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POWER REACTOR EVENTS

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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 NRC/GPO Sales Program, (301) 492-9530, or at Mail Stop P-130A, Washington, DC 20555.

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Editor: Sheryl A. Massaro
Associate Editor: James T. Fry
Office for Analysis and Evaluation
of Operational Data
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Period Covered: January-February 1984

1.0 SUMMARIES OF EVENTS

1.1 Through Wall Crack in Vent Header of BWR Containment Torus

On February 3, 1984, during routine visual inspection of the torus interior at Hatch Unit 2,* a through wall crack was discovered in the vent header. The crack extended about 330° around the 54-inch header, degrading the pressure suppression capability of the torus. The vent header material for Hatch Unit 2 is SA 516 Grade 70 carbon steel, with the nil ductility transition temperature below -40°F.

The primary containment for Hatch Unit 2 is a Mark I pressure suppression system consisting of a drywell, pressure suppression chamber (torus) containing a large volume of water, a connecting vent system between the drywell and water pool, isolation valves, vacuum relief systems, containment cooling systems, and other equipment. The drywell is a steel pressure vessel which houses the reactor vessel, the recirculation system, and other systems and components important to safety.

The pressure suppression chamber is a steel pressure vessel in the shape of a torus, and is located below the drywell. Eight vent pipes form a connection between the drywell and the torus. The vent pipes exhaust into the 54-inch diameter continuous vent header, which is located in the torus, from which 80 downcomer pipes extend into the water in the torus.

During operation, the drywell and suppression chamber free air spaces are inerted with nitrogen to minimize the possibility of hydrogen combustion during or following a loss-of-coolant accident (LOCA). The nitrogen supply system is designed to vaporize liquid nitrogen and warm the nitrogen gas before it is discharged into the primary containment. At Hatch, the temperature of the nitrogen gas at the vaporizer controller is normally controlled between 100-250°F. By the time the gas reaches the discharge outlet to the torus, the gas temperature would be somewhat lower. However, under worst case conditions of equipment failure, the discharge temperatures into the torus could drop far below 0°F. The discharge of nitrogen into the containment at such temperatures could cool structural materials below their nil ductility temperatures, causing them to become susceptible to brittle fracture.

Hatch Unit 2 was shut down on January 13, 1984 for an extended outage to replace recirculation system piping. On February 3, during inspection of the torus interior, the licensee discovered the crack in the vent header. The ends of the pipe on either side of the crack were displaced about 1/2 inch. The vent header has a wall thickness of 1/4 inch.

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*Hatch Unit 2 is a 771 MWe (net) BWR located 11 miles north of Baxley, Georgia, and is operated by Georgia Power.

The containment system is designed such that in the event of a LOCA, pressurized steam and water is released into the drywell. Drywell pressure quickly increases and forces the steam flow through the vents into the vent header. The vent header directs the steam through the downcomer pipes into the torus water, resulting in condensation of the steam. The condensation of steam serves to limit the maximum pressure the containment structure will experience. However, as a result of the large through wall crack in the vent header, the amount of steam condensed by the torus would be reduced because some steam would bypass the vent header and reduce the differential pressure used to drive the steam into the water. This increases the possibility of overpressurizing the primary containment, allowing for a release into the secondary containment. This condition has not been specifically analyzed in the plant's final safety analysis report (FSAR), thus leading to a potential safety concern.

The location of the crack was directly below a nitrogen supply discharge nozzle outlet to the torus. The nitrogen line is 20 inches in diameter with the outlet about 7 feet above the vent header. The licensee stated that there have been problems with operation of the nitrogen evaporators and heaters, and that the low temperature isolation provisions had also malfunctioned. The licensee reported that the nitrogen inerting system had recently (at least) been used without the gas pre-warmer equipment working because of failure of the site auxiliary boiler. In addition, several nitrogen system valves were reported to have failed because of frost/ice buildup.

The crack was determined to be a brittle-fracture type of failure. The primary contributor to the cracking was attributed to impingement of low temperature nitrogen onto the vent header. Apparently, the vent header temperature dropped below the nil ductility temperature when the nitrogen evaporator and heater and/or isolation system were not functioning properly. The thermal stresses generated by this cooling contributed to crack initiation and propagation.

Component failures, combined with deficient management/procedural controls pertaining to containment inerting evolutions, are believed to be the principal causes of the cracking problem. Corrective actions included operational testing of the vent header on February 3, 1984 on the operating reactor, Hatch Unit 1,* and shutdown of the unit on February 4, 1984, to further verify that the same condition did not exist. Visual inspections of the vent header were made and no cracks were found. Unit 1 was then restarted. It was also determined that the Unit 1 nitrogen line discharge was not located directly above the vent header. For Unit 2, repairs to the vent header have commenced.

The licensee removed samples from the vent header for failure analysis examination by General Electric (GE). This analysis determined that the material met all physical and chemical requirements for SA 516 Grade 70 carbon steel and that the failure mode was transcrystalline brittle fracture characteristic of crack propagation at temperatures below the nil ductility transition

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*Hatch Unit 1 is a 764 MWe (net) BWR located 11 miles north of Baxley, Georgia, and is operated by Georgia Power.

temperature. An NRC independent failure analysis by Brookhaven National Laboratory confirmed that the material met SA 516 Grade 70 physical and chemical requirements, and that the failure mode was characteristic of crack propagation at temperatures below the nil ductility transition temperature.

Inspection and Enforcement (IE) Bulletin No. 84-01, dated February 3, 1984, was issued to all BWRs with operating licenses or construction permits. The IE Bulletin requested that facilities with operating licenses in cold shutdown and with primary containments similar to the Hatch containment (Mark I) perform inspections as to the condition of their vent headers and report the results to NRC. (The inspections made showed no indications of cracking.) It was also recommended that, for BWRs with Mark I containments that were in operation, the licensees review plant data on differential pressure between the drywell and the torus for anomalies that could be indicative of cracks. The results of these initiatives are under review.

The BWR Regulatory Response Group (RRG) was activated. This group, together with the vendor (GE) representatives met with the NRC on February 6 and 23, 1984 to discuss actions to be taken to assure the integrity of the containment and associated systems, and to determine whether any design and/or procedure changes are necessary. This work is continuing.

General Electric issued a service information letter (SIL) which contains recommended actions to be taken by all BWR owners with Mark I or Mark II containment systems. (Ref. 3.) The actions involve evaluations of inerting system design and operation, performance of a leakage test to confirm the integrity of the vent system, inspection of the nitrogen injection line, and inspection of containment components and equipment. The owners group letter transmitting the SIL requested that the licensees and applicants report their findings to the NRC.

On March 5, 1984, IE Information Notice No. 84-17 was sent to all reactor facilities with operating licenses or construction permits to alert them to possible problems associated with cooling components to below their nil ductility temperatures with liquid nitrogen. (Ref. 4.) The notice also advised licensees and applicants of potentially similar problems associated with the use of other very cold fluids where the fluid could come in contact with safety-related components subject to brittle fracture.

The NRC has met with the vendor and the BWR RRG to determine whether the problem is unique to Hatch Unit 2, and whether other actions need to be taken to prevent recurrence of the problem. All aspects relevant to the failure will be reviewed in addition to the repairs made to Hatch Unit 2. The NRC staff will review the licensees' responses to the recommendations in the General Electric SIL, and determine if there is a need for further actions.

On March 14, 1984, NRC Region II forwarded to the licensee a notice of violations based on inspections performed at Hatch Units 1 and 2 between January 21 and February 20, 1984. The violation germane to the vent header problem pertained to procedural inadequacies in not properly implementing procedure HNP-2-1500, Primary Containment Atmospheric Control Systems. The procedural inadequacy allowed the nitrogen temperature at the vaporizer controller to drop, during containment integrity, below the specified band of 100-250°F. The procedure specifically cautioned against operation of the vaporizer below 100°F, but did not specify actions to be taken if the temperature did fall below the specified band. (Refs. 1-4.)

1.2 Emergency Diesel Generator Problems

On August 12, 1983, at Shoreham Unit 1* (still under construction), an event occurred in which emergency diesel generator (EDG) 102 failed due to a fractured crankshaft. There are three EDG units at Shoreham, all manufactured by Transamerica Delaval, Inc. (TDI). During subsequent investigation and repair of the failure, several conditions were identified which raised questions about the reliability of all TDI diesels at other nuclear power stations.

The failure at Shoreham occurred after 1.75 hours of testing at the 2-hour overload rating (3900 kW). At the time of failure, EDG-102 had accumulated about 718 operating hours and about 19 hours at the 110% overload rating. The test in progress when the crankshaft fractured was being performed to demonstrate EDG load carrying ability following replacement of all eight cylinder heads with a newer design (originally supplied cylinder heads had developed leaks from the cooling water area).

The EDG-102 crankshaft fracture occurred on the generator (load) side of the No. 7 cylinder and extended through the load side crank arm into the crank pin. (The No. 8 cylinder is closest to the load.) Examination of the other two EDGs identified cracks similar in location and orientation to the one which developed into a fracture on EDG-102. In addition, four of 24 connecting rod bearings were found to contain cracks in the bearing shells.

The EDGs are TDI Model DSR-48 diesels. These EDGs are the only DSR-48 diesels manufactured with a crankshaft assembly having an 11-inch crank pin diameter and 13-inch crankshaft diameter (11 x 13). On November 3, 1983, the applicant and its technical consultant reported that the crankshaft failures were definitely caused by a basic design inadequacy. Independent analysis by the consultant established that the crankshaft was overstressed relative to industry standards, a conclusion supported by various considerations, including: industry-standard torsional analysis methods, detailed stress analyses, and actual torsional test results on EDG-101. Factors contributing to the bearing cracks were found to include unsupported, overhung bearing ends, excessive crank pin journal yawing, and the presence of large pores or voids in the aluminum bearing shells.

In 1974, the applicant contracted with TDI to purchase three EDGs for the Shoreham station. This was the first order received by TDI to provide an EDG for a commercial nuclear power station. Each engine has eight cylinders in a straight line (straight-8). One of the Shoreham engines had been used by TDI

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*Shoreham Unit 1 (99% construction completed) is a BWR located in Suffolk County, New York, and is operated by Long Island Lighting Company.

to qualify the straight-8 series (R48) diesel engine for nuclear service. Pre-operational testing of the engines at Shoreham commenced in late 1981. Since testing began, the licensee has experienced several problems with the EDGs. Many component parts required reworking, redesign, and/or replacement.

At the present time, only two plants with operating licenses have TDI engines installed. One is San Onofre Unit 1 which has been shut down since February 27, 1982 for seismic modifications. The other is Grand Gulf which is authorized for power only up to 5%. A third operating plant, Rancho Seco, is presently installing TDI engines to supplement the existing non-TDI engines.

Grand Gulf has also experienced several problems with TDI engines. In 1981, pre-operational testing of two V-16 engines at Grand Gulf commenced. These engines represent the first V-16 units ordered from TDI; one of the Grand Gulf engines was used to qualify the entire TDI V-16 line of machines for nuclear applications.

There has been a total of 57 TDI engines ordered for 16 nuclear power plant sites in the United States. A list of these sites is shown in Table 1. Only San Onofre Unit 1, Grand Gulf, and Shoreham* have any significant equipment run time; therefore, the experience base of TDI units in United States nuclear service is limited.

For corrective actions at Shoreham, the applicant replaced the three 11 x 13 crankshaft assemblies with the 12 x 13 crankshaft assembly design that was reportedly installed in all other DSR-48 diesels. In addition, the connecting rod bearings were replaced with bearings designed to accommodate the new 12-inch crank pin diameter and to address the factors which caused the earlier bearings to develop cracks.

The applicant still intends to apply for a license to operate the Shoreham facility with the TDI diesel generators. However, as part of a long-term solution for the TDI diesel problems, the applicant has recently placed purchase orders for three diesel generators from Colt Industries. The NRC was informed that the applicant intends to ultimately replace the TDI diesels with Colt diesels. Delivery of the Colt diesels is scheduled for the fall of 1985, which coincides with the completion of a new diesel generator building that is currently under construction.

In December 1983, the NRC staff was informed that a TDI diesel engine owners group had been formed to address the EDG reliability issue. In addition, the NRC performed inspections of the TDI facility in Oakland, California during

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*San Onofre Unit 1 is a 436 MWe (net) PWR located 5 miles south of San Clemente, California. and is operated by Southern California Edison.

Grand Gulf Unit 1 is a 1250 MWe (net) BWR and was granted a low power license in June 1982. It is located 25 miles south of Vicksburg, Mississippi, and is operated by Mississippi Power and Light.

Shoreham Unit 1 99% construction completed) is a BWR located in Suffolk County, New York, and is operated by Long Island Lighting Company.

