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POWER REACTOR EVENTS

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This bi-monthly newsletter summarizes noteworthy information about nuclear power plants obtained from Licensee Event Reports and NRC Inspection Reports. This information is reported in the belief that its open communication benefits all interested individuals and organizations. The events reported are or have been under NRC review and usually concern safety-related issues. Although most events summarized have occurred recently, reporting on some is delayed either because certain generic problems become evident only after an extended period or because certain issues require lengthy resolution.

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FUEL DEGRADATION

During a fuel inspection program at Trojan* on April 26, 1982, 17 assemblies were found to have degraded fuel cladding. The inspection was pre-planned by the licensee to locate fuel assemblies that were believed to be leaking, since dose-equivalent iodine coolant activity had reached 80-85% of the technical specification limit near the end-of-cycle prior to shutdown for refueling. Severe damage to eight fuel assemblies was found by visual inspection; portions of rodlets were missing and loose fuel pellets were found. After fuel sipping, nine additional assemblies were found damaged.

The apparent cause of the fuel damage was water-jet induced vibration of fuel pins in fuel assemblies that are adjacent to baffle plate joint locations with enlarged gaps (see Figure 1). The degradation of the balance of the assemblies was due to minor clad defects, which were detected by the sipping technique. Two types of baffle gap related failures were present. Type 1 is the outside corner or center injection jetting failure. In this case, the water jet impinges directly on the third rod from the corner and causes it to fail in the upper axial regions from direct water impingement combined with induced rod whirling/vibration. Type 2 of baffle gap related failure is the inside corner or corner injection jetting failure, whereby a jet of water flows parallel to the fuel bundle perimeter face between the fuel and the baffle plate. The flow causes fuel rod whirling to occur at the first few rod locations and leads to severe rod failure in the upper axial regions.

Previously (April 25, 1980) abnormal degradation had been discovered in two fuel pins at Trojan. The apparent cause of this fuel damage was also water-jet impingement on the fuel pin via an enlarged baffle plate joint gap. Corrective peening action was taken in 1981 to close these gaps. In 1982, it appears that the jetting problem in the Type 2 failures was caused by the peening done in 1981 on the outside corner joints of the baffle plate. The assemblies that failed during the recent cycle by the Type 1 mechanism, however, appeared to have less damage than those failing before the peening.

The licensee conducted an augmented fuel inspection program in which all fuel assemblies to be used in the subsequent cycle were leak checked by fuel sipping and visually inspected to be damage free. Accessible loose pellets and debris will be retrieved from the reactor vessel internals and refueling cavity. Damaged assemblies adjacent to the baffle will be replaced with new modified fuel assemblies using stainless steel pins in place of fuel rods to ensure fuel integrity until permanent repairs can be made.[1-3]

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*Trojan is a 1080 MWe PWR located 42 miles north of Portland, Oregon, and is operated by Portland General Electric.

