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NUREG/CR-0369
ORNL/NUREG/NSIC-144

Reactor Operating Experiences

1975 - 1977

U.S. NUCLEAR REGULATORY COMMISSION LICENSEE OPERATIONS EVALUATION BRANCH

Prepared for the U.S. Nuclear Regulatory Commission
Office of Nuclear Regulatory Research
Under Interagency Agreements DOE 40-551-75 and 40-552-75

NUCLEAR SAFETY INFORMATION CENTER

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NUCLEAR SAFETY INFORMATION CENTER SERVICES

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1. General Safety Criteria
2. Siting of Nuclear Facilities
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5. Heat Transfer and Thermal Hydraulics
6. Reactor Transients, Kinetics, and Stability
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9. Nuclear Instrumentation, Control, and Safety Systems
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11. Containment of Nuclear Facilities
12. Plant Safety Features — Reactor
13. Plant Safety Features — Nonreactor
14. Radionuclide Release, Disposal, Treatment, and Management (inactive September 1973)
15. Environmental Surveys, Monitoring, and Radiation Dose Measurements (inactive September 1973)

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REACTOR OPERATING EXPERIENCES 1975–1977

U.S. Nuclear Regulatory Commission
Licensee Operations Evaluation Branch

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*This event occurred in 1975 but was published in *Current Events* in 1976.

PREFACE

Over the years the Nuclear Safety Information Center has produced a series of documents of selected reportable occurrences experienced at reactor facilities. These reports were designated ORNL-NSIC-17, ORNL-NSIC-64, ORNL-NSIC-103, and ORNL-NSIC-121. Their formats were similar, although the reportable events occurred between 1963 and 1974.

This report, ORNL/NUREG/NSIC-144, updates the four aforementioned reports. It is a compilation of reactor operating experiences reported during the period January 1975 through December 1977 and selected for publication in the NRC bulletins, *Current Events* and *Operating Experience*. The individual reports were filed from 1975 through 1977 and were compiled by the Office of Management and Program Analysis (originally the Office of Management Information and Program Control).

Through the years the Nuclear Safety Information Center has enhanced the usefulness of these individual reports by combining them into single documents with indexes.

We wish to acknowledge our appreciation to the Office of Inspection and Enforcement and the Office of Nuclear Reactor Regulation for their assistance in reviewing the original draft documents.

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FOREWORD

The Nuclear Safety Information Center (NSIC) is pleased to publish the fifth compilation of unusual reactor operating experiences collected by the U.S. Nuclear Regulatory Commission. The earlier reports — ORNL/NSIC-17, *Abnormal Reactor Operating Experiences*; ORNL/NSIC-64, *Abnormal Reactor Operating Experiences 1966–1968*; ORNL/NSIC-103, *Abnormal Reactor Operating Experiences 1969–1971*; and ORNL/NSIC-121, *Reactor Operating Experiences 1972–1974* — are still available from the National Technical Information Service (see page ii for address).

This compilation contains those experiences reported during the period January 1975 through December 1977 and selected for publication in the NRC bulletins, *Current Events* and *Operating Experience*. The reports in *Current Events* are presented in the order in which they appeared in individual issues, with the issues arranged in chronological order. The issues of *Operating Experience* are also arranged chronologically. A keyword index has been prepared using the NSIC thesaurus of indexing terms. In addition, a permuted-title index is included to assist the reader in locating reports of interest.

G. T. Mays and R. L. Scott
Nuclear Safety Information Center

CURRENT EVENTS
POWER REACTORS
UNITED STATES NUCLEAR REGULATORY COMMISSION OFFICE OF OPERATIONS EVALUATION

EVENTS SELECTED FROM REPORTS SUBMITTED TO THE UNITED STATES NUCLEAR REGULATORY COMMISSION AS OF:

JANUARY 1975

FEEDWATER SPARGER MOVEMENT

Unit 3 of the Humboldt Bay Power Plant was shut down for a regular scheduled refueling outage when it was discovered that five of the eight hold-down U-bolts on the feedwater sparger had failed where the bolt enters the upper lock nut; the sparger and thermal sleeve had shifted approximately 1.7-inches from the vessel inlet nozzle. Both 0.5-inch diameter type 304 stainless steel legs were broken on three U-bolts; the other two had one leg broken. There were no missing parts.

