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POWER REACTOR EVENTS

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Power Reactor Events is a bi-monthly newsletter that compiles operating experience information about commercial nuclear power plants. This includes summaries of noteworthy events and listings and/or abstracts of USNRC and other documents that discuss safety-related or possible generic issues. It is intended to feed back some of the lessons learned from operational experience to the various plant personnel, i.e., managers, licensed reactor operators, training coordinators, and support personnel. Referenced documents are available from the USNRC Public Document Room at 1717 H Street, Washington, DC 20555 for a copying fee. Subscriptions and additional or back issues of Power Reactor Events may be requested from the NRC/GPO Sales Program, (301) 492-9530, or at Mail Stop P-130A, Washington, DC 20555.

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

Period Covered: May-June 1984

1.0 SUMMARIES OF EVENTS

1.1 Inoperable Containment Spray System

On March 17, 1984, the licensee for San Onofre Unit 3* discovered that the containment spray pump manual discharge isolation valves were locked shut, thus rendering both independent containment spray systems inoperable. It was found that the condition had existed for about 13 days, during which the plant had operated at power levels up to full power. The NRC's concerns are that the event resulted in a significant degradation of the facility's engineered safety features, and that inadequate management controls contributed substantially as an underlying cause.

The containment heat removal system (CHRS) at San Onofre Unit 3 is an engineered safety features system designed to remove heat from the containment atmosphere in the event of a loss-of-coolant accident (LOCA) or main steam line break inside containment. Removal of heat reduces the containment pressure and temperature, which reduces the potential for leakage of airborne activity from containment. The CHRS includes the containment spray system (CSS) and the containment emergency fan cooler system. The CSS also contains a chemical additive (sodium hydroxide) which would reduce the concentration of radioactive iodine in the containment atmosphere in the event of a postulated accident.

On March 17, 1984, with the unit operating at approximately 100% power, manual isolation valves MU012 and MU014 were observed by a plant operator to be in the closed position. These valves are on the discharge side of the containment spray pumps and are located outside of containment. With both valves closed, both trains of the CSS were inoperable for automatic actuation. Investigation revealed the following details associated with the event.

On February 17, 1984, the unit entered hot shutdown from cold shutdown. Procedure S023-3.2.9, "Containment Spray/Iodine Removal System Operation," Checklist 5.1 was performed to align the CSS in preparation for hot standby operation. Valves MU012 and MU014 were verified to be in the locked open position. On February 28, preparations were being made to return to cold shutdown in order to repair a high pressure safety injection (HPSI) valve. Valves MU012 and MU014 were closed in accordance with procedures in order to return to shutdown cooling operation. On March 2, following repair of the HPSI valve, preparations were being made to return to hot standby. The Control Room Supervisor developed a partial valve alignment checklist from Checklist 5.1 of Procedure S023-3.2.9 to realign the CSS. Since the outage did not involve work on the CSS and the entire Checklist 5.1 had been performed four days earlier on February 28, the plant personnel agreed that a complete alignment checklist was unnecessary. CSS valves MU012 and MU014 were erroneously omitted from the partial checklist.

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*San Onofre Unit 3 is a 1080 MWe (net) PWR located 5 miles south of San Clemente, California, and is operated by Southern California Edison.

There was a second opportunity on March 2, 1984 in which the licensee could have detected the valving error but did not, when a containment spray pump was operated to flush the spray header and the operator failed to verify flow from the flow-rate-meter in the control room.

At 9:55 a.m. on March 4, 1984, the unit entered hot standby with both trains of the CSS inoperable in violation of the technical specifications. The plant operated in hot standby, startup, and power operation in this manner until the condition was corrected at 2:00 p.m. on March 17, a period of about 13 days. During this period, another violation occurred which further degraded the CHRS. From about 4:20 a.m. on March 15, 1984, to about 5:35 p.m. on March 16, one of the two diesel generators was removed from service (placed in maintenance lockout); thus, the emergency power source (had there been a total loss of offsite power) for the associated train of the containment emergency fan cooler system was inoperable. This violation occurred since the licensee was unaware that the CSS was inoperable at the time.

In addition, substantial degradation of the capability of the systems to mitigate the consequences of a postulated LOCA existed. During the 13-day period, automatic actuation of the CSS would not have been possible. However, there are indications in the control room which could inform the Reactor Operators that spray injection is not taking place. Upon recognizing the situation, manual actuation of the CSS could have been made.

The apparent underlying causes of the event were: (1) inadequate review and approval of changes made to a previously established valve alignment check list, and (2) the existence of an administrative procedure (S023-0-35), promulgated by management, which allowed such changes to be made without adequate review and approval.

At San Onofre, administrative procedures provide authorization for a Senior Reactor Operator (SRO) Supervisor to designate only a portion of a checklist for use when circumstances warrant. This authorization was included to avoid, for example, errors resulting from development of special purpose checklists when conducting retests following correction of component failures within surveillance procedures. Other objectives of this provision included ALARA (as low as reasonably achievable) exposure considerations, where complete system alignment checklists included vents and drains in high radiation areas which were not affected by a particular evolution, and secondary plant equipment alignments which usually involved only a portion of any one system checklist. It was not made clear that this authorization was not intended for use in establishing a partial checklist of main process valves when performing a system evolution such as leaving shutdown cooling alignment and establishing CSS operability. In this case, the authorization was used to, in effect, revise the procedure intended to establish CSS operability contrary to the intent.

The Control Room Supervisor (an SRO) did not recognize that the containment spray pump manual discharge isolation valves were closed when entering the shutdown cooling alignment. Therefore, in designating the subset of CSS valves to be repositioned and verified upon leaving the shutdown cooling alignment, valves MU012 and MU014 were omitted and remained closed until identified on March 17. No piping and instrumentation diagram was provided to explicitly show the valve alignment for shutdown cooling. Also, no partial checklist was provided for the subset of CSS valves required to be repositioned when leaving shutdown cooling. Accordingly, there was no effective procedural means to ensure MU012 and MU014 would be opened, short of performing again the entire CSS valve alignment checklist. As described in the sequence of events above, since the entire checklist had been performed on February 28, 1984, the Control Room Supervisor and the Shift Superintendent considered that it did not need to be performed again.

To prevent recurrence, the licensee has revised written procedures to ensure the proper alignment of valves prior to entering a mode of operation for which the system is required to be operable. Steps have also been taken by the licensee to ensure more effective control over the preparation of and changes to operating procedures. The licensee's training program is being revised to provide additional emphasis on operator recognition of proper system alignments during various plant evolutions. The NRC will monitor the corrective actions taken by the licensee.

During the past several years, there have been several events at various nuclear power plants involving degradation of containment spray systems. On May 25, 1984, the NRC issued Inspection and Enforcement Information Notice 84-39, "Inadvertent Isolation of Containment Spray Systems," to all facilities holding an operating license or construction permit. (See p. 58.) This may help to reduce the frequency of these types of events by heightening the industry's awareness of the potential for such events and the circumstances associated with their occurrence. (Refs. 1 and 2.)

1.2 Held Open Check Valve on Residual Heat Removal System

On October 28, 1983, with the plant in cold shutdown, personnel at Hatch Unit 2* discovered during valve operability testing that isolation check valve 2EII-F050B on the residual heat removal (RHR) system B train was open and could not be closed. The testable valve was found being held open by its air actuator because its air supply lines were connected backwards. A subsequent investigation by plant personnel revealed that the check valve had been open since June 7, 1983. During this 4-month period, the plant had operated at close to full power.

Isolation valve 2EII-F050B is a swing-type testable check valve manufactured by the Rockwell International Company. It has an air actuator controlled by a four-way solenoid pilot valve manufactured by the Automatic Switch Company (ASCO). The air actuator for check valve 2EII-F050B is of the rotary type. The valve, its actuator, and the solenoid valve are situated on the 24-inch low pressure coolant injection (LPCI) line inside the primary containment structure. The valve provides the first of two isolation boundaries between the high pressure reactor coolant system (RCS) and the low pressure RHR system. Downstream of the check valve, and located immediately outside containment, is a normally closed motor-operated injection gate valve. The outboard valve

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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.

opens automatically on an accident (high drywell pressure or low reactor water level) signal, and when pressure in the RCS falls below the low pressure permissive setpoint. The injection valve is the second and last isolation boundary between the RCS and the RHR system piping.

The air actuator for isolation check valve 2EII-F050B is used by the licensee to perform inservice testing of the valve during cold shutdown. (It can also be used for this during power operation.) Prior to a test opening via the air actuator, the bypass valve on the 1-inch line around the check valve is opened to equalize the pressure on both sides of the disc of the 24-inch check valve. When the remote test push button is depressed, power is supplied to the solenoid pilot valve causing the pilot valve to shift. This in turn causes the actuator rod to rotate from its neutral position. When the actuator rod reaches its 150° position, it engages the check valve disc via a disc pin. Further rotation of the actuator rod lifts the disc from the valve seat. The actuator rod will rotate another 30° to its 180° position, where it will stop. The limit switch on the actuator gives an indication of actuator travel (the full 180° from neutral) via a light on the control panel in the control room. A proximity switch tripped by a ferrous cam connected to the valve disc gives an indication of disc position (open) via another light on a control panel in the control room. The isolation check valve is a safety-related component, while its air actuator and the pilot solenoid valve are not classified as safety-related.

On June 7, 1983, at the end of a maintenance activity to repair an air leak on the check valve air actuator, the two air supply lines to the actuator were reconnected. However, the supply line which should have been connected to the right-hand cylinder of the actuator was incorrectly connected to the left-hand cylinder, and vice versa. This error was primarily attributed to the failure of the maintenance personnel to obtain and use the check valve maintenance manual during the repair work. The two air supply lines should have been arranged to physically cross each other on their way from the solenoid valve to the actuator cylinders. Instead, they were routed to go straight to the actuator. The installation error caused the check valve actuator (rod) to move to the 180° position when air supply pressure was restored to the deenergized solenoid pilot valve. This action opened the check valve.

Even though post-maintenance testing was recognized by the licensee as a requirement for returning safety-related valves to service, the error was not discovered by such testing. (It is not known whether post-maintenance testing had been conducted at all.) This requirement is stated in ASME Section XI, IWV-3000. In the ensuing 4 months, during which the reactor was operating at substantial power levels, the open check valve went undetected by plant operating personnel even though valve position and actuator travel indications were available in the control room. It is not known for certain if the valve position indicators were also reversed so that the valve misposition was not evident.

The immediate corrective action taken by the licensee following the discovery of the maintenance error was to correctly reconnect the air supply lines to the check valve air actuator. This placed the valve in its normal closed position. A subsequent licensee action was to counsel the involved plant personnel on the importance of performing equipment maintenance correctly.

Specifically, plant personnel were reminded of the need to perform maintenance according to the valve maintenance manual and to perform thorough post-maintenance testing before returning a valve to service. For the long term, the licensee is considering deactivating the air actuator and adopting an alternative testing method for the LPCI isolation check valves. This alternative test method, which is in accordance with ASME Section XI, IWV-3520, allows inservice testing of the isolation check valves to be performed by passing shutdown cooling flow through the valve during each cold shutdown more than three months apart.

This event is significant because the open isolation check valve reduced safety margins for preventing an interfacing loss-of-coolant accident (interfacing LOCA) involving the RCS and the RHR systems during the 4-month period that the valve was open. The isolation check valve on the 24-inch RHR injection line provides the first barrier to protect the low pressure RHR system from an interfacing LOCA from the RCS. The second isolation device on the 24-inch LPCI injection line is the normally closed motor-operated outboard gate valve. This gate (injection) valve is designed to open on an LPCI signal (i.e., low-low-low vessel water level, or the combination of high containment pressure and low vessel pressure) when pressure in the RCS drops to the low pressure permissive setpoint. The valve is also provided with independent diverse interlocks to prevent the gate valve from opening at full differential (reactor) pressure across the disc. When the testable check valve is open, a postulated failure or inadvertent opening of the motor-operated valve could allow discharge of high-pressure reactor coolant into low-pressure systems. The consequences of such an event are not certain. The flow rate through the motor-operated valve could vary from a small amount of leakage to a massive discharge. If the flow force were moderate, it could close the check valve despite the actuator. This would effectively terminate the event. If, however, the forces were large, the movable internal portions of the check valve could be severely damaged. A substantial failure of the low-pressure system, if it were to occur, would lead to a LOCA that bypasses the containment and could flood the low-pressure emergency core cooling system pumps. This would be an accident exceeding current design basis, with radioactive material discharged outside the primary containment.

As discussed above, this event was traced to a series of human errors. During maintenance on the valve actuator, the two air supply lines were installed backwards. The air supply line to the right-hand cylinder of the actuator was incorrectly connected to the left-hand cylinder, and vice versa. Failure to use a vendor maintenance manual appears to have contributed to this error. Inadequate post-maintenance functional testing of the valve allowed the initial error to go undetected. The check valve position is indicated in the control room. It is not known with certainty why this did not lead to early detection. However, it appears likely that, after maintenance, the indication was readjusted to show a closed position in the belief that the check valve must actually have been closed.

A Hatch plant maintenance worker was counseled by utility management on the importance of performing correct maintenance and the importance of using maintenance manuals and performing thorough post-maintenance testing before returning components to service, particularly for components that are safety-related. For the longer term, the licensee is considering alternative methods of testing the check valve using shutdown cooling flow. This could allow permanently deactivating the actuator without interfering with check valve operability or position indication.

A number of other instances have recently been noted where actuators were found holding testable check valves open in boiling water reactors. Specific mechanisms include reversal of air lines (as discussed above), reversal of spool pieces in solenoid valves, mistiming of gear trains, rusty actuators, and tight packing. Systems involved include RHR, high pressure coolant injection, and core spray. In some cases, the motor-operated valves were also inadvertently opened, causing actual overpressurization of the low pressure system. (Refs. 3 through 7; see also p. 69.)

1.3 Reactor Trip on High Reactor Coolant Pressure Following Loss of Non-nuclear Instrumentation

On April 26, 1984, while Crystal River Unit 3* was operating at 97% reactor power, the Y non-nuclear instrumentation (NNI-Y) power supply failed, causing erroneous signals to be sent to the integrated control system (ICS). The ICS rapidly reduced main feedwater flow to the B steam generator, causing an undercooling transient. The reactor tripped on high reactor coolant system pressure. The main steam atmospheric dump valves (ADVs) and main steam safety valves (MSSVs) subsequently opened. One ADV and several MSSVs failed to reseat following the reactor trip. Due to existing small steam generator tube leakage, a minor radioactive release occurred when the ADVs and MSSVs opened. The MSSVs did not reseat until steam generator pressure was reduced slightly. The ADV was manually isolated. The NNI-Y failure was due to a shorted high frequency filter capacitor in the 120 V ac input to the +24 V dc power supply (Lambda Electronics Corporation Model LM-E24). The failed capacitor, which had been installed by the manufacturer, was found to have incorrect voltage and capacitance ratings.

Although the NNI-Y failure caused erroneous indications and prevented the automatic control of some non-safety related systems, no engineered safety feature other than the reactor protection system was challenged or manually initiated. Plant operators were able to identify the erroneous indications and control the plant by using the redundant set of instrumentation (powered from the NNI-X power supply) for vital plant parameters. It should be noted that the consequences of this event were substantially mitigated in comparison to a similar event that occurred at Unit 3 in February 1980, in which power was lost to NNI-X. The licensee attributes the improvement to the corrective actions taken at that time, which included installation of the redundant instrumentation panel and operator training in this type of transient.

Other systems affected by the loss of NNI-Y included the condensate system, the plant computer, and the annunciator alarms. Significant erroneous indications on the plant computer and annunciator alarms were detected by use of redundant instrumentation powered from NNI-X. The condensate pumps were controlled manually to balance flows in the secondary system.

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*Crystal River Unit 3 is an 821 MWe (net) PWR located 7 miles northwest of Crystal River, Florida, and is operated by Florida Power.

Slightly lowered steam generator pressure (990 psig versus 1010 psig) and visual observation of valve tailpipes revealed that several MSSVs and an ADV had failed to fully reseat. The ADV was isolated by an upstream valve, while the MSSVs were fully reseated by lowering main steam pressure to 900 psig.

Corrective actions included replacement of the failed capacitor with one having correct ratings, verification that the -24 V dc NNI-Y power supply capacitor and the spare NNI-X power supply capacitors had correct ratings, repair of the failed ADV, and adjustment of the setpoint of the MSSVs that failed to reseat. Redundant 24 V dc power supplies were installed in NNI-Y to prevent a similar transient from occurring as a result of a single 24 V dc power supply failure. The capacitors for the installed redundant NNI-X power supplies, which are of slightly different design than for NNI-Y, will be inspected during the next long outage (presently scheduled for spring 1985). After completion of this action, both NNI-X and NNI-Y will have redundant power supplies. (Ref. 8.)

1.4 Natural Circulation in Pressurized Water Reactors

Operating events involving natural circulation cooling in pressurized water reactors (PWRs) occur frequently and involve gravity induced thermal-hydraulic phenomena in maintaining reliable core cooling. Operating experience shows that the unavailability of reactor coolant pumps (RCPs), which normally provide forced circulation in the reactor coolant system (RCS), results primarily from loss-of-offsite power events and from operator actions to trip the RCPs as required by procedures.* As a result, natural circulation events occur at a rate of about 0.15 per PWR reactor year.

Because of the frequency of recurring events involving natural circulation, a study was initiated by the NRC's Office for Analysis and Evaluation of Operational Data to evaluate and compare PWR responses during natural circulation. (Ref. 9.) The primary purposes of the study were to determine (1) whether the various PWR designs responded in a similar manner, (2) whether the thermal-hydraulic responses of PWRs were behaving in an expected manner in comparison to analytical predictions, and (3) whether natural circulation criteria could be developed that would apply to all operating PWRs such that operators could determine that satisfactory natural circulation has been established during an event and communicate this information to the NRC in unambiguous terms. The basic approach was to collect and compare actual plant data obtained during natural circulation events occurring between 1980-1982 and apply existing analytical techniques to calculate the natural circulation responses of operating PWRs having different nuclear steam supply systems.

Natural circulation of the RCS is the normal and preferred method for removing decay heat after a reactor trip when the RCPs are not available, and until the decay heat removal system can be placed in operation. Natural circulation cooling was the subject of indepth analyses and evaluation by the NRC and licensees after the accident at Three Mile Island Unit 2 in 1979. The

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*In 1983, the NRC eliminated specific requirements for tripping the RCPs. Currently, the criteria for RCP trip following a transient is determined by the licensees on a case-by-case basis.

conditions necessary to establish natural circulation cooling have long been understood, i.e., decay heat source, heat sink, elevation difference between source and sink, and adequate inventory.

However, it is also important to understand that many plant variables and opertor actions can affect the response of plant systems during natural circulation (e.g., secondary pressure control, time of reactor pump trip, safety injection). For example, natural circulation events usually involve unexpected plant anomalies which can affect the trend of the thermal-hydraulic parameters used by the operators to infer that natural circulation is established and effective. Operator actions taken during some natural circulation events show that operators do not always have a good understanding of the thermal-hydraulic response. This can lead to confusion and unnecessary operator actions.

Natural circulation flow rates are generally too low to be within the measurement range of RCS loop flow instruments; therefore, operators must infer that natural circulation flow is established based on other thermal-hydraulic parameters. Incore or hot leg temperatures, in combination with other parameters, are generally used by the operators to ascertain whether natural circulation flow is established and decay heat is being removed from the RCS.

Generic emergency operating guidelines which incorporate plant anomalies have been developed by the PWR owners groups by providing guidance to the operator to ensure the effectiveness of natural circulation using a symptoms oriented approach, i.e., maintain heat sink and subcooling margin. Each plant's emergency procedures incorporate the owners group guidelines and use criteria, which may vary from plant to plant, based on the parameters available in the plant to infer that natural circulation has been established and is effective. As a result, there is no identical set of specific criteria to judge natural circulation behavior. This is not to say that the guidance provided to the operators is inadequate, but is to point out that there are differences in the guidelines that address the same phenomena in plants which have similar natural circulation responses. Some of these differences may be unnecesary.

A review of the operational data base for the years 1980-1982 identified 25 events involving natural circulation. Of these, 12 events were selected for further evaluation based on the sequence of events and the availability of plant data to reconstruct the trend of the thermal-hydraulic parameters during the event. Analyses of the 12 events revealed that the natural circulation flow phenomena and thermal-hydraulic trends of Westinghouse (W), Babcock & Wilcox (B&W), and Combustion Engineering (CE) designed nuclear power plants were similar when various conditions affecting the response of the RCS were considered. For discussion purposes, eight of the events were chosen to compare representative PWR responses involving a variety of conditions, e.g., safety injection, sequential RCP trips, excessive cooldowns, and steam pressure control methods. These eight events are listed in Table 1.

