NUREG/BR-0051
Vol. 5, No. 6

POWER REACTOR EVENTS

United States Nuclear Regulatory Commission

Date Published: May 1984

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 016, Washington, DC 20555.

Table of Contents

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: November-December 1983

1.0 SUMMARIES OF EVENTS

1.1 Inoperable Containment Spray Systems

The following events at Indian Point Unit 2 and McGuire Unit 1* involved inoperable containment spray systems due to personnel errors.

Indian Point Unit 2

On November 29, 1983, during a routine surveillance test at full power, two containment motor operated spray header discharge valves (one located in each of the two containment spray supply headers) were found locked closed instead of locked open as required, with the associated circuit breakers locked in the off/deenergized position. This condition rendered the containment spray system inoperable for automatic operation during the safety injection phase of a postulated loss-of-coolant accident (LOCA), although manual operation was still available. Technical specifications require that two spray pumps (together with their associated valves and piping) and five fan cooler charcoal filter units be operable with the reactor critical. However, the licensee's procedures are more restrictive in that the containment spray system is to be operational prior to T-ave going above 350°F. It should be noted that, without containment spray at the time of the event, adequate cooling could have been provided by the five fan coil units.

The licensee determined that the containment spray system had been inoperable since the reactor went critical on October 25, 1983, due to the two closed discharge isolation valves. During this period, the reactor had gone critical five times, initially on October 25, and after four subsequent reactor trips.

After the initial startup on October 25, the unit T-ave was continuously maintained above 350°F. The licensee's failure to meet technical specifications requirements prior to taking the reactor critical constitutes a violation of technical specification limiting conditions for operation.

The containment spray system at Indian Point has two functions. It is used in conjunction with the containment fan coil units to provide containment cooling in the event of a LOCA and it also reduces the iodine concentration to limit the offsite dose. The licensee stated that calculations by Westinghouse, the nuclear steam system supplier (NSSS), indicate that the offsite dose from a LOCA would be at approximately the allowable 10 CFR Part 100 limits, without spray during the injection phase but with all five fan coil units operating. If the control room operator became aware that the containment spray was not operating, a field operator could have been sent to the affected valve and motor control center and returned the system to normal operation.

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* Indian Point Unit 2 is an 864 MWe (net) PWR located 25 miles north of New York City, New York, and is operated by Consolidated Edison.

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

The cause of the event is attributed to personnel error. Prior to the plant going critical on October 25, 1983, the two valves had been closed in preparation for work on the reactor coolant system. On October 28, prior to plant startup, operators were assigned to perform a safety injection system check-off list, which should have returned the valves to the open position. It was noted that valve position could not readily be confirmed by inspection and, since power is removed by the operator, remote indication was also not available. However, the operator assigned to ensure the valve positions assumed that the valves were positioned by another operator, and the operator assigned to verify the valve positions assumed the valves were locked open because the breakers were locked and deenergized.

Although during an accident the reactor operators would be expected to recognize in a timely manner that the containment spray isolation valves were closed, the NRC staff performed bounding calculations to predict worst case conditions pertaining to containment design pressure and post-accident offsite doses. The plant has two trains of fan coolers on separate power sources; one train has two fan coolers and the other train has three fan coolers. Since, for the present situation, both containment spray trains would be out of service, the staff assumed a single active failure would reduce the active containment heat removal capability to two fan coolers during a pipe break accident. Under these conditions, the reduced heat removal capability would be expected to result in a higher peak containment pressure. In addition, less filtration of radioactive iodine would be expected to result in higher offsite doses.

The peak NRC calculated containment pressure for the design basis LOCA (double-ended pump suction guillotine break) is 41.9 psig, which is slightly above the licensee's previously calculated peak pressure of 40 psig (with containment sprays) but substantially below the containment design pressure of 47 psig.

With regard to offsite dose calculations, the methods and assumptions used by the NRC staff were consistent with those used in the current licensee application reviews (i.e., Standard Review Plan 15.6.5). The calculations predict that the resultant doses would be approximately four times the 10 CFR Part 100 thyroid exposure guidelines at the Exclusion Area Boundary. An additional analysis was performed assuming that operator action was taken to initiate containment spray after 30 minutes. This calculation indicates that the resultant dose would be approximately 1.8 times the exposure guidelines at the Exclusion Area Boundary.

Both the licensee's/vendor's calculations based on actual operating conditions, and the NRC staff's calculations based on much more conservative conditions, emphasize the importance of the containment sprays in reducing potential offsite iodine doses in the unlikely event of a LOCA.

As corrective actions, the licensee opened the affected valves, reverified the safety injection and locked valves list, and verified the inclusion of the two valves on the locked valves list.

Among long term corrective action steps are a number of improvements in the licensee's quality assurance and training programs. In addition:

(1) A review of valve position indication for all safety-related valves will be made to determine if modifications are necessary to provide for positive indication of deenergized valves.

(2) The operability of all currently installed safety-related motor-operated valve position indicators will be verified and corrected if necessary.

The NRC has proposed a $40,000 civil penalty for the regulatory violations associated with this event.

McGuire Unit 1

While operating at full power on September 28, 1983, train B of the containment spray system (CSS) was declared inoperable. This declaration was made following a loss of power indication for the dc power supply to the train B containment pressure control system (CPCS) pressure transmitter. Both trains (i.e., A and B) of the CSS are required to be operable by technical specifications. However, an action statement permits operation for 72 hours with one train inoperable.

On September 29, an operator was sent to inspect nuclear service water (NSW) pump 1A. The operator noted water in the oil reservoir for the outboard pump bearing. The pump was declared inoperable by the Shift Supervisor and the Assistant Operating Engineer, which meant that train A of the NSW system also was inoperable.

The NSW system provides cooling to the CSS heat exchanger and the air handling unit motor cooler for the CSS pump. Therefore, the inoperability of train A of NSW caused train A of CSS to be inoperable. CSS train A inoperable coincident with the inoperability of train B of CSS resulted in the inoperability of both CSS trains, and placed the unit outside the Action Statement of Technical Specification 3.6.2. This inoperability was confined to the recirculation mode of operation of the CSS.

The impact of the inoperable NSW train upon the single remaining operable CSS train was not realized when NSW pump 1A was tagged out. The discovery that both CSS trains had in fact been inoperable was made when CSS train B was being cleared from the Technical Specification Action Item Log (TSAIL). The technical inoperability of both trains existed for approximately five hours on September 29.

The Technical Specification Reference Manual provides a list of related technical specifications with applicable modes to be considered when a system is declared inoperable. As a result of this incident, the list of related technical specifications was reviewed and it was discovered that the NSW system's impact upon CSS and on DG-1A was not addressed by the reference manual.

Other systems which depend upon NSW for operability and are required during power operation are the chemical and volume control system, auxiliary feedwater system, component cooling water system, control area ventilation system, and the diesel generator (DG). All of these systems had the redundant train operable when the NSW train became inoperable. However, a requirement exists to declare dependent systems inoperable when a support system is taken out of service. The common but not totally uniform approach used when declaring a support system inoperable is to list dependent systems in the TSAIL. This approach was not applied when NSW pump 1A was declared inoperable.

Thus, with DG-1A inoperable due to loss of NSW pump 1A, certain action statements of the associated specification were applicable. Compliance with Technical Specification Action Statement 3.8.1.1, was not achieved during this incident. This required (1) that an active test of DG-1B's operability be performed by starting the DG and verifying generator parameters, and (2) that required equipment relying on DG-1B as an emergency power source, and the turbine-driven auxiliary feedwater pump, be verified to be operable. Since the dependency of systems upon NSW train A was not evaluated and DG-1A was not declared inoperable, these actions were not met.

The causes of this event were the failure of the power supply for the containment pressure control system and the clogging of the drain line for the NSW pump 1A seal catch basin, which allowed water to back up and enter the outboard bearing. The failure to identify the impact of NSW train A on CSS train A's operability is attributed to personnel error. Appropriate personnel were counseled and a technical specification manual was revised.

As corrective actions, the power supply was replaced, the NSW pump outboard seal catch basin drain line was cleared, and the bearing was inspected for damage and flushed with oil. The oil reservoir was then refilled with clean oil. Also, a memorandum was issued September 30, 1983. This memorandum was addressed to all Senior Reactor Operators and stated the policy of declaring all dependent systems inoperable (and making the appropriate TSAIL entries) whenever a support system is declared inoperable. Technical Specification Reference Manual-Section IV was updated to include the impact of NSW systems on CSS operability. (Refs. 1 through 3.)

1.2 Total Loss of AC Power

At Fort St. Vrain* (a high-temperature gas-cooled reactor) in May 1983, an event occurred in which all ac power to the station was temporarily lost. Subsequent investigations showed that the event was attributed to the interconnection of the emergency diesel generator with an offsite grid that had developed problems during a storm. The event illustrates how operating the emergency diesel generators in parallel with the offsite grid can compromise their ability to function as designed in an emergency.

On May 17, 1983, with the reactor shut down and the 1A emergency diesel generator (EDG) set shut down for planned maintenance, the offsite power system developed problems due to severe weather conditions. The 1B EDG was started and tied to the 1C essential bus (EB) and operated in parallel with the plant electric distribution system, which was being supplied by the offsite power system. Thirty minutes later, all offsite power was lost to the station due to high winds and snow.

Normally, on a loss of offsite power and turbine trip the EDGs start and load shedding relays actuate to strip the 480 V EBs of all electrical loads. The load shedding relays are then automatically reset when voltage on either the 1A or 1C 480 V EB is reestablished via the respective EDG set. Essential loads are then picked up by the load sequencer associated with the EDG set.

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* Fort St. Vrain is a 330 MWe (net) HTGR located 35 miles north of Denver, Colorado, and is operated by Public Service of Colorado.

At Fort St. Vrain, the load shedding circuit for each EDG includes four time delay relays (227-1A and -1C that monitor voltage losses on the 1A 480 V EB and 227-3A and -3C that monitor voltage losses on the 1C EB). During the event, two of these relays (227-3A and -3C) remained deenergized even after the 1B EDG had reenergized the 1C 480 V EB due to burned out coils. The other two relays (227-1A and -1C) also remained deenergized since the 1A EB had no power (loss of offsite power and 1A EDG out of service). With all four relays deenergized, the load shedding circuit remained in the tripped state (energized) and prevented the loads on the 1C and 1B EBs from sequencing as designed.

The relays that failed were voltage monitoring relays on the 1C EB. At the time of the loss of offsite power, the 1B EDG was operating in the parallel configuration described earlier. It is possible that the relays failed due to this method of operation. Voltage surges propagated from the unstable offsite grid system combined with voltage transients at the EDG could have caused or contributed to the relay failures. In addition, a review of existing test procedures for the diesel generators found that, due to procedural inadequacy, these time delay relays are not tested as individual components on a regular basis. Thus, the failures of these relays would remain undetected during normal surveillance testing. Only due to the uniqueness of the event were the coil failures discovered.

The operation of the onsite emergency power source (the EDG) in parallel with an unstable grid system can compromise its ability to function as the onsite emergency power source. The potential adverse effects are (1) the EDGs would be exposed to voltage surges propagating from the troubled offsite power system which could cause immediate or cumulative damage to the EDGs and associated control circuitry, (2) the EDGs would be overloaded if offsite power was lost and would require the proper functioning of the EDGs' protective circuits to separate the EDGs from the plant's electrical distribution system, and (3) the subsequent restart of the emergency onsite power system would require the proper functioning of the automatic load shedding and load sequencing circuits whose components may have been exposed to the voltage surges in item (1) above.