A metallographic examination of two bolts led to the conclusion of failure from high cycle fatigue; the U-bolts vibrated in response to the feedwater pump or to recirculation flow. It was postulated the sparger was not vibrating or that the vibration amplitude was very small because there were no unusual wear marks.

The sparger was reinstalled in its original location with redesigned and substantially stronger sparger restraints which clamp tightly around the sparger. Because the restraints are in firm contact with the sparger, the new restraints should be less susceptible to vibration.

The failure of the bolts and movement of the sparger did not impair the ability of the sparger to perform its intended function during either normal or accident conditions. There were no indications of any changes in the thermal-hydraulic operating characteristics of the feedwater or reactor systems. Since the thermal sleeve is an interference fit and the nozzle inside diameter is uniform for the entire length of the nozzle, no increase in feedwater flow around the sleeve would have occurred as a result of any shift in the sparger.[1,2] This event did not affect the health and safety of the public.

REACTOR STARTUP ON INCORRECT POWER RANGE RECORDER

Power level at the Oconee Nuclear Station Unit 2 was being increased following a shutdown the previous day, and was at 3% of full power as indicated on the Reactor Power Range Recorder. Following a control room shift change, the operator noted from redundant instrumentation that the reactor power level was actually at 15% of full power. The Power Range Recorder was in the 0 to 125% full power range instead of the 0 to 25% full power range. The selector switch for the power range recorder had not been changed to the expanded range after the reactor shutdown.

The operator normally uses the power range recorder during startup because of the instrument's expanded scale. Because of the assumed lower power level, the control operator did not utilize other redundant instrumentation for comparison because of their limitations at low power levels.

The Trip Recovery Procedure has been revised to specify that the lower range on the power range recorder be utilized whenever reactor power is below 20% of full power. In addition, personnel were reminded of the importance of utilizing redundant instrumentation.

The Reactor Protection System is totally independent of reactor power indication devices, and would have functioned to protect the unit even with the power range recorder in the wrong range. This incident did not affect the health and safety of the public.[3]

UNPLANNED RADIOACTIVE RELEASES - PERSONNEL ERRORS

Dresden - 1

With Unit No. 1 of the Dresden Nuclear Power Station operating at a steady state power of 143 MWe, an operator was given instructions to line up the valving to discharge the "B" Waste Holdup Tank. The procedure for this operation is specified on a discharge card which contains all information necessary to discharge the tank, and includes a check-off sheet. The operator misinterpreted the card to be for the "B" Laundry Holdup Tank. As a result, the unsampled liquid from the Laundry Holdup Tank was discharged for a period of 45 minutes.

Upon realization that the wrong tank was being discharged, the action was terminated and the water remaining in the Laundry Holdup Tank sampled for radioactivity. The gross Beta Gamma analysis of this sample was 1.2×10^{-4} μCi/cc. An estimated release rate of 20 gallons per minute led to a calculated release concentration of 20 μμCi/cc after dilution.

It was concluded the health and safety of the general public was not affected by the unplanned release of liquid from the "B" Laundry Tank; at no time was the technical specification allowable limit for liquid releases exceeded.

The corrective action to prevent the recurrence will be to color code the discharge cards with a different color for each tank. Each discharge card will contain instructions and valve check-off list only for the specified tank. In addition valves required for discharging tanks will have color coded identification tags matching the discharge card for the specific tanks.[4]

Palisades

With the Palisades Plant in a cold shutdown condition, the south filtered waste tank containing laundry waste was placed on recycle for analysis to determine if the contents could be released. The technician performing this analysis had calculated the release, and transferred the data to the batch release form. The following day, an operator released the north filtered waste tank as authorized by the batch release form. The release should have been for the south filtered waste tank; when transposing the data to the batch card, the technician wrote down the wrong tank identification.

No safety limits were exceeded by the release; none of three monitors sampling the release alarmed. A sample of water remaining in the north tank was analyzed for activity, and a comparison was made with the south tank analysis. No significant differences were found. The total release was estimated to be 17 millicuries.