Table 1

Nuclear Plants with Transamerica Delaval, Inc.
Diesel Generators

Site	Licensee	Location	Engine Model No.
Bellefonte	Tennessee Valley Authority	Jackson County, AL	DSRV 16
Catawba	Duke Power Co.	York County, SC	DSRV 16
Comanche Peak	Texas Utilities Generating Company	Somervelle County, TX	DSRV 16
Grand Gulf	Mississippi Power & Light Company	Claiborne County, MS	DSRV 16
Harris	Carolina Power & Light Co.	Wake & Chatham Counties, NC	DSRV 16
Hartsville*	Tennessee Valley Authority	Trousdale & Smith Counties, TN	DSRV 16
Midland	Consumers Power Co.	Midland County, MI	DSRV 12
Perry	Cleveland Electric Illuminating Co.	Lake County, OH	DSRV 16
Phipps Bend*	Tennessee Valley Authority	Hawkins County, TN	DSRV 16
Rancho Seco	Sacramento Municipal Utility District	Sacramento County, CA	DSR 48
River Bend**	Gulf States Utilities	West Feliciana Parish, LA	DSR 48
San Onofre	Southern California Edison Co.	San Diego County, CA	DSRV 20
Shoreham	Long Island Lighting Co.	Suffolk County, NY	DSR 48
Vogtle	Georgia Power Co.	Burke County, GA	DSRV 16
WPPSS	Washington Public Power Supply System	Benton County, WA	DSRV 16
WPPSS 4*	Washington Public Power Supply System	Benton County, WA	DSRV 16

*Project delayed or cancelled

**River Bend Unit 2 has been cancelled

Note: Of the plants listed above, only San Onofre Unit 1, Rancho Seco, and Grand Gulf have received operating licenses.

July, September, and October 1983. These inspections were performed at the request of NRC Region I, in response to allegations of irregularities in the quality assurance (QA) program. Several potential nonconformances with NRC requirements were found during the July 1983 inspections. During the September and October 1983 inspections, the staff identified conditions which indicate that portions of the TDI QA program may not have been carried out in accordance with the provisions of 10 CFR 50, Appendix B.

The NRC continues to gather information regarding problems concerning TDI units, and is developing a course of corrective actions. The NRC believes that before additional licensing action is taken to authorize the operation of a nuclear power plant with TDI engines, issues relating to quality assurance, operating experience, and the ability of the machines to reliably perform their intended function, must be addressed. (Ref. 5.)

On August 30, 1983, the NRC issued Inspection and Enforcement Information Notice No. 83-58 to licensees to inform them of the Shoreham event. (Ref. 6.) Previous to the Shoreham event, the NRC issued Information Notice No. 83-51 to licensees to inform them of various diesel generator problems. (Ref. 7.)

1.3 Loss of Onsite AC Power Results in Loss of Normal Communication Links

On January 8, 1984, Palisades* experienced a complete loss of all normal communication links between the plant, the NRC and State/local authorities. (This event has also been discussed in NRC's IE Information Notice 84-42, issued in June 1984.)

The event was precipitated by the need to isolate a faulty switchyard breaker. To accomplish the isolation, it was necessary to interrupt the offsite power supply to the plant. At the time of the event, Palisades was in a refueling outage with all fuel removed from the reactor and one diesel generator inoperable. While operating procedures require two operable diesel generators prior to removing offsite power, the Shift Supervisor proceeded with the evolution after determining the safety of the fuel would not be jeopardized. In preparing for the evolution, however, the operators failed to realize that there would be no operable service water pumps supplied by the operating diesel. Consequently, after approximately 50 minutes the diesel overheated due to lack of cooling water and was manually tripped. The resulting loss of onsite ac power caused a loss of all plant telephones and radios for approximately 45 minutes. Onsite power was subsequently reenergized from the switchyard, resulting in the restoration of normal communications. The incident resulted in the declaration of an unusual event. The detailed sequence of events reported by the licensee follows.

At 7:00 a.m., a low air pressure alarm was received on the isolator column of a switchyard breaker (25R8). (See Figure 1.) The plant, in a refueling outage since August 1983, was receiving station power from the switchyard's 345 kV R

*Palisades is an 635 MWe (net) PWR located 5 miles south of South Haven, Michigan, and is operated by Consumers Power.

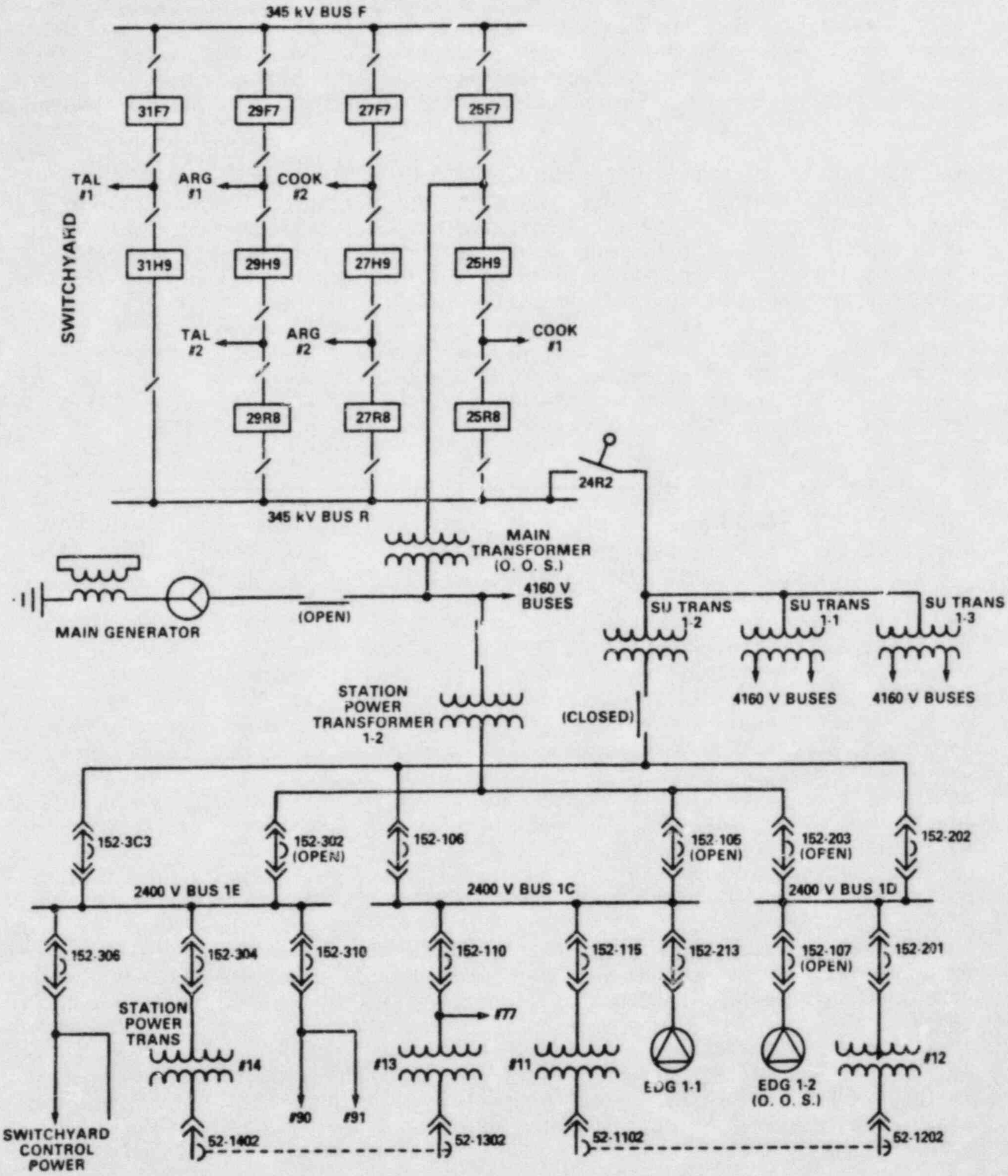

Figure 1 PALISADES COMBINATION WIRING DIAGRAM

bus through the plant's startup transformer. The licensee's Regional Power Control expressed concern regarding the condition of the breaker on several occasions throughout the morning to the plant Shift Supervisor. Regional Power Control had been having some difficulties along the power lines and was concerned that if a fault developed on the line, the breaker would fail to open. For this reason, Regional Power Control requested the R bus be removed from service to isolate and repair breaker 25R8.

At 12:15 p.m., the Shift Supervisor decided to deenergize the R bus. He knew there was no immediate threat to the plant or public with all fuel in the storage pool. He also knew that the standard operating procedure for removing the R bus from service stipulates that the plant be shut down with station power load supplied by diesel generators 1-1 and 1-2, or through the main and station power transformers 1-1 and 1-2. The Shift Supervisor realized that neither of these requirements could be fully met because both the main transformer and the 1-2 diesel generator were out of service. He reasoned the requirement for a backup power source was for occasions when maintaining core cooling to a fueled reactor was the utmost priority, and consequently he decided to proceed with the request to deenergize the R bus, with only diesel generator 1-1 loaded to the 1C bus to supply the station power load.

Diesel generator 1-1 was started, bus 1C was subsequently loaded to the diesel generator, and the appropriate breakers were opened to deenergize the R bus, leaving the plant powered solely by diesel generator 1-1 at about 12:48 p.m.

As a result of deenergizing the R bus, the plant security systems and all plant service water flow were lost. The three plant service water pumps (P-7A, -B and -C) are powered from buses 1C and 1D such that P-7B comes off the 1C bus, while P-7A and P-7C are powered from the 1D bus. With P-7B tagged out of service since mid-December, service water on this day was being provided by P-7A and P-7C. The Shift Supervisor was cognizant of P-7B being out of service, however, he did not relate the fact to the situation at hand. When the R bus was deenergized, and with the diesel generator 1-2 out of service, bus 1D was deenergized; therefore, the two operable service water pumps were lost, leaving diesel generator 1-1 to supply station power with no service water cooling available.

By approximately 1:36 p.m., the switchyard breaker had been isolated, and the appropriate breakers closed to reenergize the R bus. At this time, however, the R bus was not supplying the plant load because supply breakers to buses 1C, 1D and 1E were still open.

One minute later, an operator reported smoke in the area of the 1C bus. The Shift Supervisor immediately went to the 1C bus area and determined the origin of the smoke to be the 1-1 diesel generator room. Diesel generator 1-1 was immediately locally tripped using the manual overspeed trip. The smoke/steam resulted from overheating the diesel, which caused a gasket to rupture on the jacket water heat exchanger. There was no fire present.

Tripping the diesel generator resulted in the loss of all ac power with the exception of preferred ac. All onsite telephones and radios, except two offsite-powered pay phones, were rendered inoperable. Additionally, the control room fire detector alarm panels became inoperable. This loss of the fire detector alarm panel required the establishment of continuous fire watches to comply with technical specifications. The operators failed to recognize and thus comply with this requirement, although hourly fire tours were being conducted for inoperable fire penetration barriers.

Since the R bus was already energized, attempts were made to restore ac power by closing the supply breakers to buses 1C, 1D and 1E. Although unsuccessful on the first attempt, the breaker to bus 1D was closed on the second attempt, restoring partial ac power to the plant at 2:25 p.m. With this action, plant security systems and radios regained power; however, all plant telephones remained inoperable (except for pay phones).

At 3:11 p.m., the R bus was purposely deenergized to attempt closing the supply breaker to bus 1C on a "dead" bus. The attempt failed, and R bus was subsequently reenergized. Bus 1D was restored to power, at 3:50 p.m. During this time (3:11 to 3:50 p.m.), the plant was again without ac power and, consequently, without power for security systems and radios. At 4:18 p.m., bus 1E was energized, resulting in partial restoration of the phone system.

Investigation into the inability to close the supply breakers to the 1C and 1E buses revealed that bus 1E was locked out due to safety injection load shed relay actuation, and the bus 1C supply breaker was locked out by an automatic transfer interlock.

The condition apparently was not classified as an emergency because all fuel was in the storage pool, and the probability of a radiological release was substantially nonexistent. However, at approximately 4:30 p.m., the site emergency plan was activated, classifying the incident as an unusual event. The Shift Supervisor, with assistance from the Duty Health Physics Supervisor, completed some of the immediate notification requirements.

At 7:30 p.m., previously inoperable phones were jumpered to an energized source, resulting in a complete restoration of plant-powered telephones. On January 9, 1984, the instrument ac bus was reenergized, resulting in the fire detection alarm panels being returned to service. Following several unsuccessful attempts at repairing the 1C supply breaker, a replacement breaker was installed and bus 1C was reenergized.

Evaluations by the licensee indicated that (1) the loss of normal communications significantly hampered the notification process, (2) the likelihood of a recurrence under operating conditions was very remote because of technical specifications and procedural limitations, and (3) the failure of the 25R8 breaker under fault conditions could be handled without any adverse consequences.

The evaluation of this incident and the related faults and failures resulted in numerous corrective action items. (See Ref. 8 for details.) The following are significant lessons learned:

- Plant administrative guidelines should be established to ensure sufficient equipment remains available to maintain the plant in a safe condition, and to meet the commitments of the site emergency, security, and fire protection plans, since the technical specifications limiting conditions of operation (LCOs) do not provide sufficient guidance to adequately control equipment outages during cold and refueling shutdowns.

- A more effective means of tracking the status of equipment and work in progress is needed, since equipment status boards routinely used during power operation are inadequate to monitor equipment status during major outages.

- Licensed operators should have an adequate knowledge of the communications and security systems. System training and readily accessible system prints are essential to allow the operators to quickly assess system malfunctions and effect restoration.

- All modifications to communications systems must be formally controlled, because they are a vital portion of both the site emergency plan and the security plan.