A review of operating experience and practice shows that there is variation in the methods of operating onsite emergency power sources at nuclear plants during situations when the offsite power system is experiencing problems. The method of parallel operation used at Fort St. Vrain may be used in other nuclear power plants as well, however, there appears to be no advantage to this type of operation. As seen at Fort St. Vrain, when offsite power is lost, the EDG tends to overload and will either trip or disconnect from the emergency bus.

Also, problems in the offsite power source could propagate to the onsite emergency system and affect its operation. Thus, the intent of this operating configuration, that of maintaining the plant's emergency loads when offsite power is lost, is not attained. It should be noted that Fort St. Vrain was maintained without much difficulty in a safe shutdown condition, mainly because the large heat capacity of a gas-cooled reactor core provides adequate time to consider and resolve such problems as occurred during this event. However, a similar total loss of ac power conditions at a light water reactor would provide an operator with much less time to act.

An alternate method of operation would be to start the EDGs when offsite power problems are encountered and keep them running unloaded, ready to energize the EBs when offsite power is lost. Another method would be to start the EDGs and energize the associated emergency buses and loads and then isolate the emergency power system from the offsite power system that is experiencing problems.

The licensee tested all four time delay relays and replaced the faulty ones. A new procedure for testing these relays was developed by the licensee and was implemented in July 1983. However, the use of these time delay relays in the above described configuration appears to be unique to Fort St. Vrain and, hence, has no implication on other nuclear power plants. NRC is reviewing the practice of parallel operation of the onsite emergency power sources with the grid system. (Refs. 4 and 5.)

1.3 Isolation of Flow from Charging Pumps to the RCS

In September 1983, an event occurred at San Onofre Unit 3* in which the closing of two manual isolation valves isolated flow from the charging pumps to the reactor coolant system (RCS) and violated technical specifications.

As a result of excessive unidentified leakage from the RCS, Unit 3 was placed in hot standby on September 29, 1983, and action was initiated to localize the source of the leakage. This action was in accordance with limiting conditions for operation (LCOs). In preparation for cooldown, the RCS was borated to the shutdown margin required for hot shutdown conditions, which exceeds the shutdown margin for cold shutdown conditions.

Cooldown was then commenced in parallel with continuing efforts to locate the leakage source. During swing shift on September 29, charging flow was isolated by closing manual isolation valves for the makeup system in accordance with an abnormal valve lineup provided to the Operating Foreman by the Plant Superintendent. This abnormal lineup was developed as an effort to locate the leakage source. RCS was being held constant at about 480°F in order to measure the leak rate accurately.

On September 30, as the leak rate check with these valves secured was being completed, the graveyard Shift Supervisor recognized that the shutting of the two valves violated the technical specifications. Shutting of these valves represented isolating flow from the charging pumps to the RCS, and is inconsistent with LCOs for boration flow paths via the charging pumps and emergency core cooling system subsystems during hot standby operation. He immediately ordered the valves to be opened. The valves had been closed for about 3-1/2 hours.

The cause of this event was personnel error in that the abnormal lineup was not reviewed relative to technical specification requirements. The lineup was documented and reviewed in accordance with the abnormal valve lineup section of the work authorization procedure. Although a revision to the abnormal valve lineup procedure was issued on September 13 to more specifically call out the need to

*San Onofre Unit 3 is a 1070 MWe (net) PWR located 5 miles south of San Clemente, California, and is operated by Southern California Edison.

review abnormal lineups relative to technical specification requirements, training in the revision had not yet been provided to the operating shifts, and the abnormal valve lineup section of the work authorization procedure had not been revised to refer to the revision.

As corrective action, special training in the revised abnormal valve lineup procedure was provided in shift briefings, and additional training will be included in the requalification program. Applicable sections of the work authorization procedure have been revised to refer users of the procedures to the control of system alignments procedure when performing abnormal system alignments. Personnel involved have been counseled. In addition, acceptable means for isolating systems for the purpose of determining RCS leakage will be procedurally specified. (Refs. 6 and 7.)

1.4 Large Diameter Pipe Cracking in Boiling Water Reactors

On March 23, 1982, Nine Mile Point Unit 1* reported an event involving leakage from welds on two nozzles connecting recirculation system piping to the reactor vessel. The leakage was discovered during performance of a routine hydrostatic pressure test prior to return to operation from a scheduled maintenance outage. Subsequent inspections and evaluations showed extensive intergranular stress corrosion cracking (IGSCC) in heat affected zones near weld areas of large diameter (28-inch) piping in the reactor coolant recirculation system. After extensive analysis and review the licensee decided to replace the recirculation piping in all five recirculation loops, all ten safe ends, and branch piping as warranted by inspection and evaluation. The replacement material is of a type less susceptible to IGSCC.

Cracking in austenitic stainless steel piping in BWRs has been observed for many years. Although cracking in large diameter piping had been reported on some foreign reactors, the findings at Nine Mile Point Unit 1 were the first examples of major cracking in large diameter piping in the United States. The causes of IGSCC are not fully understood, and are being investigated extensively.

The NRC issued Inspection and Enforcement (IE) Bulletin 82-03, Revision 1 (Ref. 8) in October 1982 for action by nine BWR plants scheduled for refueling outages in late 1982 and early 1983. Inspections pursuant to this bulletin showed cracking in five of the first seven plants examined, prompting issuance of IE Bulletin 82-03 in March 1983. (Ref. 9.) This bulletin required augmented inspection of welds in the recirculation system piping, using ultrasonic testing (UT) inspection procedures of demonstrated effectiveness, for all plants beyond those identified in Bulletin 82-03, Revision 1, at their next refueling or extended outage but no later than January 1984.

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* Nine Mile Point Unit 1 is a 610 MWe (net) BWR located 8 miles northeast of Oswego, New York, and is operated by Niagra Mohawk Power.

As of early July 1983, five plants (Browns Ferry Unit 3, Brunswick Unit 2, Dresden Unit 3, Pilgrim Unit 1, and Quad Cities Unit 2)* had not yet begun inspections. These plants were scheduled for inspections at various times from August 1983 through January 1984. However, the NRC concluded that these uninspected facilities may have IGSCC, which may be unacceptable for continued safe operation without inspections and repair or replacement of the affected pipes and additional surveillance requirements. Therefore, on July 21, 1983, the NRC sent letters to the licensees of the five uninspected plants requesting that by August 4, 1983, they submit information regarding justification for continued operation, costs and impact of conducting the inspections on an accelerated schedule, availability of qualified personnel, and other bases to support their previously established schedules for IGSCC inspections.

On August 8 and 9, the NRC staff met with licensee representatives from the five BWR plants yet to be inspected to discuss their responses to the NRC letters. As a result of the meeting, accelerated schedules for inspections and interim additional compensatory measures (improved leak detection capability, emergency core cooling system availability, and operator training) were committed to by the licensees. The staff evaluated the information and commitments received from the licensees. On August 26, the NRC issued orders for each of the five plants that would confirm these accelerated inspection schedules and impose new interim compensatory measures, or confirm compensatory measures proposed by the licensees. Inspections conducted in response to the IE bulletins as well as the other inspection requirements revealed extensive cracking in both large diameter recirculation and residual heat removal system piping welds at several facilities.

Table 1 is a summary of the cracking observations from BWRs where piping has been examined and defects found, and indicates the extent of cracking in large diameter recirculation and RHR system piping as of March 1984.

Throughout the month of October 1983, the NRC staff drafted requirements for reinspection of plants inspected under the provisions of the IE Bulletins, and criteria for repair and/or replacement of piping. At a meeting with BWR licensees on October 21, the NRC staff described the development of these plans and brought the industry up to date on the pipe crack issues. At the same meeting, the licensees described their past and planned future actions regarding inspection, repair, and replacement. These meetings with licensees as a group, and individual meetings with licensees to discuss specific proposals, continued in late October and into November 1983.

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* Browns Ferry Unit 3 is a 1065 MWe (net) BWR located 10 miles northwest of Decatur, Alabama, and is operated by Tennessee Valley Authority.

Brunswick Unit 2 is a 790 MWe (net) BWR located 3 miles north of South Port, North Carolina, and is operated by Carolina Power and Light.

Dresden Unit 3 is a 773 MWe (net) BWR located 9 miles east of Morris, Illinois, and is operated by Commonwealth Edison.

Pilgrim Unit 1 is a 670 MWe (net) BWR located 4 miles southeast of Plymouth, Massachusetts, and is operated by Boston Edison.

Quad Cities Unit 2 is a 769 MWe (net) BWR located 20 miles northeast of Moline, Illinois, and is operated by Commonwealth Edison.

Plant Name	Licensee	Plant Location	12" - 28" Pipe Welds No. Examined	No. Defective*
Big Rock Point Unit 1	Consumers Power Co.	Charlevoix County, Michigan	11	0
Browns Ferry Unit 1**	Tennessee Valley Authority	Limestone County, Alabama	123	47
Browns Ferry Unit 2	Tennessee Valley Authority	Limestone County, Alabama	34	2
Browns Ferry Unit 3	Tennessee Valley Authority	Limestone County, Alabama	191	0
Brunswick Unit 1	Carolina Power & Light Co.	Brunswick County, No. Carolina	32	3
Brunswick Unit 2	Carolina Power & Light Co.	Brunswick County, No. Carolina	131	16
Cooper***	Nebraska Public Power Dist.	Nemaha County, Nebraska	135	20
Dresden Unit 2	Commonwealth Edison Co.	Grundy County, Illinois	51	10
Dresden Unit 3	Commonwealth Edison Co.	Grundy County, Illinois	240	64
Duane Arnold	Iowa Electric Power & Light	Linn County, Iowa	51	0
FitzPatrick	Power Authority of the State of New York	Oswego County, New York	55	1
Hatch Unit 1	Georgia Power Co.	Appling County, Georgia	58	7
Hatch Unit 2**	Georgia Power Co.	Appling County, Georgia	108	39
Millstone Unit 1	Northeast Nuclear Energy Co.	New London County, Connecticut	11	0
Monticello**	Northern States Power Co.	Wright County, Minnesota	135	6
Nine Mile Pt. Unit 1	Niagara Mohawk Power Co.	Oswego County, New York	**	**
Oyster Creek	Jersey Central Power & Light	Ocean County, New Jersey	31	0
Peach Bottom Unit 2**	Philadelphia Electric Co.	York County, Pennsylvania	123	26
Peach Bottom Unit 3	Philadelphia Electric Co.	York County, Pennsylvania	111	15
Pilgrim Unit 1**	Boston Edison Co.	Plymouth County, Massachusetts	**	**
Quad Cities Unit 1	Commonwealth Edison Co.	Rock Island County, Illinois	18	0
Quad Cities Unit 2	Commonwealth Edison Co.	Rock Island County, Illinois	225	22
Vermont Yankee	Vermont Yankee Nuclear Power	Windham County, Vermont	60	34

*None exceeded crack propagation criteria.
**Replacing pipe.
***Planning pipe replacement.

During the inspection process, questions were raised regarding the reliability of the UT inspection techniques. In conjunction with the NRC bulletin activities, joint efforts by the NRC and industry were begun to train and qualify inspection personnel, using improved UT procedures on well characterized pipe cracks in pipe segments removed from Nine Mile Point Unit 1, to assure higher reliability in the inspection process.

In general, the probable consequences of small cracks are crack propagation and minor leakage of primary coolant. When small but measurable leaks occur, leakage monitoring systems detect the change of leak rate, and a plant shutdown is required if allowable leak rate limits are exceeded. Licensees are also required to perform periodic inspections of piping to detect evidence of pipe cracks and repair or replace piping, if necessary. Redundant core cooling systems also are available to provide cooling of the core even in the remote case of a pipe failure.