This event was reviewed with the responsible technician and operator.[5]

Oconee - 2

With the Oconee Nuclear Station at 99% power, preparations were being made to replace the letdown filter. The valves necessary to isolate the filter were properly positioned and tagged. However, maintenance personnel accidentally disconnected the vent piping from the filter (a quick disconnect fitting). This action resulted in release of reactor coolant to the letdown filter room and adjacent hallways in the auxiliary building. The maintenance men immediately evacuated the area.

The resultant spray from this incident discharged approximately 3500 gallons of water, and a total gaseous release of 16.5 curies. The gaseous release was 3.7% of the one-hour release rate permitted in the technical specifications. The water was analyzed for particulates, iodine and tritium; only negligible quantities were found. It was concluded that the health and safety of the public was not affected by this incident.

The apparent cause of this occurrence was the failure of maintenance personnel to identify the filter they were to replace. The filter had no identifying markings.

Identification of the letdown filters will be made permanent, legible, and easily recognizable to prevent future occurrences. In addition, a program will be developed to assure that all equipment is identified by unit and component.[6]

Oconee - 1

Unit 1 of the Oconee Nuclear Station was in a cold shutdown condition when an operator discovered three feet of water standing in the pump room. Electrical power was isolated from the pumps and a submersible pump was used to pump the water to the low activity waste tank. Electrical and functional checks of the low pressure injection and reactor building spray pumps were performed to verify operability.

Samples of water were taken from the pump room; chemical and gamma spectrum analyses indicated a radioactivity level and boron concentration consistent with water from the Low Pressure Injection System.

The apparent cause of the flooding was personnel error. A utility operator incorrectly assumed that isolation of the low pressure injection header had been completed by the control room operator by closing the remotely operated valves; he did not visually verify that the valves were closed. The header drain valves were open.

The water drained from the header to the floor drains and the automatic cycling sump pumps apparently tripped because of pump overload. The draining water collected in the pump room.

The draining of the pump room and subsequent verification testing of the affected components was completed ten hours after initial discovery. Since the radioactive water was not discharged to the environment, it was concluded that the health and safety of the public was not affected.

To prevent a similar recurrence, a sump pump monitoring alarm was installed to detect early pump failure, and the necessity for attention to detail in all station operations was stressed to personnel.[7]

Also at Unit 1 of the Oconee Nuclear Power Station, with the reactor operating at 30% power, several radiation monitors alarmed in the auxiliary building. An instrument line for the unloading valve on the gaseous waste separator tank was found disconnected. The loose tubing was reconnected.

Apparently, during a station modification performed by the day shift, the piping was not fully connected. The contents of one of the gaseous waste decay tanks emptied into the auxiliary building.

The total gaseous activity released was 25.8 Ci, which was 0.05% of the annual release limit. The total iodine released was 2.4×10^{-4} Ci, which was 0.06% of the annual limit. The maximum release rate averaged over a one-hour period was not exceeded, and personnel did not receive any significant radiation exposure. The health and safety of the public was not affected.

At a meeting of the station manager and all supervisors the necessity for attention to detail and completeness of maintenance action was discussed.[8]

Quad-Cities

While Units 1 and 2 of the Quad-Cities Nuclear Power Station were in operation, discharge of a known quality of liquid from the "A" floor drain sample tank (FDST) to the river was initiated. Later in the day, a radwaste operator started processing the controls of the floor drain collector tank to the "A" FDST rather than to the correct tank, the "B" FDST. The incorrect transfer continued for about fifteen minutes during which about 1000 gallons of water of unknown quality was moved to the "A" FDST. The radwaste operator noticed the level increasing in the "A"

FDST and checked the valve line-up. Realizing the mistake, the discharge to the river was stopped. Approximately, 90 gallons of uncontrolled, but monitored effluent was discharged to the river in this fifteen minute period.

The mistake was caused by operator error. Between the time the "A" FDST discharge was initiated and the pumping of the floor drain collector tank there had been a shift change. Following the shift change, the new operator made a valving error while processing the water from the floor drain collector tank.

Samples were taken at the floor drain collector filter effluent and on the "A" FDST after it had been recirculated. The floor drain filter effluent concentration was 1.2×10^{-3} μCi/cc. The "A" FDST activity analyzed for the original batch release was 2.9×10^{-3} μCi/cc. In this occurrence the activity of the water coming from the floor drain collector was less than that being discharged.