- During an incident, the Shift Supervisor needs to be in a location where he can maintain an overview of the situation and best direct the available resources. While this location may not always be the control room, the Shift Supervisor should be cautious about leaving the control room during casualties.

- Attention to detail is essential in the conduct of routine maintenance activities, because seemingly minor errors on nonsafety-related systems can impact on the safe operation of the plant.

1.4 Electrical Power Interaction Problems

On February 12 and again on February 16, 1984, onsite power disruptions caused dual reactor trips at Turkey Point Units 3 and 4.* During both events, safety systems worked as designed. (These events are also discussed in NRC's IE Information Notice 84-38, issued in May 1984.)

February 12, 1984

At 6:38 a.m., the Unit 3 reactor tripped from 100% power. The event was due to spurious actuation of the C phase differential fault protection relay on the adjacent fossil Units 1 and 2 startup transformer, which initiated the lock-out of the northeast (NE) 240 kV switchyard bus. This resulted in deenergizing the 3C auxiliary transformer (240 kV/4 kV), originally powered from the NE 240 kV

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* Turkey Point Units 3 and 4 are 666 MWe (net) PWRs located 25 miles south of Miami, Florida and are operated by Florida Power & Light.

bus, and its feeder circuits associated with 4160 V bus feeder breakers 3AC16 and 4AC01 (the normal and alternate supplies to the 3C and 4C 4160 V buses, respectively). Breaker 3AC16 was closed-in on the nonsafety-related 3C 4160 V bus when the lock-out and, thus, loss of power to the 3C bus and thus to the 3B steam generator feedwater pump occurred, which ultimately resulted in the reactor trip.

At 9:45 a.m., the Unit 4 reactor tripped from 100% power. This event was due to a malfunction of an electrical synchronism-check relay which did not prevent the erroneous closure of a deenergized 4160 V bus feeder breaker (4AC01) onto the energized nonsafety-related 4C 4160 V bus. Bus protection relaying opened the energized 4C 4160 V bus normal feeder breaker (4AC16) and deenergized the 4C bus and its power supply to the 4B steam generator (S/G) feedwater pump. The reduced feedwater flow transient resulted in a reactor trip on RPS logic.

The synchronism check relay checks the voltage and phase-angle of the 4C 4160 V bus (running voltage) against that of the selected 4C 4160 V bus feeder breaker (incoming voltage) to prevent closure of the breaker if the voltage and phase-angle differences exceed design setpoints. The failure of the synchronism-check relay to prevent closure of the deenergized feeder breaker (4AC01), which was closed erroneously by an operator during attempts to power the nonsafety-related 3C 4160 V bus from its alternate power supply (3AC01 was the correct breaker to be closed), resulted in deenergizing the 4C 4160 V bus which ultimately resulted in the reactor trip.

<u>February 16, 1984</u>

While at steady state operation on Units 3 and 4, a dual trip occurred from 100% power. In both cases, the loss of the 3C and 4C 4160 V buses resulted in the reactor trips.

In response to concerns relating to an unexplained failure of the synchronism check relay, a Nuclear Turbine Operator (NTO) was directed to rack out breaker 4AC01 (alternate feed to 4C bus from Unit 3), which was already open. In opening the door to the breaker cubicle, interference was encountered with a bolt that bound the door. As the door opened, the jarring set up vibrations in the door. The vibrations spuriously actuated an auxiliary relay mounted on the cubicle door, which caused a 4C bus lockout. This signal tripped all input and load breakers on the 4C bus, including the 4B steam generator feedwater pump. Loss of the B feed train caused a Unit 4 turbine governor runback followed by a reactor trip on steam flow greater than feed flow, coincident with low level on the 4A S/G.

Approximately 1 minute later, the NTO proceeded to close the 4AC01 cubicle door. Again the door travel encountered interference by the same bolt. The resulting vibrations spuriously actuated a fault detector overcurrent relay, which was also mounted on the cubicle door. This, coupled with the fact that breaker 4AC01 was open, caused the 62/SAM timer to be energized, producing a Unit 3 3C transformer lockout. As a result, zone E of the NE bus differential protection was actuated and initiated a lockout on the NE bus, deenergizing the 3C transformer, and the Unit 3 startup transformer. Also, voltage was lost to the 3C 4160 V bus, thus deenergizing the 3B steam generator feedwater pump. System response was unable to control the transient and the reactor tripped due to high pressurizer pressure.

Unit 3 entered natural circulation (reactor coolant pumps deenergized) following the loss of offsite power caused by the startup transformer being deenergized. Natural circulation was verified by an operating procedure and parameter displays for inadequate core cooling. A post trip review was performed for each unit and found all safety system responses to be adequate. Unit 4 was stable following the trip, with offsite power available.

The cause of the event was attributed to the bolt interfering with 4AC01 breaker cubicle door travel. When the door hit the bolt, the resulting vibrations spuriously actuated sensitive relay mounted on the door. The equipment installed for the auxiliary power upgrade is non-class 1E.

Immediately following the dual unit trip, the licensee notified the NRC and declared an unusual event. Technical and management staffs began to review the sequence of events and possible concerns arising from the transients. Restart of either unit was held until an evaluation of the electrical system was performed and results discussed with NRC staff. The following is a summary of recovery actions taken in an attempt to stabilize both units and related systems:

(1) The undervoltage condition on the 3A and 3B 4160 V buses was cleared upon auto start and loading of both emergency diesel generators.

(2) The NE bus differential was reset and the Unit 3 startup transformer energized.

(3) The 3A and 3B 4 kV buses were energized, then the emergency diesel generators were secured.

(4) The 3A reactor coolant pump was started and RCS temperature stabilized, ending natural circulation.

(5) The normal feed train was returned to service (3A S/G feed pump).

(6) The unusual event was terminated and proper notifications were made to the State and the NRC.

(7) The 4C 4 kV bus was reenergized.

(8) Using an approved temporary operating procedure, the 3C 4 kV bus was energized from the 4C transformer.

(9) Containment parameters and RCS chemistry (iodine) were verified to be normal.

At this point, both units were stable and recovery actions continued to return all systems to normal configuration. Short term corrective actions included those described below.

The licensee removed the interfering door bolt, and checked and adjusted all other doors for proper clearances. Signs were painted on breaker cubicle doors to use caution when opening them. Due to the sensitivity to vibration of certain relays* when mounted on cubicle doors, these relays were relocated. Switching modifications were implemented, including cross-feeding the 4C 4 kV bus from the 3C transformer and the 3C 4 kV bus from the 4C transformer, and isolating all ties and alternate feeds to the C 4 kV buses by racking out and locking all respective breakers. Administrative controls were placed to assure that both startup transformers will be operable when either unit is above 50% rated feedwater flow.

Long term corrective actions include reviewing offsite and onsite electrical power supply configurations and related technical specifications, and evaluating the possible need for relocating all relays mounted on cubicle doors in the C 4 kV bus switchgear. In addition, a major switchyard improvement is currently underway at Turkey Point. Current planning calls for the addition of six new 240 kV breakers. The purpose of this effort is to create a switchyard arrangement that has less chance that an upset at one generating unit will affect any of the other generating units. Also, a connection has been installed that allows any two of the five black-start diesel generators to supply the engineered safety features buses of the nuclear units. These diesel generators are in addition to the dedicated nuclear plant emergency diesel generators. (Refs. 9-11.)

1.5 Temporary Loss of Shutdown Cooling

At Browns Ferry** on February 14, 1984, the licensee reported that while bringing Units 1 and 2 to cold shutdown because of the residual heat removal (RHR) service water system air release valves not being properly certified for the design pressure, valve FCV-1-74-48 on Unit 1 failed to open, making it impossible to achieve cold shutdown using the RHR system. An alert was declared per the radiological emergency plan. The plant was brought to cold shutdown through other normal means, and the alert was cancelled after the valve was opened manually and shutdown cooling restored.

With Units 1 and 2 operating at 99% power and Unit 3 in a refueling outage, the decision was made to bring Units 1 and 2 to cold shutdown due to the air release valves on the RHR service water/emergency equipment cooling water system not being properly certified for the design pressure. After manually scramming Units 1 and 2, Unit 1 could not be placed in shutdown cooling using the RHR system due to the inability to open electrically operated shutdown cooling suction valve FCV-1-74-48. This valve is located inside primary containment, which was inerted at the time of the event, and thus the valve was not accessible for manual operation. An alert was declared per the radiological emergency plan because of the inability to use the RHR system in the shutdown cooling mode. The alert was cancelled after drywell entry was made, the valve was manually opened, and shutdown cooling was established using the RHR system.

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*These relays are manufactured by General Electric (Type HGA, model No. 12HGA17C61). Their function is to perform as an auxiliary relay for breaker tripping and alarming with a 0.25-second time delay drop out feature.

**Browns Ferry Units 1, 2, and 3 are 1065 MWe (net) BWRs located 10 miles north west of Decatur, Alabama and are operated by the Tennessee Valley Authority.

Prior to establishing RHR cooling, cold shutdown had been achieved by normal cooldown to the condenser and then by using control rod drive system pumps and the reactor water cleanup system as an alternate method for shutdown cooling.

Emergency core cooling systems (low pressure coolant injection and core spray) were available throughout the event. In addition, the condensate system was also available if needed for reactor vessel makeup, and both high pressure coolant injection and reactor core isolation cooling could have been made available by using auxiliary steam if required. The pressure suppression chamber was available for heat rejection if it had been required.

An investigation of this event revealed that the B phase winding of the motor on valve FCV 74-48 had failed, although it is not yet known if the valve's failure to open resulted from the motor winding failure or other causes. Valve FCV 74-48 is a 20-inch Walworth-Gate valve with a limitorque valve operator with a Reliance Electric Company motor. (Refs. 12-13.)

1.6 Unauthorized Entries Into Locked High Radiation Areas

The events described below illustrate a recurring problem pertaining to unauthorized entries into the cavity beneath the reactor vessel while the retractable incore detector thimbles are withdrawn. These are the tenth through twelfth exposures since 1972 (six were overexposures) that have occurred under similar circumstances. (See Table 2). The NRC is particularly concerned that these more recent exposures occurred, since the licensees involved had received earlier notification of similar events at other sites. (The events discussed below have also been described in NRC's IE Information Notice 84-19, issued in March 1984; previous events have been covered in Information Notice 82-51.)

Although the radiation doses received by personnel in these and previous incidents have not been greater than 10 rems, extremely high radiation fields are created in reactor cavities by withdrawn, irradiated incore instrumentation thimbles. Radiation levels of thousands of roentgens per hour (R/hr) are possible, and in at least one of the incidents, an individual entered a field of at least 2000 R/hr. Entry into radiation fields of this magnitude seriously jeopardizes the health and safety of personnel. (Refs. 14-16.)

Turkey Point Unit 3*

On October 14, 1983, during the evening shift, work was being performed in the reactor containment in preparation for refueling activities. The reactor cavity was being filled with water as a prerequisite for the anticipated movement of fuel. Earlier, during the day shift, radiation protection supervision had anticipated the need to examine the reactor sump area when the cavity was filled because leaks in the seal between the reactor vessel and the cavity had been found in this area when this operation had previously been performed. The roving radiation protection technician in the containment had been provided with a key to the sump area by his supervisor, and had been cautioned to only look in the door and not to enter the sump. This precaution was believed to be necessary because the retractable thimbles of the incore detection system were

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*Turkey Point 3 is a 666 MWe (net) PWR located 25 miles south of Miami, Florida and is operated by Florida Power and Light.

TABLE 2

DATE	PLANT	DOSE*
October 1972	Point Beach	5 rems
March 1976	Zion 1	8 rems
April 1976	Indian Point	10 rems
May 1978	Kewaunee	2.8 rems*
April 1979	Surry 2	10 rems
April 1980	Davis Besse	5 rems
October 1980	Salem 1	*
March 1982	Zion 1	5 rems
October 1983	Turkey Point 3	1.3 rems; 0.2 rem
February 1984	H. B. Robinson 2	0.5 rem

exposed in the sump area and this resulted in high radiation levels being present, exceeding 50 rems/hr. However, the filling of the cavity did not take place on the day shift. When the shift personnel were changed, the on-coming technician received the key to the sump from the off-going technician, but he did not recall being told he was not to enter the sump.

When the cavity filling process began, another worker, a Shift Technical Advisor (STA), was sent into the containment to determine if there were leaks. By chance, he met the technician at the door to the reactor sump. The door was conspicuously marked with signs reading "EXCLUSION AREA, HIGH RADIATION AREA, STAY-OUT, RWP REQUIRED FOR ENTRY," but the two workers decided to open the door to determine if there was any leakage into the sump. Each worker had in his possession a dose-rate indicating instrument, which could detect radiation levels of up to 5 rems/hr.

The STA could not determine if leakage was occurring, so he decided to enter the sump. The technician descended the ladder approximately half way and performed a radiation survey. The radiation levels measured were approximately 0.03 rems/hr. The technician allowed the STA to descend after setting the STA's instrument on the 0.5 rems/hr scale. The STA proceeded down the ladder into the sump and was followed by the technician. When the technician reached the bottom of the ladder, the STA was 6-8 feet toward the area under the reactor vessel. At that time the technician asked the STA what his instrument was reading. The STA replied that it was off-scale. The technician immediately told the STA to get out of the sump and both exited promptly.