However, the Nine Mile Point Unit 1 results and subsequent inspections performed on other BWRs resulted in increased safety concern regarding the extensive range of pipe sizes involved, the large number of plants affected, the size and number of cracks, the adequacy of detection and characterization of such cracks, the repair techniques, and the adequacy of licensees' compensatory measures (leak detection capability, emergency core cooling system availability, and operator training). Although IGSCC in the sensitized material of the heat-affected zone in BWR piping is influenced by the environmental conditions existing in the BWR reactor coolant system and stresses in the piping, including residual stresses induced by welding, there is no clear correlation between the extent of cracking and operating time. Some plants with a relatively brief operating history, e.g., Hatch Unit 2,* show extensive cracking. The licensee for Hatch Unit 2 will replace the affected piping in 1984.

As corrective actions to prevent recurrence, inspections of piping either have been or are being made in accordance with IE Bulletins 82-03, Revision 1, and 83-02. Where cracking is observed, resolution is in accordance with NRC requirements, as discussed below. Efforts continue to train and qualify inspection personnel, using improved UT procedures, to assure higher reliability in crack detection and sizing. The Electric Power Research Institute (EPRI) is involved in programs for the detection and characterization of cracks, and is working with the licensees in formulating qualifications programs for weld inspectors. Included in EPRI's efforts is a "round robin" program to compare crack depth measurements made by UT versus results of actual destructive examinations. EPRI is also conducting a large number of UT operator training courses to upgrade the capabilities of inspection teams in detecting and sizing IGSC cracks, based on the results from the round robin. The NRC is participating in portions of this program. A cooperative effort between EPRI and the BWR Owners Group has also concentrated on developing remedial measures for both operating plants and plants under construction to extend the service lifetime of piping systems.

General Electric, the nuclear steam supply system vendor for the BWRs, has also been involved in studying field and laboratory data on cracks caused by intergranular stress corrosion, rate of crack propagation, as well as suitable

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* Hatch Unit 2 is a 748 MWe (net) BWR located 11 miles north of Baxley, Georgia, and is operated by Georgia Power.

remedial measures. A number of remedial measures have been developed, qualified, and implemented. These include solution heat treatment, alternate nuclear grade materials, heat sink welding, induction heating stress improvement, and weld overlay. Startup de-aeration techniques and the use of hydrogen water chemistry are currently being investigated as a means of retarding the rate of IGSCC.

The NRC is closely involved in the licensees' and the vendors' efforts to assure proper detection, characterization, and resolution of the cracking problem. The NRC staff has been reviewing the inspection results of each plant on a case-by-case basis. For the licensees which had not yet made inspections required by the IE Bulletins, interim compensatory measures (e.g., improved leak detection capability, emergency core cooling system availability, operator training) were established where necessary. In general, for those plants where cracking has been observed, repairs, analysis and/or additional surveillance conditions were required. Where repair was proposed, consideration was given to the strength (relative to ASME Code margin) of the repair, its effect on the piping system, and further inspectability. Where repair was not proposed, consideration was given to uncertainties in the measurements of cracking depth and to projected growth of cracks during subsequent operation. NRC staff evaluation criteria require maintaining the inherent factor of safety prescribed by Section III of the ASME Boiler and Pressure Vessel Code for normal and faulted conditions with consideration of the uncertainties in crack size and growth rate. (Ref. 10.)

1.5 Nitrogen Bubble Formation in Reactor Vessel Head During Extended Outage

Between November 18 and 27, 1983, while in an extended cold shutdown outage (since February 1982), San Onofre Unit 1* experienced the unexpected formation of a nitrogen gas bubble in the reactor vessel head. The bubble was discovered as a result of investigations of unexplainable increases in pressurizer water level. The event described below illustrates the continuing need to independently and concurrently assess the various factors (i.e., liquid, gas, pressure, temperature, etc.) that can cause pressurizer level changes to occur.

On November 18, 1983, with one power operated relief valve (PORV) out of service, the reactor coolant system (RCS) was lowered to an indicated pressurizer level of less than 50% in order to meet the intent of a pending technical specification change which requires two operable PORVs whenever pressurizer water level is greater than 50%. Also, in accordance with an operating instruction, the volume control tank (VCT) was pressurized to 45 psig to allow RCS charging and letdown using pressure rather than a charging pump as the motive force for flow. Experience had shown that a high differential pressure develops across a control valve during charging pump operations with the RCS depressurized, which is detrimental to the valve and its seating surfaces.

During the next three days, the pressurizer level increased 2% to 3% each day. Operators looked for possible sources of inleakage from adjoining systems. Once on November 21, and twice during the subsequent five days, pressurizer level was lowered to stay below the 50% level, while the search for suspected inleakage continued.

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

On November 27, the plant staff concluded that no liquid inleakage path existed which could account for the continued increase in the pressurizer level, and that the increase in pressurizer level could be caused by gas ingress into the RCS. To check for a gas bubble, the reactor vessel head was vented. As a result of this venting, identified pressurizer level decreased from 45% to 16% in 2-1/2 hours. The pressurizer level was restored by charging 3684 gallons into the RCS.

The licensee attributed the cause of the event to the increased nitrogen gas pressure used in the VCT to force charging flow to the RCS. Since the solubility of nitrogen gas is less in the reactor vessel head location than it is in the VCT, nitrogen gas came out of solution in the RCS and collected in the reactor vessel head.

As corrective action, the licensee reduced the VCT nitrogen pressure to 35 psig, and the reactor vessel head will continue to be periodically vented when nitrogen pressure is used in the VCT as the motive force for charging flow. The licensee informed all operating shifts of this occurrence and the manner in which it developed. In addition, the operating instruction has been rewritten to include directives for venting a nitrogen accumulation in the reactor vessel head. The licensee also committed to evaluate alternate methods of providing charging flow to the RCS with the unit in cold shutdown.

Had the nitrogen generation continued, reactor vessel level would not have been depressed below the top of the hot leg piping. The geometry of the vessel is such that it would inhibit the core uncovering under the existing plant conditions. (Ref. 11.)

1.6 Failed Fuel Assemblies and Damaged Thermal Shield

During Cycle 5 operation of Millstone Unit 2,* a Combustion Engineering (CE) designed plant, the licensee noted elevated levels of radioactive iodine and other fission products in the reactor coolant. By the end of the cycle, the primary system activity was about 2% of the plant's technical specification limit; this was indicative of 10 to 30 fuel pin failures.

The plant was shut down on May 28, 1983, for refueling and maintenance. The licensee established a fuel pin failure investigation program. Fuel sipping (analysis of the fuel assembly for leakage of fission products) was conducted on the entire core, and 26 fuel assemblies were identified which had one or more failed fuel pins. Five of the assemblies were supplied by one vendor and were scheduled for discharge at the end of Cycle 5; these assemblies had been irradiated for three cycles. Twenty-one of the assemblies were supplied by another vendor and had been scheduled for reinsertion for Cycle 6; these assemblies had seen no more than one or two cycles of operation.

Ultrasonic inspections showed that there were 32 failed fuel pins in the 26 fuel assemblies. The licensee evaluated a number of possible failure mechanisms and concluded that the failures apparently resulted from multiple sources, none of

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* Millstone Unit 2 is an 860 MWe (net) PWR located 5 miles southwest of New London, Connecticut and is operated by Northeast Nuclear Energy.

which were indicative of a situation that may lead to continued serious degradation of the fuel cladding. For example, there was evidence of debris induced wear of the cladding and one case of confirmed grid spring/fuel rod fretting. The probable cause of the latter was a damaged cell, most likely related to either fuel manufacturing or handling. To reduce the possibility of debris induced wear, the licensee performed an extensive cleanup of the primary system.

Visual inspections revealed that 15 fuel assemblies had broken holddown springs. The probable cause was attributed to flow induced vibration, near the core periphery, leading to fatigue failure of the springs. The licensee's analysis concluded that, although broken, the springs remained functional and the assemblies could continue in operation. Redesigned springs were placed on all new fuel assemblies.

Further inspections revealed two fuel assemblies with structural damage; one of the two also had a broken holddown spring. However, the requirements for structural integrity, such as strength and loading capability, were still met for normal as well as for accident conditions by these fuel assemblies. The cause was attributed to insufficent gap clearances between the assembly structurals and the fuel alignment plate. Additional clearances will be incorporated into new fuel assemblies.

The problems described above necessitated a revision to the licensee's originally planned reload core for Cycle 6. A combination of new and previously discharged fuel assemblies were used to replace the leaking and two damaged fuel assemblies. Nine fuel assemblies, each with a single broken holddown spring, were also used for Cycle 6 (the licensee decided that repair of these springs on the irradiated fuel assemblies would involve a high risk of damage to fuel pins).

As part of the scheduled shutdown activities, the reactor vessel internals were inspected. Damage was noted to both the thermal shield and the core barrel. The damage appeared similar to that experienced at St. Lucie Unit 1,* another CE designed facility. The damage incurred at St. Lucie 1 is described in Appendix C of Ref. 12. (See also Power Reactor Events, Vol 5, No. 3, pp. 14-15.) As described in that report, it is believed that the damage to the thermal shield was not a single event, but rather occurred over a period of time and was related to mechanical stress caused by flow induced vibrations. Also as described in the report, the use of a thermal shield is an optional design in CE plants. The licensee for Millstone Unit 2 decided to operate the plant in the future without the thermal shield. The thermal shield was therefore removed and the minor damage to the core support barrel was repaired.

The Cycle 6 core reload changes, together with operation without the thermal shield, were submitted to the NRC for approval. NRC approval was granted on December 30, 1983 and the plant achieved criticality on January 5, 1984.

The number of fuel pins which failed constituted less than 0.1% of the total number of fuel pins in the core. The resultant primary activity was only a small fraction of the technical specifications limitations. (Refs. 13 and 14.)

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* St. Lucie Unit 1 is an 822 MWe (net) PWR located 12 miles southeast of Ft. Pierce, Florida, and is operated by Florida Power and Light.

1.7 Damage to Optical Isolator Output Cards and Solid State Devices

At Grand Gulf Unit 1* in August of 1983, an event occurred in which residual heat removal (RHR) pump A failed to start, Division 1 buses were incorrectly shown tripped, and numerous annunciators on the Division 1 control room panel incorrectly alarmed. The event was attributed to imposing an ac voltage onto a dc voltage circuit, and shows how this method of operation damages voltage sensitive components.

The cause of the event was personnel error, in that a computer cable was incorrectly terminated in a motor control center across ac relay contacts. As corrective action, the computer cable was disconnected and the licensee has initiated a program to eliminate future construction error through closer supervision at work activities, training, improved inspections, and clearer work instructions. All solid state breaker trip devices in Division 1 have been inspected and tested and no damage was found. The effects on safety were limited to Division 1 with the plant in cold shutdown. A detailed description of the event follows.

On May 27, 1983, a computer cable which provides a signal to the computer when an automatic start of the drywell recirculation fan unit A occurs was incorrectly terminated during a drywell ventilation modification which added the recirculation fan to the system. The cable should have been terminated across a set of isolated relay contacts but was instead incorrectly terminated across the overload (OL) device in the 120 V ac control circuit for recirculation fan unit A in its motor control center (MCC). The power for the computer cable is supplied from a 125 V dc bus through an isolation panel.

The breaker to the recirculation fan was not closed until August 3, 1983, to perform preoperational testing. Therefore, no electrical interconnection between ac and dc existed prior to this date. When the breaker was closed, no adverse effects occurred because the OL device was closed; therefore, no ac current flowed into the dc circuits.

As part of preoperational testing, the OL device and the penetration cabinet failure relay contact were opened and closed on the evening of August 3, 1983, and the morning of August 4. The opening and closing of these contacts inserted and then removed the 120 V ac on the 125 V dc bus. This resulted in the following effects:

(1) An optical isolator output card in the RHR A pump trip circuit failed, which caused a continuous pump trip;

(2) A continuous trip occurred on a standby service water system load center breaker; and

(3) Numerous annunciators on the Division 1 control room panel incorrectly alarmed.