There had been a similar occurrence about seven months earlier when an operator had accidentally opened the inlet to the "A" FDST instead of the "B" FDST while processing water from the floor drain collector tank. The "A" FDST was being discharged to the river at the time.

In both events there were no adverse effects on the health or safety of the public or plant personnel. The applicable limits in 10 CFR 20 were not violated because of the inherent safety limitations designed into the discharge procedure.[9]

PIPE WALL EROSION

With Unit No. 1 of the Calvert Cliffs Nuclear Power Plant in a cold shutdown condition, a pinhole leak was discovered in piping immediately downstream of a butterfly valve in the saltwater return system. An ultrasonic test measured a maximum thinning of the 0.375-inch pipe wall to 0.110 inches at the 12 o'clock position, approximately one and a half inches from the valve flange. Also, a general reduction of pipe wall thickness had occurred in the top portion of the pipe in an area about four inches downstream of the valve.

The pipe erosion was assumed to have occurred from prolonged operation with the butterfly valve partially closed, thus acting as a throttle valve. This valve is throttled to control temperature in one of the service water subsystems; a similiar erosion of the pipe wall had occurred previously in another saltwater subsystem.

The pipe erosion had been a slow localized process and would not have resulted in a catastrophic loss of the service water or saltwater subsystems. There was no immediate safety hazard to the plant, its personnel, or to the general public.[10]

LEAK IN LOW PRESSURE INJECTION SYSTEM

A leak was discovered in the low pressure injection system piping in the decay heat removal room at the Oconee Nuclear Station Unit 3. The leak originated from a common sample line for the A and B low pressure injection discharge headers. The defect was found two inches from the A header isolation valve. The 3/8-inch stainless steel piping failed from vibration of the low pressure injection discharge headers.

The leak was discovered when the reactor was in a cold shutdown mode. The small size of the piping did not have any effect on the decay heat removal operation; the leak did not affect the health or safety of the public. The line was repaired and a coil was added to absorb vibrational stress.[11]

DIESEL GENERATOR FIRE

At Unit No. 1 of the Three Mile Island Nuclear Station, a small fire occurred in the lagging around the diesel generator engine exhaust manifold adjacent to the turbocharger exhaust gas inlet. The fire was promptly extinguished and the diesel engine was shut down.

The cause of the fire was oil leaking from the engine inspection cover plate into the exhaust manifold lagging. The oil-soaked lagging was ignited by the heat from engine exhaust manifold. Since there was no apparent damage to the engine, it was restarted and the operational surveillance procedure was completed satisfactorily.

A temporary oil catch tray was installed under the engine cover plate to prevent oil contact with the exhaust manifold lagging. The engine manufacturer was contacted for a permanent solution to the oil leakage problem.[12]

VALVE FAILURES - SEPARATED DISCS

Kewaunee-1

Unit I of the Kewaunee Nuclear Station was preparing for reactor startup when a valve developed a packing leak. The affected valve was isolated, repacked, and the isolation valves were reopened, but flow through the hot leg portion of the resistance temperature detector (RTD) bypass loop could not be reestablished.

X-ray revealed the stem had separated from the disc of a valve; the direction of flow through the valve then caused the free disc to act as a check valve.

The defective valve was a Rockwell-Edwards F. stainless steel Univalve, General Assembly Number 3624-F-316J.

The apparent cause of failure was excessive closing torque. An impact handle is designed into the valve to aid in opening or closing. Failure occurred from continued impacting after the valve was either in the fully closed or fully open position.

A plant directive was issued specifying the number of turns required to open and close the valve, and that the impactor handle was not to be used to force the disc against the backseat.

The bypass loops were provided with flow indication and temperature signals, so a reduction or stoppage of bypass flow at operating conditions would be adequately sensed and corrective measures could be taken. There was no danger to the public or plant personnel.[13]

Prairie Island 1

A similar event occurred at Unit 1 of the Prairie Island Nuclear Generating Plant. A low flow condition was indicated in one of the RTD manifolds. Normal flow was observed in the redundant loop. By isolating the hot and cold leg manifolds, it was determined the obstruction existed in the hot leg RTD manifold. X-rays of valves in the hot leg showed separation of the valve stems from the discs. Again the, separated discs were acting as check valves obstructing flow in the manifolds.

