NUREG/BR-0051
Vol. 7, No. 3

POWER REACTOR EVENTS

United States Nuclear Regulatory Commission

Date Published: December 1985

Power Reactor Events is a bi-monthly newsletter that compiles operating experience information about commercial nuclear power plants. This includes summaries of noteworthy events and listings and/or abstracts of USNRC and other documents that discuss safety-related or possible generic issues. It is intended to feed back some of the lessons learned from operational experience to the various plant personnel, i.e., managers, licensed reactor operators, training coordinators, and support personnel. Referenced documents are available from the USNRC Public Document Room at 1717 H Street, Washington, DC 20555 for a copying fee. Subscriptions and additional or back issues of Power Reactor Events may be requested from the Superintendent of Documents, U.S. Government Printing Office, (202) 257-2060 or -2171, or at P.O. Box 37082, Washington, D.C. 20013-7982.

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Period Covered: May-June 1985

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

NOTE TO RECIPIENTS: NRC IS CONSIDERING TERMINATING PUBLICATION OF POWER REACTOR EVENTS

The NRC has been reviewing a sampling of licensee operating experience feedback programs. As a part of this review, we discussed how Power Reactor Events was being used by various personnel at nuclear power plants. We found that a variety of people read the publication, and that at some plants the training departments used the document as a source of background information for preparing lesson plans. This usage, however, was not universal or widespread. In addition, the document was not widely used by licensees to feed back the lessons learned from experience to plant personnel to initiate corrective or mitigative action. It thus did not appear to be meeting several of the primary objectives for its publication.

We are aware that over the past five years the increased attention to nuclear power plant operating experience has led to an increase in the number of feedback sources. For example, INPO created NUCLEAR NETWORK and SEE-IN; the NRC increased the number of IE Information Notices directly associated with operational events; more descriptive information is contained in Licensee Event Reports; and commercial and trade publications have increased the availability of information on reactor events.

In light of these findings, we are considering terminating the publication of Power Reactor Events. Prior to terminating the publication, however, we will consider comments from recipients as to the need to continue the publication. Comments may be sent to Sheryl Massaro, Editor/USNRC/EWS-263A/Washington, DC 20555, or may be phoned in to Sheryl at 301-492-9752 or to Jack Crooks at 301-492-4425. To be considered, comments must be received by February 28, 1985.

1.0 SUMMARIES OF EVENTS

1.1 Loss of Main and Auxiliary Feedwater Event at Davis-Besse

At 1:35 a.m., on June 9, 1985, one of the two main feedwater pumps at Davis-Besse Unit 1* tripped on overspeed while the plant was operating at 90% power. Thirty seconds later, the reactor and turbine were automatically tripped on high reactor coolant system pressure. Soon after the reactor tripped, both main steam isolation valves closed spuriously, resulting in a loss of steam to the second main feedwater pump. Subsequent to this complete loss of main feedwater, an operator error, malfunctions of two redundant valves in the safety-related auxiliary feedwater system, and overspeed trips of the two redundant, steam turbine-driven auxiliary feedwater pumps resulted in loss of all sources of feedwater to the steam generators.

Separate actions by the operators were required to (1) correct the initial operator error, (2) open the valves which malfunctioned, and (3) reset the overspeed trips of the turbine-driven auxiliary feedwater pumps. Actions outside the control room were required to open the valves and place the pumps in operation. While operators acted to restart the safety-related auxiliary feedwater system, operator actions outside the control room were also taken to place a nonsafety-related, motor-driven, startup feedwater pump in service. The plant's two steam generators had essentially boiled dry before feedwater from any source became available to them. Further, a number of additional equipment problems complicated the event. Nevertheless, operators were successful in bringing the plant to a stable shutdown, and in preventing any abnormal releases of radioactivity and any major damage to the plant.

Details of this event, results of NRC and industry investigations, and descriptions of the extensive corrective actions initiated by the licensee have been reported in several NRC and industry documents. A listing of the most comprehensive reports is provided below:

- Toledo Edison's Licensee Event Report 85-13 for Docket 50-346, issued July 9, 1985
- NRC's IE Information Notice 85-50, "Complete Loss of Main and Auxiliary Feedwater at a PWR Designed by Babcock & Wilcox," issued July 8, 1985
- NRC's investigation report, Loss of Main and Auxiliary Feedwater Event at the Davis-Besse Plant on June 9, 1985 (NUREG-1154) issued July 1985
- An independent Assessment of Actions at Davis-Besse Resulting from the June 9, 1985 Loss of Feedwater Event, issued August 30, 1985 by Basic Energy Technology Associates, Inc., for Toledo Edison
- Toledo Edison's Davis-Besse Nuclear Power Station Course of Action Report, Vols. 1 and 2, issued September 9, 1985

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*Davis-Besse Unit 1 is an 860 MWe (net) MDC Babcock & Wilcox PWR located 21 miles east of Toledo, Ohio, and is operated by Toledo Edison.

The NRC concluded that the key safety significance of the event was that multiple equipment failures occurred, including several common mode failures, resulting in a transient beyond the design basis of the plant. Furthermore, the NRC concluded that the underlying cause of this event was the licensee's lack of attention to detail in the case of plant equipment. The performance of the reactor operator was the key to the successful mitigation of a serious event.

1.2 Flooding Results from Expansion Joint Fatigue Failure and Installation Error at LaSalle

On May 31, 1985, LaSalle Unit 1* was manually scrammed due to decreasing vacuum in the main condenser. The licensee determined that a 9-foot diameter flexible expansion joint on the discharge of the 1B circulation water pump (CWP) had ruptured, and the lake screen house was flooded. All service water pumps and CWPs were lost on Units 1 and 2 due to the flooding. The reactor water cleanup system (RWCU) isolated on high flow after the scram. No leaks were found during a system walkdown, and the RWCU system was returned to service. The local fire department responded with a pumper truck to assist in pumping the water out of the lake screen house. The event is detailed below.

On May 31, 1985, at 7:45 p.m., with Unit 1 at 64% power, the reactor was manually scrammed due to a failed 1B CWP discharge valve (1CW006B). Prior to the manual scram, Unit 1 had been at 85% power with the 1A and 1B CWPs in operation and the 1C pump in standby. Unit 2 was in cold shutdown for a scheduled surveillance outage.

At 6:22 p.m., the 1B CWP tripped. Unsuccessful start attempts were made on this pump and the standby 1C pump. (Difficulty in starting CWPs is not unusual at LaSalle; the pumps have several start permissives, such as discharge valve full closed, gland water pressure available, and exciter interlocks.) At 6:25 p.m., the 1C pump started. The Unit 1 Shift Foreman (Senior Reactor Operator) and a non-licenseed Operator went to the lake screen house, where the CWPs are located, to determine the cause of the 1B pump trip.

At 6:29 p.m., a Security Officer on a routine inspection of the lake screen house reported a major water leak in the basement. Moments later, the Shift Foreman and the Operator arrived. They discovered that water was gushing from a failed rubber expansion joint between the 1B pump discharge and its discharge valve. Flow was conservatively estimated at 2000 gpm. Based on the Shift Foreman's evaluation, a load drop of 200 MWe/hr was initiated on Unit 1 at 6:35 p.m., and the 1B CWP was shut down.

At 7:45 p.m., the unit was manually scrammed in anticipation of a loss of circulation water. The Unit 2 CWPs were then shut down because the water level was approaching the location of the CWP exciter panels, which would eventually flood and short out. Unit 1 and Unit 2 heat loads were reduced to maintain cooling to the most important plant systems, primarily the air systems.

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*LaSalle Units 1 and 2 are 1036 MWe MDC General Electric BWRs. They are located 11 miles southeast of Ottowa, Illinois, and are operated by Commonwealth Edison.

At 7:46 p.m., the 1C CWP was shut down, and the 1A pump was shut down about 8 minutes later. From 8:30 to 8:45 p.m., the 2A CWP and common service water pumps tripped on neutral overcurrent. Equipment in the lake screen house was deenergized to prevent water damage. (Residual heat removal service water and essential equipment service water for shutdown decay heat removal capability were unaffected by this event since they are located in separate, watertight compartments. Only the plant service water pumps, providing non-vital cooling, were affected by this event.)

Service water provides cooling to non-safe shutdown equipment associated with turbine lube oil cooling, primary containment chill water, closed cooling water for the reactor and turbine buildings, and the process computer. Cooldown of the reactor was initiated with a combination of the reactor core isolation cooling (RCIC) system and the cycling of the main steam safety relief valves (SRVs). RCIC is the preferred and designated high pressure system for safe shutdown of the plant. The operators were following standard procedures for shutting the plant down after a loss of main condenser (normal heat sink) event.

At 8:57 p.m., the process computer was shut off due to a loss of air conditioning. The safety parameter display system became non-functional when the computer was shut down.

At 9:45 p.m., RWCU isolated on high differential flow created by the change in reactor pressure following cycling of the main steam safety valves at 9:30 and 9:35 p.m.

At 10:00 p.m., emergency procedure LGA-03, "Containment Control," was entered due to high temperatures in the drywell and suppression pool. This was a result of manually depressurizing the reactor with the SRVs in order to reach cold shutdown. The steam condensing mode of residual heat removal was not used because plant instrument air was at risk when service water was lost.

At 10:25 p.m., an Unusual Event was declared, and notifications were made per appropriate procedures.

Water level in the lake screen house basement reached lake level of 698 feet at 1:15 a.m. on June 1, 1985. This was approximately 675,000 gallons of water. At 10:27 a.m., Unit 1 was brought to cold shutdown.

The primary cause of the event was fatigue failure of the 1B CWP discharge valve gear operator mounting bolts. After the valve bolt failure, the valve disc rapidly rotated towards the closed position, rotating in the reverse-to-normal direction. As determined by the licensee's Engineering Department, a closure rate of 5 to 10 degrees rotation in 20 to 30 milliseconds created an extremely rapid transient hydraulic pressure spike, peaking in excess of 50 psig. This was sufficient to blow the expansion joint out of its retaining bars, and occurred while the 1B CWP was running. The rapid valve closure caused the pump to become deadheaded. The motor load suddenly increased, and under the influence of excess shaft torque, the motor speed decreased, causing the rotor and stator fields to become out of synchronism and slip, which resulted in a "slip guard relay" trip.

Two root causes precipitated this event. The first was a valve installation error. The fractured gear operator mounting bolts and corresponding bolting from other circulation water discharge valves revealed that the applied assembly torque was significantly less than the valve manufacturer's specification.