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*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.

Previous incidents of ac voltage being imposed on a dc voltage circuit occurred during the preoperational phase of startup. These resulted from imilar wiring errors in construction and design. Applying 120 V ac on the 125 V dc logic and control circuits will not generally damage wiring, relay coils, contacts, and most instruments if the voltage is not excessive. However, it can be expected to damage optical isolator output cards and other solid state devices. Whether components are damaged depends on their logic arrangement in the associated circuits during the time the ac is present. It can also affect the operation of non-solid state devices; e.g., a relay may not deenergize with ac present.

The optical isolator output card in the RHR pump trip logic circuit was damaged as a result of the ac voltage during this event. Only two isolators are connected directly to the Division 1 125 V dc bus. One was not damaged because the output card was in parallel with other relay contacts that were closed. The relay contacts parallel with the other were open, thus the ac current flowed through the output side and destroyed the output transistors. This type of optical isolator would be expected to fail if ac voltage is present. The isolator output card was manufactured by General Electric. The model number is 204B6188AAG2 and the serial number is TWRE5-17.

The emergency safety features 480 V standby service water load center breaker gave dual indication during the time the ac voltage was present on the dc bus, and then tripped. The breaker is equipped with a solid state trip device, and its control circuits receive power from the Division 1 125 V dc bus. The ac voltage apparently caused a trip signal from the solid state trip device, but no damage to the device.

The licensee decided not to perform extensive inspection and testing of other components within the 125 V dc Division 1 system because:

(1) Past experience showed that low ac voltage (less than or equal to 120 V ac) did not damage non-solid state devices;

(2) The 18-month surveillance on the affected circuits and components were to be performed within the next 30 days, including the 18-month diesel generator loss of coolant accident/loss of offsite power tests;

(3) The solid state trip devices in all of the safety-related breakers were scheduled to be inspected, tested and possibly replaced due to an unrelated potential failure previously reported; and

(4) Daily channel checks and monthly functionals are adequate to uncover any other damage. (Ref. 15.)

1.8 Temporary Connection Between Air Storage Tank and Division 1 Diesel Generator

At Grand Gulf Unit 1* on September 13, 1983, the Operations Shift Superintendent was notified of a temporary connection made without proper reviews, authorizations, and documentation from the Division 2 diesel generator (DG) starting

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* 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.

air system to the Division 1 DG barring device. The Shift Superintendent notified maintenance to remove the connection, and issued a Plant Quality Deficiency Report (PDQR). At the time of the event, the plant was in cold shutdown, and the Division 1 DG was inoperable.

The temporary line was connected to a non-Q pipe downstream of the Division 2 starting air storage tank isolation valve, just before the Division 2 engine barring device. The line was routed through a normally locked security door and attached to the Division 1 diesel engine barring device. The connection was made to roll the Division 1 engine to inspect and dry the generator. Also, the isolation valve was opened by non-operations personnel. The pressure in the C and D tanks remained above 160 psig during the event, which indicated that the Division 2 DG had adequate air pressure to assure emergency starts if needed.

The cause of the event was due to personnel error. The Mechanical Superintendent instructed craft personnel to prepare the connection while simultaneously requesting the Nuclear Support Manager to verify if such a connection would be approved by the Operations Shift Superindentent. On September 12, the Shift Superintendent denied the request. Technical specifications required the Division 2 diesel generator to be operable. It was discovered on September 13, that the connection had been made. The error was due to miscommunication and noncompliance with administrative procedures. The personnel involved were counseled and made aware of the proper procedure. (Ref. 16.)

1.9 Main Steam Line Radiation Monitor Found with Trip Setpoint Greater than Three Times Normal Background

At Vermont Yankee Unit 1* on September 28, 1983, during normal operation, main steam line radiation monitor RM-17-251A was found be have a trip setpoint exceeding the less than three times (3X) normal background at rated power required by technical specifications. As a result, the licensee tripped the A main steam line instrument system and adjusted the setpoint. The cause of the event was attributed to procedural inadequacy, in that the procedures did not address the requirement to periodically determine normal fuel power background in order to calculate correct setpoints.

The functions of the main steam line radiation monitors are to provide immediate indication of excessive radiation in the lines and to initiate automatic action to contain the radiation. Each monitor has an upscale trip. This trip is connected to the reactor protection system (RPS). Circuits are arranged such that an upscale trip from a monitor activates one of two RPS safety channels. This monitor also annunciates a control room high-radiation alarm through a switch in a recorder. This switch is set at less than 3X the normal background radiation. The trip is set at 3X normal radiation, per technical specifications. Activating both channels (A and B) results in a control room main steam line high-high radiation alarm and initiates the following protective actions:

(1) All Group 1 primary containment isolation valves are closed (main steam isolation valves, steam line drains, and reactor water sample lines).

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*Vermont Yankee Unit 1 is a 504 MWe (net) BWR located 5 miles south of Brattleboro, Vermont, and is operated by Vermont Yankee Nuclear Power.

(2) The off-gas to the stack pilot valves, the holdup valve, and the drain valve are closed.

(3) The mechanical vacuum pump is tripped.

(4) The reactor is scrammed.

During a review of control room instrumentation and switch positions on September 27, 1983, an NRC inspector observed that the A channel main steam line high radiation monitor (RM-17-251A) indicated a normal background radiation level of 155 mr/hr with the reactor at a power of 1589 MWth (99.8% power). The inspector noted that a sticker on the front of the indicator panel indicated that the high-high trip setpoint was 500 mr/hr. Technical specifications require the trip setting to be less than 3X normal background at rated power. At these conditions, the trip setting was equal to 3.22X the normal background at rated power.

The inspector immediately reviewed Instrument and Control (I&C) calibration records to determine the current trip settings. These records indicated that the A channel trip setting was routinely verified to be at 500 mr/hr. The last change to the setpoints was performed on November 13, 1979. Records of normal full power background reading on the A channel between September 10 and 24, 1983 indicated a background of between 145 to 160 mr/hr. The inspector was informed by the licensee management that the normal full power background was considered to be 200 mr/hr based on initial startup readings and, therefore, the trip settings could be as high as 600 mr/hr. The setting of 500 mr/hr was thus conservative.

The inspector also questioned the plant chemist with regard to whether the check of the trip settings had been performed as required since the last startup from the refueling outage. The licensee representative indicated that this check had not been performed.

The licensee's management reviewed these findings and agreed that the A main steam line high radiation trip setting was not in accordance with the technical specification requirements. On September 28, 1983, the licensee tripped the A main steam line instrument system, and actions were initiated to adjust the trip setting on the A channel down from 500 mr/hr to 425 mr/hr. The licensee also adjusted the D channel from 500 mr/hr to 450 mr/hr for conservatism. (The B and C channels were within technical specification requirements during the event.) Background was established for all monitors and the trips were reset, as required, to be less than 3X background. The inadequate procedure is being revised to address the specific method for background determination. (Refs. 17 and 18.)

1.10 Load Reduction Transient at Salem Unit 2

At Salem Unit 2* in January 1982 a load reduction transient occurred involving five separate and unrelated failures, including a failure of the rod control system. The event initiated from a feedwater transient involving a loss of suction to the feedwater pumps. During the event reactor power exceeded

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* Salem Unit 2 is a 1106 MWe (net) PWR located 20 miles south of Wilmington, Delaware, and is operated by Public Service Electric and Gas.

turbine load by up to 70% and the reactor coolant system (RCS) average temperature (T-ave) exceeded technical specification limits. The plant, however, was stabilized without a trip, avoiding an overcooling transient. Although the scram function was available when the rod control system failed and T-ave exceeded technical specifications, there was no requirement for a reactor trip.

The initiating event prior to load reduction was a high level in a heater drain tank followed by steam generator feed pump (SGFP) low suction pressure alarm. Due to several previous trips attributed to instability in the heater drain system, the licensee had established guidelines for dealing with low feedwater pump suction pressure. These guidelines called for bypassing the condensate polishing system and reducing load in 10% increments. After the manual load reduction, and in order to reduce the RCS T-ave, the operator tried to insert the control rods in bank D, but was inhibited because of a failure of the firing circuit control card in the power cabinet. An urgent failure alarm in the rod control system annunciated. Due to the rod control urgent failure alarm, the rod control system placed a "hold signal" on all rods controlled by that power cabinet. Because control bank D was first in the programmed sequence for rod insertion, the operator could not insert any control banks. According to procedure, the operator manually initiated RCS boration at 10 gpm in order to reduce RCS T-ave.

The condenser steam dump system had been armed in the load rejection mode of operation as a result of the turbine load reduction. When RCS T-ave exceeded the programmed T-ref by 5°F, the steam dumps began modulating to control T-ave at 5°F above T-ref. High steam flow alarms for all steam generators annunciated due to the opening of the condenser steam dump valves.

The SGFP low suction pressure alarm again annunciated. At this time there was a mismatch of approximately 70% between turbine load and the reactor power. The mismatch was being rejected to the condenser by the steam dump system. The turbine load was increased in order to reduce the power mismatch. The dump valves started to modulate closed, and T-ave was held stable at 580°F. The operator believed that the transient was under control and reset the steam dump system load rejection signal, not realizing that resetting of the load rejection arming signal would cause the steam dump valves to close, and thereby increase T-ave at a rapid rate. At that time, there was a mismatch of approximately 46% between turbine load and reactor power. T-ave peaked at 592°F, causing a rapid increase in pressurizer level from 54% to 78% and in pressurizer pressure from 2200 psig to a peak pressure of 2340 psig. Both pressurizer spray valves operated to offset the pressurizer pressure increase.

The elevated T-ave was reflected back into the secondary side, causing steam line pressure to increase rapidly. This resulted in two main steam line isolation/stop valves (MSIVs) coming off their open seats and closing partially. The operator re-opened the two valves. When steam pressure increased to 1080 psig, the No. 23 steam generator safety valve lifted. An operator was sent to determine which valve was discharging. The combined effects of RCS boration and increasing turbine load started to reduce the RCS T-ave. Pressure decreased under the influence of pressurizer sprays with both spray valves fully open. Manual boration was stopped. Even though the spray demand signal was at zero, only one valve indicated closed while the other valve failed to close automatically. The operator went to manual on the spray valve controller and the valve closed.

Pressurizer level dropped to 22% and pressurizer pressure dropped to 2050 psig. All the pressurizer heaters energized and pressure was increased to 2260 psig. Pressurizer pressure controls were returned to automatic.

Approximately one hour after the transient, the unit was at stable conditions: pressurizer pressure at 2230 psig, pressurizer level at 32%, T-ave at 558°F, and reactor power at 46%. The steam generator safety valve had failed to fully reseat and was still relieving steam. An attempt was made to fully reseat the safety valve by lowering RCS T-ave 4-6°F below T-ref, and then by manually cycling the steam generator atmospheric relief valve. Steam generator pressure decreased to 800 psig, but the safety valve still failed to fully reseat. It was discovered that the lifting disc associated with the manual lifting arm had rotated approximately two full turns down the valve stem and was preventing valve closure. The manual lifting arm was removed 4 hours after the safety valve had lifted and the valve then was fully closed.