Table 1. Natural circulation events

Plant/Vendor	Date	Event	Relevant Conditions
Arkansas Nuclear One-Unit 2/CE	4/80	Loss of offsite power	Mainsteam isolation valves closed; safety valves opened; auxiliary spray used to control RCS pressure
St. Lucie-Unit 1/CE	6/80	Loss of cooling water to RCPs	Steam formation in upper head; Secondary pressure controlled by atmospheric relief valves and steam dumps
Arkansas Nuclear One-Unit 2/CE	6/80	Loss of offsite power	Atmospheric relief valves used to control secondary steam pressure
Arkansas Nuclear One-Unit 1/B&W	4/80	Loss of offsite power	Safety injection manually initiated; safety valves opened; atmospheric relief valves used to control steam pressure
Arkansas Nuclear One-Unit 1/B&W	6/80	Loss of offsite power	No safety injection
Yankee Rowe/W	9/81	Loss of offsite power	Excessive cooldown due to steam dumps fully opened
McGuire Unit 1/W	11/81	Loss of cooling water to RCPs	Sequential RCP trips
Prairie Island-Unit 1/W	10/79	Steam generator tube rupture	One steam generator isolated; safety injection, PORV opened

A comparison of the natural circulation response of CE-designed plants is shown in Figure 1. The two events at Arkansas Unit 2 were initiated by loss-of-offsite power caused by tornadoes or lightning. The St. Lucie Unit 1* event did not involve the loss of electrical power, but resulted from the manual tripping of the RCPs due to a loss of component cooling water to the pumps. The St. Lucie event is particularly significant as it relates to natural circulation since (1) the operator restarted an RCP because of his concern that natural circulation had not been established based on increasing hot leg temperature (five minutes after reactor trip), and (2) a steam bubble formed in the upper head of the reactor vessel because of a rapid depressurization of the RCS during natural circulation.

In Figure 1, the differences between the responses of the Arkansas Unit 1 and St. Lucie plants are related to the causes of the events and how steam pressure is controlled. On loss-of-offsite power, the main condenser is not available and the steam pressure is controlled by the relief valves at a higher pressure than when the steam dump system is available (St. Lucie). The hot leg temperature differences between the two Arkansas events are due to operator actions to reduce the steam pressure by opening the atmospheric relief valves shortly after reactor trip during the April event. As a result, the duration of the transitional phase after RCP coastdown is reduced. After natural circulation is established, the hot leg temperature is relatively constant or decreasing, which is characteristic of fully developed natural circulation flow.

Figure 2 shows the natural circulation responses at three W-designed plants. This comparison shows the responses of the RCS due to different initiating events for different RCS designs, i.e., different number of RCS loops.

The responses of W and CE plants were generally comparable, largely because of similarities between the RCS and steam generator designs. Also, there was no significant difference in the responses of W plants which have a different number of reactor coolant loops (McGuire Unit 1 and Yankee-Rowe have four loops, and Prairie Island Unit 1 has two loops).** The comparison of the temperature differences between the hot and cold coolant loops in Figure 2 shows that this parameter responds in the same manner for different Westinghouse designs, even with extenuating conditions during the transition to fully establish natural circulation flow. Note that the remaining RCP was tripped at 4 minutes and 9 minutes after the reactor trips at Yankee-Rowe and McGuire, respectively.

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*Arkansas Unit 2 is an 858 MWe (net) PWR located 6 miles northwest of Russellville, Arkansas, and is operated by Arkansas Power and Light.

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.

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

Yankee-Rowe is a 167 MWe (net) PWR located 25 miles northeast of Pittsfield, Massachusetts, and is operated by Yankee Atomic Electric.

Prairie Island Unit 1 is a 503 MWe (net) PWR located 28 miles southeast of Minneapolis, Minnesota, and is operated by Northern States Power.

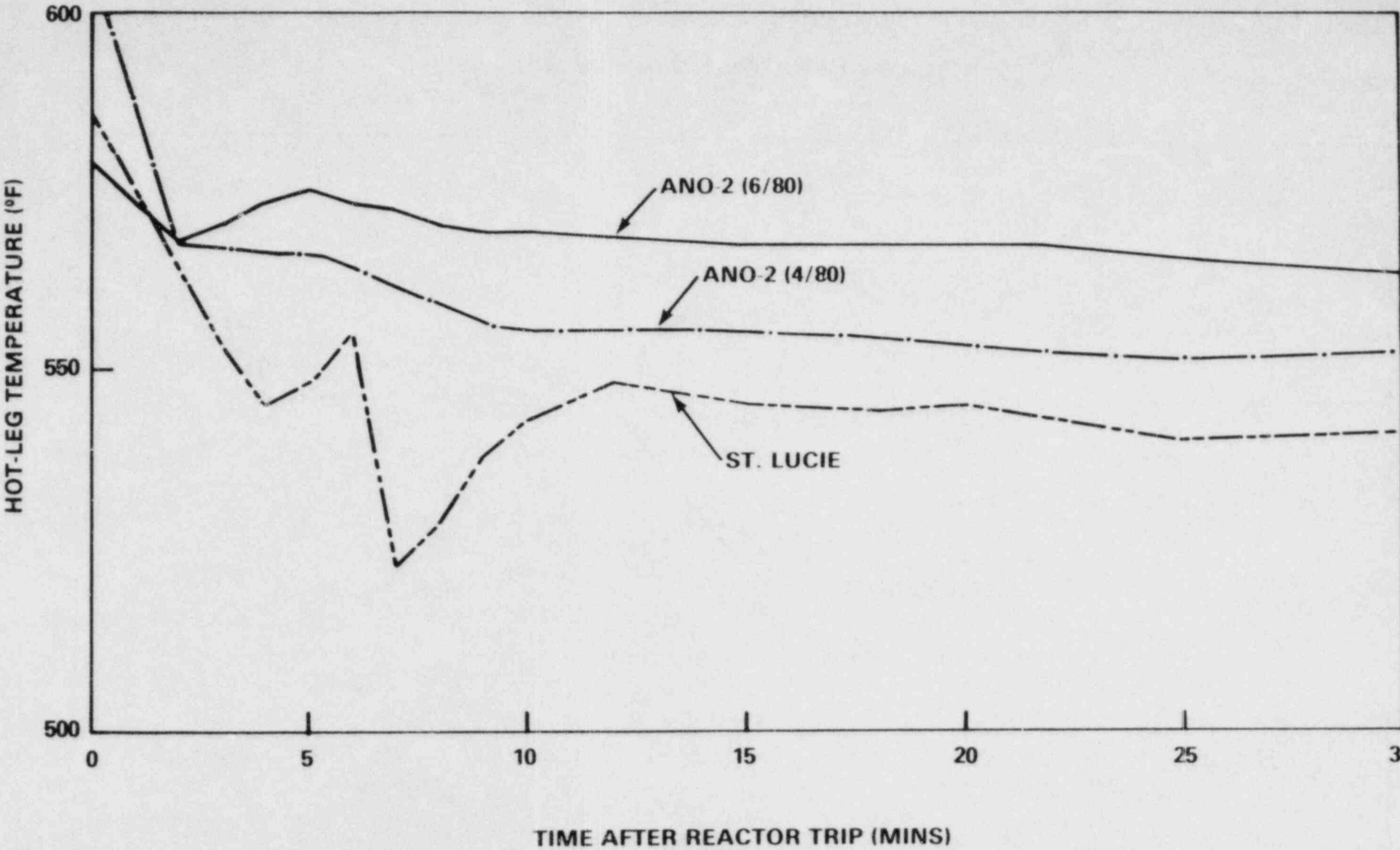

FIGURE 1 NATURAL CIRCULATION RESPONSE OF CE-DESIGNED PLANTS — HOT-LEG TEMPERATURE

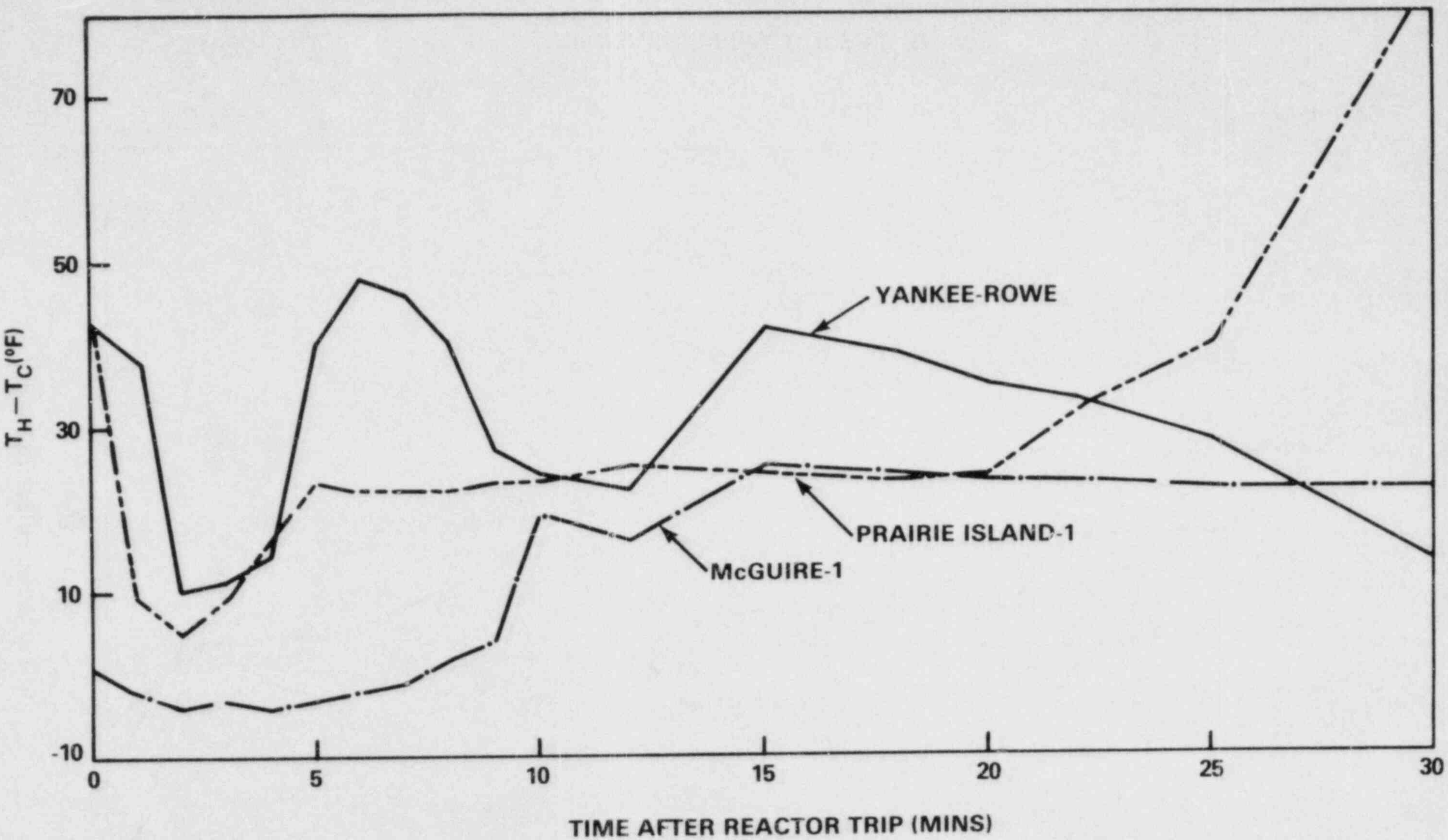

FIGURE 2 NATURAL CIRCULATION RESPONSE OF W-DESIGNED PLANTS — LOOP DIFFERENTIAL TEMPERATURE

The hot leg temperature responses of a B&W-designed plant following the loss-of-offsite power are shown in Figure 3. The small effects of safety injection on natural circulation can be seen in comparing the temperature responses during the two events at Arkansas Unit 1. The event in April 1980 involved the manual initiation of the high pressure injection system immediately following reactor trip and during coastdown of the RCPs. The primary effect was to reduce the magnitude of the reactor coolant temperature and to reduce the natural circulation flow rate by reducing the loop differential temperature.

Figures 4 and 5 show the temperature responses of the three PWR designs (B&W, W, CE) during natural circulation cooling. In general, the trends of the parameters during the transition to establish natural circulation flow are the same when the conditions affecting the parameters discussed previously are considered. These comparisons show that design of the nuclear steam supply system is not a major factor affecting single phase natural circulation cooling, but that the conditions affecting the thermal-hydraulic response (e.g., steam pressure control) are more important in understanding the response of PWRs during natural circulation.

The trends of reactor coolant temperatures are one of many indications that can be used as criteria for operators to confirm that natural circulation is established and effective. The data for these events show that within about 7 minutes after forced flow was lost, both the hot leg temperature and the loop differential temperature peaked, and were relatively constant or decreasing during effective natural circulation. The hot leg temperature was always below the saturation temperature for the existing RCS pressure. These criteria can be applied to all PWR designs. It is important to note that neither of these parameters is sufficient by itself, but that they can be used together or in combination with other relevant parameters, to confirm that natural circulation is effective. (Ref. 9; see also p. 68.)

1.5 Inadvertent Draining of the Pressurizer During Preparations for Plant Startup

On June 12, 1984 at 9:23 p.m., while in preparation for plant startup (cold shutdown conditions) after a 10-week refueling outage, the licensee for Maine Yankee discovered the pressurizer had been inadvertently drained. This event appears to be due to operators failing to react and follow through on anomalous pressure level indications, compounded by a leaking level transmitter. The event is discussed in detail below.

At approximately 4:00 p.m. on June 12, 1984, the licensee was making preparations to vent reactor coolant pump (RCP) seals. The pressurizer was cold, and the level was drained to about 55%, as indicated on the cold calibrated level instrument. At 7:35 p.m., the Reactor Operator noticed pressurizer level was slowly increasing. He brought this to the attention of the Shift Operating Supervisor. The Shift Supervisor was then called to the control board to witness the increase of 1% or 2% level. The Reactor Operator was walking down the board with the Shift Supervisor, pointing out refueling water storage tank level and volume control tank level and discussing how these indications had

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*Maine Yankee is an 810 MWe (net) PWR located 10 miles northeast of Bath, Maine, and is operated by Maine Yankee Atomic Power.