Rockwell-Edwards considered excessive backseating to be the probable cause of failure. However, they believe that backseating with the impactor handle would not cause valve damage unless a sledge or cheater is utilized. The two valves at Prairie Island 1 were located under floor plating in a position where it would be almost impossible to utilize a sledg or a cheater.

To prevent recurrence, the valves are to be seated gently. Rockwell-Edwards is analyzing one of the damaged valve stems and discs to determine the cause of failure.[14]

Point Beach 1

In early 1973, Unit 1 of the Point Beach Nuclear Plant was experiencing problems with the seventeen Rockwell-Edwards valves in the RTD bypass line. The most common were associated with valve packing leakage.

When packing leakage was discovered, it was difficult to disassemble or remove the valves. Galling and lack of access space, together with high radiation levels because of crud accumulation, created removal difficulties.

When attempting to back flush the valves to reduce the radiation level, some of the valves appeared to be acting as stop check valves. X-ray inspection revealed two of the valve discs had become separated from their stems; because of the orientation of these valves, they were acting as check valves.

Because of radiological and disassembly problems, the entire piping was cut intact from the system.

Three valve discs were found to have separated from their stems. No parts were missing. The valves were replaced with similar valves with a modified method of retaining the stem to the disc.[15]

MALFUNCTION OF MAIN STEAM LINE TRIP VALVES

During periodic testing of the Main Steam Trip Valves (MSTV's) at the Surry Power Station Unit 2 while the reactor was at 58% of rated power, three MSTV's did not respond to a signal. On the second test of Valve B, all the air was bled from its actuating cylinders; the valve closed fully before limit switches could operate solenoid valves to restore air to the cylinders. Closure of the valve prevented normal steam flow, and a reactor trip occurred as a result of "B" steam generator Lo-Lo level. During the unit trip, Valve A closed correctly, but Valve C remained open.

Following the trip, the reactor was brought to a cold shutdown. An investigation of Valve C revealed a slight crud buildup and mechanical binding of the rockshaft in the stuffing box bushing. This binding apparently was caused by a minor bend in the rockshaft as it passed through the stuffing box bushing. Repair involved relieving the oilite bushings in the area of the splined portion of the rockshaft to eliminate interference and removing the crud buildup.

Each of the main steam lines has a main steam trip valve and a non-return valve. These six valves, in total, prevent blowdown of one or more steam generators regardless of a break location even if one valve fails to close. During this occurrence, one valve remained open even though the other two experienced some binding. If a steam line rupture had occurred, five valves would have performed their function. Hence, the incident did not represent any danger to the health and safety of the public.[16]

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CURRENT EVENTS

POWER REACTORS

UNITED STATES NUCLEAR REGULATORY COMMISSION

EVENTS SELECTED FROM REPORTS SUBMITTED TO THE UNITED STATES NUCLEAR REGULATORY COMMISSION AS OF:

FEBRUARY 1975

FUEL ROD CLADDING FAILURES

On October 30, 1974 at Dresden Nuclear Power Station Unit 3, while the position of the control rods was being changed, excessive power peaking was observed in the lower region of the core. Additional control rod movements to reduce peaking caused the peaking to increase. This was accompanied by a high off-gas radiation alarm. The control rods were then inserted to reduce both peaking and power, and the radiation alarm ceased.

The estimated stack off-gas release rate during the transient was approximately 300,000 μCi/sec. The off-gas release rate for the day of the occurrence has been estimated by the licensee to be an average of 45,000 μCi which is less than half the technical specification limit; the 48-hour technical specification limit probably was exceeded for less than 10 minutes.

Prior to control rod movement, reactor power was 440 MWe; the power increased to 520 MWe during control rod movement and stabilized at 370 MWe after clearing the high off-gas radiation alarm. Design power is 800 MWe.

The apparent cause of the occurrence was personnel error. A xenon transient occurred, with a known condition of very low fuel exposure at the core bottom. The rapid changes in power occurring low in the core probably resulted in some fuel rod perforation. Failure of fuel rod cladding resulted in the high off-gas release rate.

Unit 3 had a known flux distribution peaked toward the top of the core, with relatively unexposed fuel at the lower section of the core. The control rods were being moved to change the axial power distribution of the core at the time of xenon peaking, and when xenon started burning out, the bottom power peak, which had just formed by control rod movement, increased rapidly. Because the bottom of the core had relatively little exposure, the power peaking problem was exaggerated.