The inadequate bolt tensioning undoubtedly led to loosening of the bolts in service through normal flow induced oscillations of the valve disc in the open position. The loosening permitted relative motion between the gear operator and the valve yoke, and led to application of a relatively high amplitude, low frequency, cyclical shear load on the bolts. This cyclical load was clearly involved with the bolt fatigue fracture.

The second root cause was probably a design deficiency. First, there appears to be an error in the assumptions used to structurally size the gear operator and its associated attachment bolting. The operator structural sizing was based on a symmetrical flow velocity distribution model, whereas the LaSalle application involves an asymmetrical model. An asymmetrical distribution consistently represents a significant increase in butterfly valve operating torque and, consequently, an increase in the gear operator structural loading and susceptibility to vibration and flutter.

It is also believed that there may have been insufficient conservative design margin assigned to the gear operator-valve yoke mounting bolts. Bolt tensioning is expected to prevent both axial and rotational movement of the operator relative to the valve yoke. During the valve-operator reassembly following this event, it was discovered and verified that despite thorough operator-yoke mating surface preparation and proper torquing of new mounting bolts, manual valve actuation still produced significant operator-yoke relative motion.

The discharge isolation valve (1CW006B) is a 108-inch butterfly valve manufactured by the Henry Pratt Company. The expansion joint with restraining bars, located 2 feet upstream of the discharge valve, is also manufactured by Pratt. The manual operator, Model SMBI-40, was manufactured by Limitorque Company, as specified by Pratt.

Corrective action included placing stop logs in the intake structure for the 1B CWP. Portable pumps were used to pump the water out of the basement from 8:25 p.m. on May 31 through 7:00 p.m. on June 1, 1985, when the basement was pumped nearly dry. All of the service water pump motors were sent offsite to be dried and inspected. The first service water pump was returned to service on June 4, and the last on June 10, 1985.

A replacement expansion boot was made from a 120-inch boot obtained from Quad-Cities Nuclear Station.* This was installed on June 8, 1985. In the lake screen house, all circulating water piping expansion joint boots and their retaining rings were inspected for integrity. The same inspection was performed on the inlet waterboxes.

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*Quad-Cities Units 1 and 2 are 769 MWe (net) MDC General Electric BWRs. They are located 20 miles northeast of Moline, Illinois, and are operated by Commonwealth Edison.

Inspection of the bolts connecting the operator gear to the valve yoke was performed on the remaining Unit 1 valves and all the Unit 2 discharge valves.

The process computer was returned to service on June 4, 1985.

A special test has been written to verify that the torque developed by potentially asymmetric circulation water flow on the discharge valve does not exceed the allowable torque specified by the vendor. The test will also collect vibration data on the gear operator and valve body during valve operation.

Data sets will be obtained for the following two operating conditions on the Unit 2 discharge valve (2CW006B) in order to envelope the highest anticipated valve operating torques and gear operator loads: (1) start, run, and shutdown of the 2B CWP; and (2) start and run of another CWP and the 2B CWP associated with the instrument valve followed by the tripping of the 2B pump, followed by rapid start and run of the remaining CWP.

The test results will determine what valve design changes, if any, are necessary, and generate quantitative acceptance standards for such changes. The test results will also serve to further characterize the probabilistic risk of similar valve failure initiating event recurrences in the future.

An investigation is being conducted to consider moving the CWP exciters to a location above lake level. In addition, there is a study being performed to investigate possible long-term corrective actions which can be taken to prevent loss of all circulation water and service water systems due to flooding.

The loss of service water during this event caused loss of cooling to the station air compressors and the primary containment air coolers among other loads. One of two station air compressors was running hot and subsequently shut down. The fire protection system diesel fire pumps were crosstied to the service water system using hoses, to supply sufficient cooling to keep the second compressor operating in order to provide air for the plant instrument air system.

Loss of the turbine lube oil cooling system could result in costly turbine generator bearing damage due to lack of cooling to the bearings before the turbine generator could be put on its timing gear. The turbine lube oil coolers were cooled by crosstying the fire protection system to the turbine building closed cooling water system.

Loss of drywell pneumatics could jeopardize long-term operation of the SRV relief function, which could inhibit one pathway to cold shutdown. Fire protection water was also crosstied to reactor building closed cooling water (RBCCW), which cools the drywell pneumatics compressor, and the operability of the SRVs was maintained.

Loss of cooling to the primary containment cooling system caused drywell temperature to rise to 167 degrees F. This is 32 degrees above the technical specification temperature limit of 135 degrees F. The drywell pressure was kept below the isolation pressure of 1.69 psig by venting the containment. A containment air sample had been taken just prior to the water leak occurring, which proved that containment venting could be performed. This action prevented isolation of water to the containment coolers. The drywell temperature exceeded technical specification limits for approximately 8 hours. An analysis by Sargent & Lundy has been performed, and it was determined that the temperatures experienced in the drywell had insignificant impact on all the equipment. The station heat recovery system, which uses glycol to air heat exchanger, was tied into the chillers for the primary containment cooling water system. This was used until service water was returned to service.

The RWCU system pumps were expeditiously shut down following the reactor scram to help reduce the RBCCW heat load. It was minimized to allow reactor recirculation pump operation, which provided accurate moderator temperature indication. The normal RWCU shutdown procedure closes the inboard and outboard valves. Because the valves were not closed, the pressure transient from the SRV closure was sensed by the RWCU inlet flow sensor, and a high differential flow isolation occurred. The sensor taps off the RWCU suction line. The isolation occurred under unique conditions, and was of minor concern. (Refs. 1-3.)

1.3 Failed Fuel in One Rod Assembly Due to Vibration from Water Impingement at Point Beach

During the April 27, 1985 routine inspection of discharged fuel during refueling at Point Beach Unit 1,* failed fuel rod cladding in assembly H9 was discovered. The fuel rod cladding appears to have failed due to vibration of the rod against the grid and grid springs. This vibration is believed to have been caused by water impingement through a joint gap in the core baffle discovered on May 15, 1985. Assembly H9 was located in position D12, an outside position of the core next to a core baffle plate corner. No fuel pellets escaped from the fuel rod. The event is detailed below.

On April 27, 1985, during inspection of discharged fuel assemblies, the inspection supervisor noted a failed fuel rod in fuel assembly H9. This inspection was being done as part of the normal routine inspection of all discharged fuel assemblies, and also to search for any debris remaining after steam generator replacement done just prior to Cycle 12.

On April 27 and 30, 1985, visual inspections of fuel assembly H9 noted that a section of cladding on rod No. 14 (the outside corner rod next to the baffle joint) immediately behind grid No. 2 (the second grid from the top of the assembly) had failed. (See Figure 1.) The fuel was visible inside the rod. The same rod was found to have a torn grid spring at grid No. 3 and another cladding failure with the grid spring showing at grid No. 1. Rod No. 14 was touching the bottom nozzle. All other rods were in their normal off-the-bottom position. Fuel assembly H9 was placed in the reactor in location D12 such that rod No. 14 was located in the southwest corner of the fuel assembly during Cycle 12.

An inspection was performed of the corner joint of the core baffle plate forming the southwest corner of position D12 of the core. This joint is a simple butt joint with the line of the joint running north-south. The baffle plate joint

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*Point Beach Unit 1 is a 485 MWe (net) MDC Westinghouse PWR located 15 miles north of Manitowac, Wisconsin, and is operated by Wisconsin Electric Power.

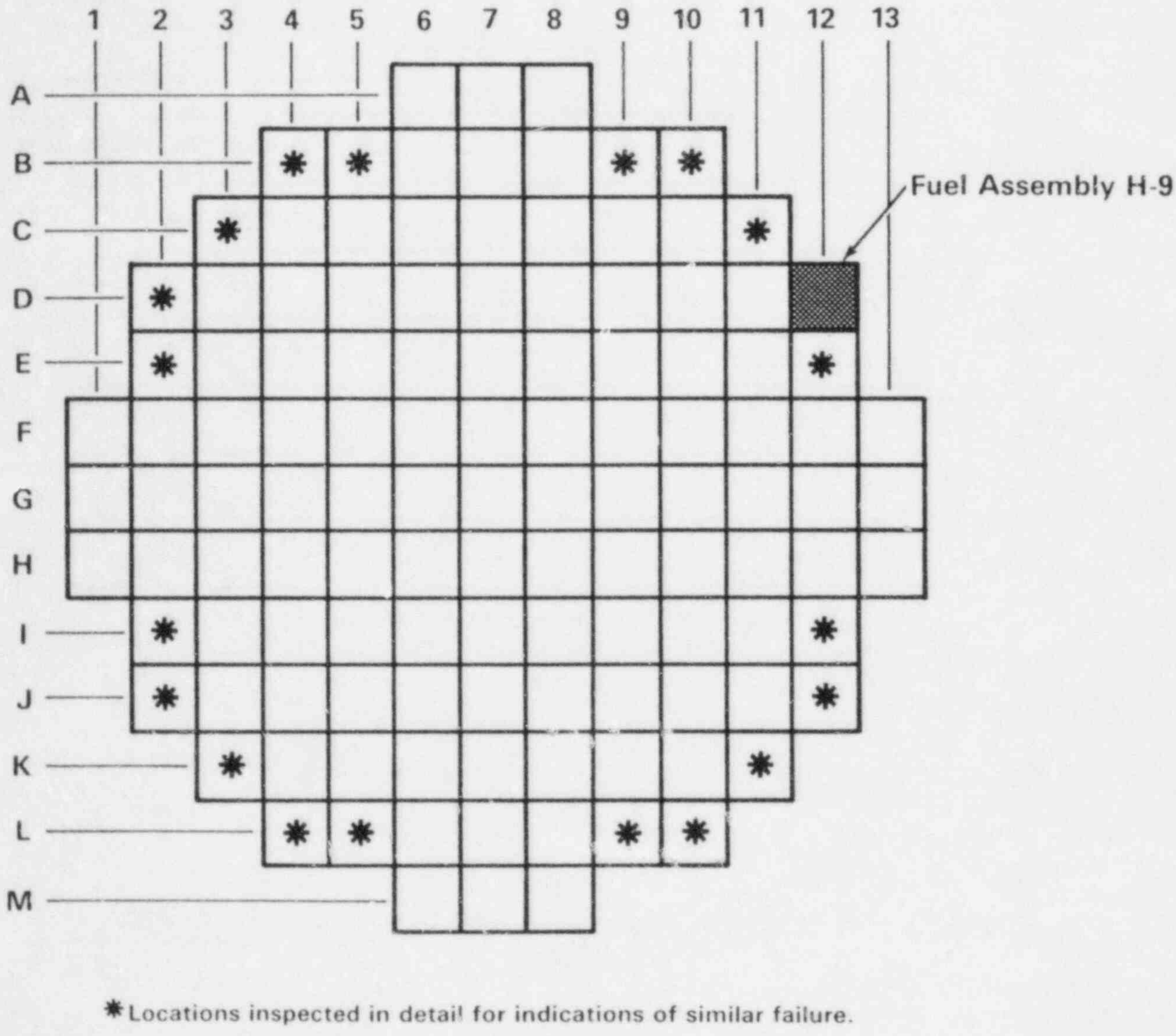

Figure 1. Location of Failed Fuel Assembly at Point Beach

is a bolted joint. During an inspection of the full length of the joint forming the southwest corner of the baffle at D12, two areas were found which indicated possible flow (baffle jetting) through the baffle joint.