The STA then read his self-indicating pocket dosimeter and found it to be off-scale (greater than 0.200 rems). The workers reported this event to the licensee's radiation protection supervision. Subsequent evaluation of the STA's thermoluminescent dosimeter indicated that he had received 1.3 rems

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*Near overexposure (10 CFR 20.102 allows a whole body exposure of 3.0 rems per calendar quarter).

(whole-body) as a result of his entry into the reactor sump. The workers estimated that the time spent in the sump was less than one minute. A radiation worker with an appropriately established exposure history is permitted by 10 CFR 20.101 to receive up to 3 rems whole-body in a calendar quarter.

The cause of this event was the failure of the licensee to establish appropriate controls, including administrative control of keys, adequate training of supervisory and operating personnel regarding the hazards of entering locked high radiation areas, and specific written procedures for entry into potentially hazardous radiation fields. The licensee was fined $40,000 by the NRC for the regulatory violations associated with this event. (Ref. 17.)

H. B. Robinson Unit 2*

On February 19, 1984, work was being performed in the containment in preparation for defueling the reactor. The reactor cavity was being filled with water as a prerequisite for the anticipated movement of fuel. The operating staff knew that the incore detector thimbles had been withdrawn into the reactor sump. The Shift Foreman instructed a licensed Reactor Operator to go to the reactor keyway sump to check for leaks. The Shift Foreman did not give explicit instructions concerning the method the operator was to use to check for leaks, nor did he caution the operator about the radiation hazards that would be encountered in the sump.

A key locker was maintained in the control room as a means of satisfying the administrative control requirements for keys to locked high radiation areas. The operator obtained the key to the reactor sump from the locker and proceeded to the reactor containment. The operator explained to a radiation protection technician that he needed the technician to unlock the steam generator bay door and to provide health physics (radiation protection) coverage while the operator checked for leaks in the reactor keyway sump.

When the two workers entered the steam generator bay, the operator proceeded to the keyway sump entrance. This entrance was posted with radiological caution signs reading: "HIGH RADIATION AREA, AIRBORNE RADIOACTIVITY AREA, NO ENTRY, CONTACT RC FOREMAN." Despite these signs, the two workers decided to open the floor hatch to determine if there was any leakage into the sump. The operator had in his possession a respirator for use in entries into airborne radioactivity areas but the technician did not. After the operator unlocked and opened the sump cover, the technician used a radiation dose-rate instrument (a Teletector) to measure the dose-rate at the bottom of the first ladder. It was between 1.5 and 2.0 rems/hr.

The operator did not know the extent of the survey which had been done by the technician, yet he donned his respirator and entered the sump. He proceeded across the platform at the bottom of the first ladder and went down the second ladder to a level just below the biological shield. In this location, he was

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*H.B. Robinson is a 665 MWe (net) PWR located 5 miles northwest of Hartsville, South Carolina, and is operated by Carolina Power and Light.

exposed to the withdrawn incore detector thimbles without intervening shielding. This area was later surveyed and the dose-rate was approximately 75 to 100 rems/hr.

After approximately 30 seconds in this area, the operator left the sump and relocked the sump cover. The operator performed other work in the containment and left at the containment checkpoint approximately 30 minutes later. The checkpoint monitor determined that the operator had 0.40 rem indicated on his self-reading pocket dosimeter and as a result of this finding, the licensee initiated an investigation into the circumstances of the unanticipated dose the operator had received. The operator's thermoluminescent dosimeter read 0.539 rem.

The cause of this event was a failure to have procedures which adequately implement technical specifications for entry into a locked high radiation area. Escalated enforcement actions are under review by the NRC staff. (Ref. 18.)

1.7 Heat Damage to Cables and Mechanical Snubbers in Upper Drywell

On November 10, 1983, the licensee for LaSalle Unit 1* reported that two cables in the upper area of the drywell were found damaged by excessive heat. The heat damage occurred as a result of higher than design ambient temperatures (about 180°-200°) as well as localized "hot spots" (about 280°). The physical damage occurred primarily at elevation 807, but localized damage was found in other areas. An evaluation of the expected life of safety related equipment, parts and components was performed using temperature profiles extrapolated from actual temperature measurements in the drywell. At the same time, the licensee began inspections to determine the extent of visible damage.

No safety related electrical equipment was found inoperable, although several cables were damaged and six mechanical snubbers were found inoperable. An analysis of the piping affected by the six inoperable snubbers revealed that no adverse stresses or usage factors in excess of code allowables had occurred as a result of these inoperable snubbers. Therefore, the integrity of systems important to safety was not jeopardized. The plant was maintained in a safe condition at all times.

The cause of the high ambient temperature was air stratification at the higher drywell elevations. Adding to the high ambient temperatures were localized "hot spots" which caused areas of temperature above ambient. Small gaps in the mirror insulation around valves and pipe clamps contributed to the heating problem.

Corrective actions taken by the licensee include the following:

-- Safety related cables which were visibly damaged have been repaired/ replaced as required.

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*LaSalle Unit 1 is a 1078 MWe (net) BWR located 11 miles southeast of Ottawa, Illinois, and is operated by Commonwealth Edison.

-- Environmentally qualified equipment required for power operation has been analyzed as having sufficient qualified life to permit unit operation.

-- Failed mechanical snubbers have been replaced, and affected piping analyzed and determined to be acceptable. Additionally, ten snubbers which may have been subjected to high temperatures are being replaced.

-- An inspection was performed to identify any gaps or damaged insulation.

-- A modification has been initiated to provide augmented mixing of air at the upper drywell elevations.

In addition, a long-range solution to drywell temperature problems is being tracked. A work request has been initiated to place temporary thermocouples in selected locations within the drywell. Temperature profile information obtained from these temporary thermocouples as well as existing thermocouples will be used as an input to a temperature monitoring restart plan which will be in place by unit startup. This plan will be used to identify any necessary corrective action, should the temperature in a given area exceed that for which the equipment is qualified during its remaining life. (Ref. 19.)

1.8 Reactor Trip Due to Low Steam Generator Level

On February 9, 1984, with St. Lucie Unit 2* operating at 100% power, the main feedwater pump tripped due to low condensate booster pump suction. The reactor subsequently tripped on low steam generator level. Following the trip, the 2C auxiliary feedwater pump started, then tripped on overspeed. Also, three out of eight secondary code safety valves lifted; one valve on the A steam generator failed to fully re-seat and stayed partially open for 45 minutes. Cooldown from the open safety was successfully controlled.

Although the specific cause of the low suction pressure to the feedwater pumps was not determined, it is believed that pump vent line design characteristics probably contributed. The 2C auxiliary feedwater pump tripped due to transients on a power supply during auxiliary feedwater actuation. The safety valve stuck open because a cotter pin was missing from a spindle nut. When the safety valve opened (as expected) the nut vibrated down and held the valve partially open.

Corrective actions included replacing the nut pin and checking all safety valves to assure full seating, and modifying the auxiliary feedwater pump power supply to reduce electrical noise. In addition, the licensee plans to change the condensate pump vent line design to allow proper venting during strainer cleaning. (Ref. 20.)

1.9 Isolation Valves Fail to Open

On February 22, 1984, an event occurred at Big Rock Point Unit 1** in which three of four reactor depressurization system (RDS) isolation valves failed to

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*St. Lucie Unit 2 is a 786 MWe (net) PWR located 12 miles southeast of Ft. Pierce, Florida, and is operated by Florida Power and Light.

**Big Rock Point Unit 1 is a 64 MWe (net) BWR located four miles northeast of Charlevoix, Michigan, and is operated by Consumers Power.

open during a routine surveillance test (performed every 90 days). At the time of the event, the plant was in hot standby (reactor shut down, system at reduced pressure of approximately 50 psig, temperature at 265°F). The plant had been shut down since February 19 for various maintenance activities. When the three isolation valves failed to open during the test, the licensee declared the incident to be an unusual event until the plant was placed in cold shutdown (reactor shut down, system at atmospheric pressure, temperature below 212°F). The event was due to a design change made by the licensee to ensure safety of workers in the drywell, involving an increase of air pressure in order to hold the valves closed, which resulted in the disk binding in the seat.

The RDS is a set of piping and valves which was installed at Big Rock Point in the mid-1970s. One large pipe from the steam drum feeds four parallel lines; each line contains an isolation valve and depressurization valve (both normally closed). Both valves must open to allow flow through the line. The purpose of the RDS is to provide a method of rapidly depressurizing the reactor in the event of a small break loss of coolant accident (SBLOCA). In such an accident the reactor would lose cooling water while the system pressure would remain high. Since Big Rock Point does not have a high pressure injection system, the RDS reduces the system pressure to the point (roughly 75 psig) where the core spray system (a low pressure system) can deliver cooling water to the reactor. The plant technical specifications require that three of the four lines be operable whenever the reactor is not in cold shutdown. Safety analysis calculations indicate that three lines would be needed to properly depressurize the reactor under the worst case accident conditions. If the RDS did not operate properly in the event of an SBLOCA, use of the core spray system could be delayed and the core could become uncovered and damaged.

The isolation valves are 6-inch flexible wedge-type gate valves manufactured by Anchor-Darling. The valves are opened by a spring and closed by a pressurized air system. In 1983, the licensee installed an air amplifier system to increase the air pressure which holds the valves closed. No change was made to the springs.

After consulting with the valve manufacturer and conducting tests of the valves, the licensee determined that the cause of the valves' failing to open was a combination of thermal binding and the increased force holding the valves closed due to the recently installed air amplifier system. Thermal binding occurs when the valve is closed hot and then cooled down. The cooling causes contraction of the valve seat and therefore requires additional force to open the valve. The increased force holding the valve closed resulting from the installation of the air amplifier further heightened the effects of thermal binding to the point that the springs were not strong enough to open the valves.

Based on the results of past testing, the licensee concluded that the valves would have opened at normal operating temperature, which is approximately 550°F. Since the valves failed to open at approximately 265°F and there was no testing at temperatures between 550°F and 265°F, the licensee was unable to determine the temperature at which failures would have begun.

In reviewing past operating experience, the licensee determined that prior to the installation of the air amplifier, there had been no instances of valves failing to open because of thermal binding.

To prevent recurrence, the licensee removed the air amplifier system from service, and returned to the closing air pressure used previously. This action reduced the force holding the valve closed and minimized the potential for thermal binding. The licensee disassembled one valve for inspection and found no defects. The valves were then cycled at operating temperature and retested during a partial unit cooldown and depressurization. All valves functioned properly during these tests. The licensee also committed to test the valves again during the next cold shutdown. (Refs. 21-22.)

1.10 Potential Radiation Overexposure

At Pilgrim Unit 1* on January 18, 1984, three individuals entered the control rod drive (CRD) repair room (a portion of the restricted area) to perform work. The individuals were briefed by radiation protection personnel on the apparent status of the area prior to their entry. However, they were not informed of the presence of a container of radioactive material producing dose rates as high as 20 rems/hr (later found to contain material with contact doses as high as 2880 rems/hr) in their immediate work area. Consequently, the individuals unknowingly subjected themselves to substantial potential for personnel exposure in excess of the limits specified in 10 CFR 20.101, "Radiation Dose Standards for Individuals in Restricted Areas," by working with the material in that container.

The container was a plastic 5-gallon bucket filled with water and containing highly radioactive debris and CRD parts from work performed on January 14, 1984. On January 18, the three workers entered the CRD room between 8:00 and 9:30 a.m. and started collecting and decontaminating CRD parts. During this work, one worker moved the bucket from the northwest corner of the CRD room.

The worker rinsed the parts in the bucket with fresh water and then removed and decontaminated the parts. The bucket was then moved to a central location in the room by a second worker. The third worker did not handle the bucket. None of the workers had extremity dosimetry.

The workers later stated that they were not aware of the radiation fields near the bucket on January 18. One of the workers recalled being told on January 14 about a bucket with a high contact dose rate in the room. The workers stated that it was not unusual to collect CRD parts from one or more unlabeled buckets in the CRD room.

The workers received twice the expected whole body radiation dose during the morning work, based on their self-reading dosimeter measurements (25 to 50 mrems instead of 10 to 25 mrems). The health physics technician immediately entered the room to investigate and found that general area dose rates in the central portion of the room were ten times higher than shown on the January 17 radiation survey.

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*Pilgrim Unit 1 is a 670 MWe (net) BWR located four miles southeast of Plymouth, Massachusetts, and is operated by Boston Edison.

The technician identified the bucket with a contact dose rate of 10 rems/hr as the major radiation source in the room. The technician surveyed the CRD parts in the bucket and found that they had contact dose rates of less than 100 mrems/hr. The technician placed the bucket on a nearby table to prevent the bucket from being knocked over, and exited the room.

He then reported the bucket to his supervisor and noted the bucket in the CRD log (the only entry about the bucket in the log). The technician reentered the CRD room at 12:10 p.m. to further survey the bucket, in anticipation of further work in the room that afternoon. During the survey, the technician picked up small metal chips from the bottom of the bucket with his fingers and attempted to measure their contact dose rates with his survey instrument. (Note: During this activity the technician wore full protective clothing, including two pairs of rubber gloves and a cotton glove liner. While whole body dosimetry was used, no extremity monitoring devices for his hands were worn.)

