systems to provide a defense in depth approach. Acceptance criteria for these system walk-downs were specified in licensee procedure WI-100, Security Event Recovery Guidelines, Enclosure 1, Comprehensive Walkdown Guidelines.

In the Auxiliary Building, one core flood nitrogen supply line valve, CFV-82, was found to be partially open, but the valve is located on a capped line. The cap was verified to be present. In the Reactor Building, several cables for pressurizer heaters were found to be disconnected without being tagged. The licensee verified that these cables were for failed heaters and had been disconnected under a Maintenance Request. In the main control room, several fuse holders were found with the fuses removed. The inspector observed the Engineering, Operations, and Management personnel review and resolution of these holders. Each of the holders had been jumpered, as part of permanent modifications, and the fuses removed. No additional discrepant conditions were identified.

The inspectors performed an independent general tour of the Turbine, Auxiliary, and Control Buildings. No obvious indications of tampering were identified.

Review of Previous Problem Reports (PRs) for Evidence of Tampering

The licensee reviewed the PRs issued since January 1, 1996, in an effort to determine if any other suspected issues existed that had the potential to have been caused by tampering. A total of 392 PRs were reviewed, using the following criteria developed to detect potential tampering:

- Loose bolts or fasteners
- Mispositioning - valves, breakers, etc.
- Foreign material
- Lost parts or equipment when work in progress
- Mislabeled equipment
- Unexplained spills
- Radioactive material found outside control areas
- Controlled doors left open
- Damaged equipment (i.e. stepped on tubing, Mecatiss, Thermolag, etc.)

- Broken bolts
- PA speakers turned off or stuffed with rags
- Changes to setpoints not explained by normal drift
- Fires of undetermined origin
- Unexplained contamination or overexposure

Based on the screening criteria, 82 PRs were identified that warranted further review. A panel of three experienced licensee representatives, two permanent employees and one contractor, reviewed the details of the events in the PRs and reduced the number of PRs needing investigation to twelve, including the PR for the penny found in the strainer.

A review of the remaining events was conducted, which consisted of reviews of documentation, interviews with involved personnel, and review of the licensee's root cause determinations. A recent event involving a mispositioned CRD breaker was investigated in depth. The licensee's investigation, based on interviews and review of reports and logs, found no credible evidence of tampering and concluded that the open breaker was most likely caused by human error. The licensee concluded that none of the additional identified events were the result of deliberate tampering.

The inspectors performed an independent review of the PRs since January 1, 1996 and determined that the licensee list of PRs for additional review was reasonable and in good agreement with the inspector's list. The inspectors reviewed the licensee's analysis of each of the twelve identified PRs and examined, where applicable, the areas where location in the plant (e.g. high radiation area) played a role in the licensee determination. The inspectors found the basis for conclusions to be reasonable.

c. <u>Conclusions</u>

Based on independent review of the documentation of licensee's inspections and walkdowns of the plant, the inspectors concluded that no additional examples of tampering were identified. The more likely cause of the misadjusted valve was poor performance by licensee personnel.

The inspectors concluded that the licensee adequately evaluated other systems for signs of tampering and correctly concluded that no additional signs of tampering were evident.

Based on independent review of documentation and observations of the involved equipment, the inspectors concluded that for the mispositioned CRD breaker, tampering, although it could not be conclusively ruled out, was not likely the cause of the mispositioned breaker. The most probable cause of this event was personnel error.

The inspectors concluded that there was no evidence of additional potential tampering and that the licensee had adequately evaluated the plant problem reports for additional examples of potential tampering.

O2.1.3 Site Management's Response to the Event

a. Inspection Scope

Review the actions taken by site management in responding to the potential tampering on the EGDG-1A cooling fan gear drive to determine if management's response was appropriate for the circumstances.

b. Observations and Findings

The inspectors observed the licensee's actions throughout recovery from the event. Prompt action was taken to declare an UE and a Recovery Action Plan initiated. The Action Plan included the following four general steps:

- Ensure integrity/operability of equipment required for core cooling
- Initiate/conduct an independent investigation
- Develop plan for recovery from the unusual event
- Communications and event documentation

Management initiated the following immediate measures: (1) compensatory security measures to guard against any continued acts of tampering, (2) detailed walkdown inspections by Operations and Engineering to ensure there was no evidence of tampering with plant equipment, and (3) an independent investigation to determine if tampering had occurred and the extent of any tampering. Management met frequently with plant personnel to discuss the status of the recovery plan and direct the recovery effort. Management kept NRC (site personnel, Regional NRC management, and NRR management) informed of the actions being taken and the status of the recovery plan.

c. Conclusions

The inspectors concluded that site management appropriately pursued identification of the cause for the penny in the EGDG-1A cooling fan gear box lube oil strainer and identification of any additional potential tampering with plant equipment.

The inspectors concluded that tampering with EGDG-1A cooling fan gear box lube oil strainer could not be conclusively ruled out based on the existing evaluation documentation. However, as concluded by the licensee's investigation, the penny most likely entered the strainer by accident during installation of the strainer screen after removal for measurements on September 15, 1996.

02.1.4 Implementation of Interim Action to Detect New Tampering

a. Inspection Scope

Determine if adequate inte   actions to detect new tampering had been implemented.

b. Observations and Findinr

After the identification of     ected EGDG tampering, a Security Emergency was declared. The licensee impie.   d immediate compensatory posts at the two entrances to the diesel generatoı area. Doors D-201 and D-207 were posted respectively with armed security officers to preclude access to the diesel generator area. In addition, supplementary personnel were added to perform additional patrols. The inspectors observed that the additional random patrol was being performed on the evening of September 24, 1996. Site security officers were briefed to heighten their awareness of the potential for other tampering activities. The inspectors questioned several security officers concerning their understanding of their duties and considered their responses appropriate and in accordance with the licensee's PSP. Upon exit of the UE, the Security Emergency was downgraded to a Security Alert. In response to this downgrade, the licensee removed the two compensatory posts previously established at Doors D-201 and D-207.

In accordance with WI-100, Revision 3, "Security Event Recovery Guidelines," the licensee initiated a walkdown of the security system mainframe and peripherals located in the Nuclear Security Operations Center (NSOC), in addition to plant local and remote computer cabinets and printers associated with those systems. No evidence of tampering was identified.

c. Conclusion

The licensee appropriately identified actions to be taken to enhance detection of additional tampering.

**S1 Conduct of Security and Safeguards Activities**

S1.2.5 Security Investigation of the Event

a. Inspection Scope

Determine if Security and Investigative staffs adequately reviewed the event.

b. Observations and Findings

The corporate investigators responded to the site on September 19, 1996, to independently determine when and how a penny became lodged in the 1A EGDG cooling fan lube oil strainer. PR 0386, Revision 1, was initiated to track the results of this investigation.

Immediately after discovery of the event, the strainer, penny, and the oil taken from the strainer were taken into custody by Security and locked in a security container. Interviews, bench tests, and applicable logs, and other documentation were reviewed by the investigators.

The Federal Bureau of Investigation (FBI) was notified of the potential tampering event and currently has possession of the strainer and penny in question. The FBI is reviewing the issue. The NRC Office of Investigations and Region II Physical Security Staff are maintaining liaison with the FBI.

The corporate Investigators interviewed 33 individuals relative to the EGDG penny issue and 20 other individuals associated with other PRs reviewed by the investigators for potential tampering. In addition, the Investigators reviewed applicable documentation and observed testing of the physical evidence. A separate Problem Report Review Team (PRRT) convened to determine if other events identified could support a pattern of tampering. The PRRT used a 14 point checklist to screen problem reports that could indicate possible tampering (See Paragraph O2.1.2 for additional details). This screening resulted in 82 problem reports which were reviewed in detail; with 12 requiring an additional followup. Only one of the 12 events identified required a separate investigation.