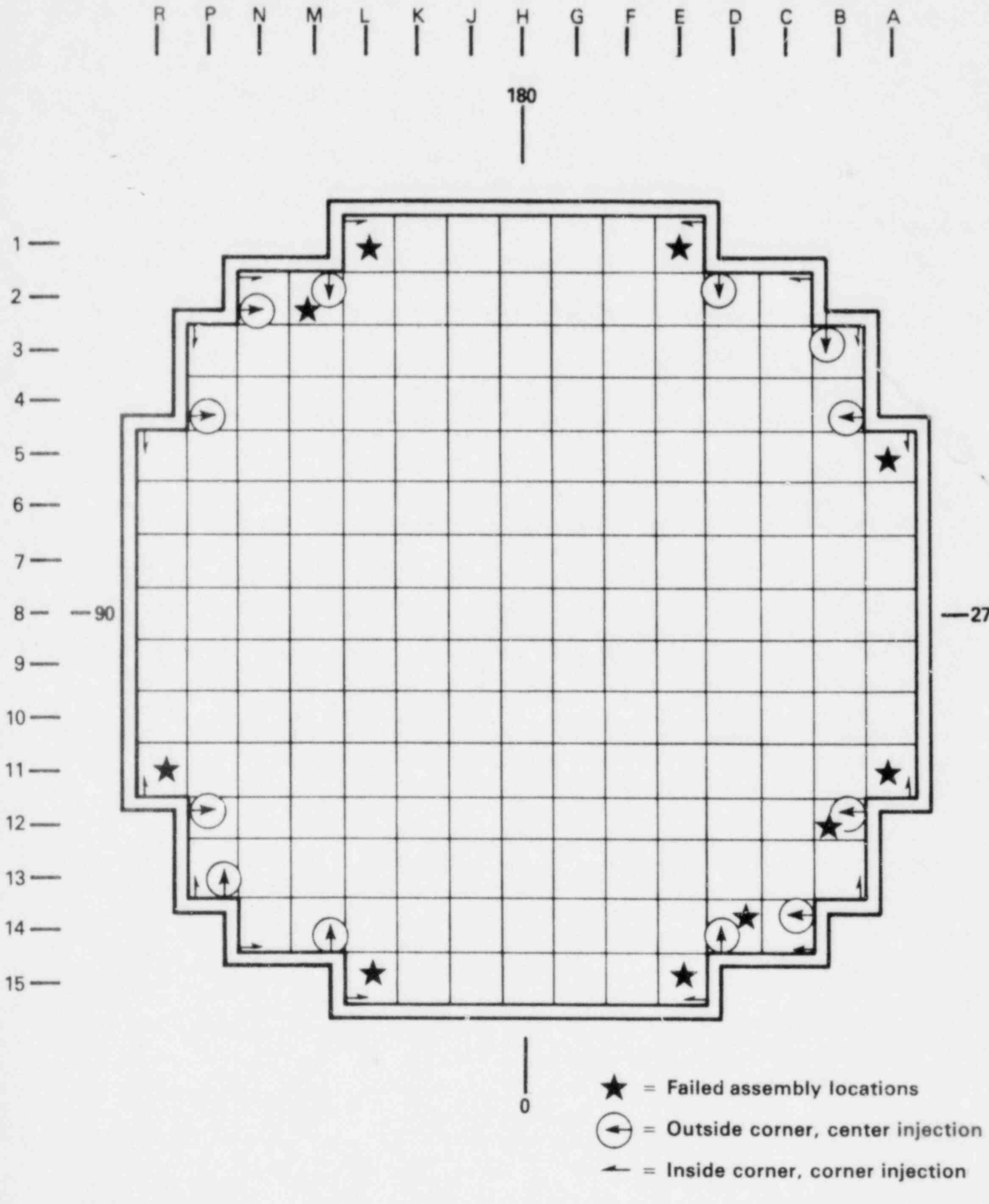

Figure 1. Grid of Trojan Core

HIGH CONDUCTIVITY IN THE REACTOR COOLANT SYSTEM

At Hatch Unit 1* on April 24, 1982, with the reactor operating at full power, operations personnel observed an increase in condensate, feedwater and reactor water conductivity, along with an increase in main steamline radiation and offgas recombiner temperature. Reactor power was decreased to 35%, to reduce the main steamline radiation. Approximately three hours into the event, reactor water conductivity exceeded the technical specification limit of 10 umhos/cm. After the reactor was brought to cold shutdown on April 25, conductivity eventually reached 21 umhos/cm; coolant pH reached 4.6, not meeting the technical specification limit of 5.2; and the chloride level of 2.5 ppm exceeded the technical specification limit of 0.5 ppm. Following the decrease of coolant pH, the casings of 35 (out of 124) local power range monitors (LPRMs) failed within 48 hours.

After extensive investigation, the licensee identified trichloroethane (in "Momar Electro Safe") as the coolant water contaminant. This chemical is used as a cleaning solvent for decontamination at Hatch. Prior to the event, while precoating condensate demineralizer D, a leaking valve caused the backwash receiving tank and the precoat tank to overflow to the turbine building equipment drain sump, which apparently contained trichloroethane used during recent electrical equipment cleaning. The sump pump automatically started and pumped the sump water along with the chemical to the radwaste waste collector tank, which was processed to the waste sample tank through the waste demineralizer. After routine sampling of the waste sample tank, the transfer of waste sample tank water to the condensate storage tank was completed. Conductivity increases were first noted approximately one half hour after this transfer.

The licensee tested trichloroethane by heating it and lowering a bottle containing it close to a fuel bundle, confirming decomposition of the chemical under heat and/or radiation. This decomposition yields high conductivity, low pH and chlorides.

The concern of this event is its impact on the reactor coolant pressure boundary, components in the reactor coolant system and the fuel cladding. Existing on-line instrumentation does not detect the intrusion of organic chemicals in reactor coolant water systems until the chemicals break down; existing ion exchange systems do not remove the organic chemicals; and, in most cases, analytical methods used for sampling water are not designed to detect organic chemicals. An increase in chlorides may cause LPRM failure, and may be caused by chlorinated hydrocarbons or condenser cooling water leaking into the system. This increase in chloride level could affect other stainless steel components in the reactor coolant/cleanup systems by promoting stress induced corrosion cracking. Corrective actions required to alleviate these problems are being investigated by the licensee.[4-6]

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*Hatch Unit 1 is a 757 MWe BWR located 11 miles north of Baxley, Georgia, and is operated by Georgia Power.

AUXILIARY FEEDWATER HEADER DEFORMATION

On April 23, 1982, the licensees of Davis-Besse Unit 1,* Rancho Seco,** and Oconee Unit 3*** met with representatives of Babcock & Wilcox (B&W) and the NRC to discuss auxiliary feedwater (AFW) header damage that had recently been discovered in the once-through steam generators (OTSGs) at these B&W-designed plants.