The technician later stated that he twice removed inch long pieces of metal from the bucket. The first chip had a dose rate of 10 rems/hr according to his survey instrument and the second a dose rate of 100 rems/hr. The technician then removed several small pieces (estimated to be 1/8 inch on a side) and noted survey instrument readings in excess of 250 rems/hr. After each survey, the technician threw the pieces into a nearby lead pig.

The licensee conducted time-motion studies of the January 18 incident. These indicated that the technician held all the chips for a total time of less than 10 seconds. A contact dose rate survey of the chips was conducted using thermoluminescent dosimeters which indicated a maximum contact dose rate of 2880 rems/hr. A gamma spectral analysis was performed on one chip to evaluate whether beta radiation contributed to the technician's dose. The licensee estimated that the technician had received 4.5 rems of extremity dose from the January 18 incident.

The cause of this event was a lack of adequate radiological controls, in that: (1) a container was not adequately identified with information to permit individuals handling or using the container, or working in the vicinity of the container, to take proper precautions; (2) access to the container and the associated high radiation area was not positively controlled; and (3) personnel were not adequately informed of the presence of highly radioactive material in the container, and procedures and precautions for minimizing their exposure relative to that container.

The licensee was fined $40,000 by the NRC because a substantial potential for a technical overexposure existed during the event. (Refs. 23-25.)

1.11 Breakdown of Solder in Pump Motor Commutator

At Susquehanna Unit 1* on July 24, 1983, the reactor core isolation cooling system (RCIC)** barometric condenser condensate vacuum pump motor tripped

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*Susquehanna Unit 1 is a 1036 MWe (net) BWR located seven miles northeast of Berwick, Pennsylvania, and is operated by Pennsylvania Power and Light.

**Although it is used for normal plant shutdown, RCIC is not an emergency core cooling system and is not required for safe shutdown of the plant.

while the RCIC system was running for spray pond testing. The event was caused by mechanical failure of the condensate pump motor commutator. Failure of the condensate pump caused water level in the barometric condenser to rise, tripping the vacuum pump on thermal overload.

The barometric condenser cools and condenses small amounts of RCIC steam from several turbine-related sources. (RCIC steam used to drive the RCIC turbine is not condensed in the barometric condenser.) It receives steam from the RCIC turbine gland seals, stop valve drains, governor valve leak-off, and exhaust line drain pot. This steam is condensed in the barometric condenser by spraying relatively cool water from the RCIC pump discharge line into the barometric condenser through a series of spray nozzles. Condensate and non-condensable gases are collected in the vacuum tank. The condensate pump automatically maintains vacuum tank condensate level by periodically pumping excess condensate to the RCIC pump suction line. Non-condensable gases are transferred to the suppression pool by the vacuum pump which continuously maintains a negative pressure in the vacuum tank.

Investigations discovered the condensate pump motor commutator was open circuited. Failure of the commutator was caused by solder being lost from a commutator slot, resulting in the failure of the electrical connection in the commutator slot and an open coil condition. The investigation also revealed that the vendor of the motor has experienced this condition a few times in the past. The vendor stated that increased maintenance is not likely to reveal, in advance, the mechanical breakdown of the solder connection in the commutator; the only probable indication of this condition may be the discoloration of the motor commutator, which the licensee inspects in maintenance test procedures.

As corrective actions, the licensee replaced the condensate motor and reset vacuum pump overloads. RCIC was tested and returned to service. (Ref. 26.)

1.12 References

(1.1) 1. Georgia Power Company, Docket 50-321, Licensee Event Report 84-01, Revision 1, March 21, 1984.

2. NRC Memorandum from C. J. Heltemes, AEOD, to W. J. Dircks, EDO, transmitting "Abnormal Occurrence Recommendation - Through Wall Crack in Vent Header Inside BWR Containment Torus," April 5, 1984.

3. General Electric Nuclear Services Operations, Service Information Letter (SIL) No. 402, "Wetwell/Drywell Inerting," February 14, 1984.

4. NRC, Inspection and Enforcement Information Notice No. 84-17, "Problems with Liquid Nitrogen Cooling Components Below the Nil Ductility Temperature," March 5, 1984.

(1.2) 5. NRC, Abnormal Occurrence Report, October-December 1983, NUREG-0090, Vol. 6, No. 4, May 1984.

6. NRC, Inspection and Enforcement Information Notice No. 83-58, "Transamerica Delaval Diesel Generator Crankshaft Failure," August 30, 1983.

7. NRC, Inspection and Enforcement Information Notice No. 83-51, "Diesel Generator Events," August 5, 1983.

(1.3) 8. Consumers Power Company, Docket 50-255, Licensee Event Report 84-01, February 7, 1984.

(1.4) 9. NRC, Preliminary Notifications PNO-II-84-12 (February 13, 1984) and PNO-II-84-14 (February 16, 1984).

10. Florida Power and Light Company, Docket 50-250, Licensee Event Reports 84-06 (March 13, 1984) and 84-07 (March 19, 1984).

11. Florida Power and Light Company, Docket 50-251, Licensee Event Reports 84-01 and 84-02, March 13, 1984.

(1.5) 12. NRC, Preliminary Notifications PNO-II-13 and PNO-II-13A, February 14, 1984.

13. Tennessee Valley Authority, Docket 50-259, Licensee Event Report 84-12, March 6, 1984.

(1.6) 14. NRC, Report to Congress on Abnormal Occurrences, NUREG-0090-3 (January-March 1976) pp. 4-5, and NUREG-0090, Vol. 5, No. 2 (April-June 1982), pp. 8-10.

15. NRC, Power Reactor Events, Vol. 3, No. 2 (May 1981), pp. 10-11, and Vol. 4, No. 4 (November 1982), pp. 1-6.

16. NRC, Inspection and Enforcement Information Notices 82-51 (December 21, 1982) and 84-19 (March 21, 1984).

17. Letter from J. O'Reilly, NRC/Region IV, to J. Williams, Florida Power and Light Company, re: Proposed Imposition of Civil Penalty, February 2, 1984.

18. Letter from J. O'Reilly, NRC/Region IV, to E. Utley, Carolina Power and Light Company, re: Proposed Imposition of Civil Penalty, February 27, 1984.

(1.7) 19. Commonwealth Edison Company, Docket 50-373, Licensee Event Report 83-143, December 8, 1983.

(1.8) 20. Florida Power and Light, Docket 50-389, Licensee Event Report 84-04, March 9, 1984.

(1.9) 21. NRC, Preliminary Notifications PNO-III-84-20 (February 23, 1984) and PNO-III-84-20A (March 6, 1984).

22. Confirmatory Action Letter from J. Keppler, NRC/Region III, to J. Reynolds, Consumers Power Company, March 3, 1984.

(1.10) 23. NRC/Region I, Inspection Report 50-293/84-03, February 9, 1984.

24. Letter from W. Harrington, Boston Edison Company, to R. Starostecki, NRC/Region I, re: Response to Confirmatory Action Letter 84-03, February 15, 1984.

25. Notice of Significant Enforcement Action, EN 84-23, for Docket 50-293, April 12, 1984.

(1.11) 26. Pennsylvania Power and Light Company, Docket 50-387, Licensee Event Report 83-109, January 13, 1984.

These referenced documents are available in the NRC Public Document Room at 1717 H Street NW, Washington, D.C. 20555 for inspection and/or copying for a fee.

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. There has been minimal effort to edit the text provided, since it is assumed that the LER descriptions are accurate and complete, as required by 10 CFR 50.73(b).

Because the purpose of this section is to objectively highlight the information selected, event dates and plants involved are not included in the abstracts. Persons interested in the plant docket number and LER number may obtain this information by contacting the Editor on 301-492-4499, or at U. S. Nuclear Regulatory Commission, EWS-263A, Washington, DC 20555.

2.1 Increased Loads and Revised Design Margin Indicate Undersized Battery

The No. 1 125 V dc battery was determined to have insufficient capacity to satisfy the design duty cycle of 90 minutes, indicating a condition outside of the design basis of the plant. This discovery was made while performing sizing calculations to provide a replacement for the No. 1 battery due to the approach of its end of service life.

Previous sizing calculations indicated that the existing No. 1 battery had sufficient capacity for a 90-minute duty cycle. The new sizing calculation indicates that the replacement battery should be of greater capacity. The increase in capacity is due to: (1) the new sizing calculation requiring several major nonsafety-related loads supplied from the No. 1 dc bus to remain operating for longer periods of time than required previously; and (2) additional design margins being incorporated into the new sizing calculation in accordance with IEEE 485-1978. Nonsafety-related loads have been reduced temporarily until a larger capacity battery can be installed.

2.2 Procedural Deficiency Could Have Isolated RHR System

During the initial use of the quarterly section of the current revision of the emergency core cooling system operability test, an error that would have rendered both residual heat removal (RHR) trains inoperable was discovered by the Unit Supervisor. A quarterly step in the procedure called for the closing of the west RHR heat exchanger outlet valve, while a monthly step had earlier closed the east RHR heat exchanger outlet valve. With both valves closed, both RHR trains would have been inoperable. The procedure was stopped and at no time were both trains inoperable.

The error in the procedure was originally introduced into the previous revision by a procedure change sheet (PCS) dated the 18th. The reason the PCS was written was to correct the inability of the RHR pump discharge check valve to pass the quarterly in-service inspection valve test. The PCS had been trial run on the 17th, with no problem encountered, but at the same time the quarterly steps were performed without performing the monthly step. Therefore, the problem with both valves being closed was not discovered.

The PCS had been incorporated into the current revision of the procedure about two months later. During a subsequent testing which was the first use of the new revision, the problem was discovered by the shift running the procedure in its entirety. Had the procedural error not been recognized, neither train of RHR would have been able to inject into the core automatically if a safety injection signal had been received.

2.3 Valve Handwheel Markings Give Erroneous Position Indication

With the unit at 100% power, an operator was performing a once-per-shift surveillance. During a step in the procedure to verify that the shutdown cooling heat exchanger flow control valve was throttled open with air removed, in accordance with technical specifications, the operator noted a discrepancy between the handwheel valve position indication and the limit switch position indication. The handwheel markings indicated that the valve was properly throttled, but the limit switch indication showed that the valve was full open. The operator investigated this discrepancy and discovered that the handwheel clutch was disengaged.

The cause of this event was procedural inadequacy. The surveillance procedure did not require a cross check between indicators. Operators had considered the local handwheel indication to be a reliable indication of the valve position. However, the handwheel can turn freely with the clutch disengaged and provide an erroneous indication.

2.4 Inadequate Corrective Action Causes Boron Dilution in Core Flood Tank

Chemistry personnel added boric acid and demineralized water to the 1A core flood tank (CFT). A sample was taken to satisfy the monthly sampling-after-addition requirements. This first sample indicated a boron concentration of 1601 ppm. A resample confirmed the validity of the first sample when the results indicated a boron concentration of 1571 ppm. Technical specifications require a minimum boron concentration in each CFT to be 1835 ppm when the reactor coolant system is in a condition with a pressure above 800 psig. The low boron concentration made the 1A CFT inoperable, and thus placed the operating unit in a condition that did not meet the limiting conditions for operation. An unusual event was initiated because of the loss of the 1A CFT, which is a portion of the engineering safeguards system.

At the end of the last outage, it was determined that a CFT fill valve was leaking past the seat, allowing inleakage of the reactor coolant to the 1A CFT. Repair attempts were made but could not be completed due to the discovery of the leaking of an associated isolation valve. Repair efforts were to have continued during the next sufficient outage. The decision to operate with the inleakage of water to the 1A CFT did not consider the dilution of boron, the need to periodically add boron, and the need to increase the sampling frequency of the 1A CFT due to this inleakage. Sufficient compensatory action was not taken. This lack of adequate management control over a known problem, an administrative deficiency, is the cause of this occurrence.

2.5 Failed Contact Causes Continuous Half-Scram

During the weekly surveillance test of intermediate range monitors (IRMs), a full reactor protection system (RPS) actuation occurred while IRM-B was under test. Normally, a single channel trip (half-scram) is expected. Indication at the time of the actuation was a half-scram in system B and scram air header pressure low. Approximately 5 seconds after the half-scram annunciated, operators noticed that the core map accumulator indicators showed all hydraulic control units had depressurized, indicating a full RPS actuation. RPS logics were reset and the IRM-B surveillance was rerun, this time with the expected results (half-scram in system B only).

The Shift Manager directed maintenance to check wiring in the RPS logic panel A for any abnormal conditions in hardware and wiring. Maintenance personnel found a loose connection in the coil circuit of relay C72-K31C, which provides input to RPS channel C for high scram discharge volume level trip. It was postulated that since no other indication could be found as to what contributed to the RPS actuation, this loose wire may have allowed relay C72-K31C to deenergize a channel of trip system A, and when IRM-B surveillance was run, the trip generated a full RPS actuation. However, this loose wire did not explain why there was no half-scram indicated in trip system A. If relay C72A-K31C had actually been deenergized, there would have been a half-scram system A and a scram discharge volume high water level trip annunciated in system A. Neither annunciator was observed. (It was noted that after the core map indicated that all hydraulic control units had depressurized, both scram discharge volume high water level trip annunciators for system A and B alarmed. This was not an immediate action, however.)