The inspectors noted that the Licensee's "Report of Independent Investigation Team Concerning Possible Instances of Tampering at Crystal River #3 - September 1996" provided little detail relative to the rationale regarding which individuals were interviewed as part of the investigation. Based on discussions with the investigation team, the inspectors did not have concerns with which individuals were interviewed and the conclusions reached by the investigation team, just that bases for the conclusions were not documented appropriately in the report. At the exit interview, the licensee stated that the report would be supplemented to provide this information. Subsequent to the inspection, the Report was revised to provide rationales for which individuals were interviewed and why and was reviewed by the inspectors prior to leaving the site.

c. Conclusion

The corporate investigative staff adequately reviewed the event and concluded that the penny most probably entered the strainer accidently and there is no evidence that suggests a pattern of tampering at the facility.

S1.2.7 Evaluation of Compliance with the Physical Security Plan (PSP)

a. Inspection Scope

Determine if the licensee was in compliance with their PSP and applicable procedures.

b. Observations and Findings

To preclude individuals from being authorized access to the facility who may engage in tampering, the licensee established a screening program in accordance with 10 CFR 73.56 requirements. The PSP states that "the Fitness for Duty Program (10 CFR 26), Personnel Access Program (10 CFR 73.56), and Criminal History checks (10 CFR 73.57), contribute to the overall effectiveness of the physical security program in combatting possible insider threats within the Plant."

The PSP further requires that, "all ingress and egress from the Protected Area and Vital Areas is controlled by human, mechanical, or electronic means. Only a limited number of portals are provided, and they are locked and alarmed..." In addition, the PSP states, "Only those persons required to enter Vital Areas to perform work functions necessary for the operation of the Plant are granted access. Each individual's need to have access to Vital Areas is reviewed once every 31 days to ensure that need still exists."

The EGDGs are accessible through Doors D-201 and D-207. Door D-201 leads from the protected area through the EGDG area. Access is controlled by a cardreader system. Door D-201 is located on the opposite side of the EGDG area. This door is neither locked or alarmed because access is gained through the Auxiliary Building, which is controlled by a cardreader system. This vital island is approved in the licensee's PSP.

c. Conclusion

The licensee was in compliance with the PSP with respect to fitness for duty, personnel access authorization, criminal history checks, and access control of vital areas. The licensee appropriately recorded the suspected tampering event in the Safeguards Event Log, as required by 10 CFR 73.71, "Reporting of Safeguards Events," Appendix G.

Personnel access to the EGDGs was controlled in accordance to the licensee's PSP and applicable procedures.

**INSPECTION PROCEDURES USED**

| | |
|---|---|
| IP 37551: | On Sight Engineering Review |
| IP 61726: | Surveillance Observations |
| IP 62707: | Maintenance Observation |
| IP 71707: | Plant Operations |
| IP 71750: | Plant Support Activities |
| IP 81601: | Safeguards Contingency Plan Implementation Review |
| IP 81700: | Physical Security Program for Power Reactors |
| IP 92901: | Followup - Plant Operations |
| IP 92902: | Followup Maintenance and Surveillance |

## X1 Exit Meeting Summary

The inspection Scope and findings were summarized to licensee management at the conclusion of the inspection on October 9, 1996. The inspectors described the areas inspected and discussed the inspection results. The inspectors discussed the limited documentation in the licensee's report. The licensee acknowledged the inspectors' comments and noted that the report would be supplemented appropriately. Proprietary information is not contained in this report. Dissenting comments were not received from the licensee. Subsequent to the inspection, the licensee modified the investigation report, which was reviewed by the inspectors.

## PARTIAL LIST OF PERSONS CONTACTED

### Licensee

P. Beard, Senior Vice President Nuclear Operations
G. Boldt, Vice President, Nuclear Production
J. Campbell, Assistant Security Manager
J. Carter, Corporate Security
R. Davis, Assistant Plant Director, Operations and Chemistry
A. Glenn, Corporate Counsel
B. Gutherman, Manager, Nuclear Licensing
G. Halnon, Assistant Director, Nuclear Operations Site Support
B. Hickle, Director, Nuclear Plant Operations
L. Kelly, Director, Nuclear Operations Site Support
D. Kurtz, Senior Nuclear Staff Specialist
P. McKee, Director, Quality Programs
R. McLaughlin, Nuclear Regulatory Specialist
J. Pelham, Corporate Security
J. Terry, Manager, Nuclear Plant Technical Support
D. Watson, Manager Nuclear Security

### NRC

R. Butcher, Senior Resident Inspector

Other licensee employees contacted included Operations, Engineering, Licensing, and maintenance personnel.

## LIST OF ACRONYMS USED

| | |
|---|---|
| CR | Condition Report |
| CRD | Control Rod Drive |
| EGDG | Emergency Diesel Generator |
| FBI | Federal Bureau of Investigation |
| IN | Information Notice |
| NPWO | Nuclear Plant Work Order |
| NRC | Nuclear Regulatory Commission |
| NRR | Nuclear Reactor Regulation |
| NSOC | Nuclear Security Operations Center |
| PR | Problem Report |
| PRRT | Problem Report Review Team |
| PSP | Physical Security Plan |
| REA | Request for Engineering Assistance |
| SP | Security Procedure |
| SRO | Senior Reactor Operator |
| UE | Unusual Event |
| WI | Work Instruction |
| WR | Work Request |

## CHRONOLOGICAL SEQUENCE OF EVENTS

| DATE | TIME | EVENT |
|---|---|---|
| 8/10/94 | - | WR NU 0321409 issued, EGDG 1A fan gear drive lube oil strainer cleaned and re-installed August 16, 1994, attempt to clean gear box delayed until September outage |
| 8/23/94 | - | WR NU 0321632 issued because of low oil pressure, flushed and attempted to clean gear box, strainer cleaned and re-installed September 13, 1994 |
| 9/14/94 | - | WR NU 032119 was issued because of low pressure after flushing and attempted cleaning of the lube oil gear Box - strainer cleaned and re-installed September 22, 1994 |
| 4/28/95 | - | WR NU 0327782 issued documenting low pressure (still above administrative limit) and dirt/foreign material in gear box - gear drive assembly replaced April 2, 1996, in 1996 Refueling Outage |
| 2/29/96 | - | Because of problems with oil pressure, EGDG 1A fan right angle gear drive assembly replaced, including gear box lube oil strainer assembly which was part of gear drive assembly |
| 3/18/96 | - | WR NU 0334062 issued because of low gear drive lube oil pressure - strainer removed, cleaned, and re-installed March 18, 1996 |
| 4/02/96 | - | Gear box assembly replaced in 1996 refueling outage |
| 5/16/96 | - | WR NU 0335432 documented low gear drive lube oil pressure and strainer screen completely clogged - cleaned and re-installed June 12, 1996 |
| 9/11/96 | - | WR NU 0337661 issued documenting need to clean strainer because of low lube oil pressure during monthly surveillance, screen cleaned and re-installed September 12, 1996 |
| 9/14/96 | - | WR NU 0337742 issued to remove strainer, compare mesh size with proper mesh size and install new strainer |
| 9/15/96 | - | Determination had been made that 20-mesh screen was needed for lube oil strainer screen, removed existing 40-mesh screen from strainer assembly, cleaned, measured screen (for purpose of obtaining 20-mesh), photographed, and re-installed |
| 9/17/96 | - | Mechanic noted deformation of screen during performance of maintenance |

| DATE | TIME | EVENT |
| --- | --- | --- |
| 9/18/96 | - | Decided to replace strainer assembly with new assembly, which contained 20-mesh screen since 20-mesh screen to fit existing filter housing was not available |
| 9/19/96 | 0215 | Started hanging clearance on 1A EGDG for replacement of gear drive lube oil strainer assembly |
| | - | Nuclear Shift Manager reported that mechanics had found a penny lodged in the removed strainer assembly at the inlet to the strainer screen. An inspection was made by the NMS, Engineering and Mechanical Supervisor. |
| | 0455 | Security notified of event |
| | 0510 | Security was notified and an Usual Event (UE) was declared |
| | 0514 | Security Emergency declared |
| | 0525 | Security Officer posted at D-201 |
| | 0527 | NRC notified of UE |
| | 0555 | Security Officer posted at D-207 |
| | 0615 | PR 96-0386 issued to document potential tampering with 1A EGDG fan gear drive lube oil strainer |
| | 0830 | Detailed walkdown inspection 1ADG by Operations, Engineering, Security, and NRC Resident Inspector |
| | 0915 | Random patrol initiated. |
| | 0950 | Completed detailed inspection of 1A EGDG room, including inspection of exhaust system for the Hot Machine Shop roof - also completed inspection of core cooling systems for tampering |
| | 1555 | Complete valve line up verified for all systems associated with 1A EGDG |
| | 1944 | Operations completed comprehensive inspection for tampering of essentially all site areas, including Intake Structure |
| 9/20/96 | 0221 | Monthly Functional Test of 1A EGDG completed |