The toroidal AFW header is located near the top of the shell on B&W OTSGs (see Figure 2). At these three units only, the header is located inside the OTSG. It is rectangular in cross section and encircles the steam generator tube bundle. It is totally supported by the steam shroud attached at eight locations by brackets and pins. A thermal sleeve connects the header to the AFW inlet nozzle. This thermal sleeve is slip fitted into a hole in the outboard face of the header. The as-fabricated clearance between the header and the tubes varies from 9/16 to 2 inches. The header size and shape was selected to minimize the interference with steam flow.

The damage was first discovered at Davis-Besse Unit 1 on April 13. Personnel found indications of tube denting in the vicinity of the AFW ring header inside steam generator No. 1 during eddy current inspection of the peripheral tubes. Further investigation determined that one of the supports for the ring header was damaged, and a holding pin was missing from a second support. A 16-inch access port in the shell of each steam generator was removed to allow further inspection. The ring header was found separated from the thermal sleeve and had a concave deformation in the outer wall. The thermal sleeve was out of the header, misaligned, and butted against the header penetration. In this configuration, AFW flow through the header was reduced and forced into the space between the shell and the shroud. Of the eight brackets holding the ring header, the four which were closest to the access ports were bent, with the holding pins missing from two brackets and damaged in two others. Steam generator No. 2 was subsequently examined. The four pins closest to the access port were missing and two bracket pieces were broken off. Three of the pins were located and recovered.

Other licensees with similarly designed AFW systems were notified of the problem. Subsequently, the licensee at Rancho Seco visually inspected the AFW discharge header in the B steam generator on April 19 and 20. Header deformation on the outside face was concave and uneven, and up to at least three inches in one spot. The thermal sleeve had pulled about one inch away from

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*Davis-Besse Unit 1 is an 874 MWe [illegible] located 21 miles east of Toledo, Ohio, and is operated by Toledo [illegible]

**Rancho Seco is an 873 MWe PWR located 25 miles southeast of Sacramento, California, and is operated by Sacramento Municipal Utility District.