Seven days later, the IRM surveillances were reperformed per technical specifications. IRMs that input into RPS A were run first, with all channels performing correctly. Surveillances for IRMs that input into trip system B were started with IRM B, which again resulted in a full RPS actuation instead of the expected half scram in system B. This time when the surveillance was reperformed, the full actuation again resulted instead of the expected half-scram.

Troubleshooting revealed that an auxiliary contact on scram contactor K14E in trip system A that makes up half of the system B backup scram logic was failing to reset when the RPS logics were reset. This failure was determined to be a normally closed contact that was not opening. This in turn caused backup scram system B to be in a half-scram condition all the time. When the IRM surveillances in trip system B were run, the logics associated with an RPS trip system B scram completed the logics required to cause a full RPS actuation via backup scram system B. This conclusion explains why the Operations personnel were seeing all the hydraulic control units depressurizing while having no attendant annunciation of a full RPS actuation. Because there is no annunciation of a backup scram system actuation, there was no immediate way to tell what had caused the full actuation.

Analysis of the failed auxiliary contact revealed that a spot weld holding half of the contact to an electrical terminal had failed. The initial actuation had probably been caused by the beginning of the failure of the auxiliary contact. This probably caused the complete failure of the auxiliary contact. When the surveillances were run again, the sequence began with trip system A IRM inputs. This probably caused the complete failure of the auxiliary contact. When system B surveillances were started, the failure was complete and hence any IRM surveillance on the B trip system would cause a full RPS actuation. This was proven during troubleshooting by causing IRM trips on all four IRMs in trip system B which all resulted in full RPS actuations.

New auxiliary contactors are being procured from General Electric for the remaining K14 relays and will be installed and tested at first opportunity.

2.6 Ground Troubleshooting Light Causes Reactor Trip

A feedwater pump trip occurred while electricians were trouble-shooting a -85 V ground on a 125 V dc bus supplying power to the control oil trip circuitry of the north main feedwater pump. The ground was due to wire insulation damage caused by the wire rubbing against a nut on an oil line routed through the control box. This wire supplies the trip solenoid that relieves the main feedwater pump control oil. While troubleshooting, a ground troubleshooting light was attached to the bus to locate the ground. The troubleshooting evolution caused enough current flow (about 200 ma) to actuate the trip solenoid and cause the main feedwater pump to trip. The subsequent transient resulted in a reactor scram from 100% power.

2.7 Overflow of Diesel Generator Fuel Oil Tank

A diesel generator load test was done on diesel generator #2 (DG-2) after maintenance. After the test, the diesel generator oil tank level was verified, using the level gauge, to be greater than the technical specification (TS) limit of 14,500 gallons. Subsequently, DG-2 was again load tested for approximately 1 hour. The level was checked prior to the test, and the gauge indicated a level lower than the TS limit. However, the oil level was visually verified to be at a point in the tank which is above the 14,500 gallon limit. After the test, the level was again checked visually and was found to be above the TS limit. The level gauge still indicated the same level as it did before the test, a value below the TS limit. Due to past problems with overflowing the tank, the Operations personnel decided not to transfer oil at that time.

During the following shift, DG-2 was run again for 10 minutes in order to obtain water and oil samples. About an hour later, the oil tank level was found to be below the limit of 14,500 gallons on the level gauge by an operator making his tour. A total of 500 gallons of oil was transferred into the diesel generator oil tank, which brought the level up to approximately 14,850 gallons.

The apparent cause of the occurrence is attributed to operator error by not sufficiently following through on the low level indication. A fuel oil transfer should have been made either during or immediately after the DG load test. There are several contributing factors to this event and its cause. The design capacity of the tank is too close to the TS limit for minimum oil capacity, and it does not allow sufficient operating flexibility. By not having this flexibility, the possibility of overflowing the tank or going below the TS limit is increased significantly. In addition, Operations personnel have little confidence in the level indicator due to past problems with overflowing the tank.

There is obviously some disparity between the level as obtained by visual check into the tank manway and the level obtained using the gauge. The diesel generator fuel oil tank is a cylindrical tank with a conical roof. Calculations done earlier showed that if oil level was maintained above the point where the cone roof begins, the TS limit would not be violated. These calculations were used during the period when the level indicator was being replaced. The level indicator has an accuracy of ± 0.066%, yet there is another factor which can affect the accuracy of the reading. The indicator is set using a specific gravity of 0.84, however, a 1% change in specific gravity causes a 1% change in level indication. The values for specific gravity usually range from 0.82 to 0.86. The most recent sample taken has yet to be analyzed for specific gravity. If the specific gravity is different than 0.84, it would affect the accuracy of the level indicator.

In addition, there are other problems associated with the diesel fuel oil tank. A major problem is the design capacity of the tank. The TSs require a minimum of 14,500 gallons at all times, yet the tank is only capable of holding approximately 486 gallons above this limit. This capacity is actually lessened by the fact that the tank will begin to overflow through a vent prior to the level actually reaching the top of the roof. In fact, this tank has been overflowed in the past due to concerns about approaching the TS limit. This was one of the major factors contributing to the original decision not to transfer oil.

2.8 Inadequate Latching Mechanisms Impair Fire Doors

With the plant operating at 100% power, a routine insurance fire inspection revealed that an interior fire door in the screenwell building leading to the hypochlorite storage room did not have a complete latching mechanism. A fire watch was posted and the latch was repaired.

A subsequent review of the other fire doors (18 total) required by technical specification to be operable, revealed seven additional non-conforming conditions. Fire watches were established in all affected areas in accordance with technical specifications, and continued until the door repairs were completed.

Investigation of this incident has resulted in the conclusion that station management and personnel did not have a complete understanding of the technical requirements for fire doors. In all cases the non-conforming doors were in the closed position, but either lacked an automatic self-closing mechanism or did not have a complete latching mechanism.

2.9 Improper Documentation Causes Missed Surveillance

The routine functional check of the radiation monitor for the control room air supply duct was not performed within the monthly schedule required by technical specifications, due to personnel error. The monitor tested satisfactorily when the functional check was performed.

The incident was discussed with appropriate maintenance personnel and the importance of documenting job completion only after a job has actually been performed was stressed. No further corrective action is required.

2.10 Troubleshooting Unintentionally Starts Diesel Generator

At 5:50 p.m. the plant was shut down for surveillance testing. Electrical Maintenance personnel were attempting to isolate a ground fault on the train A battery bus (train A vital 125 V dc bus) by selectively cycling breakers. When one breaker was cycled, the dc control power for 1DA undervoltage relaying was momentarily interrupted. The interruption started the A diesel generator and actuated the blackout sequencer, which deengergized 1DA for less than 10 seconds. This is the normal time for the diesel to achieve rated speed and energize the bus. During the event, the B diesel generator was out of service for maintenance which required 1DA to be operable to meet the power source technical specification requirements for cold shutdown. The normal power to 1DA was restored in approximately 10 minutes.

The cause of the event is attributed to personnel error. Maintenance personnel were aware that cycling the breaker would interrupt the dc control power to 1DA, but were unaware that actuation of the undervoltage scheme would result.

2.11 Short Circuit Starts Diesel Generator

While drilling a hole on the diesel generator (D/G) 1B load sequencer panel for a modification, the drill bit struck some wires inside the cabinet, causing a short circuit. This short circuit caused a blackout signal to be generated. The blackout signal started D/G 1B, which was subsequently loaded by the load sequencer. This incident is attributed to personnel error, due to the electrician not taking the necessary precautions when drilling holes in the cabinet.

Although D/G 1A was inoperable due to maintenance being performed on the diesel, permission to perform the modification on the D/G 1B load sequencer panel was given after the electricians assured the shift supervisor that the work could be done with no problems. The modification required that the electricians cut holes in the door of the D/G 1B load sequencer panel so that test blocks for undervoltage could be installed. The electricians stated that before they started work, they looked into the cabinet, and determined there was enough room to drill the holes. After the last hole was drilled, the hole had to be elongated so the saw blade could be inserted for cutting. To elongate the hole, the electrician moved the drill from side to side. While moving the drill from side to side, the drill bit grabbed, forcing the drill and drill bit farther to one side. The drill bit hit the wiring harness inside the cabinet, cutting the insulation off several wires and causing a short circuit. The short circuit caused two fuses on the secondary side of the transformer to the undervoltage relay to open. This tripped the undervoltage relays, resulting in a blackout signal. The blackout signal caused D/G 1B to start and load.

When D/G 1B loaded, centrifugal charging pump 1B started without a suction flow path. The volume control tank outlet isolation valve had been closed earlier in the day to prevent water from the volume control tank from entering the reactor coolant system. The pump ran approximately three minutes without suction before a control operator remembered the valve in the suction flow path was closed. The control operator had been systematically going over the control board verifying the diesel had started and was loading correctly when he realized that the valve was closed. He opened the valve supplying water to the suction side of pump 1B, and the pump was apparently undamaged.

Later, the Control Operators tried to stop pump 1B so they could resume core cooling with residual heat removal pump 1B. The charging pump could not be stopped due to the continuous blackout signal present, caused by the open fuses. The pump was stopped by removing the control power fuses and tripping the breaker locally. The breaker was racked out as a further precaution, though it was not necessary, and the charging pump was declared inoperable. The pump was returned to service, after being retested, when the blackout signal was cleared.

2.12 Concurrent Surveillance and Maintenance Disable Auxiliary Feedwater System

With the plant operating at full power and steady state conditions, a periodic instrument and control test (PICT) was performed on the A train auxiliary feedwater (AFW) pump. During the surveillance test, the B train AFW pump was inoperable due to a concurrent maintenance item to change lubrication oil in the pump's oil sump. Subsequent review to determine the operability of the A pump revealed that the safety injection and low-low steam generator level auto start signals to the A AFW pump are overridden by the test switches used to perform the PICT. Both pumps were determined to be potentially inoperable, in accordance with technical specifications. On the same day, the B AFW pump was returned to service. Prior to this event the control room operator did not realize that the PICT would render some of the A train automatic AFW pump start signals inoperable. Both AFW pumps remained inoperable for approximately 80 minutes before the B train auxiliary feedwater pump was returned to service. The A auxiliary feedwater pump was available for manual starting as well as available for auto start from bus undervoltage and concurrent main feedwater pump trip signal during the performance of the PICT.

The cause of this occurrence was personnel error in that the plant staff did not properly consider equipment inoperability when performing the required surveillance testing.

2.13 AK Breaker Problems

During power operation, while attempting to start a battery charger motor generator set following maintenance, the circuit breaker tripped on overcurrent. Several days later, while maintaining cold shutdown on the #12 shutdown cooling (SDC) pump, an unsuccessful attempt was made to start the #11 SDC. The circuit breaker was replaced with the circuit breaker from the inoperable #13 SDC pump, and again SDC pump #11 failed to start. A third attempt to start SDC pump #11 was successful using the circuit breaker from #12 control rod drive (CRD) pump. All transfer of breakers was done in conformance with technical specifications.

Based on these three failures, bench testing was conducted on the three circuit breakers. This testing revealed that one phase of the circuit breaker for the batter charger tripped prematurely, while the other two phases failed to trip. Testing of the circuit breakers for SDC pumps #11 and #13 revealed a problem with failing to trip at the specified time-overcurrent values, not a problem with premature tripping.

A program was established to test all safety-related and selected nonsafety-related AK breakers. As of this date, no further premature tripping has been discovered, but failure to trip on at least one phase on time-overcurrent has been found to occur on these additional safety related breakers: liquid poison pump #12 (type AK-2A-25); liquid poison pump #11 (type AK-2A-25); CRD pump #12, used to successfully start SDC pump #11 (type AK-2A-25); and SDC pump #12 (type AK-2A-25). Tripping will occur if only one of the three phase devices operates correctly.

The failure to trip and the premature trip are both attributed to age induced hardening of grommets which form an oil seal on the pivot arm of the oil dashpot linkage of the type EC-2A overcurrent device. The hardening causes a loss of oil which allows the dashpot to move freely, resulting in premature trip. Alternately, the hardening and/or loss of oil can cause binding of the pivot arm, which causes a failure to trip. This failure mechanism apparently results in erratic behavior, in that SDC pump breakers #11 and #13 tripped prematurely, and then when bench tested, failed to trip. This erratic behavior was not demonstrated by load testing, but can be demonstrated when actuating a removed EC-2A unit by hand.

2.14 Inadequate Monitoring of Plant Startup

During a normal reactor startup, the heat-up rate exceeded the technical specification limit of 100°F per hour by approximately 4°F.

The Reactor Operator conducting the reactor heatup was observing the nuclear instrumentation and withdrawing control rods to increase reactor power; while attempting to correlate the heatup rate with the IRM trace and receiving 15-minute updates from the Senior Nuclear Operator on the actual heat-up.

During this period of time, reactor temperature was also recorded on the trend recorder which was indicating that the rate of change of temperature was increasing. The Reactor Operator conducting the heat-up also observed that reactor water level was increasing and required constant attention. The Senior Nuclear Operator at this time was relaying heat-up rate information from the process computer to the Reactor Operator conducting the heat-up.

The Senior Nuclear Operator stated that during this period of time, there was a great deal of activity in the control room due to vessel level control, and that just previous to the period of time that the heat-up rate was exceeded, other operational activities were occurring. The Senior Nuclear Operator, although relaying the heat-up information off the process computer, was reading the data off the computer printout incorrectly.