| DATE | TIME | EVENT |
|---|---|---|
| | 0900 | 1A EGDG declared operable except for issue with diesel loading during design basis accidents |
| | 1100 | 1B EGDG removed from service for inspection of gear drive lube oil strainer |
| | 1818 | Completed comprehensive inspection of 1B EGDG for potential tampering |
| | 2131 | Monthly functional test of 1B EGDG completed |
| 9/21/96 | 0100 | Engineering system inspections complete |
| | 0255 | 1B EGDG declared operable except for issue with diesel loading during design basis accidents |
| | 0300 | WI-100 walkdown inspections of plant equipment completed, exited UE after determining there was no ongoing security compromises |
| | 0305 | Security steps down from a Security Emergency to a Security Alert |
| | 0323 | Security Officers posted at D-201 and D-207 removed |
| 10/3/96 | 0900 | Independent investigation of possible tampering instances complete and report issued |

## LIST OF LICENSEE DOCUMENTS REVIEWED

PR 96-0386, Revision 1

EM-202, Emergency Implementing Procedure, "Duties of the Emergency Coordinator," Revision 54, dated July 29, 1996

Shift Supervisor's Log of September 19, 1996, 1100-2300

Security Incident Report 10541, dated September 19, 1996

WI-100, Revision 3, "Security Event Recovery Guidelines," dated September 21, 1996

Safeguards Contingency Plan, Revision 4

Physical Security Plan, Revision 6-13

Security Procedure SS-206, "Security Safeguards Contingency Events," Revision 7, dated June 12, 1996

Report of Independent Investigation Team Concerning Possible Instances of Tampering

Work Requests NU 0321409, NU 0321632, NU 032119, NU 0327782, NU 0334062, NU 335432, NU 0337661, and NU 0337742 for work related to the 1A EGDG cooling fan gear Box Lube Oil strainer

Operability Concern Resolution EG-96-EGDG-1A/1B, Revision 2, EGDG-1A/1B Gearbox Pump Discharge Pressure

Request for Engineering Assistance (REA) 960902 dated September 20, 1996

D. O. James Gear drive Service Manual

D. O. James Drawing H-72578, Change C, Increaser Drive Size NO.-CH-1000VHB

Operations and Engineering Documentation of Plant Walkdown Inspections

All Problems Reports issued in 1996 were screened, selected reports reviewed in detail

Licensee Unusual Event Initiation and Recovery Documentation

**INFORMATION PROVIDED TO LICENSEE BY NRC ON SEPTEMBER 19,1996**

(1) NRC IN 83-27

(2) NRC Internal memo dated December 12, 1985

(3) NRC Internal memo dated July 14, 1982

(4) Draft Document 89-XX, Guidelines For Assessing Indications of Equipment Tempering/Sabotage

ATTACHMENT C

SSINS No.: 6835
IN 83-27

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF INSPECTION AND ENFORCEMENT
WASHINGTON, D.C. 20555

May 4, 1983

IE INFORMATION NOTICE NO. 83-27: OPERATIONAL RESPONSE TO EVENTS CONCERNING DELIBERATE ACTS DIRECTED AGAINST PLANT EQUIPMENT

Addressees:

All nuclear reactor facilities holding an operating license (OL) or construction permit (CP).

Purpose:

This information notice is provided as a notification of events which may have involved deliberate acts directed against plant equipment and a lack of station procedures concerning response by operating personnel. It is expected that recipients will review the information for applicability to their station procedures. No specific action or response is required at this time.

Description of Circumstances:

A review of recent operating reactor events indicates that some improper valve positioning and instrumentation irregularities may have involved deliberate acts directed against plant equipment in vital areas. The following is a brief account of these events.

At the first facility, during routine operation, the Control Room Operator received a steam generator feedwater pump (SGFP) high vibration alarm. Subsequently the SGFP tripped and the operator immediately reduced turbine load to prevent the unit from tripping. The instrument valves on the low vacuum trip sensing line located outside vital areas were apparently deliberately repositioned resulting in the pump trip. The licensee concluded that this deliberate act could have been a result of a labor dispute.

At the second facility, during a routine operator tour at approximately 1:00 a.m., a manual valve was found shut in the common suction piping to the high head safety injection (HHSI) pumps. The valve was immediately reopened. This valve, which is checked by operators each shift, had been verified open at about 4:30 p.m. the previous day. The chain and padlock which secured this valve in the open position were missing. Additionally, on the previous day the manual suction isolation valves of the three auxiliary feed-water pumps had been found unchained and unlocked in violation of technical specifications requirements. These valves were found in their normally open position. The motive behind the actions was not proven, but the actions resulted in the HHSI system being inoperable.

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These events, and events at other plants, demonstrate that the potential for deliberate acts directed against plant equipment must be recognized. In the two above events the licensees were not totally prepared for operational followup actions. Other licensees may or may not be prepared to assess the situation and take necessary steps to assure operability of systems important to safety or make decisions concerning continued operation. Guidelines or procedures prepared by the licensee outlining a process for followup of both deliberate and inadvertent acts with respect to plant operation should be available.

The guidelines and procedures should include a verification of the affected system(s) alignment, the system(s) control logic, and the availability of the system(s) main power supply. In addition interrelated systems should be inspected and selected safety-related electrical panels and cabinets, both in the plant and in the control room, may require a detailed inspection. If additional tampering is detected, the licensee should be prepared to make a decision on whether or not continued operation is justified and whether or not systems necessary for a safe shutdown are operable.

Operational and security procedures to cope with radiological sabotage and other threats to safety must be developed in accordance with 10 CFR 73.55(h)(1) and Appendix C of Part 73. The potential impact of any deliberate act directed against plant equipment must be evaluated, and actions taken to mitigate the anticipated safety consequences.

No written response to this notice is required. If you have any questions regarding this matter, please contact the Regional Administrator of the appropriate NRC Regional Office, or this office.

E L Jordan

Edward L. Jordan, Director
Division of Emergency Preparedness
and Engineering Response
Office of Inspection and Enforcement

Technical Contact: Paul R. Farron, IE
(301) 492-4766

Attachment:
List of Recently Issued IE Information Notices

---END---

December 12, 1985

MEMORANDUM FOR: DRS&P Staff

FROM: A. E. Chaffee, Chief
Reactor Projects Branch

ENCLOSURE: 1 Memorandum from ED Jordan to Brian Grimes entitled "Plant Systems Checkout Following Suspected Sabotage"

SUBJECT: POTENTIAL SABOTAGE: GUIDANCE FOR FOLLOW-UP

Enclosure 1 provides guidance for NRC and licensee actions when potential sabotage has been identified. This guidance is provided for your review and use. Please also review the licensee's program for dealing with potential sabotage from an operations standpoint. Enclosure 1 is a good guide to use in evaluating the licensee's program. You will note that this guidance is not included in any formal document. Please find a method to file this document so it is available when needed.

A E Chaffee
A. E. Chaffee, Chief
Reactor Projects Branch

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

Regis. 463 55
3m " 38c
Conf. 37:

JUL 14 1982

MEMORANDUM FOR: Brian K. Grimes, Director, Division of Emergency Preparedness, IE

FROM: Edward L. Jordan, Director, Division of Engineering and Quality Assurance, IE

SUBJECT: PLANT SYSTEMS CHECKOUT FOLLOWING SUSPECTED SABOTAGE

The enclosed procedure provides guidance for actions to be taken following instances of suspected sabotage. We request that you make this guidance available to IE Management-on-call and the IE Operations Center Duty Officer. We are issuing the procedure as a Temporary Instruction for use by the Regional Offices.