The loss of SGFP suction pressure occurred when turbine load rapidly decreased, followed by actuation of the condenser steam dump. First, steam generator level shrank and to compensate for this level decrease feed flow momentarily increased. This resulted in increased flow from the condensate pumps and heater drain pumps. Secondly, turbine extraction steam pressure decreased. This caused a decrease in pressure in the shell side of the fifth and sixth point heaters, which consequently reduced the pressure in the heater drain tanks. This resulted in flashing of the water in the tanks which reduced the heater drain tank levels, and when combined with the increased feedwater flow, caused the level in the tanks to decrease to the point where the heater drain pump discharge valves began throttling closed to maintain level. The reduction in heater drain pump flow caused a further reduction in feed pump suction pressure, since the condensate pumps were not capable of providing the required pressure. Therefore, a further reduction in load was required and the cycle continued to repeat itself until the feed pumps tripped.

As a result of this event, station procedures were revised and additional training was implemented. The licensee will replace the condensate pumps with higher heat pumps, and will trip the plant manually when the rod control system has failed and RCS T-ave has exceeded technical specification limits. (Ref. 19.)

1.11 Errata/References

Errata

Power Reactor Events, Vol. 5, No. 5 (issued February 1984) contained a summary of events regarding "Improperly Installed Fire Dampers," pp. 9-10. Several plants were listed as having dampers installed in noncompliance with National Fire Protection Association Standard 90A or with design criteria of the damper manufacturer. The operating power plants involved should have included Crystal River, Farley, Grand Gulf, and McGuire. Also listed in the writeup were Fort St. Vrain, Vermont Yankee, and Davis Besse. Although problems were found at these plants in late 1983 regarding reanalysis of plant vulnerabilities and fire protection, the three plants were incorrectly included in the "Improperly Installed Fire Dampers" writeup.

References

(1.1) 1. Consolidated Edison Company, Docket 50-247, Licensee Event Report 83-43, December 13, 1983.

2. Duke Power Company, Docket 50-369, Licensee Event Report 83-84, October 14, 1983.

3. NRC, Memorandum for R. W. Houston and D. R. Muller, NRR, from F. J. Miraglia, NRR, re: Inoperable Containment Spray Systems at Indian Point Unit 2, January 1984.

(1.2) 4. Public Service Company, Docket 50-267, Licensee Event Report 83-18, June 16, 1983.

5. NRC, AEOD Engineering Evaluation AEOD/E401, January 4, 1984.

(1.3) 6. NRC, Preliminary Notification PNO-V-83-43, October 3, 1983.

7. Letters from H. B. Ray, Southern California Edison, to J. B. Martin, NRC/Region V, September 30, 1983 and October 17, 1983.

8. NRC, IE Bulletin 82-03, Revision 1, October 28, 1982.

(1.4) 9. NRC, IE Bulletin 83-02, March 4, 1983.

10. Letter from D. G. Eisenhut, NRC, to D. L. Farrar, Commonwealth Edison Company, July 21, 1983.

(1.5) 11. Letter from J. G. Haynes, Southern California Edison Company, to J. B. Martin, NRC/Region V, re: Licensee Event Report 50-206/83-006, December 12, 1983.

(1.6) 12. NRC, Report to Congress on Abnormal Occurrences, NUREG-0090, Vol. 6, No. 2, November 1983.

13. Letter from W. G. Counsil, Northeast Utilities, to J. R. Miller, NRC, November 4, 1983.

14. NRC Memorandum for Assistant Director for Operating Reactors, NRR/DL, from L. S. Rubenstein, NRR/DSI, December 19, 1983.

(1.7) 15. Mississippi Power and Light Company, Docket 50-416, Licensee Event Report 83-115, November 3, 1983.

(1.8) 16. Mississippi Power and Light Company, Docket 50-416, Licensee Event Report 83-135, October 20, 1983.

(1.9) 17. Vermont Yankee Nuclear Power Corporation, Docket 50-271 Licensee Event Report 83-25, October 12, 1983.

18. NRC, Inspection Report 50-271/83-27, October 26, 1983.

(1.10) 19. NRC, AEOD Engineering Evaluation AEOD/E323, September 1983.

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 ABSTRACTS OF OTHER NRC OPERATING EXPERIENCE DOCUMENTS

2.1 Abnormal Occurrence Reports (NUREG-0090) (Issued in November-December 1983

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.

Date Issued	Report
11/83	REPORT TO CONGRESS ON ABNORMAL OCCURRENCES. APRIL-JUNE 1983, NUREG-0090, VOL. 6, NO. 1

There were four abnormal occurrences during the report period. One occurred at a licensed nuclear plant, and three were reported by Agreement State licensees. The occurrence at the plant involved unavailability of the auxiliary feedwater system at Turkey Point Units 3 and 4 on April 19, 1983. The Agreement State occurrences involved overexposure of two radiographers at Bayou Testers, Morgan City, Louisiana, on June 21, 1982; a missing radioactive source from Gearhart Industries, Corpus Christi, Texas on September 14, 1982; and employee exposures to americium-241 at Gulf Nuclear, Inc., Webster, Texas, reported February 25, 1983.

Also, the report provided update information on the following occurrences previously reported in NUREG-0090: cracks in pipes at boiling water reactors (75-5), first reported in NUREG-75/0090, January-June 1975; nuclear accident at Three Mile Island (79-3), first reported in Vol. 2, No. 1, January-March 1979; failure of high pressure safety injection system (81-4), first reported in Vol. 4, No. 3, July-September 1981; and deficiencies in management and procedural controls (83-2), first reported in Vol. 6, No. 1, January-March 1983.

In addition, reactor vessel internals bolting failures at Babcock & Wilcox pressurized water reactors, and damage to the thermal shield at St. Lucie Unit 1 were discussed as items of interest that did not meet abnormal occurrence criteria.

2.2 Bulletins and Information Notices Issued in November-December 1983

The Office of Inspection and Enforcement periodically issues bulletins and information notices to licensees and holders of construction permits. During the period, one bulletin and one bulletin supplement, and 11 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
83-07 Supplement 2	12/9/83	APPARENTLY FRAUDULENT PRODUCTS SOLD BY RAY MILLER, INC. On 7/22/83, IE Bulletin 83-07 was issued to all nuclear power facilities and fuel facilities holding an operating license or construction permit, requesting them to submit in writing, within eight months, their determination if certain apparently fraudulent products sold by Ray Miller, Inc., were installed in safety-related systems. (See also Power Reactor Events, Vol. 5, No. 4, January 1984, p. 25; Vol. 5, No. 5, February 1984, p. 14.) In addition, non-licensee companies that received the products were asked to identify (1) the nuclear facilities that may have been supplied the products, or (2) the customer to whom they sold the products if they themselves were not the end-user. Supplement 2 to Bulletin 83-07 was sent for action to all nuclear power reactor facilities and fuel facilities holding an operating license or construction permit, and for information to other

Bulletin	Date Issued	Subject
83-07 Supplement 2 (continued)		fuel cycle facilities and Category B, Priority I material licensees. Attachments 1 through 3 listed additional respondents identified as end-users, secondary recipients, and NRC licensees identified as secondary recipients. No additional actions beyond those specified in Bulletin 83-07 were requested by this supplement.
83-08	12/28/83	This bulletin was sent to all nuclear power reactor facilities holding an operating license (OL) or construction permit (CP), for action. The purpose of this bulletin was to assure proper operation of circuit breakers with undervoltage trip attachments being used in safety-related applications other than as reactor trip breakers. Toward this end, the bulletin described recent findings involving such circuit breakers and asked holders of CPs and OLs to take certain actions. The subject breakers are similar to those identified in IE Bulletins 83-01, "Failure of Reactor Trip Breakers Westinghouse DB-50) to Open on Automatic Trip Signal," and 83-04, "Failure of the Undervoltage Trip Function of Reactor Trip Breakers." For abstracts, see Power Reactor Events, Vol. 5, No. 1, pp. 28-29 for 83-01., Vol. 5, No. 2, p. 21 for 83-04.) Holders of CPs and OLs were asked to: (1) identify the safety-related applications of the breakers and the systems in which they are used; (2) review the adequacy of the design, testing, and maintenance of the breakers in light of their operating experience and information conveyed in the bulletin; and (3) evaluate the need to take corrective measures to ensure proper operation of the breakers.

Information Notice	Date Issued	Subject
83-74	11/3/83	RUPTURE OF CESIUM-137 SOURCE USED IN WELL-LOGGING OPERATIONS All NRC licensees authorized to possess and use sealed sources containing byproduct or special nuclear material in well-logging operations were alerted to a potentially serious problem identified during removal of a sealed source from its holder at Shelwell Services, Inc., on September 14, 1983. The source removal effort resulted in the rupture of a cesium-137 sealed source and subsequent personnel and area contamination. After several unsuccessful

Information Notice	Date Issued	Subject
83-74 (continued)		attempts to remove a cesium source capsule from its holder by inserting a lubricant into the source holder and tapping it, employees placed the source holder on a turning lathe and attempted to push the source out of its holder using a drill bit. With the source holder concentrically spinning around the bit's axis, the source capsule was ruptured. When the holder was removed from the lathe the source fell into a rag. Because of inadequate surveys, the licensee failed to evaluate the situation and take immediate corrective actions to limit personnel exposure and the spread of contamination. The licensee disregarded off-scale readings of two different radiation survey instruments, assuming that both were malfunctioning. This notice suggested that recipients review their procedures for well-logging source changes to ensure that capsules cannot be ruptured or source containment breached. Written procedures should be established for installation and removal. It was also suggested that recipients review their procedures and training programs to ensure that appropriate and operable radiation monitoring equipment is available and used, and review insurance coverage to determine if it is adequate to pay for decontamination in the event of an incident.
83-75	11/3/83	IMPROPER CONTROL ROD MANIPULATION All nuclear power plants holding an operating license or construction permit were informed of an event that occurred at Quad Cities Unit 1 in March 1983 and Hatch Unit 2 in July 1983, involving improper control rod manipulations because of inadequate communications from and controls by plant management. (See also <u>Power Reactor Events</u>, Vol. 5, No. 4, January 1984, pp. 1-5.) These events did not result in fuel damage, but affected the plants' ability to sustain a rod drop accident. It was expected that recipients of the notice review the information for applicability to their facilities.
83-76	11/2/83	REACTOR TRIP BREAKER MALFUNCTIONS (UNDERVOLTAGE TRIP DEVICES ON GE TYPE AK-2-25 BREAKERS) All nuclear power reactor facilities holding an operating license or construction permit were advised of malfunctions of the undervoltage (UV)

Information Notice	Date Issued	Subject
83-76 (continued)		trip attachments in General Electric AK-2-25 breakers, which are safety-related systems. Malfunctions of the UV trip attachments at San Onofre were described. These involved the UV armature being in midposition rather than in contact with the air gap adjusting screws. It was suggested that recipients of the notice visually inspect each UV armature to assure its proper position after each operation. If the UV armature were to be found in an improper position, the NRC would consider the reactor trip breaker to be inoperable.
83-77	11/14/83	AIR/GAS ENTRAINMENT EVENTS RESULTING IN SYSTEM FAILURES All holders of a nuclear power reactor operating license or construction permit were informed of events at Calvert Cliffs Unit 1, McGuire Unit 1, San Onofre Unit 2, and St. Lucie Unit 1 that rendered redundant safety systems inoperable because air or gas entrainment caused pump cavitation. Licensees were cautioned that the types of system inoperability resulting from such entrainment vary, and that redundant safety-related trains or components can be affected as shown by the events discussed. The serious consequences that may result from such system or component impairment cannot be overemphasized. It was expected that recipients of this notice review the information for applicability to their facilities.
83-78	11/17/83	APPARENT IMPROPER MODIFICATION OF A COMPONENT AFFECTING PLANT SAFETY All nuclear power reactor facilities holding an operating license or construction permit were informed of an event involving apparent improper modification of a component affecting plant safety. The modification was to a power operated relief valve (PORV) at Rancho Seco, and consisted of adding an indicator, visible to control room personnel, to the valve's operating lever. The additional weight of the indicator apparently inhibited its ability to reseat properly. This event pointed out two facets of component modifications which are dictated by good practice, yet can easily be overlooked in the rush to bring a plant back on line: (1) consultation with the component manufacturer before making the modification, and (2) testing of the component after the modification has been made. It was noted that the area of concern in this notice was not