***Oconee Unit 3 is an 860 MWe PWR located 30 miles west of Greenville, South Carolina, and is operated by Duke Power.

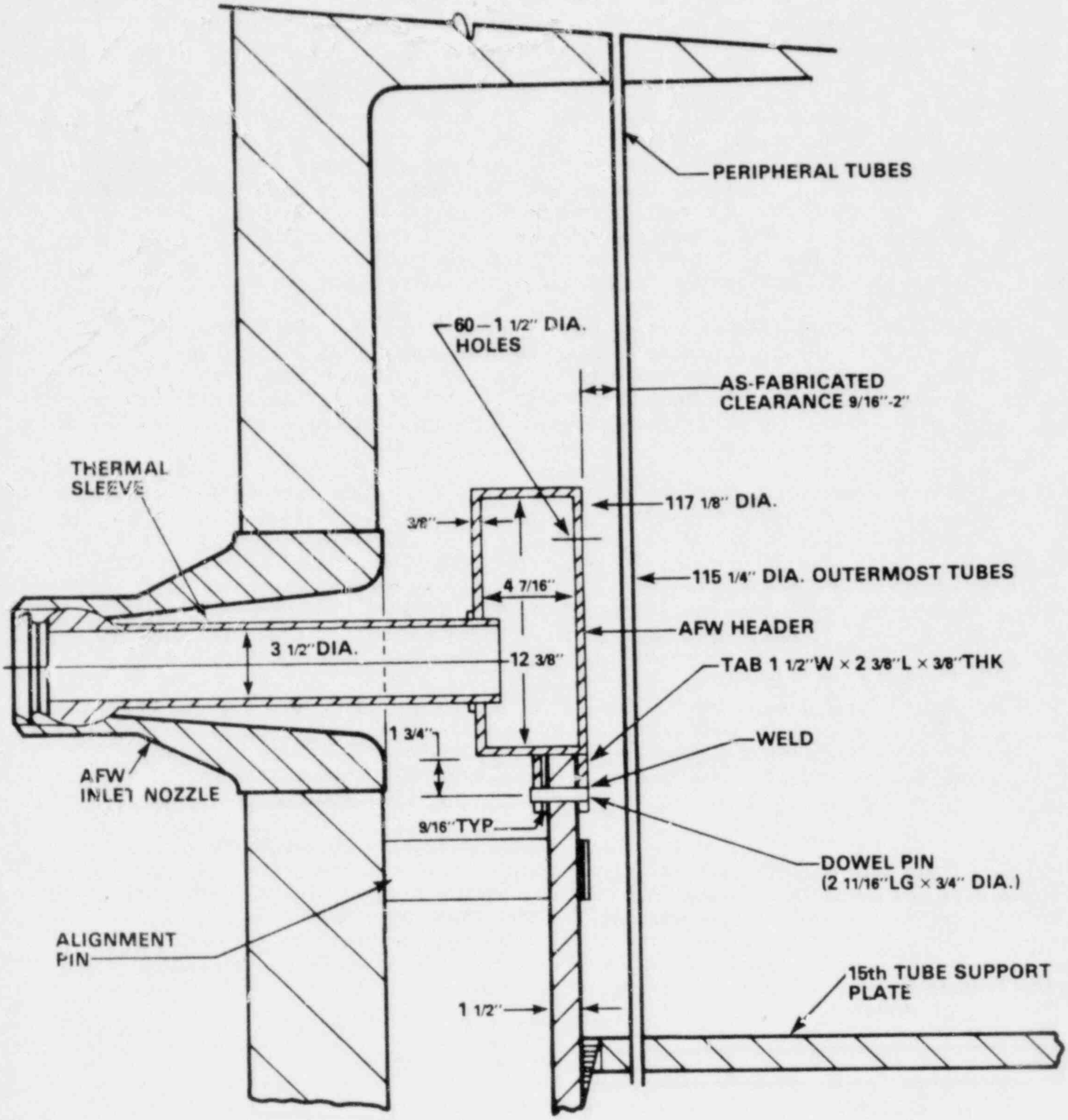

Figure 2. Internal AFW Header Design (Longitudinal Section) for Davis - Besse Unit 1

the top of the AFW header while remaining in contact with the bottom of the header. Two pins were missing on one support and the outer brackets were bent. The bottom ligament of one bracket was torn out.

The licensee for Oconee Unit 3 (the only unit at Oconee with an internal header) performed inspections on April 29 during an outage. Header and bracket damage was found in both steam generators. In the A steam generator, damage included deformation of the outer wall of the header toward the tubes and away from the shell, and a gap of about 3/8 inch over a distance of several feet between the bottom of the ring header and the top of the shroud. Header deformation in the B steam generator was also toward the tubes. In addition, both steam generator headers had bent brackets and missing pins, and both thermal sleeves showed erosion at the header entry location.

The operational history of the plants reveals that Davis-Besse has had about 30 AFW actuations, Rancho Seco about 20, and Oconee Unit 3 about ten. Davis-Besse's experience includes three tests in which AFW was initiated to demonstrate natural circulation and the ability to shut down from outside the control room. A single actuation of AFW can entail numerous cycles as flow is varied for level control.

The Davis-Besse licensee has evaluated several possible failure mechanisms and has concluded that the most likely cause is condensation-induced high pressure differentials. These can be generated when cold auxiliary feedwater is injected into the header. During normal operation, the header would be filled with super-heated steam since it sits in the upper super-heat region of the steam generator. When cold auxiliary feedwater ($\leq 100°F$) is injected into the rectangular header, very large local pressure differences can occur with large steam-water contact areas which cannot be compensated for quickly enough locally through the 60 1-1/2-inch diameter flow holes. Except for the extra strength weld areas, the 3/8-inch plate walls are not reinforced and are inadequate for the loads generated under these conditions. In addition to the possibly large reduced pressure areas, the header experiences high thermal differences when the cold auxiliary feedwater enters the header and begins to fill from the bottom up and flows around the header from the single nozzle.

B&W and the licensees of the three plants involved have developed a design change for permanent repair. These repairs are underway and nearly completed at Davis-Besse and Rancho Seco. The three plants will use the same conceptual design. The repair procedure will satisfy two major objectives: (1) the existing internal AFW header must be stabilized to preclude damage to the steam generator tubes, and (2) a different means of injecting auxiliary feedwater to the steam generators must be provided. To satisfy these objectives the internal AFW header will be further restrained to the shroud on which it currently rests, and an external AFW header will be installed with six injection nozzles (eight at Davis-Besse) to provide AFW flow. (This external AFW ring design already exist at five other B&W plants.) The AFW penetration will be blank flanged, and the internal header will not be used for flow distribution.[7-15]

LOSS OF SHUTDOWN COOLING AND POSITIVE REACTIVITY ADDITION

At San Onofre Unit 2* on March 14, 1982, with the reactor core fully loaded with unirradiated fuel, plant operators noted that there was no flow in the shutdown cooling (SDC) train then in operation. The redundant train was placed in operation, but no flow was obtained from that train either. The operators opened the pump suction valves to the refueling water storage tank (RWST), and vented the system from the high point vents to reestablish pump prime. This operation was successful and the required flow was reestablished.

The boron concentration in the RWST was less than that in the reactor coolant system (RCS) and, as a result, the concentration in the RCS was reduced to 1930 ppm, still well above the technical specification limit of 1720 ppm. This dilution, however, corresponded to a reactivity addition of about 0.64% which exceeded the 0.5% technical specification reporting limit for the subcritical condition.