The baffle is held to the core barrel with cap screws to the baffle radial supports. These radial supports are located approximately every 2 feet, vertically along the baffle plate. The first and second grids on the fuel assembly would sit between the third and fourth baffle radial supports.

The inspection of the joint revealed indications of a possible 4 to 7 mil gap in the baffle plate joint between the rows of cap screws indicating the second and third, and third and fourth baffle radial supports. These indication locations correspond to the location of the fuel damage on assembly H9.

Fuel assemblies which had been located in positions similar to D12 during Cycle 12 were also inspected in detail for the same type of failure as well as early indications of this type of failure. The locations of interest were: B4, B5, B9, B10, C3, C11, D2, E2, E12, I2, I12, J2, J12, K3, K11, L4, L5, L9, and L10.

During these further inspections, two assemblies showed slight indications of through-baffle joint flow. These were on the northeast corner of fuel assembly P29, located in position E2 during Cycle 12, and on the southeast corner of fuel assembly P4, located in position I2 during Cycle 12. Assembly P29 had faint white lines on grid Nos. 3, 4, and 5 between rod Nos. 12 and 13. Assembly P4 had a similar faint white line on grid No. 4 between rod Nos. 1 and 3.

The probable cause of the fuel clad failure in assembly H9 is water impingement through the baffle plate joint during Cycle 12. Fuel clad failure was experienced earlier at Point Beach during Unit 1 Cycle 2 at location H1 (Licensee Event Report 50-266/75-018). However, the joint at location H1 is of a different design than that at position D12. The counterflow design of the Point Beach reactor results in a higher pressure outside the baffle plate than inside the plate. This can and apparently has, in this case, resulted in flow through the plate joint (baffle jetting) if any opening occurs. In this case, the opening was wide enough and flow strong enough to allow the fuel rod to vibrate and the grid and spring assemblies to cause clad damage. In the case of assembly H9, this damage caused the cladding to fail and expose the fuel to the primary coolant. The chemical and volume control system was designed to, and did, maintain the allowable levels of primary coolant activity with the failed fuel clad during Cycle 12.

The following safety concerns have been evaluated: (1) the potential for further fuel failure by the same mechanism in the same or other locations; and (2) the effect of increased primary system activity on the health and safety of plant personnel and the general public.

There is a potential for failure of fuel rods in the same location. However, this failure does not appear to happen quickly. The fuel assembly which will be installed into position D12 has been inspected thoroughly prior to installation. This inspection has established a baseline of data for the inspection which will take place after the completion of Cycle 13. Monitoring of primary coolant activity during startup and subsequent operation will also provide indication of any failure of fuel at this or any other core position. After consultation with the nuclear steam supply system vendor, Westinghouse, the decision has been made not to modify any fuel assemblies to mitigate baffle jetting effects.

Based on the evaluation done above, operation of the Unit 1 Cycle 13 core is not considered to pose a hazard to the health and safety of the plant personnel or the public. Further evaluation of the cause of the fuel damage and the baffle plate joint gap will be done. The fuel assemblies in those areas which have been identified as potential locations for this type of situation will be thoroughly inspected after the completion of Cycle 13. (Ref. 4.)

1.4 Unisolable Reactor Coolant System Leak Due to Pipe Crack Resulting from Design and Construction Errors at Rancho Seco

On June 23, 1985, a crack was found at Rancho Seco* in a 1-inch diameter high point vent line from the reactor coolant system (RCS), resulting in a 17 gpm, unisolable primary coolant leak. The cause of the event was determined to be fatigue from high cycle vibration, induced by the nitrogen and vent header systems because of design and construction errors in 1974, 1981, and 1983. The event is detailed below.

On June 23, 1985, Rancho Seco was in a hot shutdown condition (RCS at 532 degrees F and 2145 psig). At 4:05 a.m., with the reactor approaching criticality, the Control Room Operators detected an RCS leak, estimated to be 17 gpm. Using the reactor building camera, the operators were able to detect a steam leak in the vicinity of the B once-through steam generator (OTSG). The Control Room Operators then initiated a plant cooldown, and declared an unusual event due to an RCS leakage rate of greater than 10 gpm. At 7:35 a.m., a licensee inspection team entered the reactor building in an attempt to isolate the leak. The leak was verified to be on a 1-inch line in the B high point vent system, and was not isolable. Cooldown and depressurization occurred in an orderly manner, and the plant reached cold shutdown at 6:38 p.m. By the time the RCS was depressurized, approximately 16,000 gallons of the coolant had leaked into the reactor building. There was no observable increase in the reactor building surface or airborne contamination due to the coolant leakage.

The source of the leak was found to be a crack located on a segment of piping that connects the B OTSG nozzle to the high point vent system and the nitrogen supply system for the RCS. The crack was a 120-degree through-wall, azimuthal opening on the pipe wall. The pipe was a 1-inch diameter schedule 160 line. The licensee's investigation subsequently identified that the B high point vent system had deficiencies in the pipe support configuration, as described below:

- Missing cross-brace between lines 20574-1-inch-HE and 20555-1-inch-CA;

- Missing rigid flanged spool piece that should have been installed in the nitrogen supply line during operation of the plant;

*Rancho Seco is an 873 MWe (net) MDC Babcock & Wilcox PWR located 25 miles southeast of Sacramento, California, and is operated by Sacramento Municipal Utility District.

- Missing east-west stops on support number 1S20567-2 and -3; and
- No replacement of vertical spring support with required stops on support number IS20567-2.

The above deficiencies also were identified in a stress analysis performed by the licensee's contractor in 1981 in preparation for addition of the high point vent modifications which were made to the system in 1983. The required piping supports were not installed, however, even though the need for these piping supports was transmitted to the licensee by letter from their design contractor on October 7, 1981.

In addition, the design drawings for construction of the RCS 3/4-inch high point vent lines on both the A and B sides specified seismic frames located between the two sets of solenoid valves, but these supports were found missing in June 1985. Numerous additional examples of similar deficiencies in safety-related systems were identified and documented in a licensee report to NRC's Region V Office on August 6, 1985. On September 26, 1985, the NRC issued a Notice of Violation and Proposed Imposition of Civil Penalty ($50,000) to the Rancho Seco licensee.

Based on preliminary analysis by the licensee, corrective action for this event has included the following:

(1) Repair of the high point vent line and installation of supports as designed;

(2) Assignment of a multidepartmental task force to thoroughly evaluate this event to determine the root cause of the cracked high point vent line;

(3) Engineering walkdown and evaluation of 100% of the seismic Class 1 piping support modifications made since completion of the walkdowns required by NRC's IE Bulletin (IEB) 79-14, "Seismic Analyses for As-built Safety-related Piping System," issued July 2, 1979;

(4) Additional walkdowns of the safety-related seismic Class 1 piping and supports defined in the Rancho Seco USAR but not covered in the original IEB 79-14 walkdowns;

(5) Dryout of the motor winding insulation of reactor coolant pumps C and D; and

(6) Modification of the reactor building video camera above the pressurizer to allow unrestricted rotation.

The Rancho Seco licensee is continuing an in-depth analysis of this event, its safety significance, and corrective actions. (Refs. 5-7.)

1.5 Two Stuck Control Rods Due to Loose Parts Resulting from Inadequate Installation Procedures at Point Beach

On May 30, 1985, during performance of a cold full-flow control rod drop test in preparation for restart from a refueling outage at Point Beach Unit 1,* control

*Point Beach Units 1 and 2 are 485 MWe (net) MDC Westinghouse PWRs located 15 miles north of Manitowac, Wisconsin, and are operated by Wisconsin Electric Power.

rod F-12 did not drop to the bottom of the core, but stuck about 60 inches above the bottom. The licensee reviewed the control rod drive test data and sent the findings of their investigation to Westinghouse (the nuclear steam system supplier) for analysis. The licensee continued with plans to conduct a hot full-flow drop test on all the other control rods. At 3:42 a.m., May 31, with the primary system at 370 degrees F, rod J-4, which had successfully dropped in the cold test, dropped only 45 inches, sticking 99 inches from the bottom of the core. During an inspection of control rods F-12 and J-4 with the reactor vessel head removed, the licensee determined that both control rods stuck as a result of work performed on the control rod guide tubes during the refueling outage. Control rod F-12 stuck because a broken piece from a guide tube insert had lodged in the control rod guide tube. Rod J-4 stuck because a flexure pin had lodged itself in the guide tube. All guide tube inserts and flexure pins had previously been modified as a result of problems with this equipment. The event is detailed below.

During performance of cold and hot rod drop testing, two rods failed to drop to the bottom of the core. On May 30, 1985, at 9:00 p.m. during cold, full-flow rod drop testing, rod F-12 became stuck about 60 inches from the bottom of the core. Atempts to move the rod by stepping were unsuccessful. Analysis of the stepping current traces indicated that the problem was not with the stepping mechanism. The licensee decided to proceed with reactor coolant system heatup in order to perform an inservice leak test on the system as well as hot rod drop testing. During a conference call between the licensee and the NRC, the licensee committed to not attempt any further stepping of rod F-12. During hot (370 degrees F), full-flow rod drop testing, rod J-4 became stuck about 99 inches from the bottom of the core. The licensee returned the unit to cold shutdown.

After returning to cold shutdown, the licensee attempted to move rod J-4 by stepping while taking stepping current traces for analysis. Rod J-4 appeared to move out a couple of steps, but then would not move in either direction. As with rod F-12, analysis of the stepping current traces indicated no problems with the stepping mechanism.