E. L. Jordan
Edward L. Jordan, Director
Division of Engineering and
Quality Assurance, IE

Enclosure: Procedure for Assessing Indicated Sabotage

Based on a talk w/ Perkins & Allison on 8/2, I understand that the TI will not be issued.

cc/w enclosure:
W. J. Dircks, EDO
H. R. Denton, NRR
J. G. Davis, NMSS
R. C. DeYoung, IE
J. L. Blaha, IE
R. C. Haynes, RI
J. P. O'Reilly, RII
J. G. Keppler, RIII
J. T. Collins, RIV
R. H. Engelken, RV
J. M. Taylor, IE
J. Partlow, IE

[redacted]

# PROCEDURE FOR ASSESSING SIGNIFICANCE OF INDICATION OF SABOTAGE PRIOR TO CONTINUED OPERATION

## INTRODUCTION

In view of recent events involving indication of potential sabotage at the Salem and Brunswick facilities, a procedure has been prepared for use in future instances of this kind. The purpose of the procedure is to determine if sabotage has been committed and to check out the plant to ensure continued safe conditions. The procedure is intended to provide guidance for IE, both operations center duty officer and management-on-call, and regional personnel involved with response to such events.

## OBJECTIVE

The primary objective in dealing with an event indicative of potential sabotage is to ensure continued safe facility conditions. When an event occurs, accidently or intentionally initiated, judgments must be made regarding potential consequences of the event and the corrective actions to be taken to eliminate the initiating conditions and minimize the consequences.

## PROCEDURES

After potential or actual sabotage has been identified, it is necessary to gather sufficient facts to enable a clear understanding of the significance of the identified sabotage. Gaining such understanding is the first action to be taken in responding to the identified sabotage. Information that may assist in this first action is referred to in item A below. With an understanding of the identified sabotage, it is then appropriate to establish an initial prioritized search of the associated or suspect systems. The resulting information is then the basis for determining subsequent action. Clearly,the extent to which the plant is checked (i.e., items B and C or D below) depends on judgment regarding indications of further sabotage found during the checkout.

A. Sabotage Event Evaluation

The enclosure to the memorandum dated November 6, 1981 to Commissioner Bradford from W. Dircks consists of a procedure for this evaluation. A copy is enclosed. It is to be used for general guidance on implementation of this procedure.

B. Overall Inspection of Plant

As set forth on page 3 of the enclosed "Sabotage Event Evaluation," the conduct of search and equipment check should include a check of the overall plant and then a system by system inspection, as appropriate.

The overall plant and system by system listings reflects a "hands-on" approach that would enable an inspector to verify the licensee's

action in checking out a nuclear power plant in instances of suspected sabotage. To repeat, it is the licensee, not NRC, that checks out the plant. The assumption is made that the FSAR would be available for overall guidance to plant system requirements and that the plant Technical Specifications would be satisfied before justification of continued operation or restart.

Prior to a systems checkout based on the listing in items C and D below, a broad-brush inspection of the plant should be made by the licensee. This inspection should be largely by visual means and consist of four main categories. These are:

1. control room inspection,

2. plant structures inspection,

3. piping and valve walkdown, and

4. electrical power integrity confirmation.

This broad inspection should be initially performed to spot any major abnormality such as a damaged pipeline or a planted explosive. It should not be programmed to detect all potentially faulted systems.

In the control room, visual inspection should be made of all panels, boards and inside cabinets with an eye to spotting any obvious fault. One should be alert to spotting jumpers, and certainly to any strange "packages."

In the visual checkout of plant structures, the same general attitude should be appropriate. Look for abnormalities and foreign materials. This category should include the main plant buildings, that is, containment, reactor building, turbine building and of course, the intake structure or connection to ultimate heat sink.

The piping and valve walkdown should use the same perspective. It should not seek to distinguish between system piping which is safety-grade and that which is not. This inspection should simply consist of a routine patrol of all accessible piping runs being alert to the more obvious type of faulting. For example, one should be expected to be able to "find" a cut chain of a "chain and padlocked" valve handle. On the other hand, one should not expect to confirm valve alignment during this initial check.

Finally, the initial check of the electrical system should be made with the same general approach. It should seek to verify that the vital power supplies were not "altered" in a significant way. The purpose of this check should be to make sure it was safe to turn power on for further systems checking.

When preliminary determination of sabotage has been made and further investigation indicates that specific systems might be affected, it may be necessary to perform a complete walkdown of certain systems, checking

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all accessible manual and motor operated valve positions, circuit breaker and electrical switch positions, etc. Actual system walkdowns are especially pertinent with respect to standby systems whose operability cannot be completely demonstrated during normal plant operations. Checks in high radiation areas may be required depending on detailed consideration of the evidence of sabotage in these areas and a possible ALARA consideration.

When evidence of sabotage is found and specific components and systems are identified, consideration of the consequences of corrective actions should be taken. A thorough determination of possible system response to corrective actions should be made and contingency plans to address these responses should be determined prior to taking corrective actions.

Detailed examination of systems including those associated with the identified sabotage may be necessary to establish the basis for continued operation.* The systems to be examined are listed in item C or D as applicable. Following such a checkout, it then would be appropriate to confirm systems operability throughout the plant using the Technical Specification requirements as the measure of safe operability. This conformance with Technical Specification requirements represents the overall criteria on which decisions may be made regarding changing the mode of reactor operations.

C. BWR Plant Systems

1. Reactor System

   a. Vessel - check for obvious abnormal condition
   b. Vessel Level Instrumentation - condensing chambers, piping, dp racks, wiring

2. Reactor Recirculation System

   a. Piping
   b. Valves, discharge and suction
   c. Motor, pump, and controls
   d. Power supply MG Set, cables, modules, breakers
   e. Control cabinets, wiring, boards, breakers

*If the plant is operating, continued operation should and must be permitted until sufficient checks have been made to assure that the plant can be shut down safely.

3. Control Rod Drive Hydraulic System

   a. HCUs (Hydraulic Control Units), directional control valves, isolation valves, scram valves
   b. Piping throughout HCUs, SDV (Scram Discharge Volume)
   c. SDV drain and vent valves, IV Level switches
   d. Control circuitry - cables, boards
   e. Air supply - piping and valves, controls, pilot valves

4. Standby Liquid Control System

   a. SLC tank, level, piping
   b. Pumps and motors, power supplies, controls
   c. Valves, squib, isolation
   d. Control circuitry, panels, cabinets, cables

5. Residual Heat Removal (RHR) System

   a. Heat exchangers, primary side (shell), secondary side (tube) service water
   b. Primary side (LPCI) pumps, motors, piping valves, isolation valves, drywell spray piping and valves, torus spray piping and valves
   c. Other primary side piping and valves, i.e., shutdown cooling, isolation cooling where applicable
   d. Control circuitry, wiring, panels, boards, Logic interconnections, power supplies, control power supplies
   e. RHR Service Water System
      (i) Pumps, motors, water supply structure
      (ii) Piping and valves, isolation and interconnections
      (iii) Control circuitry, wiring, boards, panels
      (iv) Power supply, cable, breakers, controls

6. Core Spray System

   a. Pumps, motors
   b. Piping and valves, isolation valves, check valves
   c. Control circuitry, wiring, panels, logic, control power
   d. Power supplies, cable, breakers, controls

7. High Pressure Coolant Injection System

   a. Pump and turbine driver
   b. Piping, valves, isolation valves, condensate traps
   c. Control circuitry, wiring, logic, control power
   d. Turbine oil system, turbine control valves, speed governor

8. Automatic Depressurization System

   a. Safety relief valves operability
   b. Control circuitry, wiring, timer, logic
   c. Air or pneumatic accumulators, air supply check valves, air supply piping

9. Reactor Core Isolation Cooling System*

   a. Pump and turbine driver
   b. Piping, valves, isolation valves, check moves, condensate traps
   c. Control circuitry, wiring, logic

10. Diesel Generator System

   a. Day tanks and storage tanks
   b. Fuel oil pumps, motors, piping
   c. Control Circuitry, wiring, logic
   d. Diesel air start and lube oil systems
   e. Generator protective devices and output interconnections (See electrical systems)

11. Containment Systems

   a. Primary containment isolation valves including MSIVs and controls
   b. Primary containment inerting system piping, valves, controls, sampling
   c. Suppression chamber water level
   d. Vacuum breakers - DW to torus to reactor building
   e. Standby gas treatment system operability
   f. DW purge and vent valves control

12. Water Systems

   a. RHR service water piping, valves, pumps, motors
   b. Emergency service water (if applicable) piping, valves, pumps, motors
   c. Intake structure integrity
   d. Reactor building closed cooling water, turbine building closed cooling water, fuel pool cooling
   e. Circulating water system
   f. Diesel generator cooling water system
   g. Condensate and feedwater system including storage tanks and demineralizers
   h. Condensate-Feedwater piping, pumps, valves
   i. Feedwater heaters with associated piping and valves

*For earlier BWRs using an isolation condenser for this function, only the above items (9.b.) and (9.c.) are applicable.