Information Notice	Date Issued	Subject
83-78 (continued)		limited to PORVs, but was related to the modification of any component that affects plant safety.
83-79	11/23/83	APPARENTLY IMPROPER USE OF COMMERCIAL GRADE COMPONENTS IN SAFETY-RELATED SYSTEMS All nuclear power reactor facilities holding an operating license or construction permit were informed of the apparently improper use of commercial grade components in safety-related systems. The event discussed involved a leaking heat exchanger outlet valve at Cook Unit 2. The valve manufacturer determined that the elastomer seat had not been properly bonded to the valve body at the time of manufacture; i.e., it was manufactured as a commercial grade valve since neither the purchase order nor the specification for the valve required fabrication under an approved nuclear quality assurance program. It was noted that commercial grade components should not be used in safety-related systems unless they are evaluated by engineering and quality assurance personnel.
83-80	11/23/83	USE OF SPECIALIZED "STIFF" PIPE CLAMPS All nuclear power reactor facilities holding an operating license or construction permit, nuclear steam system suppliers, and architect-engineers were notified of a potentially significant problem in the use of specialized "stiff" pipe clamps, which may result in significant localized stresses in Class 1 piping. The notice describes certain design concepts that have been incorporated by clamp vendors in response to recent specification requirements that clamps be designed to provide total system stiffness compatible with the shock suppressor stiffness. However, these innovations can result in localized piping stresses significantly higher than the stresses from conventional pipe clamps. The NRC staff does not believe the new clamp design to be deficient, but does believe that potential safety concerns could exist if the piping designers are not aware of the conditions under which high stress can be induced by the clamp. The applicant/licensee should be aware that post-installation control of the clamp preload may be necessary when the clamp stiffness is required to assure total piping system restraint.

Information Notice	Date Issued	Subject
83-81	12/7/83	ENTRY INTO HIGH RADIATION AREAS FROM AREAS WHICH ARE NOT UNDER DIRECT SURVEILLANCE All licensees authorized to use portable radiography devices in radiography programs were notified of a potentially significant problem pertaining to entry into high radiation areas from outside the area under direct surveillance. The notice discussed an event that occurred during radiographic examination of welds on a pipeline in Alaska. Unknown and undetected by the radiography crew was a welder who had entered the pipe on a crawler, about 300 ft from the radiographic operation, to perform repairs from within the pipeline. It was suggested that radiography crews be aware that high radiation areas are not always within vision. While access to these areas may normally be considered unlikely, it remains the licensee's responsibility to control access when radiographic operations are in progress.
83-82	12/20/83	FAILURE OF SAFETY/RELIEF VALVES TO OPEN AT BWR - FINAL REPORT All nuclear power reactor facilities holding an operating license or construction permit were provided this final supplement and update to Information Notices 82-41 (Power Reactor Events, Vol. 4, No. 6, April 1983, p. 41) and 83-39 (Vol. 5, No. 3, December 1983, pp. 23-24). An update is provided on meetings, testing results, conclusions and courses for future action involving the Target Rock two-stage safety/relief valves.
83-83	12/19/83	USE OF PORTABLE RADIO TRANSMITTERS INSIDE NUCLEAR POWER PLANTS All nuclear power reactor facilities holding an operating license or construction permit were apprised of instances at various places in which portable radio transmitters caused system malfunctions and spurious actuations. This radio frequency interference (RFI) is caused by solid state devices. As newer plants are built that use more solid state equipment, and as older plants retrofit solid state equipment, more cases of RFI by portable radio transmitters are likely to result. If plant operations make the use of portable transmitters near RFI-sensitive equipment either necessary or likely in an emergency, then administrative prohibitions are not adequate and the licensee should consider hardware fixes. Typical fixes include filters, shielded cables, and modification of affected equipment.

Information Notice	Date Issued	Subject
83-84	12/30/83	CRACKED AND BROKEN PISTON RODS IN BROWN BOVERI ELECTRIC TYPE 5HK BREAKERS All holders of a nuclear power reactor operating license or construction permit were notified of a potentially significant problem pertaining to Brown Boveri Electric (BBE) type 5HK 250/350, 1200/2000 ampere circuit breakers. The problem involves defects or failure of the puffer piston connecting rods, which are needed for low current interruptions to assist magnetic forces to move the arc into the interrupting chamber of the breaker, and to provide a pneumatic cushion which reduces the shock forces imposed on the mechanism and current-carrying parts upon opening. The manufacturer indicated that, although no breaker failed because of a broken puffer piston rod, the breaker's capability to interrupt at low current may be impaired. BBE recommends inspecting for cracked or broken rods at normal maintenance intervals and replacing the piston assembly if this condition is found. An attachment to the notice contained a list provided by BBE of 5HK circuit breakers that they have supplied for use in Class IE applications at nuclear power plants, and which may be affected.

2.3 Case Studies and Engineering Evaluations Issued in November - December 1983

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.

Special Study*	Date Issued	Subject
P301	7/83	REPORT ON THE IMPLICATIONS OF THE ATWS EVENTS AT THE SALEM NUCLEAR POWER PLANT ON THE NRC PROGRAM FOR COLLECTION AND ANALYSIS OF OPERATIONAL EXPERIENCE

On February 25, 1983, Salem Unit 1, a Westinghouse designed nuclear power plant, experienced a total failure of the reactor trip system (RTS) to automatically shut down the reactor upon receipt of a valid signal from the reactor protection system (RPS). A similar event had occurred at Salem Unit 1 on February 22, 1983. The failures were caused by two electro-mechanical circuit breakers (reactor trip breakers (RTBs)), which failed to open in response to the automatic trip signal from the RPS because the associated undervoltage (UV) trip attachment did not actuate the trip mechanisms. The breakers subsequently opened when the operators actuated

*No case studies were issued during the period. However, special study P301 issued by AEOD in July 1983, and inadvertently omitted as an abstract in the issue of Power Reactor Events that covered the July-August 1983 period, is being included in this issue.

Special Study*	Date Issued	Subject
P301 (Continued)		them via the manual scram switch. The proper functioning of the automatic feature of the RTS including the RTBs is of prime importance to the protection of public health and safety; its failure results in total reliance on operator actions to control plant transients.

On March 1983, AEOD initiated a special study to review and evaluate the implications of these anticipated transient without scram (ATWS) events at Salem on the NRC's program for collecting and analyzing operational experience. The study focused on the adequacy of NRC's reporting requirements as they relate to RTB failures, including the licensees' understanding of the requirements and the impact of proposed revisions to the requirements; and whether trends and patterns analyses of the reported RTB failures could have identified a significant potential for the problem at Salem Unit 1 before it occurred. Additional topics reviewed were the requirements for licensees to analyze operating experience with a specific focus on the ability to reconstruct the sequence of events.

Some of the conclusions drawn from the study are described below.

- The Salem ATWS events emphasize that operational data assessment requires clear and in-depth licensee reports on failure history.
- Operational event analysis and feedback by each licensee, the industry, and the NRC is essential for the safe operation of nuclear power plants.
- Such aspects as what information is to be recorded following the course of a serious event; scanning and recording rates; quantity of data recorded and retention period, and the requirements for equipment availability, reliability, and qualification; need to be specifically addressed.
- Planned trends and patterns analyses, coupled with close scrutiny of failure data and detailed engineering assessment particularly of those features related to reliability, should aid in the identification of specific plant and/or generic safety problems and the need for corrective actions.
- Even though the events at Salem involved no plant damage, no releases, and no immediate threat to public health and safety, the fact that the NRC

Special Study*	Date Issued	Subject
P301 (Continued)		and the industry have devoted extensive resources to studying its cause and implications is a strong indication of the heightened sensitivity to operational events and the progress made in understanding the lessons of operational experience.

Engineering Evaluation	Date Issued	Subject
E325	11/21/83	VAPOR BINDING OF AUXILIARY FEEDWATER PUMPS H. B. Robinson, Unit 2 has experienced four failures of auxiliary feedwater (AFW) pumps due to low discharge pressure trips caused by steam formation in the AFW piping and pump casings (vapor binding). The steam was formed when hot water from the feedwater system leaked through two check valves and a motor-operated valve in the piping to either motor- or steam-driven AFW pumps. The safety implication of the events at Robinson is that the leakage of main feedwater to the AFW system constitutes a common cause failure that can render both trains of the AFW system inoperable, although only single trains have been adversely affected to date. Similar events have also occurred at D. C. Cook, Unit 2. The potential for the loss of AFW system due to back-leakage appears generic because the designs of the systems at Robinson and Cook are typical of other PWRs; i.e., isolation between the steam conversion system and the AFW system is accomplished by check valves and motor-operated valves. AEOD has initiated a case study to better define the generic implications and establish the bases for revising the technical specifications to ensure that the AFW temperature is monitored and/or that the inservice inspection programs test the isolation capability of the check valves.
E326	11/28/83	STEAM VOIDING IN OCONEE UNIT 3 ON JUNE 13, 1975 - A PRECURSOR EVENT TO THE TMI-2 ACCIDENT On June 13, 1975 Oconee, Unit 3 experienced a reactor trip and an overcooling transient. Post-trip analyses focused on the effect that the excessive cooldown rate had upon the fuel, the violation of the plant's technical specifications and the violation of the reactor coolant pump net positive suction head requirements. Although the licensee noted anomalous plant behavior during the transient (rising pressurizer level which led operators to secure high-pressure injection and to reopen the block valve 15 seconds after closing it, the reason for the

Engineering Evaluation	Date Issued	Subject
E326 (continued)		rising pressurizer level did not appear to have been investigated by either the licensee, the nuclear steam system supplier (Babcock & Wilcox-B&W), or the NRC. It appears that primary system voiding contributed to the increase in pressurizer level, but none of the post-trip analyses recognized it at the time. Had an extensive review of this event been made and the operators at other B&W plants been made aware of the details of this event, including primary system voiding and pressurizer level increases accompanying a stuck open power-operated relief valve, it is possible that subsequent depressurization events at B&W plants (TMI-2 accident in particular) might have taken different courses. This engineering evaluation stressed the need for rigorous post mortem analysis of anomalous events and for effective dissemination of operating data throughout the nuclear community.
E327	11/28/83	GASEOUS RELEASES FROM WASTE GAS DISPOSAL SYSTEM This engineering evaluation was performed to evaluate the potential for releases of gases from the waste gas disposal system of PWRs. A search of licensee event reports was performed to evaluate the causes for such events and to determine if the events had any generic or safety implications. As a result of a review of this operating experience, it was found that the greatest potential for significant releases results from the possibility of hydrogen explosion in the waste gas decay tank. In at least one instance, an internal ignition of a hydrogen-air mixture in the tank occurred. The waste gas disposal system at most plants is not designed to sustain a hydrogen explosion. The evaluation suggested that proposed technical specification requirements should be placed on operating plants to limit the concentration of hydrogen or oxygen in the waste gas holdup system to less than or equal to 4% by volume.