The licensee decided to remove the reactor vessel head to perform further inspections of the stuck rods. The first consideration was to ensure that the rods were stuck in the upper internals and not in the head. A special procedure was developed prior to proceeding with the head lift. Provisions were made to leave the individual rod position indications for the two stuck rods connected during the initial head lift for observation of relative motion, which would indicate that the rods were stuck in the upper internals rather than in the head. The initial lift was to an elevation of 1 foot. During this lift, relative motion was observed. Using a remote tool, the licensee then tried to free the stuck rods by vibrating the drive shafts. Rod F-12 did not move during this evolution. Rod J-4 dropped approximately 8 inches and again became stuck. (This is the distance between guide cards in the guide tubes.)

Further attempts to free the rods by this method were abandoned. The head was then lifted to an elevation of 10 feet, and the F-12 and J-4 drive shafts were secured to the sides of the refueling cavity by ropes to prevent them from putting undue strain on the guide tubes and flexureless inserts (see Figure 2) when the head was lifted further, thereby removing any lateral support provided by the rod position indicator housings.

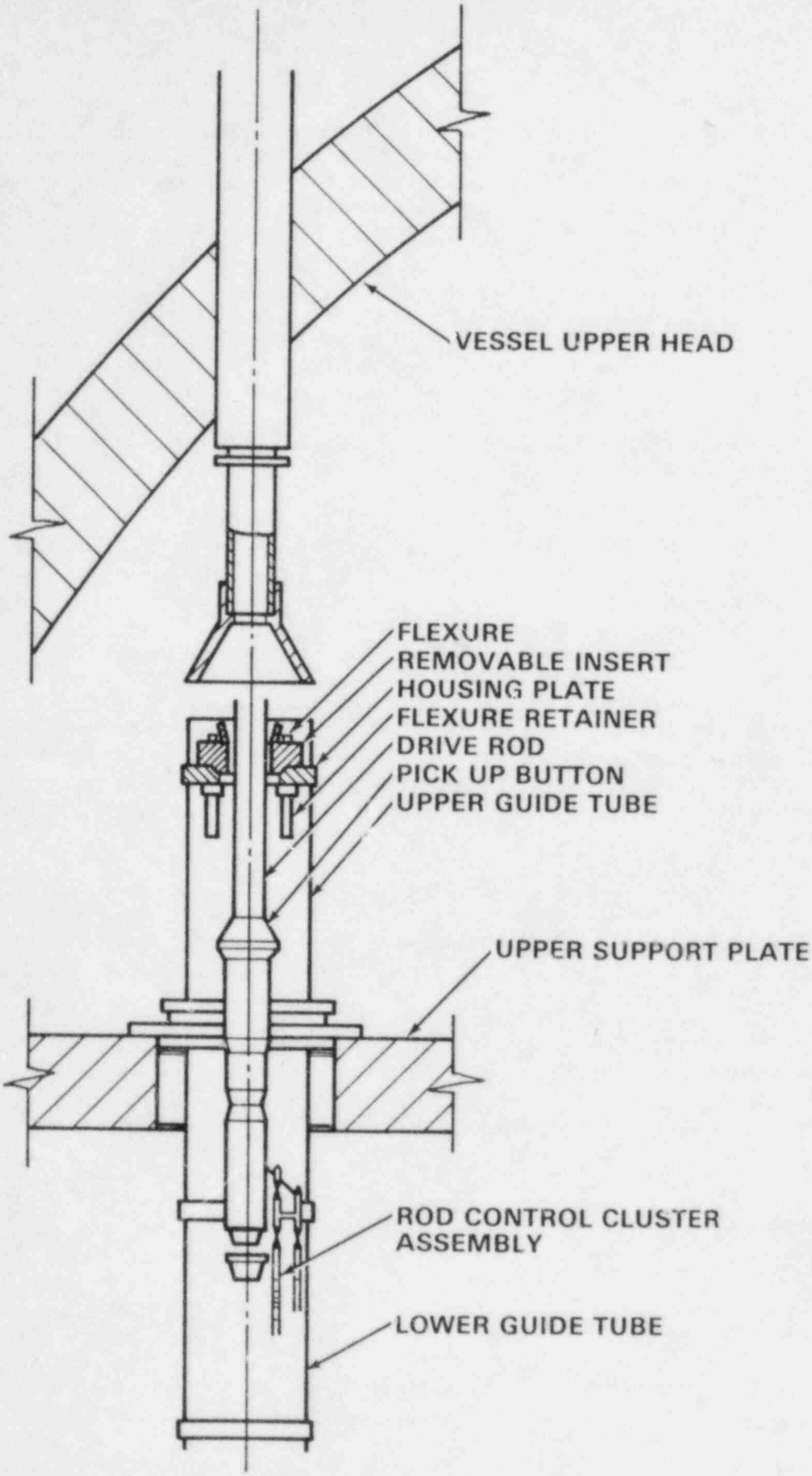

Figure 2. FLEXURES WITH ROD CONTROL CLUSTER ASSEMBLY FULLY WITHDRAWN

With the reactor head removed, the licensee used the drive shaft latching tool to attempt to free the rods. The original plan was to try and free the rods and return them to their full inserted position. These attempts were unsuccessful. The alternate plan was to raise the rods until the spider assembly at the top of the control rod was just below the top hat of the guide tube. These attempts were successful. After ensuring that the control rods would not drop from that position, the flexureless inserts were removed, and the drive shafts were unlatched from the control rods.

Inspection of the flexureless insert removed from the J-4 guide tube disclosed that a piece of the skirt section was missing. The skirt section is slotted, forming eight tabs. Four of the tabs are in contact with the latching pawls which hold the flexureless insert in place at the top of the guide tube. The slots were cut in the skirt during manufacturing to allow for forcible removal of the flexureless inserts in the event of a failure of the internal spring. The missing tab was one of the four not in contact with the latching pawl. After removal of the guide tube top hats at positions F-12 and J-4, a visual inspection of the control rod spider assemblies was performed. This inspection provided no further information.

The F-12 and J-4 control rods were then removed out of the top of their guide tubes, and a visual inspection of the guide tube internals was performed. This inspection disclosed the causes of the rods failing to drop into the core: (1) the missing piece of flexureless insert skirt was found in the J-4 guide tube on a guide tube card corresponding to the elevation at which rod J-4 had stuck, and (2) a flexure pin was found in the F-12 guide tube on a guide tube card corresponding to the elevation at which rod F-12 had stuck. These loose parts were determined to have resulted from control rod guide tube (CRGT) flow insert replacement conducted during the refueling outage. The piece of the insert skirt was part of a new "flexure pinless" flow insert which had broken, and the loose flexure pin had been removed from the control rod guide tube during the outage. Four flexure pins had been used to hold down the previous flow inserts, and had been removed during his outage in conjunction with flow insert replacement due to their susceptibility to stress induced cracking.

The licensee performed a complete visual inspection of all of the guide tube internals. The flexure pin and piece of flexureless insert were removed and no other debris was found. All flexureless inserts were removed and inspected. Three were found to have bent tabs. These three and the one from location J-4 with the broken tab were replaced from spares. It is believed that the cause of the damaged flexureless inserts was due to the installation procedure. This procedure was revised and all flexureless inserts were reinstalled with no problems. The control rods from positions F-12 and J-4 were replaced and the control rod drive shaft from position F-12 was replaced due to damage noted during visual inspections.

On June 14, 1985, control rod exercises were performed with no problems encountered. On June 15, cold rod drops were performed, and on June 18, hot rod drops were performed. Again, no problems were encountered. At 3:05 p.m. on June 18, the unit went critical, ending the refueling outage. (Refs. 8 and 9.)

1.6 Underground Pipe Break Between High Pressure Core Spray System and Cycled Condensate Storage Tank at LaSalle

On May 27, 1985, with LaSalle Unit 2* in cold shutdown, the high pressure core spray (HPCS) underground return line to the cycled condensate (CY) storage tank ruptured. Approximately 200,000 gallons of CY water were expelled into the soil, and surfaced near the offgas filter building. The line was immediately isolated. Sample results of the water revealed low but detectable contamination levels, within release limits. An aggressive test program has located and isolated all underground piping with a potential for leakage. The failures identified were limited to underground Schedule 10 stainless steel piping. The event is detailed below.

On May 27, 1985, at approximately 12:30 a.m., a Security Guard observed water bubbling out of the ground near the offgas filter building and reported this to the Operating Shift Supervisor. A review of the operations in progress revealed the Unit 2 HPCS pump had been running for several hours, recirculating CY storage tank water as part of an operation to increase the water quality of the tank. The pump was immediately secured and water flow out of the ground decreased significantly. The HPCS return line to the CY storage tank was immediately isolated and taken out of service to prevent further leakage. Sample results of the ground water revealed low contamination levels that were within 10 CFR 20 release limits. A gamma spectrum analysis of the surface water indicated that it was essentially identical to CY water. At the time of this event, the unit was in cold shutdown, with the HPCS in full-flow testing with a flow path from and to the CY storage tank.

A monitoring program was immediately established to sample the water runoff into the cooling lake. Samples were taken every 4 hours for the 32-hour period following the event. Radionuclide concentration in these samples decreased to an insignificant level shortly after the event. Cooling pond blowdown to the Illinois River was secured until samples of the blowdown were taken and analyzed for gamma emitters. No detectable concentrations were found.

After further testing, the HPCS return line to the CY storage tank was confirmed as the source of the leakage. This return line runs 24 feet below the ground from the reactor building to the CY tank, and is constructed of Class D, Schedule 10-A140 Type 304 stainless steel. Approximately 100 yards of an open drainage ditch running north-south from the origin of the leakage was contaminated to 10^4 d/m/100 cm^2 and was roped off. The area has since been decontaminated by removing soil to the point where no radioactivity above background is detected.

Due to the depth of the pipe, an extensive analysis is underway to find a means of determining the failure mode of the piping. The surrounding landfill is primarily sand, which makes excavation difficult. The Unit 2 piping is believed to be below the local water table. In addition, there are a significant number of pipes in the area, so that excavation activity would lead to concerns of adequately supporting the exposed piping. The licensee is evaluating the possible use of a self-propelled television camera to inspect the piping from the inside.

*LaSalle Unit 2 is a 1036 MWe (net) MDC General Electric BWR located 11 miles southeast of Ottawa, Illinois, and is operated by Commonwealth Edison.