13. Instrumentation and Control Systems

    a. Reactor protection system, boards, racks, relays, complete control room check
    b. Neutron monitoring system including TIP piping and valves and SRM, IRM, APRM
    c. Process control interfaces
    d. Engineered safety feature controls, racks
    e. I&C for safe shutdown including control room habitability system
    f. Other I&C - e.g., fuel pool cooling, offgas monitoring, etc

14. Electrical Systems

    a. DC system supply and monitoring on 125 volt and 250 volt batteries and chargers, switchgear and panels
    b. Vital AC equipment including 4kv, 480 volt and 230 volt buses and switchgear
    c. Vital motor control centers
    d. Emergency lighting system
    e. Remote shutdown control system
    f. Cable spreading room

15. Compressed Air System

    a. Compressors, accumulator tanks and motors
    b. Piping and valves
    c. Control circuitry, wiring

16. Main Turbine Generator

    a. Turbine control system including electrohydraulic oil system
    b. Bypass valve controls
    c. Generator protective systems

D. <u>PWR Plant Systems</u>

1. Reactor System

    a. Reactor pressure vessel
    b. Control rod drive mechanism above reactor vessel
    c. Control and instrumentation for the reactor protection system (RPS) and the overpressure protection system

2. Reactor Coolant System (RCS)

    a. Primary and secondary coolant loop; piping, valves (including safety relief), instrumentation and control
    b. Reactor coolant pumps (RCP) and associated component cooling including component cooling of lube oil coolers and component cooling valves and piping out to containment penetration

c. Steam generator external damage, including safety relief valves
d. Pressurizer including PORV's, associated control air (or nitrogen) supply, heater control and heater backup power supply, and valves and piping to pressure relief tank

3. Emergency Core Cooling System (ECCS)

a. Accumulators and piping to RCS vent and isolation valves, nitrogen pressure and supply
b. High head charging pumps, charging lines, boron injection tanks, all other safety injection pumps (i.e., intermediate head pumps if applicable) and related piping and valve alignment (including manual isolation valves) to RCS
c. Residual heat removal (RHR) system: heat exchangers, pumps, valves including manual system isolation valve alignment, and associated control circuitry, wiring, panels, interconnections, power supplies and control power supplies
d. RHR service water system including pumps, motors, piping, valves (especially system isolation valves)
e. Refueling water storage tank, associated isolation valves and piping for ECCS pump suction
f. Instrument and control racks for the entire ECCS system

4. Component Cooling System

a. Component cooling pumps, heat exchangers, spent fuel pool heat exchangers, water seal heat exchangers
b. Special attention should go to component cooling for RCPs, emergency diesel generators, ECCS pumps and associated isolation valves and piping

5. Instrumentation and Control

a. Visual inspection and functional testing of RPS and engineering safeguards systems
b. Visual check of instrument racks and wiring for RHR, auxiliary feedwater system and shutdown systems
c. Preoperational testing of SRMS, IRMS and all other power level instruments
d. Control room and auxiliary room ventilation system
e. Instrument control air (or nitrogen) pressure valves and piping for safety systems
f. Control room panels and cabinets

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6. Waste Disposal and Radition Protection System

   a. Radiation monitors for service water discharge headers and plant vents
   b. Reactor coolant drain tanks, CVCS holdup tanks, and the waste holdup tanks, valves, piping and radiation alarms
   c. Waste gas monitor tanks, valve line up to service water system
   d. Gas decay tanks, analyzer tanks and plant vent valve lineup and associated radiation monitors

7. Containment Systems

   a. Containment isolation valves, CVCS letdown lines, MSIVs
   b. Containment pressure relief valves, purge exhaust valves and all other manually operated containment valves which are accessible
   c. Personnel and equipment access hatches
   d. Containment spray systems, piping, valves, instrumentation and wiring, pumps, heat exchanger and recirculation system sump, pump and controls
   e. Hydrogen recombiner units including the control panels and power supply
   f. Fan coolers with safety cooling functions and ice condensers (if applicable)

8. Electrical Systems

   a. Auxiliary power system, including 4160/480 vital buses, 125 volt DC control buses/battery and 120 VAC vital instrument bus
   b. Emergency diesel generator system controls, fuel oil, lube oil, tanks and piping
   c. Cable spreading room

9. Main Steam System

   a. Associated relief valves
   b. Turbines include lube oil system, bypass valves and generator protection systems
   c. Steam generator feedpumps and valve lineup through FW heaters
   d. Auxiliary feedwater system pumps and manual isolation valves

10. Spent fuel pool and fuel handling systems (i.e., if in refueling outage), including cooling system and level indications

11. Service water system including piping, valves, pumps, and heat exchangers

12. Sampling system for appropriate systems including isolation valves

FROM NRC 1101

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION
WASHINGTON, D.C. 20555

February xx, 1989

NRC INFORMATION NOTICE NO. 89-XX: GUIDELINES FOR ASSESSING INDICATIONS OF EQUIPMENT TAMPERING/SABOTAGE

Addressees:

All holders of operating licenses or construction permits for nuclear power reactors.

Purpose:

This information notice is being provided to assist addressees in planning for events involving indication of possible sabotage. If such an event occurs, whether accidentally or intentionally initiated, judgments must be made regarding potential consequences of the event and the corrective actions necessary to eliminate the initiating conditions and minimize the consequences. It is expected that recipients will review the information for applicability to their facilities. However, suggestions contained in this information notice do not constitute NRC requirements; therefore, no specific action or written response is required.

Description of Circumstances:

Nuclear power reactor licensees personnel have identified several instances of equipment tampering, for example, misaligned breakers or valves, cut wires or cables, or the placement of foreign objects in a piece of machinery or contaminating liquids in reservoirs or tanks.

Discussion:

In determining what actions are appropriate following an indication of sabotage or tampering at a nuclear power plant, the governing principle is to avoid undue risk to the public health and safety. In implementing this principle, all pertinent factors must be carefully examined to determine whether the condition resulted from an accident or from a deliberate act of vandalism, malicious mischief, or sabotage. If judged to be an attempted act of radiological sabotage, factors such as sophistication, intent, and the possibility of other acts by the same person must be considered, as well as the event history of the plant.

In formulating any response action, the licensee should consider potential safety consequences of such actions and the condition of the plant. Before making any change in the operating status of the facility, the licensee should consider the basis for the change and its potential for mitigating or compounding the situation. As a general rule, the public health and safety are probably best served by initially maintaining a stable mode of plant operation as the transients caused by changes in plant status could contribute to a reduction in plant safety. In addition, contingency plans and other measures need to be initiated to correct the condition and prevent further acts while the facts of the matter are being fully assessed.

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Because each plant situation is unique, hard and fast rules for dealing with attempted sabotage do not seem practical. However, some general guidelines appear appropriate in most circumstances.

A. Evaluation of a Tampering/Sabotage Event

After potential or actual sabotage or tampering has been identified, it is necessary to gather sufficient facts to permit a clear understanding of the significance of the identified sabotage or tampering.

Some of the factors that should be considered in gathering this information are as follows:

- The event may prevent a safety system from performing its intended function.
- The event may prevent a system designed to prevent or mitigate the consequence of malfunction from performing its intended function, resulting in a possible release of radioactive material.
- The event may cause a safety system failure only if multiple other events occur.
- The event may prevent a system designed to support a safety system, from performing its intended function.
- There are no apparent safety implications.