2.4 Generic Letters Issued in November-December 1983

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 September and October 1983, three 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
83-32	12/2/83	NRC STAFF RECOMMENDATIONS REGARDING OPERATOR A. IONS FOR REACTOR TRIP AND ATWS All power reactor licensees and applicants for operating licenses were provided an enclosed "Staff Position on Operator Actions for Reactor Trip and ATWS." Operator action to immediately back up all automatic trips with a manual trip based solely on receipt of "positive indicatio of an "automatic trip demand" without evaluating the automatic trip system's success is believed by the NRC staff to be conservative and, therefore, the preferred method. (This operator action is not currently required by the NRC.) Facility procedures should identify the instruments that provide the "positive indication" of an "automatic trip demand."
83-35	11/2/83	CLARIFICATION OF TMI ACTION PLAN ITEM II.K.3.31 All licensees of operating reactors, applicants for operating licenses, and holders of construction permits were provided clarification of NUREG-0737, Item II.K.3.31, which requires all licensees to submit plant-specific small-break loss-of-coolant accident (SBLOCA) analyses using evaluation models revised per II.K.3.30, which requires that each licensee revise its current emergency core cooling system (ECCS) SBLOCA models. Unless a revise

*Generic Letter 83-34 has not yet been issued; Generic Letters 83-33 and 83-38 were abstracted in Power Reactor Events Vol. 5, No. 5, covering documents issued during September-October 1983.

Generic Letter	Date Issued	Subject
83-35 (continued)		model shows a previously approved model to be nonconservative, however, the previously approved models would remain in compliance with Appendix K to 10 CFR 50, as would the ECCS analyses performed with the previous model. The requirements of II.K.3.31 can be satisfied by each licensee submitting a plant-specific analysis that demonstrates that current SBLOCA analyses using previously approved evaluation models are more limiting than analyses using the previously revised (II.K.3.30) models.
83-36	11/1/83	NUREG-0737 TECHNICAL SPECIFICATIONS All boiling water reactor licensees were provided guidance in meeting the requirements of NUREG-0737, "Clarification of TMI Action Plan Requirements," which identifies items for which technical specifications are required. The guidance provided in Generic Letter 83-02 covered NUREG-0737 items scheduled for implementation by 12/31/81. (See also Power Reactor Events, Vol. 5, No. 1, p. 34.) A number of NUREG-0737 items which require technical specifications were scheduled for implementation after 12/31/81. Each of those items was presented in either Enclosure 1 or Enclosure 2 of this letter. Enclosure 3 contained samples in standard technical specification formats with blanks or parentheses appearing where the information is plant specific. Licensees were requested to review their facility's technical specifications to determine consistency with the guidance provided in Enclosure 1. It was recommended that licensees respond within 90 days of receipt of this letter.
83-37	11/1/83	NUREG-0737 TECHNICAL SPECIFICATIONS All pressurized water reactor licensees were provided guidance on the same subject discussed in Generic Letter 83-36 above, and were referred to Generic Letter 82-16 for guidance on NUREG-0737 items scheduled for implementation by 12/31/81. Licensees were requested to review their facility's technical specifications to determine consistency with the guidance provided in Enclosure 1. It was recommended that licensees submit technical specifications for reactor coolant systems within 30 days of receipt of this letter, and within 90 days for the remaining items discussed in Enclosure 1.

Generic Letter	Date Issued	Subject
83-39	12/8/83	VOLUNTARY SURVEY OF LICENSED OPERATORS Representatives of various utilities on an attached list were informed that the NRC has contracted with Battelle Pacific Northwest Laboratories to undertake a mailed survey of selected licensed operations personnel at commercial operating nuclear power plants. The purpose of this voluntary survey is to provide information that will be useful in understanding current work and staffing practices in nuclear power plant operations. Survey results will be presented in aggregate form to prevent the identification of individual respondents and specific utilities or plants.
83-40	12/21/83	OPERATOR LICENSING EXAMINATION All power reactor licensees and applicants for an operating license were referred to Generic Letter 83-01 (Power Reactor Events), Vol. 5, No. 1, p. 34), which requested information to form the basis for scheduling manpower and resources to licensed operators and senior operators through 1985. Recipients were requested in Generic Letter 83-40 to provide updated information and information through 1987; i.e., a best estimate of the need for operator licensing examinations for the remainder of FY 1984 as well as for FYs 1985 through 1987. Responses were requested by 1/16/84 to Mr. Don Beckham, AR-5221, Washington, DC 20555, or at (301) 492-4868.
83-41	12/16/83	FAST COLD STARTS OF DIESEL GENERATORS Widespread concern has been expressed by the nuclear industry that fast cold start surveillance testing of diesel generators may result in premature diesel engine degradation In order to determine whether the number of fast cold starts should be reduced, the NRC requested that all licensees of operating reactors voluntarily participat in providing information about the extent and effects of this practice. Responses to questions contained in this letter were requested by 1/6/84. The results of this and other efforts will be factored into the NRC's diesel generator reliability program.
83-42	12/19/83	CLARIFICATION TO GENERIC LETTER 81-07 REGARDING RESPONSE TO NUREG-0612, "CONTROL OF HEAVY LOADS AT NUCLEAR POWER PLANTS" On 12/22/80, the NRC issued Generic Letter 81-07, which requested that licensees implement certain interim actions and provide information to the NRC related to heavy loads at their facilities, in regard to NUREG-0612.

Generic Letter	Date Issued	Subject
83-42 (continued)		As indicated in NUREG-0612, one means for complying with the criteria of Section 5.1 is to demonstrate that no single failure in the heavy loads handling equipment will result in dropping of a load, as discussed in Section 5.1.6. One acceptable means of complying with the guidance of Section 5.1 was to meet the guidelines of NUREG-0554, "Single Failure Proof Cranes." However, in the course of reviewing crane designs against NUREG-0554, the NRC has identified concerns of a generic nature which indicate that NUREG-0554, until revised, may be deficient in assuring single failure proof cranes. The concerns relate specifically to assuring that a single failure in the electric power/control system will not cause a load drop. The purpose of this letter was to provide information concerning this potential problem related to single failure proof cranes to all holders of operating licenses, applicants for operating licenses, and holders of construction permits for power reactors.
83-43	12/19/83	REPORTING REQUIREMENTS OF 10 CFR PART 50, SECTIONS 50.72 AND 50.73, AND STANDARD TECHNICAL SPECIFICATIONS All licensees and applicants for operating power reactors, and holders of construction permits for power reactors were informed that Section 50.72 of Title 10 of the Code of Federal Regulations has been revised and became effective 1/1/84. A new Section 50.73 has been added and also became effective 1/1/84. Section 50.72 revises the immediate notification requirements for operating nuclear power reactors. The new Section 50.73 provides for a revised Licensee Event Report System. Copies of each of these sections to 10 CFR Part 50 were enclosed in this letter. Since paragraph (g) of Section 50.73 specifically states that: "the requirements contained in this section replace all existing requirements for licensees to report 'Reportable Occurrences', as defined in individual plant Technical Specifications," the reporting requirements incorporated into the "Administrative Controls" section of a facility's technical specifications may require modification. Also, the definition "Reportable Occurrence" may need to be replaced by a new term, "Reportable Event." The NRC will make these changes in the current version of Standard Technical Specifications (STS) for all nuclear power reactor vendors and in the technical specifications for plants not yet licensed. Because this change to the technical

Generic Letter	Date Issued	Subject
83-43 (continued)		specifications is clarifying and made at the request of the Commission, recipients of this letter were not required to remit a license fee for the change.
83-44	12/20/83	AVAILABILITY OF NUREG-1021, "OPERATOR LICENSING EXAMINER STANDARDS" This letter provided an explanation to all power reactor licensees and applicants for operating licenses of NUREG-1021, which had been forwarded separately to the recipients. The standards in NUREG-1021 provide direction to NRC examiners and establish procedures and practices for examining and licensing applicants for NRC operator licenses pursuant to Part 50 of Title 10. Comments on the standards are welcomed, and will be considered in the next revision. Comments should be directed to Mr. Don Beckham, AR-5221, Washington, DC 20555, or at (301) 492-4868

2.5 Operating Reactor Event Memoranda Issued in November-December 1983

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 November-December 1983.

2.6 Regulatory and Technical Reports (NUREG-0304) Issued in November-December 1983

The abstracts listed below have been selected from the Office of Administration's quarterly publication, Regulatory and Technical Reports (NUREG-0304). This document compiles abstracts of the formal regulatory and technical reports issued by the NRC staff and its contractors. Bibliographic data for the reports are also included. Copies and subscriptions of NUREG-0304 are available from the NRC/GPO Sales Program, PHIL-016, Washington, DC 20555 or on (301) 492-9530.

Report	Title
NUREG-0020 Vol. 7, No. 8 November 1983; Vol. 7, No. 9 November 1983; Vol. 7, No. 10 December 1983	LICENSED OPERATING REACTORS STATUS SUMMARY REPORT (No. 8 - Data as of 7/31/83; No. 9 - Data as of 8/31/83; No. 10 - Data as of 9/30/83) This report provides data on the operation of nuclear units as timely and accurately as possible. The information is collected by the office of Resource Management from the Headquarters staff of NRC's Office of Inspection and Enforcement, from NRC's Regional Offices, and from utilities. The three sections of the report are: monthly highlights and statistics for commercial operating units, and errata from previously reported data; a compilation of detailed information on each unit, provided by NRC's Regional Offices, IE Headquarters and the utilities; and an appendix for miscellaneous information such as spent fuel storage capability, reactor-years of experience and non-power reactors in the U.S. It is hoped the report is helpful to all agencies and individuals interested in maintaining an awareness of the U.S. energy situation as a whole.
NUREG-0304 Vol. 8, No. 3 November 1983	REGULATORY AND TECHNICAL REPORTS This compilation lists all NRC regulatory and technical reports published under the NUREG series during the third quarter of 1983.
NUREG-0485 Vol. 5, No. 10 December 1983	SYSTEMATIC EVALUATION PROGRAM STATUS SUMMARY REPORT (Data as of 10/31/83) The Systematic Evaluation Program is intended to examine many safety-related aspects of 11 of the older light water reactors. This document provides the existing status of the review process including individual topic and overall completion status.
NUREG-0540 Vol. 5, No. 9 December 1983 Vol. 5, No. 10 December 1983	TITLE LIST OF DOCUMENTS MADE PUBLICLY AVAILABLE (No. 9 - Data as of 9/30/83; No. 10 - Data as of 10/31/83) This document is a monthly publication containing 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

Report	Title
	radioactive materials, and (2) nondocketed material received and generated by NRC pertinent to its role as a regulatory agency. The following indexes are included: Personal Author Index, Corporate Source Index, Report Number Index, and Cross Reference to Principal Documents Index.
NUREG-0606 Vol. 5, No. 4 November 1983	UNRESOLVED SAFETY ISSUES SUMMARY (Data as of 11/18/83) This report provides an overview of the status of the progress and plans for resolution of the generic tasks addressing Unresolved Safety Issues, as reported to Congress.
NUREG-0713 Vol. 4 December 1983	OCCUPATIONAL RADIATION EXPOSURE AT COMMERCIAL NUCLEAR POWER REACTORS (Annual Report for 1982) This report summarizes the occupational radiation exposure information that has been reported to the NRC by commercial nuclear power reactors during tbe years 1969 through 1982. The bulk of the data presented in the report was obtained from annual radiation exposure reports submitted in accordance with the requirements of 10 CFR 20.407 and license technical specifications. Data on workers terminating their employment at nuclear power facilities was obtained from reports submitted pursuant to 10 CFR 20.408. The annual reports submitted by the 75 nuclear power plants that had completed at least one full year of operation as of 12/31/82 indicated that the number of personnel monitored during 1982 was 129,275 persons and the annual collective dose incurred by these individuals was 52,190 man-rems. The average annual dose for each worker that received a measurable dose was 0.6 rems, and the average collective dose per reactor was 705 man-rems. The termination reports revealed that some 65,700 individuals completed their employment with one or more reactor facilities during 1981 (the most recent year for which all of the termination data are available for analysis). Approximately 5,300 cf these workers could be considered transients and they received an average dose of about one rem.
NUREG-0871 Vol. 2, No. 4 December 1983	SUMMARY INFORMATION REPORT (data as of 9/30/83) This report provides summary data concerning NRC and its licensees for general use by the Chairman, other Commissioners and Commission staff offices, the Executive Director for Operations, and the Office Directors.
NUREG-0933 December 1983	A PRIORITIZATION OF GENERIC SAFETY ISSUES The report presents the priority rankings for generic safety issues related to nuclear power plants. The