Since the occurrence, the undesirable rate of off-gas radiation indicates several fuel rods with cladding failure. The high off-gas radiation levels have resulted in a station imposed 50% derating of power. At a derated load of 400 MWe, the stack gas release rate has been about 24,000 μCi/sec, about one fourth of the technical specification limit.

The cause of the suspected failure is evidently pellet clad interaction. No fuel safety limits were approached in the occurrence. This mode of fuel failure has occurred previously in the Dresden units during normal reactor operation.

An isotopic analysis of the off-gas composition indicated little or no holdup in the pellet or fuel column for fission product gases. This would imply that few relatively large cladding perforations occurred during the peaking transient. There was no adverse effect on the public health and safety.

As a result of this occurrence, more training for all nuclear engineers have been initiated; procedures for BWR control rod sequences have been reviewed and new procedures approved; and the General Electric Company has recommended certain operational procedure changes to reduce the number of fuel failures during normal power reduction operation.[1]

CONTROL ROD WITHDRAWAL PROBLEMS

Dresden-2

While Dresden Nuclear Power Station, Unit 2, was in a refueling outage with the mode switch locked in the shutdown position and control rod drive (CRD) overhaul was in progress, a repaired drive was installed at position 10-35 and an attempt was made to remove drive 18-11. The uncoupling tool for drive 18-11 failed to indicate if the drive had properly uncoupled from the blade, so the drive probe was reinstalled and indicated the drive had uncoupled. Shift personnel then issued a temporary procedure change to allow the General Electric maintenance crew to skip drive 18-11 and proceed to the next step, the withdrawal of drive 6-35. At this time drive 10-35 had been valved in service and not reinserted to position 00. Drive 6-35 was then withdrawn and valved out of service.

The operator and shift personnel on duty did not notice that control rod 10-35 was still at position 48 before withdrawing adjacent control rod 6-35. When it was noted, approximately an hour and a half later, drive 10-35 was immediately reinserted.

The temporary procedure change to allow the General Electric maintenance crew to proceed to the next step violated the intent of the orginal procedure. The procedure for CRD replacement had been written such that if a step in the procedure were skipped, the next CRD to be removed would be adjacent to the CRD withdrawn previously. The procedure also stated that the two CRD's could be pulled only if separated by two or more control cells. All personnel involved failed to notice that the two adjacent control rods would be withdrawn with the implementation of the temporary procedure change.

The safety of the plant and public was not in jeopardy. Neither of the withdrawn control rods were the highest worth rods; the reactor was subcritical by greater than 1.34%. There was no damage to any system or structures. No personnel received injuries or exposure, and no radioactive material was released.

A temporary procedure change was subsequently issued to instruct the operators to verify that procedure changes will not result in a control rod being pulled within four cells of a withdrawn control rod.

In the future, station nuclear engineers will review procedures involving control rod movement. The control rod drive procedure will also be revised so that several steps may be skipped without violating separation criteria.[6]

Brunswick-2

Prior to fuel loading at Brunswick Steam Electric Plant, Unit 2, and during performance of a periodic test it was discovered that the de-select interlock on four control rods had failed. The refuel interlock check required withdrawal of one control rod to position 02 and verification that the control and "Withdrawal Permissive" light remained energized. Before performance of the next step, the operator was able to select an adjacent control rod. The "rod block" alarm was not received and the operator was able to withdraw the second control rod, so all rods were fully inserted and management apprised of the situation.

Investigation revealed that one pin of a connector had lost its mechanical connection with the copper bus in a relay module of the reactor manual control system. The failure could have been caused by manufacturing, shipping, or installation error.

The relay module was removed, repaired and returned to service, and the refuel interlock check was revised to include a functional test of the de-select circuitry.

Because the malfunction of the relay module was detected prior to fuel loading, there were no adverse effects on the plant or to the health and general safety of the public.[3]

Quad Cities-1

At the Quad-Cities Nuclear Power Station, Unit 1, prior to reactor startup the rod worth minimizer (RWM) was operable. With reactor power level of approximately 5%, a control rod was withdrawn that should have resulted in a RWM stall which should alarm in the control room and block rod withdrawal; neither event happened.