Three factors should be considered in determining the probability of a malevolent act, as opposed to an accidental occurrence:

1. OVERTNESS - Sometimes by the act itself, it is obvious that an act of sabotage has been perpetrated; but more often than not the cause of an event is not obvious. The cause could be misaligned valves, for example. In such cases, the following criteria should be used in determinine whether sabotage occurred.

   a. Physical evidence clearly related to the event, for example, the lock to a valve is cut and the valve misaligned; or the actuator to the motor control valve is shorted.

   b. Physical evidence tangentially related to the event, for example, the door to the vital areas (VA) is forced open and the valve is misaligned.

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c. Circumstantial evidence clearly related to the event, for example, the lock and chain are missing and the valve is misaligned.

d. Circumstantial evidence tangentially related to the event, for example, the key to the VA door is missing and the valve is misaligned.

e. No evidence of deliberate manipulation of equipment.

2. INTENT - Some inferences concerning the intent of the adversary can be drawn from analyzing the safety significance and the overtness of the act. In addition, intent can be determined by other means, the most obvious being a communicated threat.

a. A communicated threat is received before the event.

b. A communicated threat is received, and circumstantial evidence relating to the event exists.

c. A communicated threat is received, but no other evidence (physical or circumstantial) exists. No event occurs.

d. No communicated threat is received.

3. HISTORY - The historical significance of an event should be evaluated using the following criteria:

a. History of recent similar events escalating in safety significance.

b. History of random events with no escalation in safety significance.

c. History of vandalism relating to labor/management problems.

d. No previous events.

An analysis of the above factors may lead to a conclusion about whether the act was willful or accidental. When overtness is judged to be low, and history is found to be low, the event may be less likely to involve sabotage. If the evidence is not conclusive or if the event is determined to be accidental, the appropriate corrective action to prevent recurrence and to mitigate the consequences should be taken.

If the event is determined to be an act of sabotage or, after evaluation of the previous factors sabotage cannot be ruled out, a judgment must be made regarding the level of sophistication of the event and the consequences intended by the adversary. Some inferences regarding the adversary's capability can be drawn from the safety significance of the target. If the adversary's capability is evaluated as being high, the potential to do significant damage is great; therefore, the level of sophistication of the event is a critical element in the decision. Evaluation of the following factors may provide some insight regarding the level of sophistication.

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4. Level of Sophistication

a. Target selection and timing clearly demonstrate an intention to cause consequences to the public health and safety. A high degree of knowledge of the plant, and the sabotage scheme demonstrate a high level of professional capabilities (expert employment and most advantageous location of explosives or installation of a jumper that would nullify the safety function of a vital component).

b. Evidence indicates an intention to cause consequences to the public health and safety and a sophisticated sabotage method is used but target selection and timing demonstrate limited plant knowledge.

c. Target selection and timing indicate poor knowledge of plant; a crude sabotage method is used.

-- After consideration of the above factors, a response action should be taken that is commensurate with the potential safety consequence of the act and the sophistication level of the adversary. The following is a list of possible response actions; one or more of these measures may be needed:

° Contact the FBI to request their assistance in investigating the incident and provide technical assistance to the FBI as requested.

° Ensure that effective coordination and communication exists between plant operations and security personnel during the FBI investigation.

° Identify which tampered/sabotaged equipment has had recent maintenance performed and who performed it.

° Identify by computer check (if feasible) the personnel who had recent access to the areas in which tampering/sabotage occurred.

° Increase security measures for areas of concern to include additional access controls and increase vital area patrols for the rest of the plant until the investigation is completed and the perpetrator removed.

° Designate a senior manager as the point of contact to assist and coordinate support and respond to inquiries pertaining to the investigation.

° Review recent personnel problems or issues for indications of disgruntlement.

° Initiate accelerated functional testing.

° Establish limited two-man rule for area in which event occurred.

° Establish total two-man rule for all vital areas in the plant.

° Consider controlled shutdown.

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- Initiate controlled shutdown following the approach in the technical specifications and operating procedures, for example, ensure availability of required systems before proceeding from one operating system to the next.

With an understanding of the identified sabotage, it is then appropriate to establish an initial search of the associated or suspect systems. The resulting information then will be the basis for determining subsequent action. Clearly, the extent to which the plant is checked (i.e., items B and C or D below) depends on judgment regarding indications of further sabotage found during the checkout.

B. Overall Inspection of Plant

As set forth in item A, "Evaluation of Tampering/Sabotage Event," the conduct of search and equipment check should include a check of the overall plant and then a system-by-system inspection, as appropriate.

The overall plant and system-by-system listings reflects a "hands-on" approach in checking out a nuclear power plant in instances of suspected sabotage. The assumption is made that the plant technical specifications would be satisfied before justification of continued operation or restart.

Before a system's checkout based on the listing in items C and D below, a broad inspection of the plant should be made by the licensee. This inspection should be largely visual and consist of the following four main categories:

1. Control room inspection
2. Plant structures inspection
3. Piping and valve walkdown inspection
4. Confirmation of electrical power integrity

This broad inspection should be initially performed to spot any major abnormality such as a damaged pipeline or a planted explosive. It should not be programmed to detect all potentially faulted systems.

In the control room and other areas that contain vital electrical equipment, visual inspection should be made of all panels, boards, and inside cabinets to spot any obvious fault. Unauthorized jumpers and any strange "packages" should be spotted.

In the visual checkout of plant structures, the same general attitude should be appropriate. Abnormalities and foreign materials should be looked for. Plant structures include the main plant buildings, that is, the containment, the reactor building, the auxiliary building, the turbine building, and of course the intake structure or connection to ultimate heat sink.

The piping and valve walkdown inspection should involve the same perspective. This inspection should not seek to distinguish between safety-grade and nonsafety grade system piping. This inspection should simply consist of a routine patrol of all accessible piping runs in which the inspector is alert to the more obvious type of faulting. For example, the inspector should be able to "find" a cut chain of a "chained and padlocked" valve handle. On the other hand, the inspector should not expect to confirm valve alignment during this initial check.

Finally, the initial check of the electrical system should be made with the same general approach. It should seek to verify that the vital power suppliers were not "altered" in a significant way. The purpose of this check should be to make sure it was safe to turn power on for further checking of systems.

If preliminary determination of sabotage has been made and further investigation indicates that specific systems might be affected, it may be necessary to perform a complete walkdown inspection of certain systems, checking all accessible manual and motor-operated valve positions, circuit breaker and electrical switch positions, etc. Actual system walkdown inspections are especially pertinent with respect to standby systems whose operability cannot be completely demonstrated during normal plant operations. Checks in high radiation areas may be required depending on detailed consideration of the evidence of sabotage in these areas and as low as is reasonably achievable (ALARA) consideration.

If evidence of sabotage is found and specific components and systems are identified, consideration of the consequences of corrective actions should be made. A thorough determination of possible system response to corrective actions should be made and contingency plans to address these responses should be determined before corrective actions are taken.

Detailed examination of systems including those associated with the identified sabotage, may be necessary to establish the basis for continued operation.* The systems to be examined are listed in item C or D, as applicable. Following such a checkout, it then would be appropriate to confirm system operability throughout the plant using the technical specification requirements as the measure of safe operability. This conformance with technical specification requirements represents the overall criteria on which decisions may be made regarding changing the mode of reactor operations.

C. <u>Boiling-Water Reactor (BWR) Plant Systems</u>

1. Reactor System

   a. Vessel - check for obvious abnormal condition
   b. Vessel Level Instrumentation - condensing chambers, piping, differential pressure (DP) racks, and wiring

*If the plant is operating, operation should continue until sufficient checks have been made to ensure the plant can be shut down.