At this time the Nuclear Control Operator also was focused in on reactor water level control. The Shift Supervisor was heavily involved with startup activities and was making phone calls to the Reactor Analyst Supervisor and the Assistant Operations Superintendent. He assumed that the Assistant Shift Supervisor was monitoring the startup during this period of time. The Assistant Shift Supervisor, although directly supervising the startup and heat-up prior to exceeding the heat-up rate, also got involved in additional plant activities and expressed that prior to exceeding the heat-up rate everything indicated the heat-up was going well.

Personnel error was the cause of the event. The Reactor Operator conducting the heat-up was relying on the Senior Nuclear Operator to provide heat-up rate information. The Senior Nuclear Operator was incorrectly transmitting the heat-up information from the process computer to the Reactor Operator conducting the heat-up. The control room operator was focused in on reactor water level and the overall big picture of plant startup was temporarily lost. This is primarily a result of inexperience in conducting reactor startup. In addition, the event would have been mitigated had the Shift Supervisor or Assistant Shift Supervisor been directly supervising the heat-up at the time of the event.

2.15 Excessive Cooldown Rate Due to Systems Interaction

With the primary system temperature less than 440°F, the cooldown rate exceeded 50°F/hr. Appropriate strip charts were reviewed, and a cooldown rate of approximately 65°F was determined.

At the time of the event, operators were performing a primary plant cooldown with steam dumps, when the boron injection tank (BIT) and associated lines were flushed to the primary system using colder water from the refueling water storage tank instead of normal charging. The boron system line flushes had been scheduled in preparation for the approved boron concentration reduction change. The flush, performed under a preapproved procedure, had been scheduled to be done prior to the primary plant cooldown. The BIT flush done in conjunction with the cooldown resulted in the cooldown rate exceeding the technical specification limit.

2.16 Improper Maintenance/Testing Impairs Closure of Feedwater Regulating Valves on Two Units

At 100% power, the instrument technicians determined that the main feedwater regulation valves (FRVs) would not have tripped closed upon receipt of a feedwater isolation signal.

The FRVs would not have closed because the instrument air tubing from the FRVs' actuator had been connected to the wrong part of the 3-way solenoid valves (SOVs) that deenergize to vent air and thereby allow the FRVs to close rapidly. The primary cause of the incorrect arrangement was that work was performed on safety-related equipment without an approved maintenance procedure and/or engineering work request. In addition, the testing procedure that was specified to be used following maintenance did not test the safety-related function (trip close) of the FRVs. Station management had requested that a functional test of the automatic closure feature be performed and be initiated from the protection relay racks. The instrument technicians energized the associated SOVs and verified that the FRV would open. They then denergized the SOVs by lifting leads, with the FRV in the closed position, hence, the capability of the SOVs to vent air was not verified. The statement in the completed maintenance request did not mention this method of testing.

3.0 ABSTRACTS OF OTHER NRC OPERATING EXPERIENCE DOCUMENTS

3.1 Abnormal Occurrence Reports (NUREG-0090) Issued in January - February 1984

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-0090 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.

No reports were issued in January - February 1984.

3.2 Bulletins and Information Notices Issued in January - February 1984

The Office of Inspection and Enforcement periodically issues bulletins and information notices to licensees and holders of construction permits. During the period, one bulletin, one information notice supplement, and 13 information notices 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, such as an order for suspension or revocation of a license. 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 proven 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.

Bulletin	Date Issued	Subject
84-01	2/3/84	CRACKS IN BOILING WATER REACTOR MARK I CONTAINMENT VENT HEADERS All boiling water reactor nuclear power facilities having a Mark I containment and holding an operating license or construction permit were alerted to the possibility of cracks in the Mark I containment vent header (located inside the torus). On February 3, 1984, Hatch Unit 2 reported a through wall crack which appeared to be 360° around the vent header within the containment torus. Plants in cold shutdown were required to visually inspect for cracks in the entire vent header and in the main vents in the region near the intersection with the vent header. All other operating boiling water reactor plants were advised to review their plant data on differential pressure between the wetwell and drywell for anomalies that could be indicative of cracks.

Information Notice	Date Issued	Subject
83-63, Supplement	3/15/84	POTENTIAL FAILURES OF WESTINGHOUSE ELECTRIC CORPORATION TYPE SA-1 DIFFERENTIAL RELAYS This information notice supplements the NRC Information Notice No. 83-63, "Potential Failures of Westinghouse Electric Corporation (W) Type SA-1 Differential Relays," dated September 26, 1983, and was distributed to all holders of an operating license or construction permit. This supplement notes two potentially significant problems pertaining to insufficient surge-withstand-capability (SWC) and internal capacitor failures in W type SA-1 relays. With regard to these problems, W recommends replacing the entire printed circuit module, rather than replacing the failed capacitor and adding a new surge protection module to SA-1 relays. A list of SA-1 relay customers was provided to the NRC by W and Brown Boveri Electric (BBE). BBE informed the NRC that detailed information pertaining to SA-1 modifications, replacements, calibrations and document changes was distributed to its known SA-1 relay customers.
84-01	1/10/84	EXCESS LUBRICANT IN ELECTRIC CABLE SHEATHS All nuclear power reactor facilities holding an operating license or construction permit were informed that under certain circumstances, excess lubricant may become trapped inside cable sheaths during manufacture, and may drip out where cable sheaths have been cut for terminations. On 11/1/83, Illinois Power Company (IPC) notified the NRC of a situation where an oily fluid seeped from the cut ends of some power and control cables supplied by the Okonite Company. An investigation disclosed that, as a practice, the Okonite Company applies an extruded filler material over the conductors of multiconductor cable. The Okonite Company states that the excess lubricant in no way degrades the performance of the cable. IPC, while not disputing this position, is concerned that the leakage may create a fire hazard. The situation described above, while unique to one manufacturer, is of a type which could develop in any multiconductor cable manufacturing operation.

Information Notice	Date Issued	Subject
84-02	1/10/84	OPERATING A NUCLEAR POWER PLANT AT VOLTAGE LEVELS LOWER THAN ANALYZED
		All nuclear power reactor facilities holding an operating license or construction permit were informed of an event resulting from operating a nuclear power plant's electrical distribution system at voltage levels lower than the plant's safety analysis, and were provided a description of design deficiencies in the plant's degraded voltage protection system.
		In August 1983, at the Monticello Nuclear Generating Plant, the main generator was being operated at a reduced voltage because of a lightly loaded grid. At Monticello, the voltage level of the plant's electrical distribution system is directly proportional to the main generator's terminal voltage. The event began when a large safety-related pump motor, which is served by the plant's electrical distribution system, was started. The resulting voltage drop, coupled with the low initial bus voltage, caused the voltage to dip below the degraded voltage protection system's trip setpoint. As a result, the degraded voltage protection system was actuated.
		An NRC review of the event indicated that the licensee's analysis did not take into account the effects of a lightly loaded grid. As corrective action, to assure that the plant's electrical distribution system is operated within analyzed bounds, the licensee reanalyzed the minimum operating voltage on the safety-related buses. This notice highlights the need for licensees to be more fully aware of the bases and limits of a plant's analyses, and identifies a specific deficiency in a degraded voltage protection system.
84-03	1/18/84	COMPLIANCE WITH CONDITIONS OF LICENSE AND NOTIFICATION OF DISABILITY BY LICENSED OPERATORS
		All persons licensed pursuant to 10 CFR 55 (licensed operators) and all licensees pursuant to 10 CFR 50 (facility licensees) were notified concerning the failure of licensed operators to comply with disability reporting requirements and additional medical examination and reporting

Information Notice	Date Issued	Subject
		requirements imposed as a condition of their license. Operators were advised to review their licenses and 10 CFR 55 to better understand their obligations under law, partcularly Section 55.50. Other useful references include Regulatory Guide 1.34, "Medical Evaluation of Nuclear Power Plant Personnel Requiring Operator License" (1979), which is being revised, ANSI N546-1976, and ANS 3.4-1983.
84-04	1/18/84	FAILURE OF ELASTOMER SEATED BUTTERFLY VALVES USED ONLY DURING COLD SHUTDOWNS All nuclear power reactor facilities holding an operating license or construciton permit were notified of an event where redundant elastomer seated butterfly valves failed. On April 19 and 26, 1983, Rancho Seco reported that two reactor building purge inlet valves and two reactor building purge outlet valves failed their local leak rate tests. All four valves were Allis Chalmers Model 60WR butterfly valves. Investigation by the licensee revealed that two valves required adjustment of the elastomer seat and two valves had damage to the elastomer seat. A contributing factor to this event was the fact that these valves are only opened during cold shutdowns. During normal operation, they are closed and rendered inoperable. To provide assurance of proper purge isolation, the licensee has implemented programs to: (1) ensure proper lubrication of the valves, (2) perform a local leak rate test of the purge inlet and outlet valves before bringing the unit out of cold shutdown conditions in preparation for normal operations, and (3) perform a local leak rate test before the initial purge during each cold shutdown.
84-05	1/16/84	EXERCISE FREQUENCY In September 1983, the Federal Emergency Management Agency (FEMA) published in the Federal Register (48 FR 44332) their final Rule 44 CFR 350, "Review and Approval of State and Local Radiological Emergency Plans and Preparedness." All nuclear power reactor facilities holding an operating license or construction permit were informed that this final rule (44 CFR 350) changes the exercise frequency for State and local governments' to a biennial requirement and introduces the concept of remedial exercises.

Information Notice	Date Issued	Subject
		The NRC published in the Federal Register on July 21, 1983 (48 FR 33307), a proposed amendment to its regulations [10 CFR 50, Appendix E, Part IV.F.1.a] to provide flexibility for exercise participants in regard to the required frequency and extent of participation in emergency preparedness exercises. The proposal would retain the presently required annual fall participation exercise with the proviso that if all major elements in the emergency plan are performed in a satisfactory manner, a finding may be made that another full participation exercise with State and local governments would not be required for a period of up to five years. In the interim, until the proposed amendment has been revised (incorporating the appropriate public comments), considered by the Commission, and issued in final form, licensees should continue to follow the current exercise frequency stated in the NRC regulations.
84-06	1/25/84	STEAM BINDING OF AUXILIARY FEEDWATER PUMPS All pressurized water reactor (PWR) facilities holding an operating license or construction permit were notified of a problem pertaining to steam binding in the auxiliary feedwater (AFW) pumps due to leakage from the main feedwater system. At H.B. Robinson on April 19, 1983, two minutes after a motor-driven AFW pump was automatically started, it tripped on a low discharge pressure signal. The low discharge pressure was attributed to steam binding caused by hot water (about 425°F) from the main feedwater (MFW) steam and which had leaked back through the first and second check valves to the pump and flashed to steam because of the lower pressure in the AFW system. The safety implication of this event is that leakage into the AFW from the feedwater system constitutes a common mode failure that can render the AFW inoperable. Since the isolation of the AFW system from the MFW system at Robinson is typical of other PWRs, the potential for backleakage exists in other operating plants. Routine monitoring of the AFW system temperature would detect backleakage so that the system could be periodically vented to prevent steam binding until an appropriate long term solution is developed.

Information Notice	Date Issued	Subject
84-07	2/3/84	DESIGN-BASIS THREAT AND REVIEW OF VEHICULAR ACCESS CONTROLS All nuclear power reactor facilities holding an operating license or construction permit were informed of NRC concerns regarding potential use of vehicle bombs by terrorists against nuclear activities or facilities, and actions NRC is taking and considering in regard to these concerns. Due to recent terrorist bombings on U.S. installations overseas, the NRC is considering revision to the design-basis threat defined in 10 CFR 73.1
84-08	2/14/84	EMPLOYEE PROTECTION All nuclear power reactor facilities holding an operating license or construction permit, nuclear steam system suppliers, and architect-engineers were notified concerning 10 CFR 50.7, which prohibits discrimination against an employee for engaging in certain protected activities, such as providing the Commission information about possible violations of requirements. There can be no question that public health and safety require that employees be free to raise safety issues to licensee management and to the NRC. Licensees should review activities to ensure that a mechanism exists for employees to raise safety issues free from discrimination, and that employees are aware of the mechanism.
84-09	2/13/84	LESSONS LEARNED FROM NRC INSPECTIONS OF FIRE PROTECTION SAFE SHUTDOWN SYSTEMS (10 CFR 50, APPENDIX R) All nuclear power reactor facilities holding an operating license or construction permit were informed in this notice as guidance for conducting analysis and/or making modifications to implement requirements of 10 CFR 50, Appendix R. Inspections by the NRC to evaluate licensee implementation of the requirements have found significant items of noncompliance at several facilities. As a result, the NRC has prepared and provided Supplemental Guidance on 10 CFR 50 Appendix R Fire Protection Safe Shutdown Requirements, as an appendix to this notice.