San Onofre Unit 2 has two RWSTs. This design was selected because the seismic design requirements are easier met with two smaller tanks than with one large tank. The design of these tanks is such that one tank provides most of the borated water required for refueling purposes, and this tank has a recirculation system that mixes the borated water in the tank by admitting water in the top and drawing water from the bottom. The other tank, however, has no such recirculation features. It admits borated, recirculation water into the bottom of the tank, and this water is also drawn from the bottom of the tank.

The boron concentration in the latter RWST varied from about 612 ppm at the top of the tank to about 1900 ppm at the bottom of the tank, where the boron concentration is usually measured. Prior to this event, the tank had been filled with borated water from a portable batch system. When this water was found to be contaminated with iron, the tank was emptied and flushed out with clean water. It was then filled about 15% full of clean water before borated water was added. The inadequate mixing design of this tank, coupled with the dilution of the boron concentration in the RWST by the leaking of approximately 17,000 gallons of water into the RWST, resulted in both a relatively low boron concentration and in stratification of boron concentration.

Although the actual causes for the loss of SDC are not known, the postulated causes include: (1) air entrainment due to inleakage of air into the SDC system; (2) loss of suction to the SDC pumps due to low water level plus vortexing; and (3) gas binding of the SDC pumps due to backflushing the letdown filters with high pressure nitrogen. The licensee initially thought that SDC was lost because of air inleakage into the SDC system piping, but now believes that the loss was due to gas binding of the SDC pumps while backflushing the letdown system filters with high pressure nitrogen and by-passing

*San Onofre Unit 2 was issued a fuel load and low power testing license on February 16, 1982, and is scheduled to go above 5% power in early August. It is located five miles south of San Clemente, California, and is operated by Southern California Edison.

the volume control tank such that high pressure nitrogen could enter into the SDC piping. This hypothesis requires several operator errors, some of which are due to poor human engineering features.

The positive reactivity addition was due to a misalignment of valves while the SDC system pump's suction was being transferred from the RCS hot leg to the RWST. This event was also partially due to poor human engineering features (the valve escutcheons are placed so that they can easily be misread by the operator). This misalignment resulted in draining approximately 6000 gallons of water from the RWST into the RCS by gravity feed. Since the water in the RWST had a lower boron concentration than that in the RCS, the RCS fluid was diluted and a positive reactivity addition resulted.

The licensee plans to revise the procedures for operating the backflushable filter to require isolating the purification system prior to any backflushing operation, since the pathway for injecting nitrogen gas into the SDC system exists only when the purification system is in operation. In addition, a caution statement will be added to the operating procedure for the SDC system emphasizing the need for closing the RCS suction line before opening the RWST suction line. Corrective actions are also being developed to ensure that RWST samples in the future are fully representative of tank contents.

Plant safety was not significantly affected by this event; however, the event identified a condition that has not been specifically analyzed. Possible generic implications are under review by the NRC.[16-18]

HYDROGEN EXPLOSION DURING HPI NOZZLE REPAIR (UPDATE)

As discussed in the previous issue of Power Reactor Events, various plants designed by Babcock & Wilcox (B&W) recently were found to have cracking in the makeup/high-pressure injection (HPI) nozzle thermal sleeve. (See PRE, Vol. 4, No. 2, "Cracking in Piping of Makeup Coolant Lines," pp. 7-10.) Both Units 2 and 3 at Oconee* had cracks in one makeup nozzle that had a loose thermal sleeve. Of the four HPI nozzles at Arkansas Nuclear One - Unit 1,** (1) the nozzle A thermal sleeve retainer buttons were missing, the sleeve had shifted axially toward the pipe, and the upstream end of the sleeve was worn; (2) on nozzle B, only about half of the upstream link which is specified to be rolled actually was rolled; and (3) a possible 360° crack was found in the thermal sleeve in the rolled area on nozzle D. At Rancho Seco,*** the thermal sleeve

*Oconee Units 2 and 3 are both 860 MWe PWRs located 30 miles west of Greenville, South Carolina, and are operated by Duke Power.

**Arkansas Nuclear One - Unit 1 is an 836 MWe PWR located six miles northwest of Russellville, Arkansas, and is operated by Arkansas Power and Light.

***Rancho Seco is an 873 MWe PWR located 25 miles southeast of Sacramento, California, and is operated by Sacramento Municipal Utility District.

on nozzle A was actually missing and believed to be somewhere in the reactor coolant system, and the B thermal sleeve was in place but loose.

On April 10, 1982, a hydrogen explosion occurred at Arkansas Unit 1 while repairs were being made to the HPI nozzle. The unit was shut down at the time. The event occurred during a grinding operation on the pipe of the B HPI line where the pipe was to be welded to the safe end of the B nozzle on the cold leg of the reactor coolant system. The nozzle had been inspected, but the gas concentration had not been checked since March 26. The safe end/pipe weld had been cut, and the workmen were preparing to re-roll the thermal sleeve and re-weld the HPI line to the nozzle. The explosion from the HPI pipe blew off the face mask of one worker and the breathing canister off the belt of the worker. No injuries occurred, but one of the workers was propelled backwards along the 30-ft high scaffolding.