2. Reactor Recirculation System

   a. Piping
   b. Valves-discharge and suction
   c. Motor, pump, and controls
   d. Power supply motor generator (MG) set, cables, modules, and breakers
   e. Control cabinets, wiring, boards, and breakers

3. Control Rod Drive Hydraulic System

   a. Hydraulic control units (HCUs), directional control valves, isolation valves, and scram valves
   b. Piping throughout HCUs and scram discharge volume (SDV)
   c. SDV drain and vent valves and instrumented volume (IV) level switches
   d. Control circuitry - cables and boards
   e. Air supply - piping and valves, controls, and pilot valves

4. Standby Liquid Control (SLC) System

   a. SLC tank, level, and piping
   b. Pumps and motors, power supplies, and controls
   c. Valves, squib, and isolation
   d. Control circuitry, panels, cabinets, and cables

5. Residual Heat Removal (RHR) System

   a. Heat exchangers, primary side (shell), secondary side (tube), and service water
   b. Primary side low-pressure core injection (LPCI) pumps, motors, piping valves, isolation valves, drywell spray piping and valves, and torus spray piping and valves
   c. Other primary side piping and valves, that is, shutdown cooling and isolation cooling, where applicable
   d. Control circuitry, wiring, panels, boards, logic interconnections, power supplies, and control power supplies
   e. RHR Service Water System
      (1) Pumps, motors, and water supply structure
      (2) Piping and valves, isolation, and interconnections
      (3) Control circuitry, wiring, boards, and panels
      (4) Power supply, cable, breakers, and controls

6. Core Spray System

   a. Pumps, and motors
   b. Piping and valves, isolation valves, and check valves
   c. Control circuitry, wiring, panels, logic, and control power
   d. Power supplies, cable, breakers, and controls

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7. High Pressure Coolant Injection System

   a. Pump and turbine driver
   b. Piping, valves, isolation valves, and condensate traps
   c. Control circuitry, wiring, logic, and control power
   d. Turbine oil system, turbine control valves, and speed governor

8. Automatic Depressurization System

   a. Safety relief valves operability
   b. Control circuitry, wiring, timer, and logic
   c. Air or pneumatic accumulators, air supply check valves, and air supply piping

9. Reactor Core Isolation Cooling System*

   a. Pump and turbine driver
   b. Piping, valves, isolation valves, check valves and condensate traps
   c. Control circuitry, wiring, and logic

10. Diesel Generator System

   a. Day tanks and storage tanks
   b. Fuel oil pumps, motors, and piping
   c. Control circuitry, wiring, and logic
   d. Diesel air start and lube oil systems
   e. Generator protective devices and output interconnections (see electrical systems)

11. Containment Systems

   a. Primary containment isolation valves, including main steam isolation valves (MSIVs) and controls
   b. Primary containment inerting system piping, valves, controls, and sampling
   c. Suppression chamber water level
   d. Vacuum breakers - drywell (DW) to torus to reactor building
   e. Standby gas treatment system operability
   f. DW purge and vent valves control

12. Water Systems

   a. RHR service water piping, valves, pumps, and motors
   b. Emergency service water (if applicable) piping, valves, pumps, and motors
   c. Intake structure integrity
   d. Reactor building closed cooling water, and turbine building closed cooling water, and fuel pool cooling

*For earlier BWRs using an isolation condenser for this function, only the above items 9.b and 9.c are applicable.

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e. Circulating water system
f. Diesel generator cooling water system
g. Condensate and feedwater system, including storage tanks and demineralizers
h. Condensate-Feedwater piping, pumps, and valves
i. Feedwater heaters with associated piping and valves

13. Instrumentation and Control (I&C) Systems

a. Reactor protection system, boards, racks, relays, and complete control room check
b. Neutron monitoring system, including traveling incore probe (TIP) piping and valves and source range monitor (SRM), intermediate range monitor (IRM), and average power range monitor (APRM)
c. Process control interfaces
d. Engineered safety feature controls, and racks
e. Instrumentation and control (I&C) for safe shutdown, including control room habitability system
f. Other I&C - for example, fuel pool cooling, offgas monitoring, etc.

14. Electrical Systems

a. DC system supply and monitoring on 125-volt and 250-volt batteries and chargers, switchgear, and panels
b. Vital AC equipment including 4kv, 480-volt and 230-volt buses and switchgear
c. Vital motor control centers
d. Emergency lighting system
e. Remote shutdown control system
f. Cable spreading room

15. Compressed Air System

a. Compressors, accumulator tanks, and motors
b. Piping and valves
c. Control circuitry, and wiring

16. Main Turbine Generator

a. Turbine control system, including electrohydraulic oil system
b. Bypass valve controls
c. Generator protective systems

D. Pressurized-Water Reactor (PWR) Plant Systems

1. Reactor System

a. Reactor pressure vessel
b. Control rod drive mechanism above reactor vessel
c. Control and instrumentation for the reactor protection system (RPS) and the overpressure protection system

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2. Reactor Coolant Systems (RCS)

   a. Primary and secondary coolant loop-piping, valves (including safety relief), instrumentation and control
   b. Reactor coolant pumps (RCP) and associated component cooling, including component cooling of lube oil coolers and component cooling valves and piping to containment penetration
   c. External steam generator, including safety relief valves
   d. Pressurizer, including power-operated relief valves (PORVs), associated control air (or nitrogen) supply, heater control and heater backup power supply, and valves and piping to pressure relief tank

3. Emergency Core Cooling System (ECCS)

   a. Accumulators and piping to RCS vent and isolation valves and nitrogen pressure and supply
   b. High head charging pumps, charging lines, boron injection tanks; all other safety injection pumps (i.e., intermediate head pumps, if applicable) and related piping and valve alignment (including manual isolation valves) to RCS
   c. Residual heat removal (RHR) system-heat exchangers, pumps, valves (including manual system isolation valve alignment), associated control circuitry, wiring, panels, interconnections, power supplies, and control power supplies
   d. RHR service water system, including pumps, motors, piping, valves (especially system isolation valves)
   e. Refueling water storage tank, associated isolation valves, and piping for ECCS pump suction
   f. Instrument and control racks for the entire ECCS system

4. Component Cooling System

   a. Component cooling pumps, heat exchangers, spent fuel pool heat exchangers, and water seal heat exchangers
   b. Special attention should be given component cooling for RCPs, emergency diesel generators, ECCS pumps, and associated isolation valves and piping

5. Instrumentation and Control

   a. Visual inspection and functional testing of RPS and engineering safeguards systems
   b. Visual check of instrument racks and wiring for RHR, auxiliary feedwater system, and shutdown systems
   c. Preoperational testing of SRMS, IRMS, and all other power level instruments
   d. Control room and auxiliary room ventilation system
   e. Instrument control air (or nitrogen) pressure valves and piping for safety systems
   f. Control room panels and cabinets

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6. Waste Disposal and Radiation Protection System

   a. Radiation monitors for service water discharge headers and plant vents
   b. Reactor coolant drain tanks, chemical and volume control system (CVCS) holdup tanks, and the waste holdup tanks, valves, piping and radiation alarms
   c. Waste gas monitor tanks, and valve line to service water system
   d. Gas decay tanks, analyzer tanks, plant vent valves lineup, and associated radiation monitors

7. Containment Systems

   a. Containment isolation valves, CVCS letdown lines, and MSIVs
   b. Containment pressure relief valves, purge exhaust valves and all other manually operated containment valves that are accessible
   c. Personnel and equipment access hatches
   d. Containment spray systems, piping, valves, instrumentation and wiring, pumps, heat exchanger and recirculation system sump pump and controls
   e. Hydrogen recombiner units, including the control panels and power supply
   f. Fan coolers with safety cooling functions and ice condensers (if applicable)

8. Electrical Systems

   a. Auxiliary power system, including 4160/480 vital buses, 125 volt DC control buses/battery and 120-VAC vital instrument bus
   b. Emergency diesel generator system controls, fuel oil, lube oil, tanks, and piping
   c. Cable spreading room

9. Main Steam System

   a. Associated relief valves
   b. Turbines, including lube oil system, bypass valves and generator protection systems
   c. Steam generator feedpumps and valve lineup through feedwater (FW) heaters
   d. Auxiliary feedwater system pumps and manual isolation valves

10. Spent fuel pool and fuel handling systems (i.e., if in refueling outage), including cooling system and level indications

11. Service water system, including piping, valves, pumps, and heat exchangers

12. Sampling system for appropriate systems, including isolation valves

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No specific action or written response is required by this information notice. If you have any questions about this matter, please contact one of the technical contacts listed below or the Regional Administrator of the appropriate regional office.