In parallel, the licensee is coordinating with chemical grout contractors to develop a possible method of limited excavation. The licensee also is developing a modification package for piping replacement, and may pursue leaving the failed piping in place and rerouting the full-flow test line. Completion of this plan requires coordination with the NRC and the State of Illinois regarding onsite storage (burial) of contaminated material.

A three-phase enhanced environmental monitoring program has been initiated by the licensee to identify any migration of the released liquid. Phase 1, which increases the frequency of some samples, has been implemented. It includes weekly onsite deep well samples; weekly composites of 24-hour runoff samples when available; and monthly cooling lake water, sediment, and fish samples. Sampling and analysis is performed by the licensee's environmental contractor. The licensee is also considering opening up observation wells used during construction for additional liquid monitoring. Phase 2 involves sinking boreholes along the broken pipe to sample soil and water near the break. Phase 3, which would be implemented after about 1 year, would involve an adjustment in the monitoring program depending on the evaluation of the problem.

The licensee evaluated the impact of not having the HPCS full-flow test line on unit operations. Based on a review of the technical specifications and the unit's Updated Final Safety Analysis Report, it was determined that the full-flow test line and the CY tank are not required for HPCS system operation. The system is designed under accident conditions to take a suction from the suppression pool and discharge to the reactor vessel. Full-flow test capability remains available from the suppression pool to the suppression pool. The licensee also conducted leak testing on all other safety-related pipes in the area of the leak to verify their integrity. The HPCS full-flow test piping (14-inch diameter, ASTM-A-409 stainless steel grade 304 schedule 10S) was confirmed to be intact. The system operational considerations were formalized, in accordance with 10 CFR 50.59, with a temporary system change to align the HPCS system suction to the suppression pool. (Refs. 11-12.)

1.7 References

(1.1) (Please see text)

(1.2) 1. NRC, Preliminary Notification PNO-III-85-44, June 3, 1985.

2. Commonwealth Edison, Docket 50-373, Licensee Event Report 85-45, June 26, 1985.

3. NRC, Region II Inspection Report 50-373/85-17, July 18, 1985.

(1.3) 4. Wisconsin Electric Power, Docket 50-266, Licensee Event Report 85-02, June 17, 1985.

(1.4) 5. NRC, Preliminary Notification PNO-V-85-37, June 24, 1985.

6. Sacramento Municipal Utility District, Docket 50-312, Licensee Event Report 85-10, July 1985.

7. NRC, Region V Inspection Report 50-312/85-19, August 22, 1985.

(1.5) 8. NRC, Region III Inspection Report 50-266/85-04, June 11, 1985.

9. NRC, Region III Inspection Report 50-266/85-10, August 19, 1985.

(1.6) 10. NRC, Preliminary Notification PNO-III-85-42, May 28, 1985.

11. Commonwealth Edison, Docket 50-374, Licensee Event Report 85-27, June 26, 1985.

12. NRC, Region III Inspection Report 50-373/85-17, July 18, 1985.

2.0 EXCERPTS OF SELECTED LICENSEE EVENT REPORTS

On January 1, 1984, 10 CFR 50.73, "Licensee Event Report System" became effective. This new rule, which made significant changes to the requirements for licensee event reports (LERs), requires more detailed narrative descriptions of the reportable events. Many of these descriptions are well written, frank, and informative, and should be of interest to others involved with the feedback of operational experience.

This section of Power Reactor Events includes direct excerpts from LERs. In general, the information describes conditions or events that are somewhat unusual or complex, or that demonstrate a problem or condition that may not be obvious. The plant name and document number, the LER number, type of reactor, and nuclear steam supply system vendor are provided for each event. Further information may be obtained by contacting the Editor at 301-492-9752, or at U.S. Nuclear Regulatory Commission, EWS-263A, Washington, DC 20555.

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2.1 Grease Mistakenly Pumped Into Limit Switch Compartments During Preventive Maintenance

McGuire 1; Docket 50-369; LER 85-13; Westinghouse PWR

During preventive maintenance on Limitorque motor-operated valve actuators 1VX-1A and 1VX-2B (inlet isolation valves of the hydrogen skimmer system) on May 2, 1985, gearcase lubricating grease was found in the electrical compartment. The grease was apparently pumped into the electrical compartment by mistake during the previous preventive maintenance work, approximately 12 months earlier. The grease was pumped into what was thought to be a gearcase plug, but which was actually a drain plug for the electrical enclosure.

The preventive maintenance that was being performed on the motor-operated valve actuators is completed at least once every 18 months. The Procedure "Limitorque Operator Preventive Maintenance" is used to complete this work. The procedure is adequate to perform the inspection and lubrication checks required by the manufacturer, but explicit instructions are not given to identify the correct grease plugs for checking the grease condition.

Instrument and Electrical (IAE) technicians performed the preventive maintenance on the valves on April 13, 1984. It is concluded that during this work an attempt was made to fill the gearcase with grease, but the wrong plug was removed for the grease addition.

The procedure used for this work is written to be completed in the following sequence: (1) external visual inspection and cleaning; (2) gear box lubrication inspection and filling; and then (3) limit switch compartment inspection and cleaning with quality control (QC) inspection required.

During the preventive maintenance on April 13, the order of procedure completion could not be determined. It is apparent that the grease was introduced into the electrical compartment after the limit switch cover was reinstalled. The inspection of the limit switches following the lubrication would have revealed the grease. The QC inspection was not documented on the procedure data sheet. The inspection signature was made on the work request. QC Inspector A states that he did perform the inspection but failed to sign off the data sheet, and that no grease was present during the inspection. This indicates that the grease was applied after the electrical compartment inspection.

IAE Technicians A and B performed the maintenance on valves 1VX-1A and 1VX-2B. IAE Technician A states that to the best of his memory, no grease was pumped into the actuators. IAE Technician B was a contract employee who is not presently employed by Duke Power and could not be contacted. Both technicians had limited experience with Limitorque valve actuators.

The drain plug used to put the grease in the electrical compartment appears, from the outside of the closed actuator, to enter the gearbox. It is located well below the flange where the electrical compartment cover attaches, which possibly contributed to the technicians' use of it for a grease input.

The presence of this grease in the electrical compartment of the actuators was found to be a significant problem because of an internal gearcase heater. This heater could have gotten hot enough to change the grease to a vapor or liquid.

This vapor could have been explosive if an electrical spark occurred in the electrical switches. Also, the electrical components may have been degraded by the presence of this grease.

The actuators filled with grease will be cleaned and the affected electrical components will be replaced. IAE Procedures "Limitorque Operation Preventive Maintenance" and "Limitorque Corrective Maintenance" will have further instructions given to explicitly identify the proper grease access plugs. All IAE personnel will be given documented training on the use of procedures on safety-related work and Station Directive 4.2.1 (Procedure Handling).

2.2 Reactor Protection System Actuation Due to Abnormal Vent and Drain Valve Configuration During Plant Modification

Washington Nuclear 2; Docket 50-397; LER 85-30; General Electric BWR

At 1350 hours on May 7, 1985, with the plant in hot shutdown, Control Room Operators were in the process of removing residual heat removal (RHR) pump RHR-P-2A from the shutdown cooling mode of operation and returning the system to the standby emergency core cooling system (ECCS) lineup. The operator involved had reviewed the procedure prior to the evolution and was aware of the effect of having valves RHR-V-6A (suction for shutdown cooling mode operation) and RHR-V-4A (suction from the suppression pool) open simultaneously, which would result in the loss of reactor pressure vessel (RPV) water inventory to the suppression pool. The operator initiated a close signal to RHR-V-6A and then initiated an open signal to RHR-V-4A. This took place approximately 30 seconds after the initiation of RHR-V-6A closure. Stroke times for both valves are in the range of 90-100 seconds; hence the RPV water inventory began draining to the suppression pool. RPV level immediately decreased to Level 3 (+13 inches) and a reactor protection system (RPS) actuation occurred, the shutdown cooling mode of RHR automatically isolated, both RHR pumps tripped and the operating control rod drive (CRD) pump tripped on low suction pressure due to high suction filter differential pressure. The lowest RPV water level recorded during the transient was +5 inches on the narrow range recorder. The CRD system was restarted, reestablishing a water feed path to the RPV.

Subsequently, it was noticed that the scram discharge volume (SDV) vent and drain valves had not closed, as required, following the scram. CRD-V-180 (vent) and CRD-V-181 (drain) were manually closed to isolate the volume, and an investigation was begun. RPV level was returned to normal with CRD flow, the scram was reset and RHR-P-2B was placed in service in the shutdown cooling mode of RHR. The RPV was without forced circulation for less than 1 hour, which is consistent with the plant technical specification requirement. RPV metal temperature readings were taken throughout the transient until forced circulation was reestablished.

The cause of the SDV vent and drain valves' failure to close was traced to a clearance order which secured power to the relay circuit for the backup scram valve solenoids. The clearance order, which had been implemented to allow completion of a plant modification, placed the SDV in an abnormal configuration. The circuit involved actuates on a scram signal to deenergize relays that cause air to vent through air solenoid valves which cause the SDV vent and drain valves to close.

The CRD system was returned to operation at 1359 hours and the SDV was isolated manually by closing valves CRD-V-180 (vent) and CRD-V-181 (drain) at approximately 1417 hours. RPV level was restored to normal at approximately 1435 hours.

2.3 Inadvertent Motor Start of the D-13 Diesel Generator Due to Improper Troubleshooting Methods

Limerick 1; Docket 50-352; LER 85-52; General Electric BWR

On May 6, 1985 at approximately 8:45 a.m., with the unit in cold shutdown, an inadvertent motor start of the D-13 emergency diesel generator occurred while investigating false protective relay target operations on the D-13 safeguard switchgear. At the time of the occurrence, plant staff engineering personnel were investigating the causes of false safeguard switchgear protective relay target actuations which had occurred on May 4 and May 5, 1985. No false protective relay target operations were discovered as a result of this investigation.

In order to determine the amount of vibration necessary to actuate a relay target, the D-13 diesel generator output breaker door was struck by plant staff engineering personnel. No relay operation other than a false target operation was expected.

When the door was struck, contact T1-M1 of interposing relay 152YX closed without the coil of the relay being energized. This relay is mounted on the switchgear door close to the location where the compartment door was struck. Contact T1-M1 connects directly to the D-13 diesel generator output breaker closing coil and bypasses the diesel generator output breaker closing logic resulting in closure of D-13 output breaker.