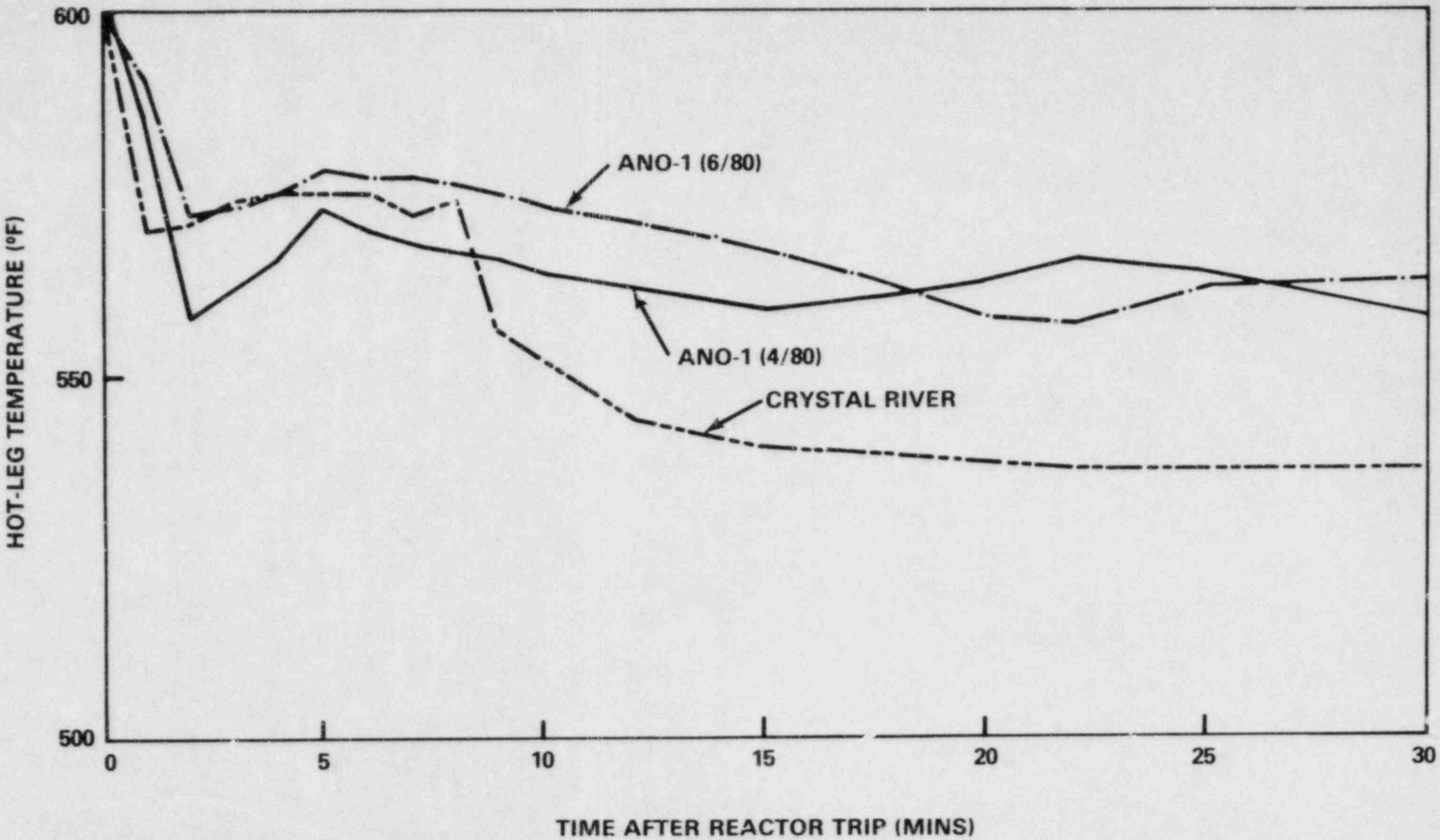

FIGURE 3 NATURAL CIRCULATION RESPONSE OF B&W-DESIGNED PLANTS — HOT LEG TEMPERATURE

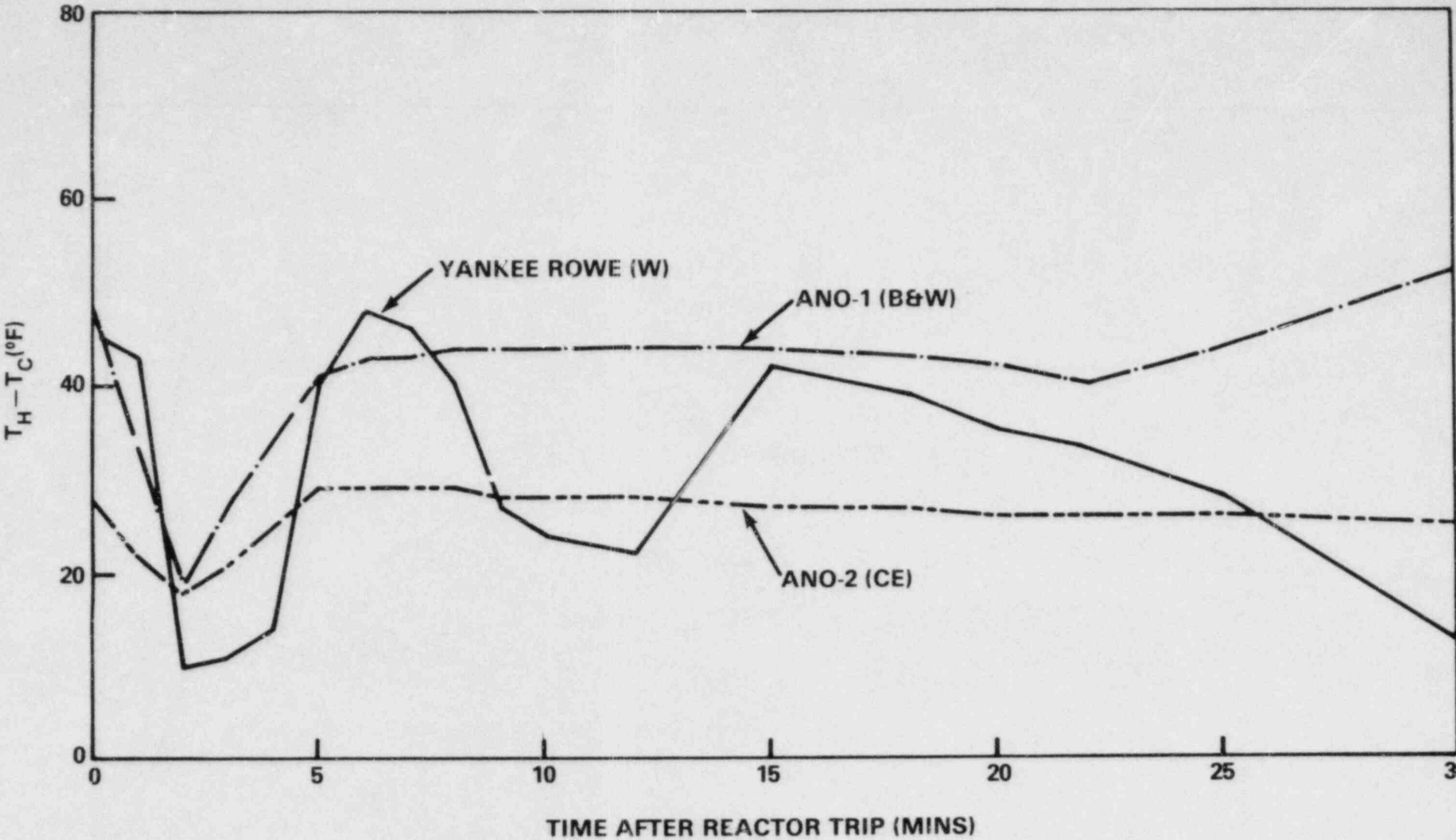

FIGURE 4 VENDOR COMPARISON OF NATURAL CIRCULATION RESPONSE – LOOP DIFFERENTIAL TEMPERATURE

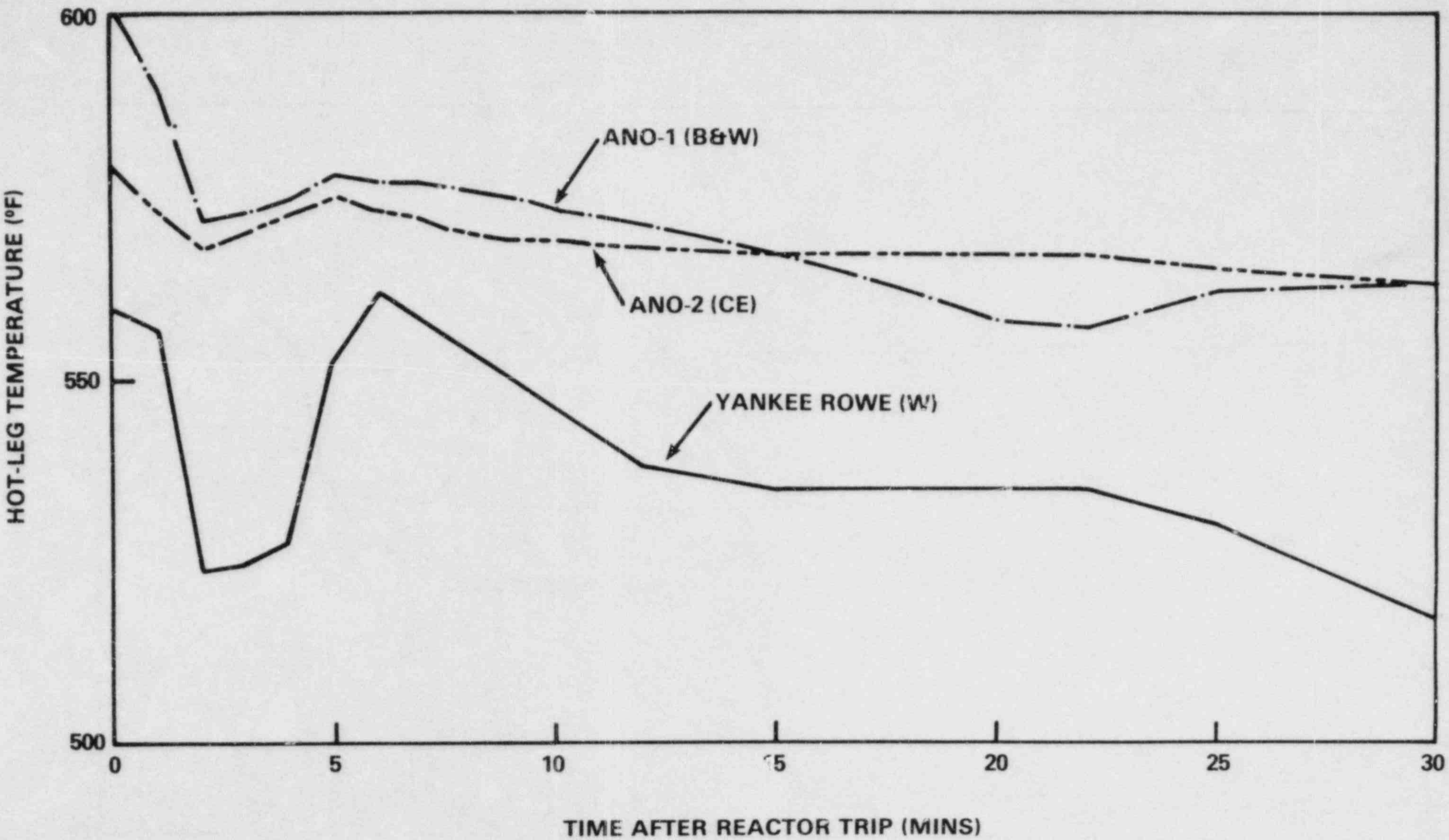

FIGURE 5 VENDOR COMPARISON OF NATURAL CIRCULATION RESPONSE – HOT LEG TEMPERATURE

changed over the shift. When they next looked at pressurizer level as indicated on the cold calibrated level instrument, it was 100%. The Shift Supervisor ordered venting of the RCP seals stopped, and charging and letdown secured. The Shift Supervisor then contacted the Instrument and Control (I&C) Foreman to discuss the pressurizer level indication problem. The I&C Foreman indicated that level transmitter LT 3002, one of the three pressurizer level transmitters associated with the plant inventory system, was being calibrated, and that he would investigate the possibility that this calibration was affecting the cold calibrated pressurizer level indication.

The plant inventory trend system has three level transmitters associated with it. Two transmitters (LT 3002 and LT 3003) are narrow range transmitters which measure level in the reactor vessel only. LT 3001 is a wide range transmitter which measures total water level over the combined range of the reactor vessel and pressurizer. LT 3001 uses a reference leg that is shared by two other pressurizer level instruments, LT 106 and wide range cold calibrated level LT 103.

On the evening shift, between 4:00 and 12:00 p.m., I&C technicians calibrated LT 3002. Upon successful completion of the calibration, LT 3002 was placed in service. The I&C Foreman directed that LT 3002 be removed from service since a portion of the piping was not installed (tubing to the reactor head was not in place). The I&C technician removed LT 3001 and LT 3002 from service and checked the calibration on LT 3002 to ensure the calibration had not suffered from valving the transmitter into a partially open system. When he reported to the I&C Foreman, he was directed to valve in LT 3001, which had been in service at the start of the shift. When LT 3001 was valved in, pressurizer level was observed to increase from 60% to 100%.

At the time, it was felt that placing LT 3001 in service had caused the common reference leg for LTs 103, 106, and 3001 to drain. Recognizing that the draining of the reference leg had caused the abrupt level increase in pressurizer level as indicated on the cold calibrated instrument (LT 103), shift personnel made arrangements to refill the reference leg using a dead weight tester (a hand pump used during calibration of level transmitters). Two other channels of hot calibrated wide range level were available on the main control board; however, both channels were reading zero. This indication was not considered abnormal since these narrow range level transmitters are calibrated for hot conditions.

As the technicians pumped the reference leg full, the I&C Foreman and control room operators were monitoring level on LT 103 and LT 3001. LT 103 (cold calibrated level) continued to decrease as the reference leg was filled until it reached zero. This was the point at which it was recognized that the pressurizer was empty (9:23 p.m.). The technician then attempted to vent the variable leg of the level transmitter to determine if any water was present, which would have indicated some level was present in the pressurizer. No water was vented, only pressurized air. Thus, the pressurizer was drained.

Total (vessel and pressurizer) level indicator LT 3001 settled at a level of 42%. This represented a level of 11 feet 10 inches in the reactor vessel. (The top of the core is 7 feet 9 inches.) This level did not correspond to the other indications on the main control board. At the time, the residual heat removal (RHR) system was in operation. The RHR suction is from the hot leg of loop 2. The loops have a centerline elevation of 13 feet 3 inches. The RHR pump should have cavitated if the actual level was below the loop. However, RHR flow and temperatures were constant throughout the event, and the pump casing had no accumulation of gasses when vented. This would indicate that the actual level was at least greater than the loops' centerline elevation.

While discussing what course of action to follow, the operators noted that pressurizer level had increased to 9% cold calibrated level. This indicated that the reference leg was still draining, causing indicated level to increase. The Shift Supervisor directed a Senior Operator to investigate possible sources of leakage from the reference leg. At 11:10 p.m., a leak was found on level transmitter LT 106. LT 106 was isolated, and the reference leg was refilled using the hand pump.

At 11:55 p.m., a low pressure safety injection pump was used to add water from the refueling water storage tank to the reactor coolant system. At 12:20 a.m. on June 13, pressurizer level was restored to 35%. A calibration check was performed on LT 103, and a discrepancy was noted between LT 103 and LT 3001 which corresponded to a level difference of 8 to 9 feet This discrepancy was later discovered to be an error in the assumed zero level used to convert actual level from percent level. Based on the discovery of this error, the lowest level observed on LT 3001 was recomputed to be 20 feet. This corresponds to the flange area of the vessel.

The vessel head was vented beginning at 2:35 a.m. on June 13. Pressurizer level was allowed to decrease from an initial level of 32% to 20% during venting operations. The venting was terminated at that point, and level was restored to 35%. The vessel head was again vented and pressurizer level decreased to 29% when water was finally observed at the vent. Based on 112 gallons per percent level, this corresponds to about 2000 gallons of water used to refill the reactor vessel head area. A total of 10,000 gallons of water was used to refill the system (loops and pressurizer) to the normal operating level.

The operators were directed to maintain pressurizer level above 30%. Over the next several days, the pressurizer was taken solid and a steam bubble was drawn as part of normal plant startup activities following refueling.

Two factors appear to have contributed significantly to this event. The first was the method used to fill the coolant loops prior to unisolating them. No form of venting was used during loop fills because of a concern that venting the loops causes a downward force on the coolant pump seals that is opposite to the normal thrust exerted on them. The licensee believed this could contribute to early seal failure. Because the reactor coolant system had residual pockets of air, the operators expected the level in the pressurizer to decrease when vented, and were not alarmed when the level decreased to 8% indicated level.

The second factor that led to this event was the low pressurizer level that preceded the event. Pressurizer level was increased on June 12 to about 20%. Pressure was increased using compressed air until a pressure of 100 psig was attained. Nitrogen was then used to increase pressure to 150 psig. Some problems were experienced with this pressurization (pressure in the quench tank increased, indicating some source of inleakage). The 150 psig pressure was maintained until 4:00 p.m. on June 12. During this pressurization, pressurizer level was allowed to shrink to 8% as indicated on the cold calibrated instrument. It is probable that this low level combined with the nitrogen used to pressurize the plant could have resulted in an air bubble in the vessel head on the morning of June 12. Subsequent filling of the pressurizer and indicated level increases caused by leaking level transmitters masked the fact that an air bubble was in the vessel head. Operators did not question the difference between cold calibrated level indication and hot calibrated level indication, because it was known that these indications would be different. In fact, the hot calibrated level indication should have read higher than cold level indication. During the 12 hours prior to the recognition of this event, the hot calibrated level indicator read zero in the pressurizer. Guidance to the operators was not sufficient to prevent allowing plant parameters to remain at that low level.

This event remains under investigation by the licensee. (Refs. 10 and 11.)

1.6 Loss of Vital Electrical Buses During Refueling

On June 5, 1984, with the reactor defueled, Salem Unit 1* lost offsite power due to an undervoltage condition on two of three vital buses. At the time, vital bus 1B was out of service for maintenance. When the normal infeed breaker to vital bus 1A was opened, no automatic switch to the alternate infeed occurred because the automatic transfer relay had been removed for use in Unit 2. With both vital buses 1A and 1B deenergized, the blackout relays actuated and automatically started diesel generators (DGs) 1A and 1C, and tripped open the normal offsite infeed breaker for vital bus 1C. The DG 1A loaded its vital bus, but DG 1C did not because the 1C battery was deenergized for maintenance, and safeguards equipment cabinet (SEC) 1C was completely deenergized. Vital bus 1C remained deenergized, resulting in a total loss of service water cooling. Numerous control room indicators failed to mid-scale, leading operators to believe that vital bus 1C was still energized. As a result, the diesels ran for about 2 hours without cooling water. Because DG 1A operated with some load on it for about 1 hour, it overheated and actuated the cardox fire protection system. At this point the operators realized that the DGs had no cooling water, and tripped them.

The root cause of this event was the lack of adequate procedural and/or administrative controls to ensure sufficient electrical systems remained in an operable status. The event started with the removal of vital bus automatic transfer relay 1A. Shift personnel did not fully understand the operation of the relay, and the effect on the plant due to its removal. They believed that it functioned only during an automatic transfer of a vital bus, and that its removal would not effect a manual transfer.

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*Salem Unit 1 is a 1079 MWe (net) PWR and Unit 2 is a 1106 MWe (net) PWR. They are located in New Jersey, 20 miles south of Wilmington, Delaware, and are operated by Public Service Electric and Gas.

In addition, 125 V dc bus 1C and vital bus 1B were out of service at the same time. With the deenergization of vital bus 1A, the resultant blackout loading signal deenergized vital bus 1C in preparation for diesel generator 1C loading. With 125 V dc bus 1C out of service, a complete loss of power to SEC 1C prevented the diesel generator 1C output breaker from closing.

The failure of control room indication to mid-scale led operators to believe that vital bus 1C was energized. A "diesel trouble" alarm, which alarmed on high diesel lube oil temperature, was apparently masked by the large number of alarms which occurred as the result of loss of power.

Had Unit 1 been in a configuration where the systems were governed by technical specifications (i.e., with the core loaded), this sequence of events would not have occurred. With the core loaded, the requirements for operable vital buses and the systems available to supply core cooling (residual heat removal, component cooling water, and service water), sufficient equipment would have been available to prevent the operation of the diesel generators without service water. Administrative controls would have prevented having the automatic transfer relay for vital bus 1A removed, vital bus 1B cleared and tagged for inspection, and 125 V dc bus 1C out of service. Any one of these buses could have been inoperable, but not all three.

Corrective actions included partial disassembly of DG 1A and replacement of all lower bearings, on the vendor's recommendation. Also, a review of the management control of equipment for plant conditions not covered by technical specification requirements will be conducted by the licensee. The review will specifically address electrical systems, and vital equipment requirements during cold shutdown and defueled conditions, to ensure that sufficient equipment remains available to maintain the plant in a safe condition. (Refs. 12 and 13.)

1.7 Overcooling Transient

In October 1983, Calvert Cliffs Unit 2* experienced an overcooling transient that had minimal safety significance, yet is an interesting event to document since it involved the following independent occurrences:

- No. 22 main feedwater pump trip;
- Failure of No. 21 feedwater regulating valve to close;
- Sticking of No. 21 main feedwater pump speed controller in high speed position;
- Failure of turbine bypass valve in 50% open position; and
- Failure of reactor coolant pump vapor seal 1-1½ hours after reactor trip.

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*Calvert Cliffs Unit 2 is an 825 MWe (net) PWR located 40 miles south of Annapolis, Maryland, and is operated by Baltimore Gas and Electric.

In addition, the pressurizer pressure behavior during pressurizer refill demonstrated an interesting phenomenon that can result when the liquid and vapor phases are not in thermodynamic equilibrium. This phenomenon, which might occur when recovering from a transient in which the pressurizer is nearly drained, can result in a temporary decrease in pressure after the level has been returned to normal and all heaters are on. This pressure response is contrary to what one would normally expect, and could be initially puzzling to plant operators. The event is discussed in detail below.

On October 11, 1983, the No. 22 main feedwater pump at Unit 2 tripped because of a leak in the pump's hydraulically operated control system. The feedwater pump trip occurred at 11:36 a.m. while the plant was operating at 100% power. In an attempt to avert a plant trip, the operators began reducing power by borating and inserting control rods. The feed flow/steam flow mismatch was too great and the plant tripped from 88% power at 11:37 a.m. Following this trip, the No. 21 feedwater regulating valve failed to close due to a failed relay in the valve positioner. This caused the No. 21 feedwater pump speed to increase, resulting in a rapid rise in the No. 21 steam generator level. The operator's attempt to decrease feedwater flow by placing the No. 21 main feedwater pump controller in manual and trying to decrease pump speed failed because the pump speed controller had stuck in the high speed position due to an accumulation of dirt in the mechanism. Feedwater flow was isolated to the No. 21 steam generator approximately 3 minutes after the reactor trip, when the operators tripped the No. 21 main feedwater pump and shut the main feedwater isolation valve, thus terminating the event. The excessive feeding of the No. 21 steam generator caused the reactor coolant system pressure to drop sharply, due to the overcooling which resulted in a shrinkage of the primary coolant. The reactor coolant temperature dropped approximately 50°F in 3 minutes and the pressure decreased to approximately 1660 psig, causing a safety injection actuation. No water was actually injected, however, since this pressure is above the shutoff head of the high pressure safety injection pumps.

The severity of the overcooling transient was heightened by the effect of a turbine bypass valve that stuck 50% open due to mechanical binding. The turbine bypass valve, which was passing about 4% to 5% of full power steam flow, was manually isolated between 11:41 a.m. and 11:42 a.m. An additional turbine bypass valve was thought to have failed open but this turned out to be an erroneous indication due to an improperly set limit switch.

Following a turbine trip, the feedwater supply to the steam generators at Calvert Cliffs is designed to ramp down automatically to 5% of full power flow in 20 seconds. This is accomplished by automatic closure of the main feedwater regulating valves on a turbine trip signal and opening of the feedwater bypass valves to a predetermined position to maintain 5% of normal full power feedwater flow. The speed of the turbine-driven main feedwater pumps is controlled to maintain a constant differential pressure across the main feedwater regulating valves. Therefore, the failure of the No. 21 main feedwater regulating valve to close on a turbine trip, and the opening of the bypass feedwater regulating valves, caused a decrease in the differential pressure across the main feedwater regulating valves which resulted in the speed increase of the No. 21 main feedwater pump. As previously mentioned, this caused the rapid rise in the No. 21 steam generator level. This level, as indicated on the narrow-range level instrumentation, went from its minimum level of -63 inches* to offscale high, which is +63.5 inches, in about 75 seconds. The level remained offscale high for approximately 7 minutes. The licensee's estimate is that the level increased only about 10 inches above the highest indicated level, or to about +73.5 inches. The level was estimated by recording the blowdown flow rate with the generator isolated, and noting how long it took for the level to come onscale. The level in the No. 22 steam generator dropped to a low of -178 inches, as indicated on the wide-range level instrumentation,** which automatically started the motor-driven auxiliary feedwater pump. The level remained at -178 inches for less than 20 seconds before increasing. This was not long enough to start the turbine-driven auxiliary feedwater pumps. Level on the No. 22 steam generator recovered to an indicated -112 inches 2 minutes after the initiation of auxiliary feedwater. (For purposes of reference, the steam generator tubes begin to uncover at the -59-inch level.)

Twenty minutes after the reactor trip, reactor coolant pump 21A was tripped to reduce the pressurizer spray flow in response to what was initially thought to be a stuck open spray valve. This was done when plant operators observed the pressurizer pressure decrease from 1985 psig to 1854 psig over the span of 15 minutes. Further investigation revealed the spray valves were not stuck open. The pressurizer pressure decrease was subsequently attributed to an inflow of relatively cool water from the hot leg as the pressurizer level was being restored, and demonstrated a facet of non-equilibrium pressurizer thermodynamic behavior in which the liquid and vapor phases are at different temperatures. The slight decrease in pressure was apparent only after pressurizer level was held constant.

Since the water is entering the pressurizer from the surge line at the hot leg temperature, approximately 530°F in this case, the liquid and vapor phase in the pressurizer are no longer in equilibrium; i.e., the water is subcooled. (Saturation temperature at 1660 psig is 609°F.) During the overcooling transient, the pressurizer level had dropped from the full power level of approximately 200 inches to 18.9 inches, well below the low level heater cutoff point of 101 inches. Since the lower pressurizer level instrumentation tap is located near the bottom of the lower head, the 18.9-inch pressurizer level attained during the cooldown transient indicates the pressurizer was nearly drained. Level was restored to the 101-inch level at 11:50 a.m., and the heaters were reenergized. At 11:59 a.m., the pressurizer level was stabilized at 145 inches; some 30 seconds later the operators noticed the pressurizer pressure begin to decrease from its value of 1985 psig.