The makeup tank is normally under hydrogen overpressure. The source of the explosion appears to be from hydrogen that was released from the water in the makeup line and trapped in the piping upstream from the nozzle repair location. No equipment damage was identified. The licensee purged the line and continued to monitor the lines for explosive gases, and intends to perform future operations of this sort under an argon atmosphere.

Since similar repair work was being performed at Rancho Seco, the licensee for Arkansas informed the Rancho Seco licensee about the event shortly after it occurred. The Rancho Seco staff then began monitoring the hydrogen concentration above the water in the drained-down reactor coolant system. On April 14, the hydrogen concentration reached 90% of the lower explosive limit, and work on the HPI nozzles was stopped. The space above the reactor coolant was purged with nitrogen to reduce the hydrogen concentration. The repair work was completed in April at both Arkansas Unit 1 and Rancho Seco.[19-22]

PARTIAL LOSS OF OFFSITE POWER

On January 27, 1982 at Beaver Valley Unit 1,* the backup residual heat removal (RHR) pump became unavailable when its normal ac power source was lost due to a fault in a section of 4 kV bus cable. The No. 1 emergency diesel generator was out of service for modifications. The remaining RHR pump remained in service for core decay heat removal.

The event began at 2:15 p.m., when a fire alarm was received in the switchgear area. Thirty seconds later, the 1C unit station service transformer supply breaker tripped on transformer differential current due to a fault in 4 kV bus cable. The faulted area was between the 1C unit station service transformer secondary and the 1A bus supply breaker. Both the 1A normal and 1AE emergency busses were deenergized. Emergency diesel generator No. 1, which is the backup

*Beaver Valley Unit 1 is an 810 MWe PWR located in Shippingport, Pennsylvania and is operated by Duquesne Light.

power supply for the 1AE emergency bus, was out of service for modifications. The loss of the 1AE emergency bus resulted in the loss of the backup RHR pump, which technical specifications require to be operable due to single failure considerations.

The bus cable section that faulted was manufactured by Okonite. The 12 Okonite cables in the bus are routed through a Husky Cabl-Bus System supported in insulating clamping blocks in a covered cable tray arrangement. Visual observations of the cables revealed that two were damaged to the extent of melting the aluminum conductor. Other cables had varying degrees of charred jacketing, and only two appeared to be undamaged. There was also some burning and melting of the cable tray side and bottom cover.

The cause of the failure is not known at this time. Samples of the faulted area were sent to Okonite for analysis. Because of the extent of the damage, it was concluded as part of the testing conducted at the Okonite facility that it would be difficult to reconstruct the failure mechanism or determine which cable failed first. The licensee is considering repairing the cable by (1) splicing in identical cable which exists in stock, and/or (2) replacing the damaged section with equivalent cable.[23]

DEFECTIVE MANUAL INITIATE ESF SWITCHES

On December 12, 1981, with McGuire Unit 1* in cold shutdown, the A train engineered safety features (ESF) manual initiate switches failed to actuate all of their designed devices during the ESF actuation periodic test. Initial indications were that when the switches were depressed, some of the contacts changed state while others did not. Following this failure, the switches were tested at least 30 times with no more failures. Controlled devices and cables on the A train were checked, and no problems were found. The switches had not been cycled since the ESF functional test was performed almost two years ago.

On December 16, a recorder was connected to the outputs from the B train manual switches in order to check the first-cycle responses after the same two years of inactivity. Failures similar to those found on the A train were also found on the "B" train during the early cycles. This test eliminated the possibility of other components in the manual initiate ESF circuitry from causing the problem, and centered attention on the switches. After the early cycle failures, the switches worked consistently. During one of the ESF periodic tests some problems were experienced with one of the reset switches, and appeared to be similar to the initiate switch problems.

There were four initiate switches and three reset switches per ESF train that were involved in the problem. The switch assemblies consisted of E-30 operators and a combination of E30KAL4 and/or E30KAL3 switch blocks made by Cutler

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*McGuire Unit 1 is a 1180 MWe PWR located 17 miles north of Charlotte, North Carolina, and is operated by Duke Power.

Hammer. The E30KAL3 switch blocks consisted of one normally open set of contacts and one normally closed set of contacts. The E30KAL4 switch blocks consisted of two normally open sets of contacts.

The only correlation between the failures was the low voltage and amperage of the circuits. The A train safety injection initiate switch failed, but the B train safety injection initiate switch did not. Voltage and current values for the switches are mostly 48VDC and 38mA or less in this service.