Closure of the output breaker connected the generator to the 4 kV line voltage from the D-13 safeguard bus. The breaker remained closed for 0.866 seconds (52 cycles) before tripping from reverse power relay operation. The field current produced enough torque to rotate the diesel engine. The diesel generator accelerated to a sufficient speed to initiate fuel combustion, at which time the engine fuel control accelerated the engine to rated speed. The diesel generator was shut down within approximately 5 minutes following the start.

To investigate the potential for insulation damage, 1000 V megger and polarization tests were performed on the generator stator and rotor insulation as well as the primary cable between the generator and D-13 safeguard bus switchgear. The testing results were satisfactory. The diesel generator was declared operable following successful load testing in accordance with procedures.

The cause of this event is improper troubleshooting methods used by plant staff engineering personnel for investigation of the false relay target operations. The individuals involved failed to adequately assess the consequences of the troubleshooting activity performed in this manner.

The plant staff personnel have been counseled on the importance of following safe and technically acceptable methods for troubleshooting plant equipment.

Two signs have been attached to each of the 4 kV switchgear cabinet doors to alert personnel that all door locking bolts must be secured at all times, and to caution personnel in the area not to impact the compartment door.

2.4 Incorrect Fastener Material Found in Pressurizer Spray Valves

Calvert Cliffs 1 and 2; Dockets 50-317 and 318; LER 85-03; Combustion Engineering PWRs

While in cold shutdown following a reactor trip on April 25, 1985, a single cracked stud was identified and replaced on pressurizer spray valve 2-CV-100F. Unit 2 was returned to service on May 6, 1985. Investigation continued on Unit 1, which was in a refueling outage at that time. Several cracked studs were identified on pressurizer spray valves 1-CV-100E and F. Incorrect stud material was also identified. Several studs in each valve were found to be made from 316 stainless rather than the correct material, which is ASTM A-564 Type 630 (17-4 pH). Following an engineering evaluation which concluded that 316 studs had insufficient tensile strength for the application, they were replaced with either 17-4 pH studs or an approved substitute. Similarly, the cracked studs were also replaced with approved material. All cracked studs were 17-4 pH material.

Following discovery of cracked studs and material problems on Unit 1, a power reduction was scheduled on Unit 2 on May 17 to allow for examination of the studs on 2-CV-100E and F. Unit 2 was reduced to 17% power at 0030 on May 18. The examination identified four of eight studs in 2-CV-100E and five of eight studs in 2-CV-100F that were not of the correct 17-4 pH material. One 17-4 pH stud in 2-CV-100E was found to be cracked. Shutdown of Unit 2 commenced immediately and the unit was placed in cold shutdown at 2235 on May 18. The incorrect studs and the single cracked stud were replaced with approved material.

A search of plant history files was conducted to determine if the pressurizer spray valve studs had been replaced during maintenance or modification. No record of such replacement could be found, leaving open the possibility that the valves may have been originally installed with studs of incorrect material. Since the pressurizer spray valves on both units were supplied by a single vendor, ITT Hameldahl, all other valves supplied by ITT on both units were then examined to verify the correct stud material. Incorrect stud material was identified on three of four pressurizer spray bypass valves. These studs were replaced with studs made of an approved material. In each case of incorrect stud material the correct material was 17-4 pH. A documentation review was undertaken to determine if valves supplied by two other major valve manufacturers specified 17-4 pH studs. No such valves were identified as being installed in either plant in other than non-critical applications.

Partial failure of the pressurizer spray valve studs would increase the unidentified reactor coolant system leakage. When the total leakage reached the technical specification limit, a power reduction would be ordered to identify and correct the valve leakage. The highly unlikely failure of the pressurizer spray valve body to bonnet pressure boundary would result in a loss of coolant accident which has been previously analyzed in the Updated Final Safety Analysis report.

Although no evidence exists to suggest that incorrect stud material was installed during maintenance activities, a special preventive action meeting was held on May 23 with plant mechancial craft personnel. During this meeting, the General Supervisor-Mechanical Maintenance emphasized to his personnel the importance of following proper bolting practices, including verification of correct material and adherence to specified torque limits. While the cause of cracking in the 17-4 pH studs has not yet been determined, evidence does exist to suggest that adequate control over the torquing of the studs has not been exercised at all times. Specific maintenance procedures are being developed for these valves which will include necessary torque limits for the body to bonnet studs. Similar limits will also be incorporated into other maintenance procedures as they are developed or revised. Maintenance personnel have been instructed to obtain torque specifications prior to tightening all pressure boundary fasteners.

2.5 Lack of Environmental Qualification for H_2O_2 Analyzer Valves Due to Vendor's Failure to Meet Procurement Requirements

Browns Ferry 1-3; Dockets 50-259 -260, -296; LER 85-17; General Electric BWRs

Unit 1 and 2 were in refueling outages; Unit 3 was in cold shutdown. All three units were affected by the event.

During the IE Bulletin 79-01B equipment review, it was discovered that teflon had been used as valve packing and valve seats in several Whitey valves. Whitey Model No. SS-7RF8 had teflon valve packing. Whitey Model Nos. SS-43XF4, SS-44XF4, and SS-45XF3 had teflon valve seats. A design evaluation completed on May 14, 1985, found that the expected radiation levels during an accident would exceed the radiation failure threshold of teflon. The cause for the teflon being used in the H_2O_2 system can be attributed to the vendor (Milton Roy Company, Hays Republic Division) not meeting procurement requirements.

Degradation of the teflon valve packing and valve seats due to a high radiation flux could allow air to enter the H_2O_2 monitoring system. Introduction of air into this system could produce erroneous readings, making it difficult for an operator to properly assess accident conditions.

A design change request has been issued for either changing the valve packing or replacing the valves. This work should be completed on Unit 3 prior to startup from the current maintenance outage. Unit 1 and Unit 2 will have the modifications completed during their current refueling outages.

A review of Milton Roy Company supplied valves will be performed to see if they have supplied other valves needing to meet strict environmental qualifications.

2.6 Inoperable Chemical Addition Pump Due to Wiring Problems During Racking in of Pump Breaker

Beaver Valley 1; Dock 50-334; LER 85-11; Westinghouse PWR

On 5/3/85 as part of the station startup procedure, several 480 V breakers (including the breaker for the A chemical addition pump) were racked onto the 480 V busses. The plant was in cold shutdown at this time. The plant entered hot shutdown on 5/6/85.

On 5/16/85, while the plant was in power operation, inservice testing discovered that the A chemical addition pump would not start. Investigation determined that although the pump's breaker was apparently correctly racked onto the bus, the breaker would not function properly. It was determined that motor control center wiring on the side of the breaker cubicle had caught on the back of the breaker as it was being racked in on 5/3/85. This resulted in a slight cocking of the breaker in its cubicle, which prevented one of the three phases from making contact. As the pump is required to be operational from power operation through hot shutdown, it was apparently inoperable for 10 days when it was required to be operable. The technical specification applying to this pump has a 7-day Action Statement.

To correct the problem with the pump's breaker, the wiring in the cubicle was tied back to prevent it from interfering with free breaker movement. This breaker, along with all the other 480 V breakers that had been racked in on 5/3/85, were then re-racked in and verified to be operable. Breakers for the other chemical addition pumps were inspected and the cubicle wiring was determined to be satisfactory.

To prevent problems similar to this from recurring, Beaver Valley has revised its 480 V breaker racking procedure. The revised procedure requires that whenever a safety-related breaker is racked in, its associated component must be cycled to insure operability. If due to plant conditions the component cannot be cycled, the Station Operating Supervisor is to provide, when possible, an alternate operability verification. Similar requirements to cycle 4 kV components after racking in their breakers have been in existence at Beaver Valley since early 1984. The station considers this type of functional testing to provide positive indication of availability of safety-related components.

2.7 SGTS Start on Refuel Floor High Radiation Signal During Removal of Steam Dryer from Reactor Vessel

Susquehanna 1; Docket 50-387; LER 85-01-01; General Electric BWR

On February 13, 1985, with the unit shut down for its first refueling outage, actions commenced to remove the steam dryer from the reactor vessel. The maintenance procedure used to move the dryer included steps for the installation of jumpers in the refuel floor wall duct trip units. (The corresponding sensors on Unit 2 remained operable throughout the event.) The intent of this action was to forestall a Zone III (refuel floor) ventilation isolation and concomitant start of the standby gas treatment system (SGTS) and control room emergency outside air supply system (CREOASS) under circumstances where it is known that conditions other than airborne radiation would cause the isolation or systems to start. (The SGTS and CREOASS are engineered safety features.) The strongback used to move the dryer has a sprinkling system installed on it, and there is a sprinkling system in the dryer-separator pool to minimize airborne radiation.

When the steam dryer move was complete, the jumpers were removed per the maintenance procedure. Within 2 minutes, Zone III had isolated on a high radiation signal, and the SGTS and CREOASS started. Operations personnel directed that the jumpers be reinstalled based on the deduction that the steam dryer was acting as a source large enough to affect the sensors in the Zone III exhaust duct. CREOASS was shut down, normal Zone III ventilation was reestablished, and SGTS was shut down. Station particulate, iodine, and noble gas monitor data showed no abnormal release rates for the day.

All system logic functioned properly except that the reactor building recirculation fans did not start. (These fans act to recirculate the air within the ventilation zones to reduce radioactivity concentrations by mixing the air before it is exhausted through the SGTS.) Investigation into the lack of fan start showed no problems; simulated conditions resulted in correct logic sequencing including the start of the recirculation fans.

The maintenance procedure used to control transfer of the steam dryer has been revised to initiate the SGTS and CREOASS in a controlled manner. Additionally, engineering evaluations will be completed to determine the feasibility of shielding the radiation monitors or altering their trip function to assure their actuation on true high airborne radiation indication. LERs 85-10 and 85-20 describe additional occurrences of SGTS and CREOASS actuations due to "shine."

2.8 Inoperable Containment Isolation Valves Due to Improper Seismic Qualification by Manufacturer

Byron 1; Docket 50-454; LER 85-55; Westinghouse PWR

On May 15, 1985, the Engineering Department reported that based on a report by the valve manufacturer, Xomox, containment isolation valves 1RF026 and 1RF027 could fail "as is" during a seismic event. The plant was at 50% power. Unit 1 containment floor drain isolation valves 1RF026 and 1RF027 were declared inoperable.

Xomox Corporation reported that the valve actuators and air receiver tanks for valves 1RF026 and 1RF027 could break off or be damaged during a seismic event, causing the valve to fail. The normal position of the valve is open; therefore, during a seismic event, the possibility exists that containment integrity would not be maintained.