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*This is referenced to zero level, which is the normal operating level and is 47 inches above the center line of the feed ring.

**The lower level tap of this instrument is located in a high velocity region which causes a localized depression of the static pressure. Therefore, at normal operating conditions the indicated reading is about 50 inches less than the actual level, i.e., an indicated -178 inches corresponds to an actual level of -128 inches.

The unavailability of the heaters in the initial phase of the pressurizer refill indicates that the initial phase of the pressure recovery, which was observed to be normal, was due to the compression of the steam bubble in the pressurizer. At the time the pressurizer reached the 145-inch level, where it was stabilized by the operators, the heaters had only been energized for 9½ minutes, not long enough to get the liquid temperature in equilibrium with the vapor temperature. If the vapor was saturated,* this would have been at 636°F, the saturation temperature corresponding to 2000 psia. A quick calculation indicates that during this 9½-minute interval of increasing level, the temperature of the liquid would increase about 40°F, or to about 570°F, assuming all 1500 kW of pressurizer heaters in operation. Therefore, the vapor could lose heat both to the liquid and to the pressurizer walls. Again, assuming a saturated vapor phase, the observed pressure decrease from 1985 psig to 1854 psig over a 15-minute period corresponds to only a 10°F decrease of the vapor temperature, from 636°F to 626°F. Calculations show it would take on the order of 15 minutes to heat the volume of water in the pressurizer from 570°F to 626°F (56°F increase). This correlated with the 15 minutes observed by the operators for the pressure to stabilize at 1854 psig. At this time, the liquid/vapor equilibrium was reestablished. As the liquid was further heated, pressure began increasing. The pressure was subsequently returned to normal without further incident. This pressurizer behavior, although not unusual, is not what one would normally expect. The instinctive assumption probably would be that when all heaters are on, the level is stable, and pressure has been increasing continuously during the pressurizer refill, pressure should continue increasing, not begin decreasing.

Reactor coolant pump 21A was restarted after being idle for 1 to 1½ hours. Following pump restart, an increase in the drainage frequency of the containment sump was noted. The cause of the leakage into containment was discovered to be a failed vapor seal on the reactor coolant pump that had been stopped. The licensee attributed this to normal end-of-life failure. This seal had been in service for 29 months and the average pump seal life at Calvert Cliffs has been shown by experience to be on the order of 23 months. The licensee did not consider the seal failure to be related to the pumps being idle for 1 to 1½ hours and then being restarted, as this is routinely done during plant startups and shutdowns without adverse effect.

As discussed above, this event at Calvert Cliffs included a demonstration of how pressurizer pressure can behave when the liquid and vapor phases are not in thermodynamic equilibrium. The non-equilibrium conditions, under certain circumstances, can make pressurizer pressure behave in an opposite manner from what operators normally would expect; i.e., cause a pressure decrease when all other conditions would lead one to believe the pressure should be increasing. This could cause a misdiagnosis of plant behavior by operators. In spite of this, and the five sequential occurrences that happened during the event, it

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*If the compression of the initially saturated vapor by the rising liquid surface was isentropic, the vapor would be superheated. Since there are irreversibilities in the process, namely heat transfer from the vapor, the compression is not isentropic. However, depending on the magnitude of the irreversibilities during compression, the vapor still may be slightly superheated.

should be noted that the operators responded well throughout this event, and that at no time were plant technical specification safety limits violated. (Refs. 14 and 15; see also p. 70.)

1.8 Loss of ECCS Charging Systems and Boron Injection Tank

On April 7, 1984 at 9:30 a.m., while Diablo Canyon Unit 1* was in hot standby, the licensee discovered during preoperational testing that both trains of the emergency core cooling system (ECCS) charging system had been inoperable since April 6 at 7:10 p.m., a period of 14 hours and 20 minutes. This condition was not in compliance with technical specifications.

The ECCS at Diablo Canyon Unit 1 consists of four separate subsystems. These are: (1) the charging system (two pumps); (2) the safety injection (SI) system (two pumps); (3) the accumulators (one per loop); and (4) the low pressure injection (LPI) system (two pumps).

The charging system has both a normal and an ECCS mode. The ECCS mode includes the boron injection tank (BIT) in its flow path. During normal operation, charging flow bypasses the BIT and flows directly into the primary system. (During the event, this normal flow path remained operable.) Upon an emergency safeguards features (ESF) signal, the bypass lines are automatically isolated and valves at both the inlet and outlet of the BIT are automatically opened. Therefore, upon an ESF injection signal, concentrated boric acid is injected into the core via the high pressure charging system.

On April 6, 1984, the plant experienced an anticipated safety injection as part of steam generator safety valve startup testing. The safety injection resulted in the discharge of the contents of the BIT into the reactor coolant system. To recharge the BIT with 12% boric acid solution, licensed operators, using approved procedures, closed the BIT inlet and outlet values during the recharging operation by securing the electrical power to the value operators. This practice prevents problems which might occur due to an inadvertent safety injection signal while the BIT is being drained prior to recharging with boric acid. (With the BIT inlet and outlet valves closed, there is no flowpath from the charging systems' flow through the BIT before entering the primary system.) Operations personnel were concentrating on restoring the BIT and did not consider the requirement of the ECCS technical specifications. The approved operating procedures were inadequate in that they did not provide any technical specification guidance to the operators that two sections of the technical specifications were involved.

In the plant's final safety analysis report (FSAR), the following accidents are analyzed assuming mitigation by injecting the 20,000 ppm BIT and from the safety grade charging system: (1) small break loss-of-coolant accident (LOCA); (2) steam line break with a stuck out control rod; and (3) large break LOCA.

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*Diablo Canyon Unit 1 is a 1084 MWe PWR located 12 miles southwest of San Luis Obispo, California, and is operated by Pacific Gas and Electric. The unit received a low power license in April 1984.

The charging system and BIT could also be utilized following a design basis steam generator tube rupture accident or a rod ejection accident. In the case of a steam generator tube rupture, one principal consideration is reducing reactor system pressure to reduce the leak flow. Loss of the charging path through the BIT would not affect the ability of the operator to depressurize the reactor coolant system. Depressurization of the reactor system would permit the safety injection pumps to discharge sufficient emergency coolant to replenish the leaked coolant, thereby preventing core uncovery.

In the case of a rod ejection accident, the negative fuel and moderator temperature coefficients would be sufficient to mitigate the event without credit for the BIT. In the long term, the event would resemble a small break LOCA.

In the case of a small break LOCA, the most severe break size would produce a peak cladding temperature of 1150°F (substantially below the 2200°F limit). The core heatup would be terminated by accumulator injection at 1050 seconds. Only one train of ECCS was assumed to be available. It is expected that this event, if analyzed without the charging system available, would result in somewhat higher peak cladding temperatures, but still substantially below the 2200°F limit.

In the event of a steam line break, the 20,000 ppm BIT provides additional shutdown margin. The BIT injection was designed to prevent excessive local power generation for the additional failure of a control rod stuck out of the core. Recently, some licensees for Westinghouse-designed plants have requested, and the NRC has approved, removal of the BIT. Thus, the NRC does not believe that the unavailability of the BIT would have a significant effect on the steam line break event.

Following a large break LOCA, the reactor system would be quickly depressurized. Emergency coolant would be injected from full flow of the SI pumps, the accumulators, and the LPI pumps. Loss of charging flow is expected to have little effect on the course of the event.

Based on the above evaluation, it is evident that there are sufficient excess margin and capacity inherently designed into the plant such that loss of the mass and negative reactivity inputs from the charging system would not significantly affect the current FSAR analysis results. It should be pointed out, however, that a detailed evaluation has not been performed of the effect of valving out the charging system (e.g., pump deadheading) and the consequential failures that might occur.

Mitigating factors included the facility's license and fuel history. At the time of this event, the reactor had not attained criticality. Thus, there was no fission product inventory in the core and no decay heat source available. This essentially eliminated the need for the BIT. Although the plant had loaded fuel in November 1983, a low power license was not issued until April 13, 1984, subsequent to the event. After fuel loading, the plant was allowed to perform preoperational tests in hot standby using pump heat to heatup the primary system. Following the event, a new operating procedure was written to permit recharging the BIT without violating the technical specifications. (Refs. 16 and 17.)

1.9 Torus Corrosion Pitting and Missing Structural Welds

This event writeup summarizes a licensee event report (LER) that was submitted voluntarily under the revised reporting requirements established in January 1984, and discusses information that is not required to be reported to the NRC. The information covers discovery and repair of corrosion pitting and missing structural welds during modifications to the torus of a boiling water reactor (BWR), and is summarized here as an item of interest to BWR licensees.

At Oyster Creek,* the torus, or pressure suppression chamber, is a large donut-shaped vessel situated beneath the drywell. The torus and drywell constitute a Mark I BWR primary containment. In the event of a loss-of-coolant accident in the drywell, steam is discharged to beneath the level of water in the torus via vent lines, header, and downcomers, where it is condensed.

In support of the Mark I containment reevaluation program, due to new pool dynamic considerations, structural modifications to the torus required sand blast cleaning of the outside bottom of the torus shell. This work began during fall 1981, and led up to the positioning of large hoop straps to the torus prior to spring 1982. The plant returned to operation, but was shut down early in 1983 for a major refueling/maintenance outage. The torus was hydrolayzed with processed, demineralized torus water, was drained, and was brush-off blast cleaned at locations where welding was to be performed.

The initial brush-off blast cleaning revealed no increased pitting of the torus shell exterior from that observed in previous inspections during the summer 1978 and spring 1980 draining operations. However, during the 1983 outage, four new temporary openings provided access to the vent system interior for the first time. No substantial corrosion pitting was observed, i.e., the corrosion pitting was less severe than what was left on the torus shell after the summer 1978 evaluation and repairs. On the interior and exterior surfaces of the vent system, the area of blast cleaning was limited to 6 inches around the downcomers. This blasting was in support of installing the vent header to downcomer reinforcement. There was no indication that the areas which would eventually require weld repair were pitted to the extent later revealed by blast cleaning in preparation for application of the protective coating.

The severity of corrosion in the vent system became apparent for the first time during October-November 1983, when the torus vent system interior was blast cleaned in its entirety. The results of this cleaning revealed moderate corrosion pitting in the ten vent lines and vent header, and severe pitting concentrated along the plate miter welds in the vent header/vent line junctions. The licensee established a program to evaluate and repair these newly discovered pitted areas of the torus.

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*Oyster Creek is a 620 MWe (net) BWR located 9 miles south of Toms River, New Jersey, and is operated by GPU Nuclear.

Corrosion evaluation (mapping) began October 25, 1983. Vent header/vent line junction weld repair began on November 2, 1983, and were directed at the vent line to vent header intersections to areas where pitting was in excess of .025 inches. Actual wall thickness measurements were not factored into the decision to start weld repairs to the vent system at that time. Concurrent with the start of repair in the vent header/vent line junctions, mapping of corrosion area size and depth, actual plate thickness measurements, and stress margins were evaluated. Plate area specific repair criteria were established, and the areas requiring repair were mapped for weld repair. The evaluation called for repair by welding all corrosion pitting that resulted in no margin when taking credit for actual plate thickness, stress margin, and mill tolerance permitted on plate thickness. No credit was taken for size nor location of corrosion area in the vent system. The evaluation for weld repair was carried out as if the entire plate where corrosion was present was missing wall thickness throughout its entire surface corresponding to the largest pitting depth measured. Approximately 138 square feet of weld metal was deposited at the vent header/vent line junctions, 20.2 square feet on the downcomers, and 24.2 square feet on vent header plates where corrosion was present.

For the torus shell evaluation, no credit was taken for actual wall thickness of the plate around the pitted areas. Factored into the evaluation was the size of the corroded area and the location of this area relative to structural attachments, i.e., ring girders or saddles. The criterion for repairs to the torus shell was to maintain a .020-inch margin above the Mark I program stress results. The Mark I stress results were converted to a stress margin value for nominal plate thickness and minimum ASME material properties. Sampling work done in 1978 showed that torus shell plates were slightly thicker than nominal plate. No credit was taken for ASME/ASTM plate thickness undertolerance margin. A total of 11.2 square feet of weld metal was deposited on the torus shell. Records of actual torus vessel plate material properties indicate a 10% higher tensile strength than ASME Code minimum. No credit was taken for the higher strength torus plate.

The weld repairs consisted of shielded metal arc welding (SMAW) using procedures qualified to ASME Section III, Division I, Subsection NE, 1977 Edition through Summer 1978 Addenda. The weld method utilized is commonly called "stringer bead." For vertical uphill welds and overhead welds, a "weave" technique was employed. Prior to depositing weld metal in a designated area, the area in question was excavated by grinding to sound metal and inspecting the cavity to ensure complete removal of the nonconformity. The weld repair was ground smooth and the repaired surface left raised approximately 1/16-inch above the surrounding plate area. The repair was then inspected by the magnetic particle method. In addition, when the repair cavity exceeded 50% of wall thickness, radiographic examination of the repair was performed as permitted by the 1962 ASME Code, Section VIII, the original code for the torus. A total of four single pit repair areas exceeded 50% of wall thickness, and were radiographed. This amounts to 3 square inches of weld area for the entire torus vessel.

In addition to the torus corrosion pitting, following blast cleaning in preparation for coating application, various structural welds were found missing. Two of 20 ring girders were found to have a section of fillet weld missing. The missing weld sections were ring girder to torus shell fillet welds. Each missing section was approximately 24 inches long. The ring girders are located inside the torus and are sectional, circumferential reinforcements. Also, various fillet welds were found missing at the ring girder flange to torus shell inner web reinforcing plates. At each ring girder flange there are four inner web reinforcing plates at the inboard equator and four inner web reinforcing plates at the outboard equator. On an average, each ring girder had 4.5 ring girder flange to web reinforcing plate fillet welds missing. Each ring girder had missing welds at the web reinforcement plate ranging in number from two to seven. In areas where the gap between the web reinforcing plate and the ring girder flange exceeded 3/16 inch, the web reinforcing plate was trimmed and a 1-1/2-inch thick plate inserted and welded all around. All areas where torus structural welds were missing were repaired to ASME B & PV Code, Section III, Subsection NF 1977 to Summer 1978 criteria.

The torus pitting due to corrosion was caused by local failures of the original red lead coating. Based on extensive efforts to characterize the extent and depth of corrosion pitting, and technical evaluations of the potential effects of the pitting during design basis conditions, roughly 200 square feet of weld metal was overlaid onto pitted torus pressure boundary surfaces. In addition, the torus was recoated with an epoxy coating which is more durable than the red lead coating. This, together with the use of high quality demineralized water to the torus, will minimize future corrosion.

The missing structural welds resulted from a lapse in construction management overview during original construction. The repaired missing welds have restored the torus to the original as-designed condition. (Ref. 18.)

1.10 References

(1.1) 1. NRC, Preliminary Notification PNO-V-84-15, March 12, 1984.

2. Southern California Edison, Docket 50-362, Licensee Event Report 84-09, March 17, 1984.

(1.2) 3. Georgia Power, Docket 50-366, Licensee Event Report 83-112/03L-0, November 11, 1983.

4. Letter from J. T. Beckham, Jr., Georgia Power, to H. Denton, NRC, April 30, 1982.

5. NRC, Region II Inspection Report 50-366/83-38, January 9, 1984.

6. NRC, AEOD Engineering Evaluation E414, "Stuck Open Isolation Check Valve on the Residual Heat Removal System at Hatch Unit 2," May 31, 1984.

7. NRC, IE Information Notice 84-74, "Isolation of Reactor Coolant System from Low-Pressure Systems Outside Containment," September, 28, 1984.

(1.3) 8. Florida Power, Docket 50-302, Licensee Event Report 84-10, May 26, 1984.

(1.4) 9. NRC, AEOD Engineering Evaluation E413, "Natural Circulation in Pressurized Water Reactors," May 25, 1984.

(1.5) 10. NRC, Preliminary Notification PNO-1-84-52, June 14, 1984.

11. NRC, Region I Inspection Report 50-309/84-14, August 10, 1984.

(1.6) 12. Public Service Electric and Gas, Docket 50-272, Licensee Event Report 84-14, July 7, 1984.

13. NRC, Region I Inspection Report 50-272; 50-311/84-19, June 27, 1984.

(1.7) 14. Baltimore Gas and Electric, Docket 50-318, Licensee Event Report 83-54, November 10, 1983.

15. NRC, AEOD Engineering Evaluation E415, "Overcooling Transient," June 6, 1984.

(1.8) 16. Pacific Gas and Electric, Docket 50-272, Licensee Event Report 84-13, July 4, 1984.

17. Letter from J. B. Martin, NRC/Region V, to G. A. Maneatis, Pacific Gas and Electric, transmitting Proposed Imposition of Civil Penalty/EN 84-30, May 17, 1984.

(1.9) 18. GPU Nuclear Corporation, Docket 50-219, Licensee Event Report 84-06, May 31, 1984.

2.0 EXCERPTS OF SELECTED LICENSEE EVENT REPORTS

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

This section of Power Reactor Events includes direct excerpts from LERs. In general, the information describes conditions or events that are somewhat unusual or complex, or that demonstrate a problem or condition that may not be obvious. There has been minimal effort to edit the text provided, since it is assumed that the LER descriptions are accurate and complete, as required by 10 CFR 50.73(b). The plant name and docket number, the LER number, type of reactor, and nuclear steam supply system vendor are provided for each event. Further information may be obtained by contacting the Editor on 301-492-4499, or at U.S. Nuclear Regulatory Commission, EWS-263A, Washington, DC 20555.

2.1 Loss of RHR During Half Loop Conditions

Cook Unit 2; Docket 50-316; LER 84-14; Westinghouse PWR

With the reactor coolant system at half loop (partially drained), the licensed control room operators started the east residual heat removal (RHR) pump in preparation for removing the west RHR pump from service. It has been a practice to start the standby pump prior to removing the running pump from service. Since the RHR pumps take their suction from the same pipe, the resulting high flow at half loop conditions can cause vortexing at the loop suction and the subsequent air binding of both RHR pumps. Both pumps were removed from service and the venting process started.

Although there was a caution in the procedure stating not to run both pumps at half loop, there were no instructions for shifting RHR pumps at half loop. The procedure has been changed to address the half loop operation.

2.2 Low Relief Valve Setting Could Disable Standby Liquid Control System

Hatch Unit 2; Docket 50-366; LER 84-05; General Electric BWR

During performance of the six-month STANDBY LIQUID CONTROL SYSTEM procedure (with the reactor in cold shutdown), plant personnel determined that the Standby Liquid Control (SLC) system's pressure relief valves for loop "A" and loop "B" lifted at a pressure lower than the expected 1350 PSIG ± 25 psig when they were bench tested. Relief valve 2C41-F029A (loop A) lifted at 600 PSIG, and relief valve 2C41-F029B (loop B) lifted at 700 PSIG. These relief valves are positioned on the discharge side of the SLC pumps. When either valve lifts, the respective pump's discharge volume is then returned to the intake side of the SLC pump, thus completing a closed loop which recirculates the solium pentaborate solution instead of injecting it into the reactor vessel.

In the event that a sufficient number of control rods could not have been inserted to control reactivity the SLC system would not have been able to inject into the reactor vessel against a pressure greater than 700 PSIG.

2.3 Technical Specification Error Allowed Only One Reactor Coolant Pump in Operation During Mode 3

Sequoyah Unit 1; Docket 50-327; LER 84-38; Westinghouse PWR

Technical specifications require two reactor coolant pumps to be operable with one pump in operation for Mode 3 operation. Mode 3 is defined by the technical specifications as reactor coolant system temperature between 350°F and no-load temperature of 547°F with the reactor subcritical as required by the shutdown margin technical specification.

Westinghouse notified the licensee that consistency between the safety analysis and technical specifications as required by 10 CFR 50.36 may not exist. Mode 3 operation is bounded by the analysis performed for hot zero power. These analyses were performed assuming that either two or all of the reactor coolant pumps are operating. The limiting accidents for hot zero power are main steam line break, rod ejection, and bank withdrawal from subcritical.

Westinghouse has reviewed these accidents under the reduced flow conditions of one pump and determined for the steam line break and rod ejection events that the inconsistency between the safety analysis and the technical specifications will not impact the conclusions presented in the safety analysis. For the bank withdrawal from subcritical accident, Westinghouse calculations showed that the DNB design basis for the condition II event may not be met when only one reactor coolant pump is in operation. Based on this evaluation, the margin for safety as defined in the basis for the technical specifications is reduced and the condition may be an unreviewed safety question according to 10 CFR 50.59.