The contacts on these switches are enclosed but not sealed. They had not been in frequent use, since the unit was in the preoperational stage. When the failures occurred, the switches had not been cycled for almost two years. On December 14 and 18, periodic testing using the defective switches was conservative in that any switch failures would have shown up in the test results. The ESF switches which fit the low voltage, low current condition include the four manual initial switches on both trains (main steam isolation, safety injection, Phase A isolation and Phase B isolation/containment spray) and three of the reset switches on each train (containment spray, Phase A isolation, and Phase B isolation).

Examination and analysis by Cutler Hammer found that a silver sulfide coating was building up on the silver-plated switch contacts, and the low voltages involved were unable to establish a current path through the coating. Cutler Hammer informed the licensee that the switches are not intended for low voltage service. Many similar switches are in 120 V service at McGuire, and none have failed.

The licensee will replace all ESF manual initiate and reset switches having contacts used in low voltage/low current applications with switch blocks having gold-plated switch contacts. Since the switch failures occurred only during the early cycles after a long period of inactivity, the length of time between periodic testing should be evaluated. If the switches at McGuire had been needed, however, the operators could have actuated all required devices by operating the individual controls. This is a procedurally-required action if equipment fails to respond.[24]

SAFETY INJECTION ACTUATION SYSTEM DESIGN ERROR

On January 28, 1982, while reviewing safety injection (SI) actuation system prints at Maine Yankee,* an NRC technical review team found that the automatic actuation system was not single failure proof for some events which require SI, such as steam generator tube rupture or a steam line break outside containment. Manual actuation capability was not affected.

Safety injection at Maine Yankee is actuated on low pressurizer pressure and/or on high containment pressure. Four channels are provided for each

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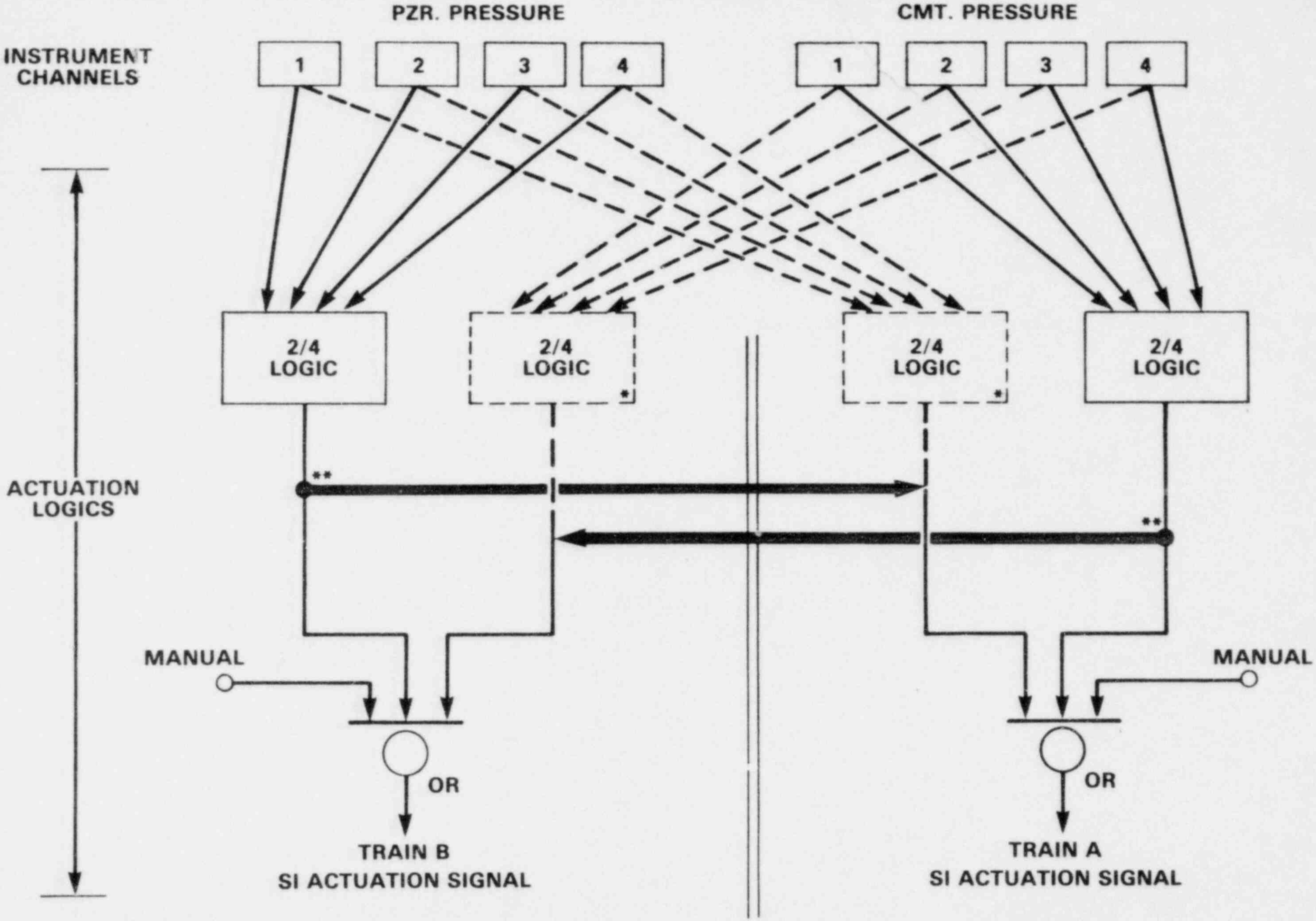
*Maine Yankee is an 810 MWe PWR located ten miles north of Bath, Maine, and is operated by Maine Yankee Atomic Power.