As required by technical specifications, valves 1RF026 and 1RF027 were taken out of service in the closed position, ensuring containment integrity. A justification for Interim Operation was verbally approved by the NRC to allow intermittent opening of 1RF026 and 1RF027 during plant operation.

Xomox supplied drawings for installation of brackets on the valves that would bring them within specifications. The brackets have been installed, and the valves have been returned to service.

2.9 Seismic Load Calculation Error Found During Inspection of Locked Up Snubber on Pressurizer Vent Piping

Millstone 2; Docket 50-336; LER 85-08; Combustion Engineering PWR

During the unit's 1985 refueling outage, a routine inspection of snubbers was conducted. As a result of the inspection, a locked up snubber was found on the pressurizer vent piping. A design review was performed to determine the impact of the locked up snubber on the piping system. The normal load calculation was found to be acceptable, but an error was discovered in the seismic load calculation. This error resulted in a significant difference between the original calculation and the review calculation. This difference was unexpected and an indepth review of the original calculation was conducted. It was determined that the inputs to the original design program were not properly formatted.

The original design utilized the ADLPIPE version 1B program. This program utilizes the response spectrum method to evaluate pipe stresses due to seismic loading. Applicable response spectra are specified for each of the three orthagonal directions (X, Y, and Z). In the ADLPIPE, these directions are specified on a "DIR" card with integers 1, 2, and 3 representing X, Y, and Z, respectively. The input of these integers is expected to be right justified in its field. If this does not occur, ADLPIPE version 1B will default to using the non-right justified spectra for all previously supplied spectra.

The input for the Y spectra used in the original calculation for the pressurizer vent piping was not right justified. As described above, this caused the Y spectra to be used for the X spectra. This substitution of the incorrect Y spectra into the X spectra resulted in lower seismic loads on the piping system. Comparing the original stresses to the stresses using the corrected Y spectra shows the original calculation to be low by a factor of 3 on the pipe.

A review of the original hangers on this piping system showed them to be satisfactory due to overdesign during the original design. Two new hangers have been added to the piping as a result of the error found in the original ADLPIPE calculation. These hangers have been installed, and the seismic qualification of this pipe has been reestablished.

All licensee calculations using ADLPIPE version 1B were reviewed for similar problems, and none were found. The latest version of ADLPIPE, Version ID now in use, has features in the program which will cause a "fatal error" to occur if the input is not right justified. The feature will eliminate any similar problem from occurring.

3.0 ABSTRACTS/LISTINGS OF OTHER NRC OPERATING EXPERIENCE DOCUMENTS

3.1 Abnormal Occurrence Reports (NUREG-0090) Issued in May-June 1985

An abnormal occurrence is defined in Section 208 of the Energy Reorganization Act of 1974 as an unscheduled incident or event which the NRC determines is significant from the standpoint of public health or safety. Under the provisions of Section 208, the Office for Analysis and Evaluation of Operational Data reports abnormal occurrences to the public by publishing notices in the Federal Register, and issues quarterly reports of these occurrences to Congress in the NUREG-0900 series of documents. Also included in the quarterly reports are updates of some previously reported abnormal occurrences, and summaries of certain events that may be perceived by the public as significant but do not meet the Section 208 abnormal occurrence criteria.

Date Issued	Report
5/85	REPORT TO CONGRESS ON ABNORMAL OCCURRENCES, OCTOBER - DECEMBER 1984, VOL. 7, NO. 4

There were four abnormal occurrences during the report period. Two occurred at licensed nuclear power plants, one occurred at a fuel cycle facility (other than a power plant), and one occurred at an Agreement State licensed facility.

The occurrences at the plants involved: (1) four control rods failing to insert during testing at Susquehanna Unit 1 on October 6, 1984; and (2) degraded upper head injection system accumulator isolation valves at McGuire Unit 1 on November 1, 1984.

The occurrence at the fuel cycle facility involved a buildup of uranium in a ventilation system on October 5, 1984 at Nuclear Fuel Services, Inc., near Erwin, Tennessee.

The occurrence at the Agreement State licensee involved the overexposure of a radiographer trainee on October 31, 1984. The trainee was employed by Ultrasonics Specialists, Inc., of Amelia, Louisiana, and received the overexposure at the Avondale Shipyards in Morgan City, Louisiana.

Also, the report provided update information on: (1) the nuclear accident at Three Mile Island (79-3), first reported in Vol. 2, No. 1, January-March 1979; (2), a through wall crack in the vent header inside the containment torus at Hatch Unit 2, a BWR (84-2), first reported in Vol. 7, No. 1, January-March 1984; (3) degraded shutdown systems at Fort St. Vrain (84-9), first reported in Vol. 7, No. 3, July-September 1984; and (4) a significant internal exposure to

Date Issued	Report
5/85 (con't)	iodine-125, which occurred at the Veterans Administration Medical Center, Bronx, New York (84-15), also first reported in Vol. 7, No. 3, July-September 1984. In addition, an item of interest that did not meet abnormal occurrence criteria was radioactive contamination of sanitary sewage systems, involving: (1) cobalt-60 found in the sludge from a sewage treatment facility in Oak Ridge, Tennessee; (2) americium-241 found in ash at the Tonawanda, New York sewage treatment plant; and (3) americium-241 found in the sludge at a sewage treatment plant in Grand Island, New York.

3.2 Bulletins and Information Notices Issued in May-June 1985

The Office of Inspection and Enforcement periodically issues bulletins and information notices to licensees and holders of construction permits. During the period, 13 information notices and three information notice supplements were issued.

Bulletins are used primarily to communicate with industry on matters of generic importance or serious safety significance (i.e., if an event at one reactor raises the possibility of a serious generic problem, an NRC bulletin may be issued requesting licensees to take specific actions, and requiring them to submit a written report describing actions taken and other information NRC should have to assess the need for further actions). A prompt response by affected licensees is required and failure to respond appropriately may result in an enforcement action. When appropriate, prior to issuing a bulletin, the NRC may seek comments on the matter from the industry (Atomic Industrial Forum, Institute of Nuclear Power Operations, nuclear steam suppliers, vendors, etc.), a technique which has proved effective in bringing faster and better responses from licensees. Bulletins generally require one-time action and reporting. They are not intended as substitutes for revised license conditions or new requirements.

Information Notices are rapid transmittals of information which may not have been completely analyzed by NRC, but which licensees should know. They require no acknowledgement or response, but recipients are advised to consider the applicability of the information to their facility.

Information Notice	Date Issued	Title
84-52 Suppl.1	5/8/85	INADEQUATE MATERIAL PROCUREMENT CONTROLS ON THE PART OF LICENSEES AND VENDORS (Issued to all power reactor facilities holding an operating license or construction permit)
84-55, Suppl. 1	5/14/85	SEAL TABLE LEAKS AT PWRs (Issued to all power reactor facilities holding an operating license or construction permit)
85-20 Suppl. 1	5/14/85	MOTOR-OPERATED VALVE FAILURES DUE TO HAMMERING EFFECT (Issued to all power reactor facilities holding an operating license or construction permit)
85-36	5/9/85	MALFUNCTION OF A DRY-STORAGE PANORAMIC, GAMMA EXPOSURE IRRADIATOR (Issued to all licensees possessing gamma irradiators)
85-37	5/14/85	CHEMICAL CLEANING OF STEAM GENERATOR AT MILLSTONE 2 (Issued to all PWR facilities holding an operating license or construction permit)
85-38	5/21/85	LOOSE PARTS OBSTRUCT CONTROL ROD DRIVE MECHANISM (Issued to all PWR facilities designed by Babcock & Wilcox, holding an operating license or construction permit)

Information Notice	Date Issued	Title
85-39	5/22/85	AUDITABILITY OF ELECTRIAL EQUIPMENT QUALIFICATION RECORDS AT LICENSEES' FACILITIES (Issued to all power reactor facilities holding an operating license or construction permit)
85-40	5/22/85	DEFICIENCIES IN EQUIPMENT QUALIFICATION TESTING AND CERTIFICATION PROCESS (Issued to all power reactor facilities holding an operating license or construction permit)
85-41	5/24/85	SCHEDULING OF PRE-LICENSING EMERGENCY PREPAREDNESS EXERCISES (Issued to all power reactor facilities holding a construction permit)
85-42	5/29/85	LOOSE PHOSPHOR IN PANASONIC 800 SERIES BADGE THERMOLUMINESCENT DOSIMETER (TLD) ELEMENTS (Issued to all power reactor facilities holding an operating license or construction permit)
85-43	5/30/85	RADIOGRAPHY EVENTS AT POWER REACTORS (Issued to all power reactor facilities holding an operating license or construction permit)
85-44	5/30/85	EMERGENCY COMMUNICATION SYSTEM MONTHLY TEST (Issued to all power reactor facilities holding an operating license)
85-45	6/6/85	POTENTIAL SEISMIC INTERACTION INVOLVING THE MOVABLE IN-CORE FLUX MAPPING SYSTEM USED IN WESTINGHOUSE DESIGNED PLANTS (Issued to all power reactor facilities holding an operating license or construction permit)
85-46	6/10/85	CLARIFICATION OF SEVERAL ASPECTS OF REMOVABLE RADIOACTIVE SURFACE CONTAMINATION LIMITS FOR TRANSPORT PACKAGES (Issued to all power reactor facilities holding an operating license)
85-47	6/18/85	POTENTIAL EFFECT OF LINE-INDUCED VIBRATION ON CERTAIN TARGET ROCK SOLENOID-OPERATED VALVES (Issued to all power reactor facilities holding an operating license or construction permit)
85-48	6/19/85	RESPIRATOR USERS NOTICE: DEFECTIVE SELF-CONTAINED BREATHING APPARATUS AIR CYLINDERS (Issued to all power reactor facilities holding an operating license or construction permit; research, test reactor, fuel cycle, and Priority 1 material licensees)

3.3 Case Studies and Engineering Evaluations Issued in May-June 1985

The Office for Analysis and Evaluation of Operational Data (AEOD) has as a primary responsibility the task of reviewing the operational experience reported by NRC nuclear power plant licensees. As part of fulfilling this task, it selects events of apparent interest to safety for further review as either an engineering evaluation or a case study. An engineering evaluation is usually an immediate, general consideration to assess whether or not a more detailed protracted case study is needed. The results are generally short reports, and the effort involved usually is a few staffweeks of investigative time.