Information Notice	Date Issued	Subject
84-10	2/21/84	MOTOR OPERATED VALVE TORQUE SWITCHES SET BELOW THE MANUFACTURER'S RECOMMENDED VALUE All nuclear power reactor facilities holding an operating license or a construction permit were notified of an event at Oyster Creek, where a review of records revealed that a number of motor-operated valve torque switches were set below the manufacturer's recommended values. The licensee attributes the error to lack of sufficient knowledge about setpoint design basis and how the setpoints affect safety system functioning. Because of low differential pressure conditions, the utility believes the torque switch settings were reduced to prevent forces that would damage the motor operator or valve during surveillance. Because differential pressure is a contributor for the amount of force necessary for full closure, the potential exists that some valves may not fully close or open under design-basis accident conditions. Design bases for operators in various systems are under investigation by the licensee and valve manufacturers. In addition, NRC is currently investigating the need for changing the inservice testing and inspection programs to ensure that safety-related valves have the torque and limit switch settings that will ensure proper operation of the valves during postaccident conditions.
84-11	2/24/84	TRAINING PROGRAM DEFICIENCIES All nuclear power reactor facilities holding an operating license or construction permit were informed of information which is available that may be of value in upgrading training programs. The notice relates to training program deficiencies associated with licensed operator training. Among the deficienies was the lack of attention to accuracy on the part of the facility and the individual trainees in the submittal of training history information pursuant to the filing of applications for operator license examinations. Failure to fully implement the required training programs calls into question the certification of the affected operators.

Information Notice	Date Issued	Subject
84-12	2/27/84	FAILURE OF SOFT SEAT VALVE SEALS

All nuclear power reactor facilities holding an operating license or construction permit were informed of the failure of soft seat valve seals to meet the leakage limits of Appendix J of 10 CFR Part 50.

On September 29, 1983, LaSalle Unit 1 reported that the inboard feedwater check valves had failed specified leakage limits. Inspection of the valves showed damage around the pressure-relieving vent grooves, some wear on the soft seat face, and slight wear on the body seat.

These valves had been modified before initial plant operating from a hard seat valve to a combination soft and hard seat configuration by modifying the valve discs to allow installation of the soft seat seals. The seals were of molded ethylene-propylene rubber obtained through the valve manufacturer, Anchor/Darling Valve Company, from the Stillman Rubber Company.

The reason these valve seals failed is believed to be due to one or more of the following: (1) sharp edges around the pressure equalizing parts located in the discs had cut the soft seal material; (2) machining of the soft seals for proper fit may have affected the sealing capability; and/or (3) service conditions encountered by the valves during plant startup and shutdown may have damaged the soft seals.

On 12/9/83, the licensee reported that, following a month of operation, the valves again failed local leak rate tests. It was determined that the leakage was a result of gaps on the perimeter of the disc seal material. Anchor/Darling believes the failure of the extruded-vulcanized seals resulted from improper vulcanizing of the seal joints. This notice provided a chronological listing of nuclear plants to which Anchor/Darling provided soft valve seals.

Information Notice	Date Issued	Subject
84-13	2/28/84	POTENTIAL DEFICIENCY IN MOTOR-OPERATED VALVE CONTROL CIRCUITS AND ANNUNCIATION All holders of a nuclear power reactor operating license or construction permit were notified of a specific design in the circuitry used for control and annunciation of certain safety-related electric motor-operated valves (MOVs). This design may, under thermal overload (TOL) bypass condition, preclude timely detection of a failure of a safety-related motor. On 9/2/83, Susquehanna reported a condition related to a failed MOV. The TOL had tripped when the valve torque switch malfunctioned. This condition went undetected for three weeks. The present control circuit design of Susquehanna does not annunciate a motor overload condition or a burned out motor if the key lock bypass switch is in a "bypass" position. Because there is no indication of a tripped TOL in such designs, emphasis is placed on assuring operability of the safety function rather than on protecting individual components from damage. However, good engineering practice would retain the TOL protection for normal or test functions of the MOV. Such a design would permit the TOL protection for the motor to be reinstated under test conditions.

3.3 Case Studies and Engineering Evaluations Issued in January - February 1984

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 event(s) discussed, and do not represent the position or requirements of the responsible NRC program office.

Case Study	Date Issued	Subject
S401	1/13/84	HUMAN ERROR IN EVENTS INVOLVING WRONG UNIT OR WRONG TRAIN

At the request of the Office of Nuclear Reactor Regulation, the Office for Analysis and Evaluation of Operational Data undertook a special study. The study concerns events similar to the April 1983 Turkey Point 3 event in which the auxiliary feedwater system (AFW) was inoperable for five days due to personnel error, i.e., events involving loss of safety system function that resulted because an action was performed on the wrong unit or wrong train and the error was not detected.

AEOD identified 26 additional events that occurred between 1/81 and 8/83 that had characteristics similar to the Turkey Point 3 event. Of the 27 total events, 19 result from human error during maintenance and surveillance testing, and 16 of these occurred near full power. This is evidence that human errors in maintenance and testing operations are major contributors to loss of safety system events. Corrective actions taken

Case Study	Date Issued	Subject
		in most events involved procedural changes and/or improved identification of instrumentation by color coding and clarified labeling. In a number of events reviewed in this study, verification was not performed or was performed inadequately. Poor and incomplete licensee verification procedures, a weak licensee management commitment to independent verification, and imprecision in NRC requirements in terms of scope of requirements and definition of terms were found to contribute to lessening the effectiveness of independent verification activities. Although the scope of the study was narrow, AEOD suggests consideration be given to the need for further clarification and/or guidance on what constitutes an acceptable independent verification program and that NRC or industry consider developing a clear and perhaps standard system(s) for identifying components and systems to distinguish more effectively between redundant trains of a system and between the same or similar systems in each unit at multi-unit sites.

Engineering Evaluation	Date Issued	Subject
E401	1/4/84	TEMPORARY LOSS OF ALL AC POWER DUE TO RELAY FAILURES IN DIESEL GENERATOR LOAD SHEDDING CIRCUITRY At Fort St. Vrain on May 17, 1983 with the reactor shutdown and the 1A emergency diesel generator (EDG) set out of service, and the 1B EDG set running and tied to the 1C 480V essential bus, severe weather conditions caused a loss of all offsite power to the station. Consequently, the 1B EDG output breaker opened due to overloading. Failure of two time delay relats in the load shedding circuit to the EDGs prevented automatic re-energization of the electrical loads to the bus. This resulted in virtually a total loss of all ac power to the station. The evaluation suggests that the possibility exists that the relay failures occurred while the 1B EDG was being operated in parallel with

Engineering Evaluation	Date Issued	Subject
		the offsite power. This event illustrates how operating the EDGs in parallel with a troubled offsite grid can compromise their ability to function as designed in an emergency. An alternative would have been to start the FDG and run it unloaded or have it supplying the emergency buses with the emergency buses disconnected from the offsite sources.
E402	1/10/84	WATER HAMMER IN BOILING WATER REACTOR HIGH PRESSURE COOLANT INJECTION SYSTEMS A review was performed to assess water hammer events involving the boiling water reactor (BWR) high pressure coolant injection (HPCI) system. The review found that there have been a significant number of HPCI water hammer events reported and that the experiences involved a spectrum of causes and consequences. The evaluation concludes, however, that the lessons learned and corrective actions formulated from previous studies of these events are adequate to prevent recurrence of the events if implemented on a plant-by-plant basis.
E403	1/17/84	DEFICIENCY IN AUTOMATIC SWITCH COMPANY (ASCO) SPARE PARTS KITS FOR SCRAM PILOT SOLENOID VALVES This engineering evaluation report provides information concerning three events involving scram pilog solenoid valves. Two of these three events occurred at Grand Gulf Unit 1 and involved quality assurance deficiencies for spare parts kits manufactured by ASCO and supplied to the utility by General Electric. The remaining event occurred at La Salle Unit 2 and involved an additional quality assurance deficiency, in that the bleedoff port for two of the valves had not been drilled during manufacturing. Based on a review of these three events, AEOD believes that they have some safety implications even though two of the deficiencies identified as a result of these events should be detected (and corrected) during post-maintenance testing. The remaining deficiency involving reserved core springs on the core assemblies may not be detected during such testing. For this deficiency, the report identifies a mechanism whereby, in time, such affectes solenoid valves may fail due to

Engineering Evaluation	Date Issued	Subject
		this common cause. Such failures could have significant safety consequences. In addition, the fact that 305 of the spare parts kits provided to the Grand Gulf Station were found to have this deficiency tends to suggest that spare parts kits provided to other facilities may also have this deficiency. Information obtained during this review suggests that broad based generic preventive maintenance schedules for the identified and related devices should be modified in accordance with actual service conditions including environmental conditions. In general for such devices, as actual service conditions become more severe, preventive maintenance activities should be more frequent (with less severe conditions resulting in less frequent maintenance activities).

3.4 Generic Letters Issued in January - February 1984

Generic letters are issued by the Office of Nuclear Reactor Regulation, Division of Licensing. They are similar to IE Bulletins (see Section 2.2) 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 January and February 1984, four 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	Subject
84-01	1/5/84	NRC USE OF THE TERMS, "IMPORTANT TO SAFETY" AND "SAFETY-RELATED" All holders of operating licenses, applicants for operating licenses, and holders of construction permits for power reactors were provided clarification of NRC's use of "important to safety" and "safety-related." Enclosures to the letter included two letters on the subject from the Utility Classification Group, and an NRC response. The NRC reply makes it very clear that NRC regulatory jurisdiction involving a safety matter is not controlled by the use of terms such as "safety-related" and "important to safety," and that pursuant to NRC regulations, nuclear power plant permittees or licensees are responsible for developing and implementing quality assurance programs for plant design and construction or for plant operation, which meet the more general requirements of General Design Criterion 1 for plant equipment "important to safety," and the more prescriptive requirements of Appendix B to 10 CFR Part 50 for "safety-related" plant equipment. In addition, the NRC intends to continues its practice of imposing additional requirements commensurate with the importance of safety of equipment involved in specific situations where quality assurance requirements beyond normal industry practice are needed.

Generic Letter	Date Issued	Subject
84-02	1/6/84	NOTICE OF MEETING REGARDING FACILITY STAFFING All applicants for operating licenses and full power authorizations were informed of a meeting held on 1/25/84, during which the NRC was to share with licensee representatives their present thinking on acceptable experience profiles for licensing new plants. It was expected that follow-up meetings with individual applicants would be necessary to discuss plant-specific issues and their resolution.
84-03	1/13/84	AVAILABILITY OF NUREG-0933, "A PRIORITIZATION OF GENERIC SAFETY ISSUES" All licensees of operating reactors, applicants for licenses, and holders of construction permits were notified that NUREG-0933, "A Prioritization of Generic Safety Issues," was published in January 1984, and may be purchased by calling (301) 492-9530 or by writing to the NRC/GPO Sales Program, Division of Technical Information and Document Control, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555, or purchased from the National Technical Information Service, Department of Commerce, 5258 Port Royal Road, Springfield, VA 22161. This report presents the priority rankings for a large number of generic safety issues related to nuclear power plants. The purpose of these rankings is to assist in the timely and efficient allocation of NRC resources for the resolution of those safety issues that have a significant potential for reducing risk. The report does not contain new requirements or guidance for licensees or applicants but does list and briefly describe, for the purpose of completeness, some of the safety issues that have been resolved and were previously issued as requirements or guidance. Although changes to nuclear power plant designs or operation are assumed, the sole purpose in prioritizing the issues is to estimate costs and other impacts that might result if such changes were implemented.

Generic Letter	Date Issued	Subject
84-04	2/1/84	SAFETY EVALUATION OF WESTINGHOUSE TOPICAL REPORTS DEALING WITH ELIMINATION OF POSTULATED PIPE BREAKS IN PWR MAIN LOOPS This letter was sent to all operating pressurized water reactor (PWR) licensees, construction permit holders, and applicants for construction permits, and referenced Westinghouse reports WCAP 9558, Rev. 2 (May 1981); WCAP 9787 (May 1981); and letter Report NS-EPR-2519 (November 10, 1981). These reports were submitted to the NRC to address asymmetric blowdown loads on the PWR primary systems that result from discrete break locations as stipulated in NUREG-0609, the NRC staff's resolution of Unresolved Safety Issues A-2. The NRC staff evaluation concludes an acceptable technical basis has been provided so that the asymmetric blowdown loads resulting from double ended pipe breaks in main coolant loop piping need not be considered as a design basis for the Westinghouse Owners Group plants; provided the following two conditions are met: (1) that maximum bending moments of reactor primary coolant main loop piping at Haddam Neck and Yankee do not exceed 42,000 in-kips for the highest stressed vessel nozzle/pipe junction, and (2) that leakage detection systems at facilities are sufficient to provide adequate margin to detect the leakage from the postulated circumferential throughwall flaw utilizing the guidance of Regulatory Guide 1.45, "Reactor Coolant Pressure Boundary Leakage Detection System," with the exception that the seismic qualification of the airborne particulate radiation monitor is not necessary. Authorization by NRC to remove or not to install protection against asymmetric dynamic loads (e.g., certain pipe whip restraints) in the primary main coolant loop will require an exemption from General Design Criteria 4 (GDC-4). Licensees must justify such exemptions on a plant-by-plant basis.

3.5 Operating Reactor Event Memoranda Issued in January - February 1984

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 Offices for Analysis and Evaluation of Operational Data, and of Inspection and Enforcement for their information.

No OREMs were issued during January - February 1984.

3.6 NRC Document Compilations

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

- 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 Pubicly 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) nondocketed 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.

Copies and subscriptions of these documents are available from the NRC/GPO Sales Program, P-130A, Washington, DC 20555, or on (301) 492-9530.

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