Westinghouse has stated that on a best estimate basis, DNB design basis can be met since the licensing basis analysis includes conservatisms (such as high reactivity insertion rates) which when removed show that the DNBR is above limits.

Upon notification of this condition, the plant implemented administrative controls to require either (1) two reactor coolant pumps operating in Mode 3, or (2) one reactor coolant pump operating with all rods on the bottom with all power removed from the rods when in Mode 3. The administrative controls will remain in effect until a technical specification change can be submitted to and approved by the NRC.

2.4 <u>Fire Potential of Urethane Foam Between Shield Wall and Containment Vessel</u>

WPPS Unit 2; Docket 50-397; LER 84-47; General Electric BWR

During a cross-discipline review of radiation shielding for penetrations through the biological shield wall, it was determined that the previous design did not consider radiant heat from adjacent fire zones to possibly ignite the urethane foam separating the biological shield wall and primary containment vessel. The resultant fire could incapacitate the electrical penetrations required for safe shutdown.

Upon notification of the event the Shift Manager assigned a person as a Fire Watch Patrol to view one side of the wall in all areas where unsealed penetrations exist, at least once every hour. This person's duties were to determine that no fire exists that could ignite the foam between containment pressure vessel and the biological shield wall.

Subsequently, all but one of the penetrations determined to need seals were sealed with a minimum of four inches of approved sealing media which will provide not less than 3 hours of fire protection to the containment pressure vessel. Engineering direction to seal the remaining penetration is in development and when complete will result in 100% sealing. Hourly fire watch patrols will be maintained until 100% closure is achieved.

The biological shield wall is a 3-hour fire barrier. In the event of a fire in the Reactor Building, had it gone undetected for a significant period of time, it was possible that high temperatures from the fire could have resulted in radiant heat transmission through the unsealed penetrations and igniting the urethane foam insulation. Burning of this foam could result in heat damage to electrical penetrations associated with dedicated safe shutdown equipment and potentially preclude achieving safe shutdown.

2.5 <u>Release Exceeding Two Times the Applicable Concentration in Appendix B, Table II, 10 CFR 20</u>

San Onofre Unit 2; Docket 50-361; LER 84-27; Combustion Engineering PWR

With Units 2 and 3 in power operation at 100% power, backleakage of flow from the Waste Gas Compressor (WGC) C010 through the discharge check valve into standby WGC C011 resulted in a release via the WGC C011 rupture disc. The waste gas released through the rupture disc was routed by the Radwaste HVAC System to the Plant Vent Stack causing the Plant Vent Monitor to alarm. An Unusual Event was declared per the Emergency Plan because the alarm on the Plant Vent Monitor continued for more than 15 minutes and the release had not been terminated. The release was isolated by manually valving out WGC C011 which terminated the Unusual Event.

The release was calculated to have been approximately 107 curies of Xe-133. The concentration in unrestricted areas, when averaged over one hour, was 7.14E-7 microcuries per cubic centimeter which is 2.38 times the applicable concentration in Appendix B, Table II of 10 CFR 20 in unrestricted areas, when averaged over one hour.

This event is similar to that reported in 1982 where the corrective action consisted of replacing the rupture disc. For this occurrence, in addition to replacing the rupture disc, corrective action will be to repair check valve during the next cold shutdown of both Units 2 and 3. Also, the need for a design modification is being evaluated to replace both WGC C010 and C011 rupture discs by relief valves piped to either the compressor discharge or surge tank. This action would eliminate the open system release path and preclude recurrence.

2.6 Loss of RHR Cooling Due to Air Entrainment

Trojan; Docket 50-344; LER 84-10; Westinghouse PWR

The RCS was being drained to near the hot leg centerline in support of routine refueling operations. The plant was in cold shutdown with the RCS open to atmospheric pressure with an average coolant temperature of 105°F. During a partially drained condition RCS level is sensed at the drain line on the suction of the "B" reactor coolant pump. A tygon hose is connected from this point to a vent line off the pressurizer. A level transmitter is temporarily connected to provide level indication on a control room level indication meter and a temporary recorder. A television camera trained on the tygon stand pipe also provides control room indication of RCS level.

The "A" RHR loop was in service to provide decay heat removal. ESF actuation response time testing was being performed which required stopping both RHR pumps to initiate an automatic start of the "B" RHR pump. The "A" RHR pump was stopped at 1640 in accordance with the procedure. A delay developed in the performance of this test so the "A" RHR pump was restarted at 1650. Pump amperage and flow oscillated, indicating air entrainment in the pump due to vortexing at the pump suction; the pump was immediately stopped. At this point it was determined that the RCS stand pipe level indication (60' 6") must be unreliable since the RHR suction line connects to the RCS at elevation 59' 8". Emergency boration was initiated for approximately five minutes followed by manual opening of the RHR suction valve from the refueling water storage tank (RWST) to increase RCS level. At 1720 the indicated stand pipe level was 62' and the "B" RHR pump was started to restore flow through the RCS and to reduce RCS temperature.

During this event, all RHR cooling flow had been suspended for a total of 40 minutes. Both RHR pumps were stopped as part of a test for the first 10 minutes while the next 30 minutes were spent restoring RCS level in order to ensure there was sufficient level to not degrade the operation of the "B" RHR pump.

The control room chart recorders indicated that the highest RCS temperature reached during this event was 201°F in the hot leg of loop "B." The maximum RCS average temperature was below 200°F; hence the plant was maintained in cold shutdown throughout the event.

The cause of this event was inaccurate RCS level indication resulting in a low RCS level which resulted in air entrainment in the RHR pump due to low net positive suction head. A partial crud blockage in the RCS level indication tap off the drain line on RCS loop "B" was responsible for the indicated RCS level being higher than the actual level. The blockage caused a very slow response to level changes by the level indicating stand pipe. The design of the RCS level indication system did not include any redundancy; this allowed the blockage of one level tap to disable the entire system.

The RCS water inventory was restored by makeup from the RWST. The "B" RHR pump was subsequently started to terminate the RCS temperature rise. The partial crud blockage in the lower tap of the RCS level indicating system was removed by applying high water pressure to the line. This action reestablished accurate level by forcing the blockage to the reactor coolant drain tank. The "A" RHR pump was also vented and test run satisfactorily.

Redundant indication of RCS level will be installed on RCS loop "C" prior to draining down the RCS in June 1984. This second level tap will be located off the "C" loop flow transmitter which is not susceptible to crud blockage due to its location in a vertical run of piping. Redundant RCS level indication stand pipes off two RCS loops will then be visible on the TV camera for remote indication in the control room. In addition, the procedure for draining the Reactor Coolant System is being revised to flush the level stand pipe "B" loop lower tap with 120-200 psig pressure to remove any corrosion products prior to placing the system in service. Also, a procedure precaution will be added to highlight the desirability of expeditiously restoring the RCS level and RHR flow.

2.7 Simultaneous HPCI and RCIC Inoperability

FitzPatrick Docket 50-333; LER 84-12; General Electric BWR

While operating at full power the RCIC and HPCI systems were discovered to be simultaneously inoperative. This placed the plant in a 24-hour limiting condition for operation (LCO).

While inspecting the area where the RCIC steam supply piping penetrates the drywell into the reactor building it was noted that the cover was missing from a condolet in the isolation circuitry for the RCIC outboard steam isolation valve 13-MOV-16. Subsequent investigation revealed that the condolet contained the thermocouple for this circuitry, that the thermocouple was disconnected, and that the wires were twisted together thereby forming another thermocouple junction. This condition made the circuit indicate and calibrate properly, thereby masking the problem during normal surveillance testing. 13-MOV-16 was closed and de-energized to properly isolate the RCIC steam supply line. RCIC was declared inoperative. The circuit was restored to normal and tested satisfactory and RCIC was declared operable again.

An investigation was conducted to determine the reason this wiring had been altered. All other thermocouple sensors in the drywell entrance area and all RCIC steam leak detection thermocouples regardless of location were inspected and found satisfactory. Work records were also reviewed in an attempt to determine the cause. No reason could be determined. It was noted during the investigation that a redundant thermocouple existed in the drywell entrance which was operable and would have isolated the RCIC steam isolation valve should a leak have occurred.

As the result of the metallurgical report on a previous failure of the HPCI stop valve stem and reports from the operators of excessive stop valve speed on opening, an inspection of the stem condition was performed coincident with the testing of the HPCI operability (necessary because RCIC was inoperative). It was noted that circumferential cracks were beginning to appear in the HPCI stop valve stem. The HPCI system was declared inoperable. The stem was replaced and the turbine was restored to operability.

The cause of the stop valve stem cracks and the previous failure reported was excessive tensile stress. This was due to failure to adjust the cushion chamber backpressure during valve overhaul. The result was a loss of damping and excessive stem speed at the end of the opening stroke. The cushion chamber backpressure was adjusted during this repair in accordance with manufacturer's instructions. This adjustment reduced the stem speed and smoothed the turbine starting transient.

Long term corrective action for this problem is to incorporate the procedure for cushion chamber backpressure adjustment into the HPCI turbine maintenance procedure.

During the time from when HPCI was declared inoperative until when RCIC was restored to service both systems were simultaneously out of service contrary to Technical Specification LCO requirements.

2.8 Battery Failure

Farley Unit 1; Docket 50-348; LER 84-11; Westinghouse PWR

Service Water Building weekly battery quality verification was performed on the B train battery. At 1035, the battery was declared inoperable due to cell number 42 having a specific gravity of 1.182 corrected to 77 degrees Fahrenheit versus 1.190 required by Technical Specifications.

It is suspected that the low specific gravity was caused by current tracking across the battery case between the cell terminals. This tracking may result from contaminants introduced during battery operation and may be compounded by the close terminal spacing of the service water battery. Such tracking could shunt the float charge in a manner as to slowly deplete the cell specific gravity. Since similar occurrences have been reported this is believed to be a potentially generic problem rather than a random problem.

The affected cell and two neighboring cells (3 cell unit) were replaced restoring the B train battery to operable status.

2.9 Inoperability of Both Loops of the Containment Spray Mode of the RHR System

Grand Gulf Unit 1; Docket 50-416; LER 84-24; General Electric BWR

On May 2, 1984 the plant entered Hot Shutdown as required by Technical Specifications due to the inoperability of both independent loops of the Containment Spray mode of the Residual Heat Removal System. The sequence of events which led to the shutdown are as follows.

On April 30, 1984 two cracks were found in a 3-inch diameter pipe which branches off the RHR B loops. This pipe allows the Reactor Core Isolation Cooling System (RCIC) to take suction from the RHR heat exchangers. The pipe has a primary pressure rating of 300 psi, is made of carbon steel and designed by ASME Boiler and Pressure Vessel Code Section III, Class 2. One crack was found at a 90° elbow just prior to valve F065. The other was in a weld-o-let fitting at the junction of the 3-inch branch line and the 18-inch diameter RHR loop B pipe. The distance between valve F065 and the branch connection is approximately 2.5 feet. As a result of the findings, Limiting Conditions for Operation were entered after declaring LPCI "B," Containment Spray "B," and the Suppression Pool Cooling Mode of RHR B inoperable.

Subsequent special inspections were then conducted which revealed RHR system pipe support nonconformances. One support base plate had loose nuts on the mounting bolts and two plates appeared to have been pulled away from the wall approximately 0.25 to 0.75 inches. Since the structural integrity of the supports were in question, RHR loops A and B including Containment Spray, LPCI, Suppression Pool Cooling, and Shutdown Cooling modes were declared inoperable. Due to Technical Specifications the plant entered Hot Shutdown at 2225 hours on May 2 and Cold Shutdown at 0745 hours on May 3. Reactor Recirculation pumps A and B were used as an alternate method of reactor coolant circulation. The Reactor Water Cleanup System and the Control Rod Drive System were also available for heat removal.

The damaged 3-inch pipe was removed and a capped 6-inch weld-o-let connection was attached to the 18-inch pipe to restore the RHR B loop. This is a temporary solution until the failure of the components can be assessed and a permanent solution developed. In addition, flow tests were performed by throttling valve F003 immediately downstream of the branch connection on the 18-inch RHR pipe. Vibration measurements taken showed some excessive vibration when the F003 valve was throttled to less than 15 percent of the fully closed position. A change to the operating procedures was made to prevent the F003 valve from being throttled to 15 percent or less of the fully closed position.

Two of the pipe supports were reworked, the other was redesigned to correct the support deficiencies.

2.10 Loss of Secondary Containment

Quad-Cities Unit 1; Docket 50-254; LER 84-06; General Electric BWR

While performing maintenance on Turbine Isolation Valves (ISVs), Main Stop Valve 1 and Main Stop Valve 2, Station Maintenance personnel noticed air flowing through the opened valve bodies. Upon alerting Operating personnel, it was quickly discovered that concurrent with the ISV work, there was also a Main Steam Isolation Valve (MSIV) in the MSIV room which was disassembled for maintenance. This resulted in a communication path via main steam piping between the Reactor Building and Turbine Building. Since both units were in Cold Shutdown at this time, and the requirements established in Technical Specification were met, Secondary Containment was not required and therefore, not affected by this event. A review of this event, in light of Secondary Containment valve disassembly during single unit outages, reveals a potential for Secondary Containment problems.

The cause of this deviation is procedural inadequacy. Personnel were not accustomed to relating valve maintenance with a potential Secondary Containment flow path, and Station procedures did not address Secondary Containment concerns with valve maintenance procedures.

A procedure assuring Secondary Containment during valve disassembly and pipe removal was implemented the following day. The procedure for use of Nuclear Work Requests is being changed to instruct Operating Engineers to signal pertinent Work Requests with stamps that read, "Caution-This Can Affect Secondary Containment."

This corrective action is deemed adequate to prevent recurrence. Occurrences of this type could have happened in the past, however, standard turbine maintenance practices have always included a temporary plug for valves opened for maintenance. The temporary plug has afforded a degree of containment integrity.

2.11 Seal Leakage Changes Relief Valve Lift Setpoint

Sequoyah Unit 1; Docket 50-327; LER 84-31; Westinghouse PWR

At 1725 CST on 05/05/84 with unit 1 in hot standby (547°F, 2235 psig), pressurizer safety relief valve 1-SRV-68-565 lifted. The required lift setpoint of the valve is 2485 psig ± 1%. Plant shutdown to hot shutdown as required by technical specification LCO 3.4.3.1. was initiated at 1800 CST.

Later on 05/06/84 at 0117 CST with the unit in hot shutdown (330°F, 600 psig), steam generator auxiliary feedwater bypass level control valve 1-LCV-3-164A failed to open sufficiently to maintain level in the number one steam generator resulting in actuation of an automatic reactor trip on low-low level in the number one steam generator.

The premature lifting of the pressurizer safety relief valve has been determined to be due to seat leakage. The spring force calculations to maintain closure of the relief valve are based on cross sectional area of the seat and zero leakage. If leakage occurs, the cross sectional area is effectively increased allowing a lower system pressure to lift the valve. The Crosby valve Model No. GM6-HB-BP-86 was replaced and the failed valve was shipped to Wyle Labs for repair and inspection.

2.12 Reactor Scram and Loss of RCIC

Grand Gulf Unit 1; Docket 50-416; LER 84-30; General Electric BWR

A reactor scram occurred at low water level, 11 inches above instrument zero. The low level was due to a trip of the condensate pump, condensate booster pump, and feedwater pump and the inability to manually start RCIC to restore level.

Maintenance personnel were investigating the cause of an indication problem on the condensate minimum flow control valve. The cause was determined to be a high voltage output on the controller which was then adjusted. As the technician touched the positioner arm linkage to check for tightness, a noise was heard inside the positioner and the valve moved to full open. A later investigation revealed a broken linkage and a bent valve stem positioner bracket which occurred at an unknown time.

With the valve full open, a path was created to the condenser bypassing the booster pumps. The running condensate and condensate booster pump and feedwater pump tripped immediately on low suction. The reactor was operating at approximately 4% thermal power. Operators attempted to restart the condensate system but the condensate pumps again tripped. The reactor water level began to decrease from 38 inches above instrument zero. Operators tried twice to manually start RCIC but both times the RCIC turbine tripped. When RCIC was initially started, it operated properly and momentarily stabilized water level at approximately 27 inches before tripping on overspeed. It was reset and again tripped on overspeed. The turbine evidently oversped on initial startup, but the trip valve failed to close instantaneously, allowing RCIC to operate for a short time. A reactor scram occurred on a low level signal. All main steam inboard isolation valves were manually closed by handswitch. RCIC was restarted and began feeding the vessel with the vessel level at 10 inches below instrument zero. The normal RCIC automatic initiation is at 41.6 inches below instrument zero at which time HPCS, which was available, would also start. RCIC was then secured with the water level at approximately 37 inches above instrument zero.

A modification was made to the RCIC turbine governor valve to restrict it from full opening and causing a turbine overspeed trip.

2.13 DC Power Applied to AC Coils

Turkey Point Unit 4; Docket 50-251; LER 84-07; Westinghouse PWR

On May 9, 1984, with Unit 4 in a scheduled refueling outage (core reload completed), tripping of "A," "B," and "D" 480 volt load center feeder breakers occurred at 6:10 p.m., 6:25 p.m., and 6:10 p.m., respectively. The root cause was determined to stem from a procedural deficiency that allowed direct current (dc) electrical power to be applied to an alternating current (ac) coil. The ac coils shorted out approximately one hour after being installed and resulted in tripping of the three 480 volt load center feeder breakers.

During preparations for performance of the Engineered Safeguards and Emergency Power Systems - Integrated Test, coil connections for a computer input relay board were being made. A procedural deficiency existed that resulted in dc power being applied to an ac coil. Previously, those coils monitored ac motor operated valves. A procedure change was instituted that changed them to monitoring load center feeder breakers (with dc control circuits) but did not specifically address the requirement for the coils to be changed out from ac to dc prior to connecting leads. As a result, the leads were connected on the ac coils while efforts were underway to obtain and install the dc coils. The ac coils, which were wired in parallel with the "breaker closed" position indication light circuit, which is in series with the breaker trip coil, shorted to ground and actuated the trip coils, tripping the associated feeder breakers. Note that the current flow through the "breaker closed" position indication light circuit is not enough to pickup the breaker(s) trip coil, but a short circuit in the ac coil is, since essentially no resistance to current flow remains. Thus, the circuits monitored were transferred over to the "breaker open" position indication light circuit to preclude a coil fault tripping the breaker being monitored.

2.14 Loss of Feedwater Control at High Power

Arkansas Unit 2; Docket 50-368; LER 84-11; Combustion Engineering PWR

A load reduction to 55% power was ordered by the dispatcher due to loss of a 600kV transmission line. The transmission line was returned to service and the system dispatcher requested that the unit be returned to 100%. Power escalation was begun at this time. Oscillations in feedwater flow occurred with main feedwater control in automatic. Steam generator levels were exhibiting divergent oscillations of over 10% from programmed level. With no operator action a reactor trip on either high or low steam generator level was imminent. The decision was made to place the main feedwater regulating valves in manual in an attempt to avert a reactor trip.

An operator who had limited experience with manipulation of main feedwater control was stationed on "B" steam generator feedwater control and was using the indication from the main feedwater master controller to determine adjustments to the position of the main regulating valve. The operator was also monitoring feed flow/steam flow chart recorders and steam generator level chart recorder as an aid in determining control actions, but to a lesser degree.

Due to feedwater flow adjustments made in response to indications from the feedwater master controller, a steam flow/feed flow mismatch occurred and was noted by the Shift Supervisor. The Shift Supervisor directed the operator to reduce feedwater flow below steam flow. Feed flow was reduced which resulted in even more of a level increase due to the "swell" effect that is characteristic of U-tube steam generators. A reactor trip occurred on high water level in "B" steam generator. The unit was at 66% FP.

Investigation of the control system oscillations revealed that the master feedwater controller proportional band was set higher than optimum for reduced power conditions which caused the feedwater system to respond slowly to transient conditions. This action had been taken while at 100% FP after startup from refueling to optimize system response at full power. This change complicated the control difficulty of this system in manual. The proportional band for the master controller was reset after the trip and the proper electronic camping for the main feedwater flow transmitters was verified. The system was tested and found to respond properly prior to plant restart. I&C Technicians have marked the proper proportional band control settings for both main feedwater controllers in the feedwater control system in an attempt to prevent a similar future occurrence.