parameter. Redundant trains (A and B) of SI equipment are provided to perform the required safety function. At the time the error was discovered, the logic matrix which combines the signals from the sensing channels to produce SI initiation, based on a trip of any two of the four sensing channels, was implemented by only a single logic element for each parameter (see Figure 3). High containment pressure was a two-out-of-four train A logic and low pressurizer pressure was a two-out-of-four train B logic. Therefore, the design satisfied the single failure criterion only for events which result in coincident low pressurizer pressure and high containment pressure, such as a design basis loss-of-coolant accident.

On February 22, the licensee provided a proposed modification of SI logic, and revised this proposal on March 8. The modification added two-out-of-four logic matrices to both the A and B train logic such that each train of SI is independently initiated based on either low pressurizer pressure or high containment pressure. This change includes a provision for separation of electrical wiring for redundant circuits in order to improve the independence between trains. The modification was judged acceptable by the NRC in a safety evaluation issued to the licensee on April 27, and has subsequently been installed at the plant.

In their safety evaluation, the NRC also noted that technical specifications for Maine Yankee require, as a minimum, only two operable high containment pressure and two operable low pressurizer pressure sensor channels. If the plant operated at these minimum requirements, a single sensor failure would have caused the failure of SI actuation for events which do not result in both low pressurizer pressure and high containment pressure. On April 12, the licensee submitted proposed technical specification changes which addressed these single failure concerns. These changes required three operable sensors for both high containment pressure and low pressurizer pressure, or two operable sensors plus one inoperable sensor placed in a configuration which simulates the tripped condition. An amendment was made to the technical specifications on July 14 increasing the number of required SI signal sensors, which assures the necessary degree of redundancy.[25,26]



*Not part of original design.

**Interconnection removed as part of design modification.

Figure 3. SI ACTUATION SIGNAL LOGIC FOR MAINE YANKEE

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2. USNRC, Information Report SECY-82-205, Enclosure B, p. 4, May 20, 1982.

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6. USNRC memorandum from M. Fairtile, NRR, to H. Denton, et al., NRR, "Hatch Unit No. 1 - Unplanned Shutdown Due to Conductivity Rise," April 28, 1982.

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8. Toledo Edison Company, Docket No. 50-346, Licensee Event Report 82-019, April 30, 1982, and Revision 1, May 24, 1982.

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13. Letter from W. Little, USNRC/R-III, to R. Crouse, Toledo Edison, transmitting Inspection Report No. 50-346/82-13 (DETP), May 3, 1982.

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15. Letter from R. P. Crouse, Toledo Edison, to T. Novak, NRC, July 15, 1982.

16. USNRC, Preliminary Notifications PNO-V-82-12 (March 15, 1982) and 12A (March 17, 1982), "Loss of Shutdown Cooling and Positive Reactivity Addition."

17. Letter from H. B. Ray, Southern California Edison, to R. H. Engelken, USNRC/Region V, March 30, 1982, transmitting Licensee Event Reports 82-02 and 82-03 (both March 30, 1982) for Docket No. 50-361.

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19. USNRC memorandum from G. Vissing, NRR/DL, to H. Denton, et al., "Daily Highlight," April 13, 1982.

20. USNRC memorandum from W. Dircks, EDO, to the Commissioners, "Daily Staff Notes - April 14, 1982," April 15, 1982.

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22. USNRC memorandum from G. Vissing, NRR/DL, to H. Denton, et al., "Daily Highlight," April 6, 1982.

23. Duquesne Light Company, Docket No. 50-334, Licensee Event Report 82-004, February 26, 1982.

24. Duke Power Company, Docket No. 50-369, Licensee Event Report 81-188, Revision 1, March 15, 1982.

25. USNRC, Preliminary Notification PNO-I-82-13, January 29, 1982.

26. USNRC memorandum from D. Eisenhut, NRR/DL, to R. Haynes, Region I, "Maine Yankee Safety Injection Actuation System Design Modification," March 12, 1982.

These referenced documents and all IE Information Notices, Bulletins, and Circulars mentioned in the report are available in the NRC Public Document Room at 1717 H Street, Washington, D.C. 20555, for inspection and/cr copying for a fee. Copies may also be obtained from the editor.

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