Charles E. Rossi, Director
Division of Operational Events
Assessment
Office of Nuclear Reactor Regulation

Safeguards Technical Contact: Eugene W. McPeek, NRR
(301) 492-3210

Operational Technical Contact: Richard Lobel, NRR
(301) 492-1157

Attachment: List of Recently Issued NRC Information Notices

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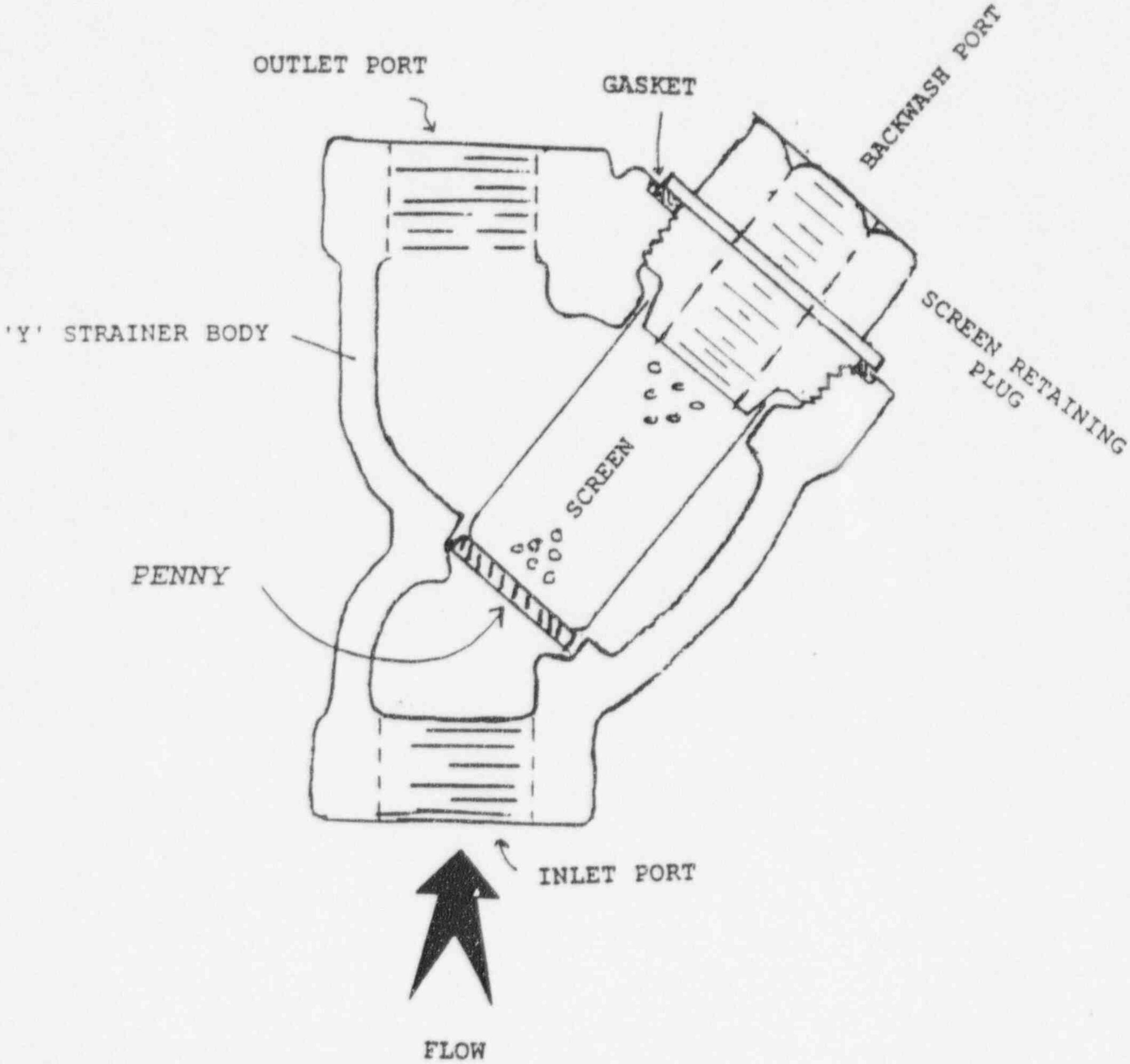
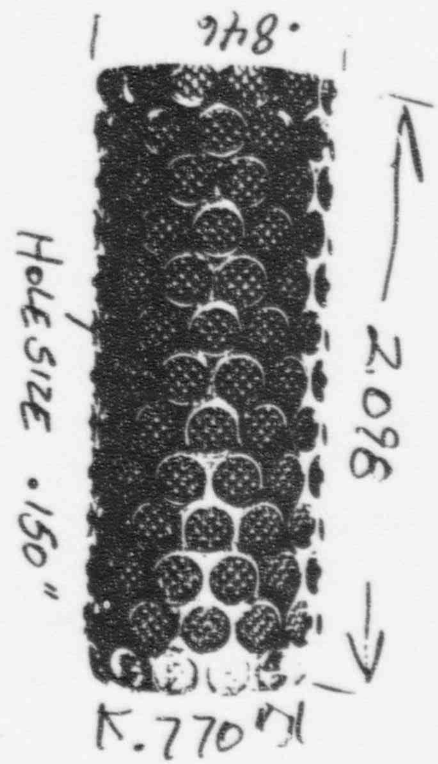
***END***

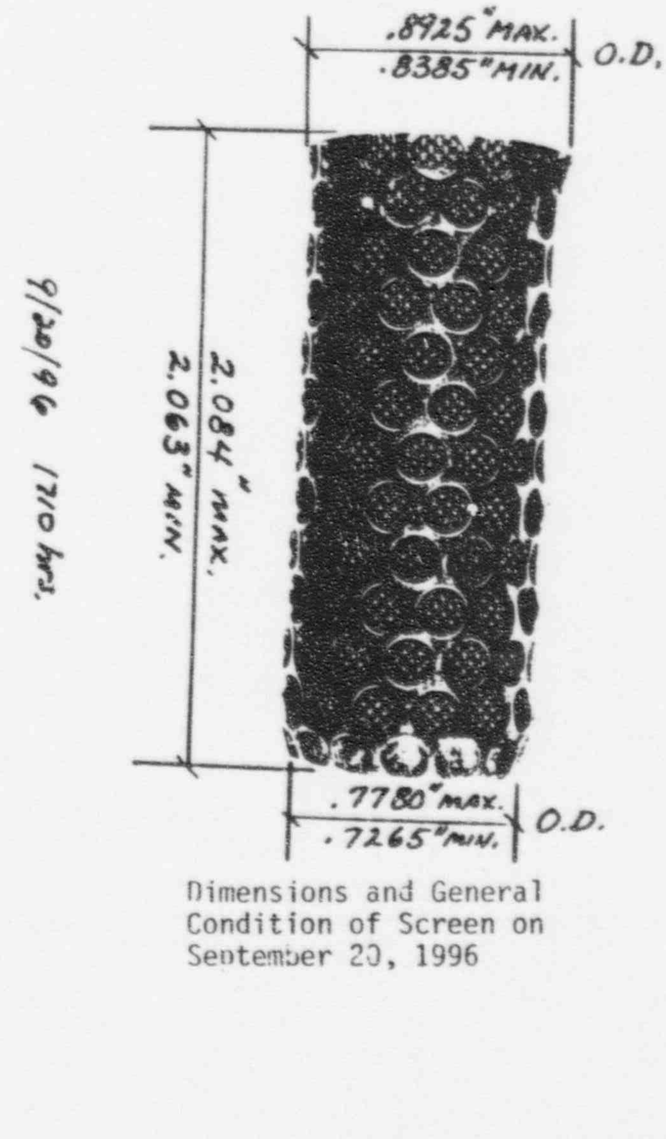



General Arrangement of "Y" Strainer
Components and Location of Penny

FIGURE 1




Dimensions and General
Condition of Screen on
September 15, 1996




Dimensions and General
Condition of Screen on
September 20, 1996

FIGURE 2