Case studies are in-depth investigations of apparently significant events or situations. They involve several staffmonths of engineering effort, and result in a formal report identifying the specific safety problems (actual or potential) illustrated by the event and recommending actions to improve safety and prevent recurrence of the event. Before issuance, this report is sent for peer review and comment to at least the applicable utility and appropriate NRC offices.

These AEOD reports are made available for information purposes and do not impose any requirements on licensees. The findings and recommendations contained in these reports are provided in support of other ongoing NRC activities concerning the operational events(s) discussed, and do not represent the position or requirements of the responsible NRC program office.

Case Study	Date Issued	Subject
C501 (NUREG/ CR-3551; ORNL/NOAC-214)	5/85	SAFETY IMPLICATIONS ASSOCIATED WITH IN-PLANT PRESSURIZED GAS STORAGE AND DISTRIBUTION SYSTEMS IN NUCLEAR POWER PLANTS

This report was prepared for NRC/AEOD by the Nuclear Operations Analysis Center of Oak Ridge National Laboratory. Storage and handling of compressed gases at nuclear power plants were studied to identify any potential safety hazards. Gases investigated were air, acetylene, carbon dioxide, chlorine, Halon, hydrogen, nitrogen, oxygen, propane, and sulfur hexafluoride. Physical properties of the gases were reviewed, as were applicable industrial codes and standards. Incidents involving pressurized gases in general industry and in the nuclear industry were studied. In this report, general hazards such as missiles from ruptures, rocketing of cylinders, pipe whipping, asphyxiation, and toxicity are discussed. Even though some serious injuries and deaths over the years have occurred in industries handling and using pressurized gases, the industrial codes, standards, practices, and procedures are very comprehensive. The most important step one can take to ensure the safe handling of gases is to enforce these well-known and established methods. The following recommendations are made for further improving the safe handling of pressurized gases.

1. Provide protection to prevent damage to safety-related equipment from gas cylinder missiles.

Case Study	Date Issued	Subject
C501 (con't)		2. Provide protection to prevent explosions from rapid releases of hydrogen in areas containing safety-related equipment.
		3. Provide easily recognizable identification of lines and tanks containing hazardous gases.

Engineering Evaluation	Date Issued	Subject
E506	5/13/85	VALVE STEM SUSCEPTIBILITY TO IGSCC DUE TO IMPROPER HEAT TREATMENT

Licensee Event Report 82-088/03L-3, dated May 24, 1984, for Brunswick 2 describes an event in which a valve stem failure occurred while attempting to open the valve manually during a refueling outage. The valve was installed in the suppression pool suction line to the residual heat removal (RHR) system. The valve stem, made of type 410 stainless steel, had completely fractured approximately 6 inches from the valve stem T-head. Metallurgical examination showed that the stem had failed from intergranular stress corrosion cracking (IGSCC). IGSCC had reduced the valve stem cross-sectional area to 30% of its original area, and the fracture was then completed by a sudden shear. The broken stem was found to have hardness higher than the specified value. A subsequent licensee investigation revealed that the excessive hardness was caused by improper heat treatment during manufacture of the stem material. Three additional events found in this review had similar valve stem failures. These defective stems were also made of type 410 stainless steel.

The additional events occurred at Farley 1, Browns Ferry 3 and Oconee 1. The valve stem failures at Farley 1 and Oconee 1 were found by examination to be caused by IGSCC, while the failure at Browns Ferry 3 can probably be related to the same cause although the examination in that case is inconclusive. The affected valves were installed in safety-related systems and are different in size and manufacturer.

Valve stems made of 400 series stainless steel and heat treated to high hardness are highly susceptible to intergranular stress corrosion under certain corrosive environmental conditions. The excessive hardness can result from improper heat treatment which may not be detected in either the licensee's or the supplier's QA programs. Furthermore, since the valve stem IGSCC cannot be observed without disassembly of the valve,

Engineering Evaluation	Date Issued	Subject
E506 (con't)		the plant routine valve operability test program cannot provide an early detection of stem stress cracking. As stress corrosion cracking can occur below the design stress limits, it is likely that IGSCC on a valve stem would go undetected until failure occurs with a sudden shear of the stem upon actuation of the valve during system operation. Such failures can prevent the system from performing its safety function. In view of this safety concern, this report suggests that the following actions be taken by the NRC: (1) The Office of Inspection and Enforcement (IE) should consider issuing an IE Information Notice to inform licensees of the potential generic problem concerning improper heat treatment of valve stem material which could lead to intergranular stress corrosion. (2) The Office of Regulatory Research (RES) should consider the adequacy of the existing code requirements with regard to assurance of proper hardness of martensitic stainless steel following the heat treatment process. If appropriate, RES should attempt to have such requirements included in the applicable code.
E507	5/17/85	ELECTRICAL INTERACTION BETWEEN UNITS DURING LOSS OF OFFSITE POWER EVENT OF AUGUST 21, 1984 This report provides the review and evaluation of an event that occurred at the McGuire Station on August 21, 1984. The event was initiated by a problem at the station's switchyard computer system, which led to the tripping of several breakers in the Unit 1 and Unit 2 switchyards. Unit 1 was operating at 100% power and Unit 2 was starting up at the time of the event. Unit 1 lost all of its offsite power and tripped. The unit's onsite emergency diesel generators started up and loaded the safety-related buses as required. Unit 2 tripped shortly after Unit 1 due to problems in the plant's common auxiliary control power supply system. The event was complicated by several failures that occurred as a result of voltage surges that were experienced during the event, and some random component failures. The operators, however, had safe control of both units all through the event. The report concludes that had the two units been operating at full power, the event could have been more complicated. It also concludes that at nuclear plant sites with multiple units, events initiating at one

Engineering Evaluation	Date Issued	Subject
E507 (con't)		unit can propagate and involve more than one unit due to problems associated with systems that are common to the units.
E508	5/85	NUCLEAR PLANT OPERATING EXPERIENCE INVOLVING SAFETY SYSTEM DISTURBANCES CAUSED BY BUMPED ELECTRO-MECHANICAL COMPONENTS A study was performed to evaluate nuclear plant operating experiences involving safety system disturbances caused by bumped electro-mechanical components. The study found that enclosed switches, relays, transmitters and possibly relays in circuit breakers are among the most sensitive electro-mechanical devices in a nuclear plant. Physical disturbance will frequently change the output state of these components. Bumped components have resulted in reactor scrams, safety system isolations, trips and initiations, and loss of power to safety systems. A reactor scram, caused by bumped reactor protection system enclosed switches, was found to be among the most common occurrences for BWRs. The data indicates that enclosed switches, relays, transmitters and possibly relays in circuit breakers would be among the most sensitive components in a plant during a seismic disturbance. It is suggested that these classes of components, and their potential for causing unacceptable system transients or conditions, be considered for NRC staff review during Phase II of the proposed resolution of USI A-46, "Seismic Qualification of Equipment in Operating Plants."

3.4 Generic Letters Issued in May-June 1985

Generic letters are issued by the Office of Nuclear Reactor Regulation, Division of Licensing. They are similar to IE Bulletins (see Section 3.2) in that they transmit information to, and obtain information from, reactor licensees, applicants, and/or equipment suppliers regarding matters of safety, safeguards, or environmental significance. During May and June 1985, six letters were issued.

Generic letters usually either (1) provide information thought to be important in assuring continued safe operation of facilities, or (2) request information on a specific schedule that would enable regulatory decisions to be made regarding the continued safe operation of facilities. They have been a significant means of communicating with licensees on a number of important issues, the resolutions of which have contributed to improved quality of design and operation.

Generic Letter	Date Issued	Title
85-07	5/2/85	IMPLEMENTATION OF INTEGRATED SCHEDULES FOR PLANT MODIFICATIONS (Issued to all operating reactor licensees)
85-08	5/23/85	10 CFR 20.408 TERMINATION REPORTS - FORMAT (Issued to all holders of construction permits and operating licenses)
85-09	5/23/85	TECHNICAL SPECIFICATIONS FOR GENERIC LETTER 83-23, ITEM 4.3 (Issued to all Westinghouse PWR licensees and applicants)
85-10	5/23/85	TECHNICAL SPECIFICATIONS FOR GENERIC LETTER 83-28, ITEMS 4.3 AND 4.4 (Issued to all Babcock & Wilcox PWR licensees and applicants)
85-11	6/28/85	COMPLETION OF PHASE II OF "CONTROL OF HEAVY LOADS AT NUCLEAR POWER PLANTS" NUREG-0612 (Issued to all licensees for operating reactors)
85-12	6/28/85	IMPLEMENTATION OF TMI ACTION ITEM II.K.3.5, "AUTOMATIC TRIP OF REACTOR COOLANT PUMPS" (Issued to all aplicants and licensees with Westinghouse designed nuclear steam supply systems)

3.5 Operating Reactor Event Memoranda Issued in May-June 1985

The Director, Division of Licensing, Office of Nuclear Reactor Regulation (NRR), disseminates information to the directors of the other divisions and program offices within NRR via the operating reactor event memorandum (OREM) system. The OREM documents a statement of the problem, background information, the safety significance, and short and long term actions (taken and planned). Copies of OREMs are also sent to the Office for Analysis and Evaluation of Operational Data, and of Inspection and Enforcement for their information.

No OREMs were issued during May-June 1985.

3.6 NRC Document Compilations

The Office of Administration issues two publications that list documents made publicly available.

- The quarterly Regulatory and Technical Reports (NUREG-0304) compiles bibliographic data and abstracts for the formal regulatory and technical reports issued by the NRC Staff and its contractors.

- The monthly Title List of Documents Made Publicly Available (NUREG-0540) contains descriptions of information received and generated by the NRC. This information includes (1) docketed material associated with civilian nuclear power plants and other uses of radioactive materials, and (2) non-docketed material received and generated by NRC pertinent to its role as a regulatory agency. This series of documents is indexed by Personal Author, Corporate Source, and Report Number.

The monthly Licensee Event Report (LER) Compilation (NUREG/CR-2000) might also be useful for those interested in operational experience. This document contains Licensee Event Report (LER) operational information that was processed into the LER data file of the Nuclear Safety Information Center at Oak Ridge during the monthly period identified on the cover of the document. The LER summaries in this report are arranged alphabetically by facility name and then chronologically by event date for each facility. Component, system, keyword, and component vendor indexes follow the summaries.

Copies and subscriptions of these three documents are available from the Superintendent of Documents, U.S. Government Printing Office, P.O. Box 37082, Washington, DC 20013-7982.

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