Report	Title
	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 safety priority rankings are HIGH, MEDIUM, LOW and DROP and have been assigned on the basis of risk significance estimates, the ratio of risk to costs and other impacts implemented, and the consideration of uncertainties and other quantitative or qualitative factors. To the extent practical, estimates are quantitative.
NUREG-0936 Vol. 2, No. 3 November 1983	NRC REGULATORY AGENDA (Data for 6/83 - 9/83) The NRC Regulatory Agenda is a compilation of all rules on which the NRC has proposed or is considering action and all petitions for rulemaking which have been received by the Commission and are pending disposition by the Commission. The Regulatory Agenda is updated and issued each quarter. The Agendas for April and October are published in their entirety in the Federal Register while a notice of availability is published in the Federal Register for the January and July Agendas.
NUREG-0940 Vol. 2, No. 3 November 1983	ENFORCEMENT ACTIONS: SIGNIFICANT ACTIONS RESOLVED (Data for 7/83 - 9/83) This compilation summarizes significant enforcement actions that have been resolved during one quarterly period and includes copies of letters, notices and orders sent by the NRC to the licensee with respect to the enforcement action and the licensee's response. It is anticipated that the information in this publication will be widely disseminated to managers and employees engaged in activities licensed by the NRC, in the interest of promoting public health and safety as well as common defense and security.
NUREG-0957 December 1983	THE PRICE-ANDERSON ACT - THE THIRD DECADE Subsection 170p. of the Atomic Energy Act of 1954, as amended, requires that the Commission submit to the Congress by 8/1/83 a detailed report on the need for continuation or modification of Section 170 of the Act, the Price-Anderson provisions. The report is divided into four sections with detailed subject reports appended to the main report. Sections I through III include an examination of issues that the Commission was required by statute to study (i.e., condition of the nuclear industry, state of knowledge of nuclear safety, and availability of private insurance), and discussion of other issues of interest and importance to the Congress and to the public. The subjects covered are as follows: (1) overview of the Price-Anderson system; (2) the state of knowledge of

Report Title

nuclear safety; (3) availability of private insurance; (4) condition of the nuclear industry; (5) causality and proof of damages; (6) limitation of liability and subsidy; and (7) a proposal that would provide for removal of the limitation of liability but with limited annual liability payments. Section IV of the report contains conclusions and recommendations. Section V contains a bibliography.

NUREG-0981
November 1983

NRC/FEMA OPERATIONAL RESPONSE PROCEDURES FOR RESPONSE TO A COMMERCIAL NUCLEAR REACTOR ACCIDENT

Procedures have been developed by the NRC and the Federal Emergency Management Agency (FEMA) which provide the response teams of both agencies with the steps to be taken in responding to an emergency at a commercial nuclear power plant. The emphasis of these procedures is mainly on the interface between NRC and FEMA at their respective Headquarters and Regional Offices and at the various sites at which such an emergency could occur. Detailed procedures are presented that cover, for both agencies, notification schemes and manner of activation, organizations at Headquarters and the site, interface procedures, coordination of onsite and offsite operations, the role of the Senior FEMA Official, and the cooperative efforts of each agency's public information staff.

NUREG-0995
December 1983

SAFETY EVALUATION REPORT RELATED TO PLANT RESTART OF SALEM NUCLEAR GENERATING STATION, UNITS 1 and 2

On February 22 and 25, 1983, the Salem Unit 1 reactor control rods failed to insert upon receipt of an automatic trip signal from the reactor protection system. Upon receipt of a manually initiated signal, however, the rods did insert and shut down the plant. These events were of major safety concern because the automatic reactor trip capability was not available; therefore, the plant safety was jeopardized when plant operating conditions required a fast shutdown to protect the integrity of the reactor core. Safe control of certain anticipated operating transients depends on the reliable and fast operation of a reactor trip, either automatically or manually.

Evaluation of these events and the circumstances leading up to them revealed a number of issues that require resolution by the licensee and/or the NRC. This safety evaluation report briefly describes the NRC and licensee actions to address and resolve equipment; operator procedures, training and response, and management issues identified by the NRC evaluation of the two events at Salem Unit 1. Actions for Salem as identified in this report fall in two groups: (1) actions that were required

Report	Title
	to be satisfactorily resolved before plant startup; and (2) actions that could be completed after restart but which were required to complement the pre-startup items implemented on Unit 2 prior to its restart.
NUREG-1024 November 1983	TECHNICAL SPECIFICATIONS - ENHANCING THE SAFETY IMPACT This report documents the work of an interoffice, interdisciplinary, NRC Task Group established in 8/83. The Task Group was established to identify the scope and nature of problems with surveillance testing in current technical specifications and to develop alternative approaches that will provide better assurance that surveillance testing does not adversely impact safety. The Task Group concluded that some of the technical specifications have the potential for adversely affecting safety and some do not appear to be cost effective. The Task Group developed five recommendations for improvement.
NUREG/CR-2000 Vol. 2, No. 10 November 1983; Vol. 2, No. 11 December 1983	LICENSEE EVENT REPORT (LER) COMPILATION (No. 10 - Data for 10/83; No. 11 - Data for 11/83) This monthly report contains Licensee Event Report (LER) operational information that was processed into the LER data file of the Nuclear Safety Information Center during the one month period identified on the cover of this document. The LERs, from which the information is derived, are submitted to the NRC by nuclear power plant licensees in accordance with Federal regulations. Procedures for LER reporting are described in detail in NRC Regulatory Guide 1.16 and NUREG-1022, Licensee Event Report System. The LER summaries in this report are arranged alphabetically by facility name and then chronologically by event date for each facility. Component, system keywords, and component vendor indexes follow the summaries. The components systems, and vendors are those identified by the utility when the LER form is initiated; the keywords are assigned by the computer using correlation tables from the Sequence Coding and Search System.

Report	Title
NUREG/CR-2987 December 1983	IDENTIFICATION AND ANALYSIS OF HUMAN ERRORS UNDERLYING ELECTRICAL/ELECTRONIC COMPONENT RELATED EVENTS REPORTED BY NUCLEAR POWER PLANT LICENSEES This report provides a useful and adaptable data base of over 700 human error events associated with the operation, testing, maintenance of instrumentation, control and in-plant electrical power components in licensed nuclear power plants. More than 8000 Licensee Event Report (LER) abstracts were retrieved from the Department of Energy (DOE)/RECON Data Base, Nuclear Safety Information Center File for certain specific safety-related systems. The data developed in this report were obtained by the application of a practical and workable human error identification methodology. The resulting human error data base is several times larger than would have been available based solely on licensee identification of human error. This data base is intended to provide a realistic assessment of the real human error populations obtainable from the LERs. As a result, this data will provide a synthesis with the NUREG/CR-3416 methodology (for a systematic evaluation of the number of opportunities for these types of errors), thus permitting the generation of human error rates from nuclear power plant date and operational experience. A note of caution is in order to minimize the improper use of the findings of this report. The purpose of this report is to identify human errors, not to obtain human error rates.
NUREG/CR-3049 November 1983	CLOSEOUT OF IE BULLETIN 79-15: DEEP DRAFT PUMP DEFICIENCIES In 1978 serious manufacturing deficiencies in deep draft pumps were found in one facility. Similar deficiencies, as well design deficiencies, were identified at about the same time in three other facilities which required pump rework and design changes, followed by extensive operational testing. These occurrences raised questions concerning this type of pump in safety-related applications where there was insufficient pre-operational testing or operating experience to assure long term operability. IE Bulletin 79-15 was issued to alert all facilities to the potential problem, to acquire information to determine the extent of the problem, and to request corrective action in facilities where the problem was found. Review of utility response to the bulletin by NRC resulted in adding the evaluation of long term operability of deep draft pumps in safety-related applications to the normal licensing process for plants under construction. The operating plants where response information is judged not adequate to assure long term reliability are listed by Regions in Appendix C

Report	Title
	together with proposed followup testing to satisfactorily assure long term operability and close out the Bulletin. There are nine of these plants out of a total of 74 operating units. Bulletin status remains open for one other facility where followup of response commitments, but no pump testing for assuring long term operability, is proposed.
NUREG/CR-3430 Vol. 1 December 1983	NUCLEAR POWER PLANT OPERATING EXPERIENCE (1981 Annual Report) This report is the eighth in a series of reports issued annually that summarizes the operating experience of nuclear power plants in commercial operation in the United States. Power generation statistics, plant outages, reportable occurrences, fuel element performance, and occupational radiation exposure for each plant are presented and discussed, and summary highlights are given. The report includes 1981 data from 71 plants - 24 boiling water reactor plants, 46 pressurized water reactor plants, and one high-temperature gas-cooled reactor plant.
NUREG/CR-3458 November 1983	AN EVALUATION OF THE NUCLEAR POWER PLANT OPERATOR LICENSING EXAMINATION This report contains findings and conclusions about the Nuclear Regulatory Commission's nuclear power plant operator licensing examination based on six months of field work in late 1981 and early 1982. This report includes chapters which describe and evaluate the examination systems as they existed at the time of the field work. There are also discussions of the concepts of validity and reliability as they relate to the control room operator examination, operator performance measures, and performance-shaping factors. The last half of the report focuses on what could and should be done to the operator licensing system. The report argues that any new examination must be based on task analysis and should incorporate methods for measuring an operator's problem-solving ability in ill-defined situations. It is argued that the NRC needs to clarify whether their licensing examination is to be a test of minimal competence or a master test, whether the examination system is to serve the selection function, and whether separate licensing tests are needed for reactor operators and senior reactor operators. The last chapter details a model of a new licensing process. Features of the process include validated selection procedures, a computerized basic knowledge examination, an apprenticeship period with documentation of performance, and a computerized, tailored test to assess problem-solving ability and system understanding.

Report	Title
NUREG/CR-3540 December 1983	RADIOLOGICAL ASSESSMENT OF STEAM GENERATOR REPAIR AND REPLACEMENT Previous analyses of the radiological impact of removing and replacing corroded steam generators have been updated based on experience at Surry Units 1 and 2 and Turkey Points Units 3 and 4. The sleeving repairs of degraded tubes at San Onofre Unit 1, Point Beach Unit 2, and R.E. Ginna are also analyzed. Actual occupational doses incurred during application of the various technologies used in repairs have been included, along with radioactive waste quantities and constituents. Considerable progress has been made in improving radiation protection and reducing worker dose by the development of remotely controlled equipment and the implementation of dose reduction strategies that have been successful in previous repair operations.
NUREG/CR-3568 December 1983	A HANDBOOK FOR VALUE-IMPACT ASSESSMENT This handbook documents a set of uniform and acceptable procedures for providing information that can be used in performing value-impact assessments of NRC regulatory actions. It describes a systematic but flexible process for performing the assessment. Chapter 1 introduces the value-impact assessment process. Chapter 2 describes the attributes most frequently affected by proposed NRC actions, provides guidance concerning the appropriate level of effort to be devoted to the assessment, suggests a standard format for documenting the assessment, and discusses the treatment of uncertainty. Chapter 3 details methods for evaluating each attribute affected by a regulatory action. Five appendices contain background information, technical data, and example applications of the value-impact assessment procedures. This edition of the handbook focuses primarily on assessing nuclear power reactor safety issues.

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