2.15 ESF Actuation During Fuse Reinstallation

Palisades; Docket 50-255; LER 84-05; Combustion Engineering PWR

While shutdown, electrical work associated with the replacement of General Electric (GE) HFA relays in safety related circuitry resulted in an Engineered

Safety Feature Actuation. The Engineered Safety Feature Actuation consisted of a left channel Safety Injection Signal (SIS) Actuation, Containment Isolation Actuation and a Containment Spray Signal.

The incident occurred while non-licensed operations personnel were reinstalling fuses in the circuitry. The procedure in use did not specify a sequence for reinstallation of the fuses. As fuses were reinstalled, the arbitrary order of installation caused the Containment High Pressure (CHP) relays to become energized through the CHP pressure switch auxiliary relays. The resulting spurious CHP signal initiated the Engineered Safety Feature Actuation.

The SIS initiation started High Pressure Safety Injection (HPSI) Pump (P-66B), and opened the appropriate loop motor operated valves (MOVs). Level in the reactor vessel increased 1% before P-66B was manually tripped. The Containment Spray Signal opened control valve CV-3001, but did not result in spray actuation, because breakers were open, preventing the Containment Spray Pumps from starting.

The procedures for GE HFA relay replacement were reviewed and revised as necessary to preclude inadvertent equipment operation when removing/restoring fuses, links and jumpers.

2.16 Clogged Hydraulic Fluid Filters Cause a Reactor Scram

FitzPatrick; Docket 50-333; LER 84-13; General Electric BWR

During a plant startup a reactor scram occurred due to a high reactor pressure transient. During the roll of the main turbine as the turbine control valves were being opened to bring the turbine up to speed, Electronic Hydraulic Control (EHC) pressure decreased due to the increased demand. During this hydraulic pressure decrease the turbine bypass valves closed. The bypass valves were controlling reactor pressure at the time. Reactor pressure spiked to approximately 1060 psig. A reactor scram occurred as the result of high pressure signals to RPS (setpoint F1045 psig). Power decreased rapidly upon the scram thereby limiting the peak pressure that occurred. Vessel pressure was significantly below the safety relief valve setpoints.

The cause of the turbine bypass valve closure was determined to be clogged hydraulic fluid filters on the servoactuators for the valves. With the filters clogged the EHC system pressure dip caused by turbine control valve motion resulted in the bypass valve closure. Additional maintenance done during the investigation included replacement of erratic servoactuators on two of the bypass valves and replacement of EHC pump discharge filters. Long term corrective action will be the periodic replacement of the hydraulic fluid filters on the inlet to the servoactuators.

2.17 ESF Actuation and Reactor Trip

Turkey Point Unit 3; Docket 50-250; LER 84-14; Westinghouse PWR

On April 24, 1984, a reactor trip occurred. The root cause was determined to stem from a personnel error that propagated into the reactor trip. A Turbine Operator (TO) taking the "A" "standby" (AS) static inverter out of service erroneously opened the output breaker of an adjacent "normal" (3A) static inverter that was in service supplying power to a vital panel. Loss of power to the vital panel resulted in a turbine runback. Upon realizing his error, the TO reclosed the 3A inverter's output breaker. However, due to the current surge associated with instantaneously picking up all of the loads, coupled with an instrument power supply failure in a rack powered by the 3A inverter, a current limiter in the 3A inverter caused its output voltage to go low. A second turbine runback occurred when the 3A inverter's output voltage went low and resulted in a reactor trip. All equipment functioned as designed on initiation of the Engineered Safety Feature Actuation Signal (ESFAS) generated in the Reactor Protection System (RPS). The TO and licensed operators and supervisors on shift were cautioned against taking remedial action before allowing the plant to stabilize, following a plant transient, without full knowledge of what such actions could result in.

2.18 Installed Multi-meter Causes a Reactor Scram

Summer; Docket 50-395; LER 84-25; Westinghouse PWR

During the spring outage, a modification was made to the Main Turbine Thrust Bearing Wear Detector circuit. During the subsequent startup of the unit, the thrust bearing turbine trip was defeated by opening the proper terminal board link. Startup and power increase continued with actual rotor movement monitored by Instrument and Control, and Operations groups. The thrust bearing wear detector measurement device was normal with the exception of having a Fluke digital multi-meter across the contacts of the pressure switches. The multi-meter was left installed (power off) during testing to save the trouble of installing and removing the meter every time a measurement was made.

The decision was made to reinstate the thrust bearing wear detector trip because the plant was at 100% power. The technician performing the closure of the link did not adequately review the system status. When the link was closed, the input impedance (with power off) of the meter was seen in the Electrohydraulic Control as a closed contact which initiated a turbine trip which caused a reactor trip.

2.19 Reactor Water Cleanup System Isolation Due to Differences in Water Density

LaSalle Unit 1; Docket 50-373; LER 84-30; General Electric BWR

On May 31, 1984, the Reactor Water Cleanup System High Differential Flow alarm came up. The Nuclear Shift Operator (NSO) acknowledged the alarm and noted that isolation valves closed as required. The NSO sent an Operator to the RWCU areas in the plant to check for any leaks. No leaks were found. The "C" RWCU filter demineralizer was placed on line and the system was restarted.

On June 1, 1984, Reactor Water Cleanup System High Differential Flow alarm came up again. The NSO acknowledged the alarm and noted that outboard isolation valve closed as required. The NSO sent an Operator to the RWCU areas in the plant to check for any leaks. No leaks were found. Again the "C" RWCU Filter Demin was placed on line and the system was restarted.

At the time of the isolation on May 31, 1984, the plant was at 0% power with reactor pressure at 750 psig. The Turbine Driven Reactor Feedwater Pump flow was being reduced and the Main Steam Bypass Valves were being adjusted to control pressure.

At the time of the isolation on June 1, 1984, the plant was at 0% power with reactor pressure at 250 psig. The "C" RWCU Filter Demin was being placed in service and the blowdown flow to the condenser was being adjusted.

The cause of these occurrences was due to the design characteristics of the differential flow leak detection scheme. This logic involves three flow loops. One "sees" input to the system and two "see" outlets from the system. Due to the differences in water temperature in various points of the system each flow loop is calibrated for a different temperature (density) of water. All these calibrations are based on reactor water being at rated conditions under steady state conditions.

To allow for transients, a 45-second time delay is built into the differential flow isolation trip. However, at other than rated conditions, such as those mentioned above, actuations of this trip logic have occurred due to the instruments "seeing" other than design conditions.

Applicable procedures are being reviewed for possible revision to alert the Operators that this can occur during plant conditions other than rated conditions and to give guidance on actions which can be taken to reduce the likelihood of isolations of RWCU occurring on differential flow.

2.20 Turbine Overspeed Testing Causes a Reactor Scram

WPPS Unit 2; Docket 50-397; LER 84-54; General Electric BWR

As part of the Power Ascension Testing Program, main turbine overspeed testing was in progress. Per Procedure the Overspeed Protection Control (OPC) System was in service with a speed reference demand of 1890 RPM and an acceleration rate of 50 RPM per minute selected at the Digital Electro-Hydraulic (DEH) turbine valve control system operator's console. As the OPC test was initiated, the turbine accelerated to the OPC setpoint speed of 1854 RPM (103.0%) and the Turbine Governor and Intercept valves tripped closed causing turbine speed to decrease. Because DEH remained in OPC service, as soon as turbine speed dropped below 103.0%, the DEH immediately re-opened the Governor and Intercept valves. Turbine speed again accelered to the 1854 RPM (103.0%) OPC setpoint, causing the Governor and Intercept valves to reclose. This open/close cycling occurred about six times during a period of approximately 30 seconds. This tripping action caused turbine first stage pressure to increase above 108.5 psig, thus exceeding the design 30% power setpoint of the Reactor Protection System pressure switches. This removed the bypass function and the turbine governor valve fast closure signal incorrectly initiated a reactor scram.

A procedure deviation has been issued to the Main Turbine Generator Operating Procedure, to secure the OPC testing function of the DEH system after one complete cycle of the turbine governor valves to prevent recurrence of valve cycling. In addition, the associated Reactor Protection System pressure switches were reset to 131.5 psig as allowed by plant setpoint change methodology to further preclude recurrence of this event. Subsequent OPC testing has been successfully performed.

2.21 Corrosion of Reactor Coolant Fan Coolers

Zion Unit 2; Docket 50-304; LER 84-13; Westinghouse PWR

During the Unit 2 refueling outage, eddy current examination of the 2C reactor containment fan cooler (RCFC) cooling coils was performed. The results of the eddy current indicated internal pitting in many of the tubes (the tubes are made of 90/10 copper-nickel). These results were verified by removing tubes and analyzing the samples. The pitting in the tubes was determined to be caused by under-deposit corrosion. This type of corrosion is due to low water velocity through the tubes and corrodents in the cooling water. The tubes have all been cleaned via water blasting in order to remove some of the corrosive deposits and slow the corrosion rate. The four remaining RCFCs were then examined using eddy current and similar degradation of the tubes was found. The normal cooling medium is service water from Lake Michigan.

Following the eddy current examination, the RCFCs were filled and pressurized with service water to determine if there was any leakage. On all five of the RCFCs leakage was observed to various degress. An extensive testing program, consisting of a series of air pressure tests, was then performed on each RCFC in order to determine which tubes were leaking. All identified leaking tubes were plugged. The number of tubes plugged in each RCFC were: 12 in 2A; 16 in 2B; 37 in 2C; 38 in 2D; 34 in 2E. The total number of tubes plugged was 137.

Plans for the replacement of the RCFC cooling coils for both Unit 1 and Unit 2 are being finalized. This is the first time that the condition of the RCFC cooling coils has been determined. All previous attempts at eddy current examination of the RCFCs have yielded inconclusive results.

2.22 Electrical Storm Causes Spurious Starting of Diesels

McGuire Unit 1; Docket 50-369; LER 84-17; Westinghouse PWR

Diesel generators (D/Gs) 1A and 1B experienced an invalid automatic start. The D/Gs started on a blackout signal generated by a momentary power distribution system disturbance caused by an electrical storm in the service area. The blackout signal (Train A and B) was generated by an undervoltage condition on a 4160 volt essential switchgear due to line voltage fluctuations when an electrical storm passed through the service area. The D/Gs started when the load sequencers received signals from two out of three 4160 volt, instantaneous, undervoltage relays. The nominal setpoint of the undervoltage relays is 3500 volts. The plant was being supplied by offsite power so that 4160 volt essential switchgear were sensitive to system fluctuations.

The load sequencer has an eight-second time delay after starting the D/G before beginning a load shed and subsequent reloading of the D/G. The time delay confirms the validity of the blackout signal. The system disturbance cleared after 3 cycles (.050 seconds); clearing the blackout signal; therefore load shedding was not started and the D/Gs did not load. The licensee is pursuing installing a time delay on the UV relay to aid in the prevention of spurious starts.

2.23 Reactor Scram Due to Operation of the Wrong Valve

LaSalle Unit 2; Docket 50-374; LER 84-17; General Electric BWR

Unit 2 was scrammed manually when it became apparent that the Motor Driven Reactor Feed Pump could not be restarted and reactor vessel level could not be maintained above 12.5 inches. At the time of the event, the unit was proceeding with a normal shutdown.

The NSO (Licensed Operator) on the unit decided that at that point in the shutdown, it was convenient to close all the Reactor Feed Pump Warming Line Valves. These valves provide a flow path to the Reactor Vessel even though the discharge valve on the Reactor Feed Pump is closed. With any Warming Line Valve open on any of the Reactor Feed Pumps, it provides enough make-up to the vessel that make-up would exceed blowdown during low power operation and vessel level would rise at a rapid rate, which is not desirable. Therefore, the NSO on the unit instructed an Equipment Attendant (Non-Licensed Operator) to close the warming line valves on all three feedwater pumps. The warming line valves on the 2A and 2B TDRFP were correctly valved out. However, the Equipment Attendant valved out the Balancing Line Valve 2CB037 on the Motor Driven Reactor Feed Pump instead of the Warming Line Valve 2FW037. The Motor Driven Reactor Feed Pump tripped and could not be restarted. Both valves, the Balancing Line Valve 2CB037 and the Warming Line Valve 2FW037, are in the same room and about five (5) feet apart.

The Motor Driven Reactor Feed Pump had tripped on low lube oil pressure. The low lube oil pressure occurred due to clogging of the lube oil strainer. The clogging of the lube oil strainer occurred due to damage to the Thrust Bearing on the Motor Driven Reactor Feed Pump which released babbit into the Lube Oil System. Damage to the Thrust Bearing occurred because of a valving error which mistakenly closed the Drum Balancing Line Valve 2CB037 instead of the Warming Line Valve 2FW037. The Drum Balancing Line Valve 2CB037 must be kept open at all times except when the Motor Driven Reactor Feed Pump is to be taken out of service to ensure that no problems will occur on the Motor Driven Reactor Feed Pump.

The Equipment Attendant who closed the Balancing Line Valve 2CB037 instead of the Warming Line Valve 2FW037 indicated that he thought he was on the correct valve because the number "37" caught his eye on the valve Equipment Part Number. He did not read the entire noun name of the valve that was indicated on the associated valve tag. The Equipment Attendant also thought he was on the correct valve when he read the number "37" on the valve tag because he had just closed the Warming Line Valves on the A and B Turbine Driven Reactor Feed Pumps and there was similarity associated with the piping and valves between the Turbine Driven Reactor Feed Pumps and the Motor Driven Reactor Feed Pump. The Equipment Attendant was not given any indication that a Balancing Line Valve 2CB037 existed or the consequences if it were closed.

The following corrective actions were taken:

(1) A sign was placed on the Balancing Line Valve indicating that the valves should not be closed unless the pump is out of service.

(2) Equipment Attendants and License Personnel and all new Equipment Attendants were trained on the purpose of the Motor Driven Reactor Feed Pump Balancing Line.

2.24 Separation of an MSIV Disc

Duane Arnold; Docket 50-331; LER 84-16; General Electric BWR

During reactor operation at approximately 80% power on May ?, 1984, with no significant evolutions in progress, operators noted a minor (approximately 5 to 7 psig) reactor pressure increase. Investigation of plant instrumentation revealed a decrease in main steam line "C" flow from approximately 1.5 to 1 million pounds per hour. Attempts to "slow" cycle the "C" inboard main steam isolation valve were unsuccessful in affecting steam flow. Therefore, in accordance with Technical Specifications, the "C" inboard isolation valve was declared inoperable and the "C" outboard isolation valve closed to effect containment isolation. Reactor power was administratively reducted to approximately 75%. The "C" MSIV Leakage Control System was declared inoperable, due to the open MSIV position. Reactor shutdown was scheduled for investigation and repair of the MSIV.

Following shutdown, maintenance activities were initiated on the "C" inboard MSIV. This component is a Rockwell International 16" valve. The as-found condition of the "C" inboard valve was that the main disc had separated from the piston and was turned 90 degrees from its normal position in the valve body. This is the first occurrence of MSIV main disc failure at Duane Arnold. Previous failures at other facilities resulted in the disc seating in the closed position (see, for example, IE Information Notice 81-28).

Removal and inspection of the valve assembly and the loose disc found that: 1) the main disc to piston pin was still in the disc but had been "rolled over" following the separation, 2) the pin hole in the piston was elongated in the axial direction, 3) the piston and main disc threads where the main thread engagement had been were stripped, and 4) the top 2 to 3 piston threads showed no indications of having been engaged. Metallurgical defects or flaws were determined not to be a contributing cause. It was determined that the maintenance reassembly activities when the valve was last reassembled during the Spring 1982 outage were the cause of the eventual piston/disc separation. The Repair Procedure and instruction manual used to attach the disc to the piston required the disc/piston assembly to be "torqued tight." In this specific case, this left the top threads unengaged and the disc not threaded completely onto the piston. Normal flow conditions caused the disc to vibrate on the piston and eventually wear the threads and locking pin to the point where the assembly separated. Material wear markings on top of the stem-disc indicated the piston/disc assembly was oscillating against it. Over the past two years of operation, the disc began to move on the piston until the threads were finally worn down and only the pin held the disc in place. The final result was a piston/disc separation. Rockwell has recently revised the torque recommendation for reassembled piston/disc assemblies to 500 ft-lb. However, Rockwell agrees that the revised recommendation does not necessitate piston/disc disassembly and retorquing of the remaining valves in service. As discussed below, our lack of prior piston/disc failures, inspections during previous valve maintenance activities and disassembly of two additional MSIVs support this conclusion.

It was decided to disassemble and inspect two additional valves in order to have a representative sample of the eight MSIVs. The "C" outboard and the "B" inboard valves were chosen. This provided a check of the downstream valve in the same line and the other valve installed with a "mirror image" piping configuration. This inspection found no similar failures, wear, or unusual conditions in the piston to piston disc assembly. In both cases, the pins were secure and the discs were fully tightened up against the piston shoulder.

2.25 Inadvertent Operation of General Electric Type HGA Relay

Duane Arnold; Docket 50-331; LER 84-18; General Electric BWR

The plant was in run mode at 72% power with the "C" steam line isolated because of an inoperable inboard Main Steam Isolation Valve. A monthly surveillance test was being performed on the RCIC Steam Line High Differential Pressure (Steam Line Break Detection) system which required removing the cover from a relay in the RCIC Steam Leak Detection High Differential Pressure circuit. The relay was inadvertently jarred which caused it to be energized. RCIC isolation and turbine trip signals were received and the inboard turbine steam supply isolation valve closed. The RCIC system was in normal standby mode at the time of the event. Operators immediately reset the turbine trip signal and reopened the valve.

A search of past plant deviations revealed no other instances of RCIC turbine isolations or other spurious General Electric Type HGA relay actuations caused by jarring or vibrating the relays. However, when reviewing the event with Electrical Maintenance and involved technicians, it was stated that it is difficult to remove the covers from some of the Type HGA relays. This is caused by slight misalignment of the mounting spring tab clips on the sides of the covers.

The licensee is currently conducting an engineering study to determine the feasibility of installing hardwired test circuits and switches to perform safety related surveillance test procedures. These will be used instead of temporary jumpers and complicated test sequences that alter circuit configurations. A request has been made to specifically include HGA relays that meet the above criteria.

2.26 Movement of Heavy Loads Over Spent Fuel

Oyster Creek Unit 1; Docket 50-219; LER 84-10; General Electric BWR

During a review of a proposed modification to the existing spent fuel storage rack configuration, a question was raised as to whether or not the fuel pool gates are moved over spent fuel during their removal or replacement sequences. Although Operations representatives could not specifically cite any one particular instance of this, they believe that movement of the gates (each of which weighs approximately 1800 lbs.) over spent fuel may have occurred several times during past refueling operations.

In reviewing engineering and design documents for the spent fuel storage rack expansion modification, Technical Functions personnel contacted on-site Operations personnel in order to determine whether or not the fuel pool gates are moved over the spent fuel during refueling operations. Technical Functions' concern was that each of the gates weighs approximately 1800 lbs., and that movement of these gates over the fuel is a violation of Technical Specifications. Although no specific instance of this could be cited by the Operations personnel, they acknowledged that it may have occurred on several occasions during past refueling cycles, but was never observed or noted.

In order to remove or replace the fuel pool gates from their in-service configuration, the station procedure requires that they be rigged to the 5-ton auxiliary hoist and moved to a staging location on the south wall of the fuel pool. The station procedure used for movement of these gates refers to the reactor building overhead crane operating procedure, with an emphasis for the personnel involved in the movement to be familiar with the precautions section of the crane operating procedure. The prerequisite section contains several paragraphs that strictly detail what loads (by weight) may or may not be lifted in the vicinity of irradiated fuel. However, the gate removal or replacement procedure does not specifically state the weight of the individual gates. It is possible that had the weight been stated, the gates would not have been moved over irradiated fuel in accordance with the crane operating procedure.

Maintenance personnel involved in the removal and replacement of the fuel pool gates will be cautioned regarding adherence to station procedures involving the reactor building overhead crane. Additionally, the station procedure for the gate movements will be revised to specifically state that the gates may not pass over spent fuel. These revisions will provide the administrative assurance that irradiated fuel will be shuffled, and suspended equipment will be rearranged in appropriate combinations such as to prevent movement of the gates over spent fuel.

2.27 Reactor Scram Caused by Securing the Wrong Lube Oil Pump

Sequoyah Unit 2; Docket 50-328; LER 84-08; Westinghouse PWR

Unit 2 had been reduced to 30% reactor power for addition of oil to reactor coolant pumps. During the reduced power level condition, various maintenance activities were being performed which included repairing oil leaks on both the 2A and 2B main feedwater pumps. The 2A main feedwater pump was removed from service, all of its oil pumps stopped, and the leaks repaired. The 2A main feedwater pump was returned to service and the 2B main feedwater pump removed from service. When it came time to stop the 2B main feedwater pump oil pumps, the operator inadvertently stopped the 2A main feedwater pump oil pumps. This action caused the 2A main feedwater pump to trip resulting in a subsequent reactor trip on low-low level in the number 2 steam generator. Unit 2 was at 30% reactor power just prior to the reactor trip.

2.28 Combined Unit Loads Exceed Battery Charger Capacity

Quad-Cities Units 1 and 2: Dockets 50-254 and 50-265; LER 84-08; General Electric BWRs

On May 3, 1984, preparations were being made for the Unit 1 125 Volt Battery Discharge Test. To isolate the Unit 1 battery for the test, the 125 Volt DC buses that are its normal load were transferred to the Unit 2 battery in accordance with the discharge test procedure. When the transfer was completed, the number 2 125 Volt Battery Charger began current limiting at 120 amperes and then tripped after 20 minutes.

Since the number 2 Battery Charger was unable to sustain the load of both units, the Unit 1 load was transferred back to the Unit 1 battery and the Unit 1 discharge test was postponed. In an effort to complete the battery discharge test promptly, repair work to the other battery charger capable of supplying the Unit 2 125 Volt DC battery, number 2A, was initiated. The number 2A charger is a larger capacity, new charger, which was out of service awaiting repair at the time of this event. After returning the number 2A Battery Charger to service, the Unit 1 load was transferred to Unit 2 again. When it was verified that the number 2A Battery Charger was sustaining the load satisfactorily, the Unit 1 Battery Discharge test was performed.

During this time, the reason for the inability of the number 2 Battery Charger to carry both Unit 1 and 2 loads was investigated. It was determined that the typical Unit 1 125 Volt DC load of 75 amperes exceeded the eight-hour discharge rating of the battery. Although the Unit 2 normal load of 50 amperes was below the battery rating, the two units' loads, when combined, exceeded the rating of the number 2 Battery Charger. Concern was then raised as to the adequacy of the 125 Volt Station batteries relative to the present load on them. This resulted in the Station Nuclear Engineering Department performing a load profile analysis for several different postulated accident conditions. Although not required in the original design basis for battery sizing, the Station Nuclear Engineering Department conservatively included the analysis of a loss of off-site power with a loss of AC feed to the 125 Volt Battery Chargers and both units at full power. The load profile for this limiting case revealed that the 125 Volt Station batteries could not bring both units to Cold Shutdown without some of the non-essential DC loads being shed.

On May 11, 1984, a procedure was implemented to reduce battery load in the event of failure of the 125 Volt Battery Chargers. A sufficient amount of non-essential load will be manually shed from the DC buses to reduce the 125 Volt battery current below 62 amperes within 30 minutes of the postulated transient.

Long-term corrective action will encompass two separate projects. The existing non-seismic 125 Volt Battery Chargers will be replaced with seismically installed units of larger capacity. At present, the Station Nuclear Engineering Department is evaluating the 125 Volt DC load profiles with regard to battery ampere-hour capacity. This will result in the existing 125 Volt Station batteries being replaced with batteries of greater capacity.

2.29 Possible Error in Calculated Thermal Power Due to Temperature Stratification

San Onofre Unit 2; Docket 50-361; LER 84-09; Combustion Engineering PWR

An analysis of startup test data established that Calculated Thermal Power (BDT), calculated by the Core Protection Calculators (CPCs), may become decalibrated relative to secondary calorimetric power as a result of changes in radial core power distribution. BDT is generated by using the mass flow rate of the reactor coolant and temperature rise across the core. Due to temperature stratification in the coolant leaving the reactor vessel, the hot leg temperature (T_H) detectors may provide signals to the CPCs which are not representative of average reactor coolant bulk temperature. The error in the calculation of BDT could result in nonconservative values of Local Power Density (LPD) and Departure from Nucleate Boiling Ratio (DNBR). Since changes in radial core power distribution directly affect the temperature stratification which occurs, once BDT has been calibrated with secondary calorimetric power, changes in power level or Control Element Assembly (CEA) configuration may result in the decalibration of BDT beyond the design allowance.

Combustion Engineering has evaluated the impact of decalibration of BDT and has concluded that the plant has operated within the bounds of its safety analysis, and even under the most adverse decalibration effects, the specified Fuel Design Limits would not have been exceeded during an accident.

It is important to note that BDT is only needed for certain CEA deviation events, and that a number of conditions are required to be present concurrently for thermal power decalibration to result in nonconservative values of LPD and DNBR. Procedure S023-5-1.7 was changed to include provisions for verifying BDT calibration at 20 percent power intervals during power ascension and following movement of CEA's. Although the probability of the events of interest is not within the definition of Anticipated Operational Occurrences, the corrective action above will explicitly account for this decalibration effect.

An interim change was made to the CPC addressable constants. This change had increased the CEA deviation penalty factor multipliers to accommodate single CEA deviation events under the most adverse BDT decalibration. However, the interim change was determined to be a contributing cause for a subsequent reactor trip due to low DNBR. To prevent recurrence of this type of trip the penalty factor multipliers were returned to the original values.

2.30 Both Trains of Standby Gas Treatment System Inoperable

Oyster Creek Unit 1; Docket 50-219; LER 84-11; General Electric BWR

Annual circuit breaker preventive maintenance had been scheduled. The maintenance required that the circuit breaker supplying power to the 460 volt Motor Control Center (MCC) be racked out, resulting in de-energization. This Motor Control Center provides power to the emergency exhaust fan and three solenoid valves for System II of the Standby Gas Treatment System (SGTS). De-energization of the System II exhaust fan renders this train of the SGTS inoperable. The three solenoid valves supply air to the diaphragm operated inlet, outlet and orifice valves for the system II exhaust fan. When power is lost to these solenoid valves the air supply to the diaphragm valves is vented off, causing the diaphragm valves to open. Since the SGTS trains are situated in parallel and feed a common discharge duct, some bypass recirculation flow would occur through the open SGTS II valves if SGTS I was initiated. This degrades the ability of SGTS I to perform its intended function.

2.31 Design Specifications Inconsistent with FSAR Commitments

Crystal River Unit 3; Docket 50-302; LER 84-01; Babcock & Wilcox PWR

During a refueling outage, the end plate on the reactor building site of a spare penetration was mistakenly cut off. A plant modification package was issued to replace the end cap on this penetration.

A subsequent routine review of the modification package discovered:

(1) ASTM A-36 was specified as the new end plate material (The FSAR requires SA-516 Grade 60, impact tested to SA-300, and having certified mill test reports.)

(2) All welding was required to be inspected per B31.7 - 1969. (The FSAR requires the NDE to be per ASME Section III Class B.)

(3) The Modification Approval Record (MAR) specified a "soap test" to be performed on the welds on the Auxiliary Building side of the penetration during the Integrated Leak Rate Test. This is not in compliance with 10 CFR 50, Appendix J, Section IV.A, "Containment Modification." The proper test, however, was performed despite the MAR specifying the wrong test.

(4) The safety evaluation in the MAR indicated that no changes to the FSAR were required. (This is a violation of Safety Related Engineering Procedure (SREP) in that the Design Engineer failed to identify the FSAR change, and a violation of SREP-4 in that the Verification Engineer failed to detect the error.)

(5) The applicable design drawing was not changed to reflect the changes in the end plate thickness, plate material, and NDE. (This is a violation of SREP-2, in that the Design Engineer did not correctly translate the design information onto the drawing and issue it as an interim drawing, and a violation of SREP-4 in that the Verification Engineer failed to detect the error.)

Personnel error is the cause in that both the Design Engineer (a contract employee) and the Verification Engineer (a licensee employee) failed to follow applicable engineering procedures.

2.32 Improved Practices to Minimize Missed Surveillance Requirements

Quad-Cities Unit 2; Docket 50-265; LER 84-06; General Electric BWR

It was discovered, during a review of the weekly summary sheet by the Instrument Maintenance Department, that the Weekly Power Operation Surveillance had not been performed. The interval of 10 days exceeded the Technical Specification interval of 7 days, +/-25% (8.75 days).

The Weekly Power Operation Surveillance is a functional test of the APRM downscale and Hi Rod Blocks, APRM Hi-Hi/Inop scrams, and Main Steam Line High Radiation scram. These functional tests are required by Technical Specifications. Upon discovery that the surveillance had not been completed, the surveillance test was immediately started, and satisfactorily completed.

The cause of this event is personnel error. The surveillance interval was exceeded due to an oversight by the Instrument Maintenance Scheduler/Planner. The Instrument Mechanic originally scheduled to perform the test was unable to complete his assignment before the end of the day and there was a failure to reschedule the test for the next day.

Since the method of discovery was a review of the weekly summary sheet, the corrective action has been to prominently display the summary sheet at the entrance to the Instrument Maintenance Foreman's office, so that a casual review will be performed daily to remind the Foreman of the need to perform this weekly surveillance.

2.33 Possible Loss of Redundant Room Cooling by Single Failure

Browns Ferry Units 1-3; Dockets 50-259, 50-260, and 50-296; LER 84-22; General Electric BWRs

During IE Bulletin 79-01B evaluations, it was determined that during a loss of coolant accident in conjunction with loss of offsite power, necessary cooling equipment for some electrical board rooms for units 1 and 2 could be lost. Because of a design error, the normal exhaust fans (common to board rooms "A" and "B" on unit 1, and board rooms "C" and "D" on Unit 2) are automatically and permanently load shed from their power supply upon receipt of an accident signal (LOCA) and concurrent loss of offsite power.

A single failure of a 480V reactor motor operated valve board (1A, 2A, or 3A) causes the loss of redundant cooling equipment for some electrical board rooms. The equipment affected is the normal exhaust fan (1A board affects electrical board rooms A and B; 2A board affects electrical board rooms C and D; 3A board affects electrical board rooms 3A and 3B) and the emergency air-conditioners for electrical board rooms A, C, and 3A. This is contrary to the Final Safety Analysis Report, (Note: Room cooling is dependent upon either the exhaust fan or the emergency air-conditioner.)

The Plant Operating Instruction - 57, and Emergency Operating Instruction - 36 have been revised to include appropriate action to be taken upon loss of the cooling units listed above. The instruction options include jumpering the 480V load shed logic contacts on the units 1 and 2 fans affected within the first hour of losing ventilation, and/or providing an exhaust path in the exhaust fan ductwork following the loss of a 480V RMOV BD (1A, 2A, or 3A) (DUCT).

It is anticipated that long-term corrective action will consist of correcting the load shedding logic, separating the power sources for electrical board room cooling equipment, and making various changes to provide environmental qualification of the ventilation equipment.

3.0 ABSTRACTS OF OTHER NRC OPERATING EXPERIENCE DOCUMENTS

3.1 Abnormal Occurrence Reports (NUREG-0090) Issued in May-June 1984

An abnormal occurrence is defined in Section 208 of the Energy Reorganization Act of 1974 as an unscheduled incident or event which the NRC determines is significant from the standpoint of public health or safety. Under the provisions of Section 208, the Office for Analysis and Evaluation of Operational Data reports abnormal occurrences to the public by publishing notices in the Federal Register, and issues quarterly reports of these occurrences to Congress in the NUREG-0090 series of documents. Also included in the quarterly reports are updates of some previously reported abnormal occurrences, and summaries of certain events that may be perceived by the public as significant but do not meet the Section 208 abnormal occurrence criteria.

Date Issued	Report
5/84	REPORT TO CONGRESS ON ABNORMAL OCCURRENCES, OCTOBER-DECEMBER 1983, NUREG-0090, VOL. 4, NO. 3

There were three abnormal occurrences during the report period. One occurred at a licensed nuclear power plant, and the others occurred at NRC and Agreement State licensed radiographers. The occurrence at the plant involved problems with Transamerica Delaval, Inc. emergency diesel generators at Shoreham. The other occurrences involved overexposures of radiographers at Pittsburgh Testing Laboratory in Pittsburgh, Pennsylvania, and at X-Ray Inspection Company in Lafayette, Louisiana.

Also, the report provided update information on the nuclear accident at Three Mile Island (79-3), first reported in Vol. 2, No. 1, January-March 1979; and on large diameter pipe cracking in boiling water reactors, first reported in Vol. 6, No. 3, July-September 1983.

In addition, discussion of items of interest that did not meet abnormal occurrence criteria included contamination due to failed fuel at Cooper, and failed fuel assemblies at Millstone.

3.2 Bulletins and Information Notices Issued in May-June 1984

The Office of Inspection and Enforcement periodically issues bulletins and information notices to licensees and holders of construction permits. During the period, one information notice supplement and 17 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.

Information Notice	Date Issued	Subject
83-66 Supplement 1	5/25/84	FATALITY AT ARGENTINE CRITICAL FACILITY All nuclear power reactor facilities holding an operating license or construction permit and nonpower reactor, critical facility, and fuel cycle licensees were provided supplemental information to Information Notice 83-66, issued on October 7, 1983, regarding the September 23, 1983 RA-2 accident near Buenos Aires. Included with Supplement 1 to this notice was a translated copy of investigation results provided to the NRC Office of International Programs by the Argentine National Atomic Energy Commission.
84-36	5/1/84	LOOSENING OF LOCKING NUT ON LIMITORQUE OPERATOR All holders of a nuclear power reactor operating license or construction permit were informed of a potentially generic problem with a Limitorque Model/ SMB-4, valve motor operator. The problem involves loosening of a set screw for the locking nut on the worm gear shaft of the operator leading to inoperability

Information Notice	Date Issued	Subject
		of the valve. Similar loosening problems with Limitorque operators were addressed in IE Circular 79-04. The concerns and recommended actions noted in that document are also applicable here. It was expected that recipients review the information for applicability to their facilities and consider actions, if appropriate, to preclude similar problems occurring at their facilities.
84-37	5/10/84	USE OF LIFTED LEADS AND JUMPERS DURING MAINTENANCE TESTING All nuclear power plant facilities holding an operating license or a construction permit were alerted to the potential for significant degradation of safety associated with the use of lifted leads or jumpers during either maintenance or surveillance testing. This information was also provided to emphasize the value of independent review of the use of lifted leads and jumpers. Discussion of serious degradation of safety-related systems in connection with the use of lifted leads or jumpers included events at San Onofre Unit 3 on February 27, 1984, and at Sequoyah Unit 1 on September 11, 1983. Recipients were expected to review the information for applicability to their facilities and consider actions, if appropriate, to preclude similar problems occurring at their facilities.
84-38	5/17/84	PROBLEMS WITH DESIGN, MAINTENANCE, AND OPERATION OF OFFSITE POWER SYSTEMS All power reactor facilities holding an operating license or construction permit were notified of potentially significant problems pertaining to the design, maintenance, and operation of offsite power systems. The general concern is that design, maintenance, and operational problems in electrical equipment considered to be non-safety related can greatly degrade access to offsite power sources. This is not consistent with the General Design Criteria objectives. The concern is particularly valid where station service loads are arranged such that a single electrical fault can cause a transient resulting in a plant trip and also defeat immediate access to offsite power sources. The concern is also particularly valid for facilities with multi-unit plants or a common switchyard for nuclear and non-nuclear units. Events discussed included those that occurred at Turkey Point in February 1984, where a series of events included reactor trips, unscheduled shutdowns, and loss of power to one unit. These events occurred as a direct result of problems with design, maintenance, and operation of the offsite

Information Notice	Date Issued	Subject
		power system. It was expected that recipients of this notice review their facilities and consider actions, if appropriate, to preclude similar problems occurring at their facilities.
84-39	5/25/84	INADVERTENT ISOLATION OF CONTAINMENT SPRAY SYSTEMS
		All pressurized water power reactor facilities (PWRs) holding an operating license or construction permit were alerted to the potential for significant degradation of safety associated with the inadvertent isolation of containment spray. During shutdown conditions when containment entries are being made, PWR operators find it desirable to close the manual isolation valves in each spray header and/or put the spray pump control switches in the pull-to-lock position. These actions prevent inadvertent containment spray actuation during maintenance and testing activities. However, when valve alignment check-off lists are completed before restart, procedural inadequacies or personnel errors have resulted in plants going back to power with the isolation valves closed or the pumps in the pull-to-lock position, thus preventing automatic operation if needed. An event at Farley Unit 2 on October 24, 1982, was discussed. It was recommended that recipients of this notice review their existing procedures for locking out and returning containment spray systems to operation, and determine whether any changes to the existing procedures would be desirable in light of the information provided. (See p. 1.)
84-40	5/30/84	EMERGENCY WORKER DOSES
		All nuclear power plant facilities holding an operating license or construction permit, research and test reactor facilities and fuel cycle licensees were informed of instances of misunderstandings concerning the proper management of personnel radiation exposures in excess of regulatory limits occurring from emergency response activities. Guidance from the NRC staff was provided to clarify this issue and to inform potential emergency preparedness volunteer workers of possible post emergency work restraints subsequent to emergency response activities. Recipients of this notice were expected to review the information for applicability to their training programs and instructions to personnel. Although no response was required, licensees were expected to correct instances of misinformation regarding NRC regulations supplied to potential emergency preparedness volunteer workers.

Information Notice	Date Issued	Subject
84-41	6/1/84	IGSCC IN BWR PLANTS All boiling water power reactor facilities holding an operating license or construction permit were provided information on further significant intergranular stress corrosion cracking (IGSCC) indications found in piping systems of boiling water reactors as a result of expanded inspection efforts not included within the scope of current augmented inservice inspection requirements. The inspections cited in this notice did not constitute new NRC requirements. The NRC staff is reviewing this information and its safety significance. If the evaluation so indicates, the NRC may require further licensee action. In the interim, recipients were expected to review their facility's status and consider nondestructive examination, as appropriate, to assess potential degradation of such piping welds during their in-service inspection activities or planned piping replacement programs.
84-42	6/5/84	EQUIPMENT AVAILABILITY FOR CONDITIONS DURING OUTAGES NOT COVERED BY TECHNICAL SPECIFICATIONS All holders of a nuclear power plant operating license or construction permit were alerted to the importance of controlling equipment availability for conditions during outages not covered by technical specifications. The notice discussed a January 8, 1984 event at Palisades, during which a complete loss of offsite and onsite ac power was precipitated by the need to isolate a faulty switch and breaker. It was expected that recipients of the notice review the information for applicability to their facilities and consider actions, if appropriate, to preclude similar problems occurring at their facilities.
84-43	6/7/84	STORAGE AND HANDLING OF OPHTHALMIC BETA RADIATION APPLICATORS All medical licensees were notified of recent findings where strontium-90 eye applicators were stored with radiation levels in excess of regulatory requirements and possibly unnecessarily exposed the public to radiation. Recipients were expected to review the information for applicability to their facilities and consider actions, if appropriate, to preclude similar problems occurring at their facilities.

Information Notice	Date Issued	Subject
84-44	6/8/84	ENVIRONMENTAL QUALIFICATION TESTING OF ROCKBESTOS CABLES All holders of a nuclear power operating license or construction permit were notified of potential generic problems regarding Rockbestos environmental qualification testing of Class 1E electrical cables. The results of NRC inspections of the QA programs established at several environmental testing facilities showed that several deficiencies were present in the Rockbestos Company qualification programs in effect at the time of the audit. It appears that the validity of some of the Rockbestos qualification reports is in doubt, however, the NRC staff has concluded at the time of issuance of this notice that no immediate safety problem existed in the use of Rockbestos cables. The NRC staff considered it to be the responsibility of the user utilities to review the information provided, and take applicable corrective action to ensure the qualification of Rockbestos cables installed in their plants. Suggested corrective actions were provided.
84-45	6/11/84	REVERSED DIFFERENTIAL PRESSURE SENSING LINES All nuclear power reactor facilities holding an operating license or construction permit were notified of a potentially significant problem pertaining to reversed differential pressure instrument sensing lines in safety-related systems. In the past few years, the NRC has received a number of reports that describe events that primarily occurred during construction and preoperational testing that involved discovery of the high- and low-pressure sensing lines for safety-related differential pressure instrumentation being reversed. Although the available information suggests that there has been a significant reduction in events involving reversed sensing lines as a result of an industry-wide improvement in plant construction and startup testing, it appears that adequate procedures for verifying the proper installation of high- and low-pressure sensing lines may not have been used for the high-flow break detection instrumentation for the isolation condensers of some early generation boiling water reactors (BWRs). It was suggested that recipients of the notice consider improving the applicable procedures, as appropriate, to ensure that reversed sensing lines in differential

Information Notice	Date Issued	Subject
		pressure instrumentation are detected and corrected. Specifically, that licensees of BWR facilities with isolation condensers consider verifying the proper installation of sensing lines for isolation condenser pipe break protection instrumentation, if not already performed.
84-46	6/13/84	CIRCUIT BREAKER POSITION VERIFICATION All holders of a nuclear power operating license or construction permit were notified of a recent event that may have safety significance. The event occurred on Februa[illegible] 1984 at McGuire. Breaker No. 1EPA-10, which con[illegible]e 1A centrifugal charging pump, was racked to [illegible]e DISCONNECT position so that a routine oil sample could be collected from the pump. Sampling was complete 2 hours later and the circuit breaker was supposedly returned to the CONNECT position. The assistant shift supervisor and a control room operator then independently confirmed that the breaker was in a CONNECT position by status indication lights on the control board. However, on February 20, 1984, during normal equipment rotation, it was discovered that the breaker had not been returned to the CONNECT position and that it had been in an inoperable state for seven days. This occurred because the assistant shift supervisor and a control room operator had used an invalid indication to verify that the breaker was in a CONNECT position. Four items required to be performed to verify breaker position and operability were provided. It was expected that recipients of the notice review the information for applicability to their facilities.
84-47	6/15/84	ENVIRONMENTAL QUALIFICATION TESTS OF ELECTRICAL TERMINAL BLOCKS All nuclear power reactor facilities holding an operating license or construction permit were provided with information pertaining to the results of a recent NRC-sponsored environmental qualification methodology research test conducted on electrical terminal blocks. The notice also served as an early notification regarding the reduction of insulation resistance values sustained by certain terminal blocks used in a Conax Electrical Penetration Assembly during a design basis event simulation test.

Information Notice	Date Issued	Subject
		The results of the testing showed that a moisture film will form on the surface of the terminal block during the simulation of the LOCA/MSLB events, and will result in the reduction of insulation resistance between terminal points and ground, and thus will allow some leakage currents to flow to ground. In addition to this concern of leakage currents, licensees and construction permit holders were reminded that other information concerning on-going preventive maintenance activities that involve periodic inspection of terminations and terminal blocks for cleanliness as described in previously published Information Notice No. 82-03 remain in effect.
84-48	6/18/84	FAILURES OF ROCKWELL INTERNATIONAL GLOBE VALVES All nuclear power reactor facilities holding an operating license or a construction permit were alerted to a potential deficiency in the design, application, or maintenance of Rockwell International globe valves that may have safety and/or economic significance at nuclear power facilities. These deficiencies have resulted in two types of failures: (1) the stem separating from the disk and (2) the disk being backed off its disk nut (Attachment 1 to this notice). Although no specified action or response was required, recipients were expected to review the information contained in this notice for applicability to their facilities and initiate any needed diagnostic, preventative, or corrective action. Likewise, licensees finding similar or related defects at their facilities were encouraged to report their findings to the Commission, including the corrective actions taken, so that the industry may benefit from their experience.
84-49	6/18/84	INTERGRANULAR STRESS CORROSION CRACKING LEADING TO STEAM GENERATOR TUBE FAILURE All pressurized water power reactor facilities holding an operating license or construction permit were notified of potentially significant problems pertaining to operation and inservice inspections of steam generators in pressurized water reactor systems. The notice discussed an event that occurred at Fort Calhoun in February 1984, in which eddy current testing (ECT) showed steam generator tube defects or flaws that were missed by an analyst reviewing the ECT tapes prior to hydrostatic testing in preparation for return to power following a refueling outage. During the hydrostatic testing, one tube failed due to intergranular stress corrosion cracking. The licensee

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		reevaluated, with independent verification, the ECT data tapes for tubes tested during 1984. Investigations by Combustion Engineering and the licensee are continuing in an effort to identify the cause of the cracking.
84-50	6/21/84	CLARIFICATION OF SCOPE OF QUALITY ASSURANCE PROGRAMS FOR TRANSPORT PACKAGES PURSUANT TO 10 CFR 50, APPENDIX B All nuclear power reactor facilities holding an operating license or construction permit were provided information to help eliminate any confusion as to the applicability of the quality assurance provisions of Appendix B, 10 CFR 50 to certain transport packages for which a quality assurance program is required by the provisions of 10 CFR 71. Past inspections of transportation activities and the associated QA programs of nuclear utilities have sometimes revealed a generic inadequacy regarding implementation by licensees of Commission-approved, 10 CFR 50, Appendix B, QA programs for transport packages. Specifically, this inadequacy usually is evidenced by nonexistent or deficiently written QA audits for transport packages. Apparently some licensees have erroneously concluded that the previous NRC approval of the 10 CFR 50, Appendix B, program implies fulfillment of the implementing QA requirements for transport packages, without reservation. Licensees should not automatically assume that such implementing procedures developed for Appendix B are adequate for transport packages unless such procedures do, in fact, address transport packages. Recipients of this notice were expected to review the information provided for applicability to their programs.
84-51	6/26/84	INDEPENDENT VERIFICATION All nuclear power facilities holding an operating license or construction permit were informed of a continuing incidence of personnel errors or procedural errors that have resulted in inadvertent reactor trips and safety-related equipment inadvertently placed in an inoperable status. These events are considered by the NRC to be avoidable contributors to risk to the public health and safety. This notice was issued to emphasize the importance of independent verification to reduce the rate of occurrence of such errors. It was expected that recipients review the information provided for applicability to their facilities and consider actions, if appropriate, to preclude similar problems occurring at their facilities.

Information Notice	Date Issued	Subject
84-52	6/29/84	INADEQUATE MATERIAL PROCUREMENT CONTROLS ON THE PART OF LICENSEES AND VENDORS All nuclear power reactor facilities holding an operating license or construction permit were informed of deficient procurement controls and quality assurance (QA) practices on the part of suppliers of nuclear materials, and of possible generic problems in procurement activities of licensees. No specific action was required in response to this information notice, but it was expected that recipients review the information presented for applicability to their facilities.

3.3 Case Studies and Engineering Evaluations Issued in May - June 1984

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

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

These AEOD reports are made available for information purposes and do not impose any requirements on licensees.

The findings and recommendations contained in these reports are provided in support of other ongoing NRC activities concerning the operational event(s) discussed, and do not represent the position or requirements of the responsible NRC program office.

Engineering Evaluation	Date Issued	Subject
E409	5/16/84	OPERATING EXPERIENCE INVOLVING AIR IN SENSING LINES

Proper operation of reactor safety systems in both PWR and BWR plants requires an accurate measurement of various differential pressure signals. Liquid level instruments are used to determine water level in the various tanks and vessels in various safety and non-safety systems. Fluid flow instruments are used to measure the fluid flow rate at various points within primary, secondary, and standby safety systems. Air getting into sensing lines of one or more redundant level, fluid flow, or pressure instruments at the same time without detection could have important safety consequences.

Nineteen instrument failures due to air getting into instrument sensing lines were reviewed. Failed instruments consisted of water level instruments, fluid flow instruments, and pressure measuring

Engineering Evaluation	Date Issued	Subject
		instruments. Only seven out of nineteen cases gave a specific cause of air getting into the sensing lines. No severe plant consequences resulted from these failures. This was mainly due to the redundancy of the instruments involved. In addition, alarms, annunciators, and instrument train comparisons usually quickly alert the operator to take the needed corrective actions. Thus, the probability of both independent trains being inoperable due to air in the sensing lines(s) in one train, in coincidence with a second instrument train failing due to a random single failure or because of instrument calibration, is considered to be very small. Therefore, the probability of this type of failure causing a significant safety problem during a transient is considered to be relatively low. In general, this engineering evaluation found that the failure of instruments due to air in the sensing lines is not a serious problem.
E410	5/21/84	OPERATIONAL EXPERIENCES INVOLVING STANDBY GAS TREATMENT SYSTEMS WHICH ILLUSTRATE POTENTIAL COMMON CAUSE FAILURE OR DEGRADATION MECHANISMS This report primarily addresses operational experience events involving Standby Gas Treatment Systems (SGTS) that illustrate potential common cause failure or degradation mechanisms. Such mechanisms may result in failure or degradation of the functional performance of redundant trains of this system or preclude the function of one train while degrading the functional performance of the redundant train. The potential common cause failure or degradation mechanisms identified in this report are the direct result of design deficiencies or inadequate testing and maintenance procedures in conjunction with actual practices. The report provides: (1) results of review and evaluation of related events and occurrences for the approximate three-year period from August 1980 to November 1983, and (2) suggested actions which if properly implemented could lead to a reduction in the potential for such mechanisms preventing or degrading the functional performance of SGTS. The primary sources of information for this report were licensee event reports and IE (Office of Inspection and Enforcement) Inspection Reports.

Engineering Evaluation	Date Issued	Subject
E411	5/22/84	FAILURE OF ANTI-CAVITATION DEVICE IN RESIDUAL HEAT REMOVAL SERVICE WATER (RHRSW) HEAT EXCHANGER OUTLET VALVE

Licensee Event Report 82-085 for Hatch 2 (Docket 50-366) describes an event in which two pumps of the RHRSW system failed to meet minimum flow requirements and were declared inoperable during a functional test. Since both pumps served in the same loop of the RHRSW system, only one of the two RHRSW loops became inoperable. The cause of this event was the failure of an anti-cavitation device which was installed in the flow control valve. This was a recurrent event; two previous events at Hatch 2 involved similar failure of anti-cavitation devices installed in the same system. In one of the events, one loop of the system became inoperable; in the other, both loops were declared inoperable. Two additional events at Salem 1 found during this review have had similar failures of anti-cavitation devices. The damaged anti-cavitation devices and their associated control valves used in these two units are different in size but were made by the same manufacturer (Fisher Vee-ball).

The apparent cause of damage to the anti-cavitation devices was erosion due to sand suspended in high velocity fluid. The sand suspended in the raw water used for cooling was assumed to have settled out before the raw water was pumped into the cooling systems. Therefore, the condition of tube erosion caused by sand has not been fully specified in the design and qualification of these devices. The damage of anti-cavitation devices could be attributed to inadequate specification of operational conditions. The flow control valve of the RHRSW system has a dual function to regulate service water flow for cooling during a reactor shutdown and to maintain a positive differential pressure between the RHR system and RHRSW system in the RHR heat exchangers to prevent primary to secondary side leakage. The damaged devices have caused their associated control valves to be stuck, and thus the control valves would not be able to regulate properly to perform their safety functions to regulate flow and differential pressure. As a result, operation of the RHRSW system could be restricted or be totally lost, and radioactivity may possibly be released into the environment in the event of tube leakage in the RHR heat exchanger. Since the

Engineering Evaluation	Date Issued	Subject
		anti-cavitation device was installed in the port of the control valve, the damage or wear of the device could not be observed without disassembly of the valve flanges. This suggests that an inservice inspection and maintenance program is needed to detect damage before it could cause adverse effects on the control valve.
E412	5/25/84	ADVERSE SYSTEM INTERACTION WITH DOMESTIC WATER SYSTEMS Domestic water systems can be in close proximity to electrical equipment that is necessary for stable plant operation, accident mitigation and safe shutdown. A floor plan survey of four PWRs identified that one interface was in the vicinity of the control room. At each plant, domestic water outlets were near the control room and the electrical equipment room or cable spreading room was directly beneath the control room. Therefore, leakage from the domestic water system has the potential to interact with either electrical equipment in the control room or in the electrical rooms below. Actual disablement of electrical equipment important to safety, however, is a statistically rare event. The proximity of electrical equipment and domestic water systems can be identified at nuclear power reactors, and the locations of domestic water systems within the plant are generally continuously manned spaces, which means that any leak should be rapidly detected. This engineering evaluation found that the adverse interaction of domestic water systems with safety-related equipment is a very small contributor to the core melt probability.
E413	5/29/84	NATURAL CIRCULATION IN PRESSURIZED WATER REACTORS The system responses of pressurized water reactors during the natural circulation mode of decay heat removal were analyzed and evaluated. Recorded plant data from 12 events at nine operating plants were presented, comparing the thermal-hydraulic responses of Westinghouse, Babcock & Wilcox, and Combustion Engineering design nuclear steam supply systems to a loss of forced circulation. Most of the events were initiated by a loss of offsite power transient. The first known comparisons of RELAP5 calculations to actual plant data during natural circulation cooling for the various vendor designs are discussed.

Engineering Evaluation	Date Issued	Subject
		The evaluation found that: (1) the three PWR designs respond essentially the same during natural circulation, e.g., the trends of the reactor coolant thermal-hydraulic parameters are the same when system conditions affecting the parameters are considered; (2) the reactor coolant temperatures can be used as criteria for identifying the establishment and effectiveness of natural circulation, and the same criteria can be applied to all PWR designs; (3) the RELAP5 calculations track actual plant data and are able to identify perturbations not recorded during the events, i.e., operator actions; and (4) the sequential tripping of the reactor coolant pumps, safety injection, and PORV actuations do not affect natural circulation effectiveness to remove decay heat. (See p. 7.)
E414	5/31/84	STUCK OPEN ISOLATION CHECK VALVE ON THE RESIDUAL HEAT REMOVAL SYSTEM AT HATCH UNIT 2
		On October 28, 1983, the isolation check valve on a 24-inch low pressure coolant injection line of the residual heat removal system at Hatch Unit 2 was found open and could not be closed. An immediate investigation by the licensee determined that the valve was being kept open by the attached air actuator. A subsequent investigation by the licensee determined that the check valve had been held open by the air actuator for over four months. During this period, the plant had operated at substantial power levels. The principal cause for this event was a maintenance error on the air actuator involving the backward reconnection of the two air supply lines to the actuator. The pneumatic pressure reversal which resulted caused the actuator to hold open the check valve. Inadequate post-maintenance testing of the valve was considered to be an important secondary factor which allowed the initial error to go undetected. A lack of adequate surveillance of the valve and air actuator control room position indications was considered to be a third contributing factor.
		This evaluation concluded that the open check valve substantially degraded the isolation boundaries installed between the high-pressure reactor coolant system and the low-pressure residual heat removal system during the four-month period. The mispositioned valve thereby resulted in a significant increase in plant risk during the period because it significantly increased the probability of an

Engineering Evaluation	Date Issued	Subject
		interfacing loss-of-coolant accident. Such an accident would involve the sudden discharge of high-pressure reactor coolant outside the primary containment and would also disable the low-pressure residual heat removal system. One suggestion of this evaluation was that an industry group define good industry practice for disabling testable check valve air actuators and their associated position indications in instances when flow testing is performed in accordance with ASME Section XI. (See p. 3.)
E415	6/6/84	OVERCOOLING TRANSIENT This evaluation discusses an overcooling transient at Calvert Cliffs Unit 2 on October 11, 1983. Although the safety significance of the event was small, it is an interesting event to document since it contained five independent failures: (1) the No. 22 main feedwater pump tripped; (2) the No. 21 feedwater regulating valve failed to close; (3) the No. 21 main feedwater pump speed controller stuck in the high speed position; (4) a turbine bypass valve failed in the 50% open position; and (5) a reactor coolant pump vapor seal failed 1-1/2 hours after the reactor trip. In addition, the pressurizer pressure behavior during the pressurizer refill demonstrated an interesting phenomenon that can result when the liquid and vapor phases are not in thermodynamic equilibrium. This phenomenon, that can occur when recovering from a transient in which the pressurizer is nearly drained, can result in a temporary decrease in pressure after the level has been returned to normal and all the heaters are on. This pressure response is contrary to what one would normally expect and could be initially puzzling to plant operators. This evaluation also noted that the licensee event report (LER) for this event was submitted under the old LER reporting system. Although in accordance with the requirements of the time, the LER lacks much of the detail that would have been reported under the LER reporting requirements adopted in January 1984. It does not provide enough information for one to get a complete picture of the event. Reviewing this LER against

Engineering Evaluation	Date Issued	Subject
		the account of the actual event demonstrates the benefit of the new reporting requirements. (See p. 20.)
E416	6/11/84	EROSION IN NUCLEAR POWER PLANTS
		This engineering evaluation covers a broad overview of erosion events in nuclear plant systems. The initial impetus was the rupture of an extraction steam line at Oconee 2 on June 28, 1982. The intent of the investigation was to identify the scope of degradation related to erosion and assess potential generic implications.
		The evaluation identified more than 140 events related to erosion of various components including pumps, valves, heat exchangers, and piping in various systems. Although a significant effort was made to obtain this data, a caution is offered that the data base should be considered as representative of the types of degradation that can occur rather than a complete list of events. Based on the data, it does not seem that a specific safety problem needs immediate corrective action; however, there are potential safety issues.
		Although specific recommendations do not appear feasible, potential constructive actions relate to: (1) cognizance of the phenomenon for certain sites and systems; (2) identification of specific plant equipment and physical configurations that may be susceptible to erosion; and (3) implementation of monitoring programs to detect degradation of equipment (pumps, valves, heat exchangers, and piping).

3.4 Generic Letters Issued in May-June 1984

Generic letters are issued by the Office of Nuclear Reactor Regulation, Division of Licensing. They are similar to IE Bulletins (see Section 3.2) in that they transmit information to, and obtain information from, reactor licensees, applicants, and/or equipment suppliers regarding matters of safety, safeguards, or environmental significance. During May and June 1984, four letters were issued.

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

Generic Letter	Date Issued	Subject
84-09	5/8/84	RECOMBINER CAPABILITY REQUIREMENTS OF 10 CFR 50.44(c)(3)(ii) On December 2, 1981, the NRC amended §50.44 of its regulations by addition of the provisions in §50.44(c)(3). One of these provisions requires licensees of those light water reactors (both BWRs and PWRs) that rely upon purge/repressurization systems as the primary means of hydrogen control to provide a recombiner capability by the end of the first scheduled outage after July 5, 1982, of sufficient duration to permit the required modifications. Those plants for which notices of hearing on applications for construction permits were published on or after November 5, 1970 are not permitted by 10 CFR 50.44(e) to rely on purge/repressurization systems as the primary means for hydrogen control. Therefore, these plants are not affected by the requirement for recombiner capability; the licensees of these plants are being furnished a copy of this generic letter for information only. Although the letter was sent to all licensees of operating reactors, those particularly affected were Mark I boiling water reactor owners.
84-13	5/3/84	TECHNICAL SPECIFICATION FOR SNUBBERS During the last several years, a large number of license amendments have been required to add, delete or modify the snubber listing within technical specifications. The NRC has reassessed the inclusion of

Generic Letter	Date Issued	Subject
		snubber listings within the technical specifications and concluded that such listings are not necessary provided the snubber technical specification is modified to specify which snubbers are required to be operable. Although no change in existing technical specifications that include a list of snubbers is required, a licensee may choose to request a license amendment to delete the tabular listing of snubbers from its technical specifications. Unless and until deleted, the list of snubbers shall be maintained in accordance with the requirements of Revision 1 of the Surveillance Requirements for snubbers that was enclosed with the Generic Letter of November 20, 1980.
84-14	5/11/84	REPLACEMENT AND REQUALIFICATION TRAINING PROGRAM One of the most important follow-up actions that has been identified as part of the operator licensing program reviews is to ensure that there is an accurate description of each licensee's requalification training program and replacement operator training program. This information is needed to ensure that candidates for operator licensing examinations have completed the necessary qualifications and training prior to examination and to ensure that requalification program audits by the Regions are based on the requalification training program as implemented. The regulations, 10 CFR Part 50.54(i-1), require that licensees have a program in effect which meets the requirements of Appendix A to Part 55 and that changes to the approved program that decrease the scope, time allotted for the program or frequency in conducting different parts be approved. Therefore, all operating power reactor licensees were requested to, in the next annual update to the FSAR, either include the current program or provide explicit reference, including date, to the submittal which is the program of record.
84-15	6/27/84	ADEQUACY OF ON-SHIFT OPERATING EXPERIENCE FOR NEAR TERM OPERATING LICENSE APPLICANTS All licensees of operating reactors, applicants, and holders of construction permits were notified that on June 14, 1984, the Chairman of the U.S. Nuclear Regulatory Commission, N. J. Palladino, sent J. H. Miller, President, Georgia Power Company, a letter (enclosed) in which the Commissioners presented their views on the subject of adequacy of on-shift operating

Generic Letter	Date Issued	Subject
		experience for near-term operating license applicants. The letter accepted, with some clarifications, an Industry Working Group proposal on this subject, presented to the Commission on February 24, 1984. In accordance with the Chairman's letter, March 31, 1985 is the latest date for use of shift advisors. Beyond that date, utilities should plan to have sufficient operating experience on-shift such that there no longer is a need to rely on the use of shift advisors.
		The acceptance of these experience requirements by the NRC does not alter the guidance for eligibility, included in Regulatory Guide 1.8 and NUREG-0737, for RO and SRO licensing examination candidates. Further, acceptance of the Industry Working Group proposal does not foreclose the development of any long term requirements for crew operating experience.

3.5 Operating Reactor Event Memoranda Issued in May-June 1984

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

No OREMs were issued during May - June 1984.

3.6 NRC Document Compilations

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

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

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

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

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