The operator was unaware of the RWM failure and continued withdrawing control rods; a violation of the technical specifications. Approximately a hour and a half later, the reactor operator mistakenly selected and withdrew an out-of-sequence control rod. Ten minutes later the error was noticed. The out-of-sequence rod was repositioned and reactor startup was halted until the source of the RWM failure could be determined.

The failure was attributed to an error in the startup procedure for the RWM. This procedure was modified during a spring 1974 refueling outage, and a step requiring the computer room console mode switch to be turned to the "off" position was omitted. As a result, with the console switch in the local position, the control room did not receive indication of a computer stall and no rod blocks followed the stall.

The postulated rod drop accident that forms the basis for the RWM technical specification would require a high worth rod to become uncoupled, the rod to stick when the drive is withdrawn, and the rod to fall before the rod was detected to be uncoupled. There were no uncoupled control rods, no rod drop, and no abnormal core transients as a result of this occurrence.

CRACKS IN FEEDWATER SPARGERS

Two cracks were discovered in the feedwater spargers during a General Electric Company recommended feedwater sparger inspection at Unit 2 of the Dresden Nuclear Power Station. One crack was located on the upper part of the right side header pipe to the junction box weld area of the southwest quadrant sparger. The crack was relatively straight and extended about 90 degrees around the pipe circumference. The other crack was located on the upper part of the left side header pipe to the junction box weld area of the northeast quadrant header. This crack was more jagged, near the weld area and extended about 200 degrees around the pipe circumference.

The bearing bars (preload spacers) on the right side of the southeast and northwest quadrant spargers were not in contact with the vessel wall.

TV inspection and cold flow tests led to the conclusion that the primary cause of cracking was flow induced vibration.

Tests by GE have shown that sparger vibration will occur even if only leakage flow between the inside of the thermal sleeve and the outside of the feedwater nozzle is present. The typical service conditions of changing feedwater flow rate, the temperature difference between feedwater and the water in the vessel, and movement of water within the vessel also contribute to the problem by producing thermal cycling and thermal stress.

The four spargers were to be replaced during a refueling outage with spargers of a new design, a design based on tests where there was no vibration under flow conditions and of schedule 80 rather than schedule 40 stainless steel pipe.

After an evaluation by General Electric and Commonwealth Edison it was concluded that the consequence of sparger cracking when sparger position is maintained is not of safety significance. The event did not cause any personnel injuries, exposures, or release of radioactive material. It was concluded that this event did not endanger the health and safety of the public.

CRACKS IN REACTOR PIPING

Dresden-2

When insulation was removed from the core spray lines at the Dresden Nuclear Power Station, Unit 2, cracks were discovered in each line.

The core spray lines are 10-inch diameter stainless steel pipe welded to the reactor vessel nozzles. Short pieces of welded stainless steel pipe (Dutchmen) connected the core spray line with the safe-end of the reactor vessel.

Two longitudinal cracks one 0.75-inch, and the other 0.5-inch, occurred at the heat affected zone of the Dutchmen to the safe-end weld. One 0.4-inch circumferential crack occurred at the heat affected zone of the Dutchmen to the inlet pipe. Two circumferential cracks occurred at the heat affected zone of the other core spray loop Dutchmen to the pipe weld. Each crack was 0.12-inch in length. All five cracks were weeping, indicating each was a through-wall penetration. All other welds in the core spray lines were to be examined.

Engineering drawings indicated the safe-ends and Dutchmen were type 316 furnace sensitized stainless steel. The inlet piping was type 304 stainless steel.

The reactor was shutdown for refueling and replacement of the 4-inch recirculation line bypass piping; there was no danger to the health and safety of the public.[6]

Zion-2

Water was discovered to be spraying from a crack in the suction pressure indicator piping of the charging pump at Unit 2 of the Zion Station. The leak was estimated to be 1 gal/min, so the pump was stopped and isolated. Normal flow was maintained without interruption with an alternate charging pump.

The crack developed in a 3/4-inch pipe immediately adjacent to a socket weld which had been repaired one month earlier. The failure was aggrevated by high vibration; the charging pump is of positive displacement design and nearby piping is subject to high vibrations. Material adjacent to the crack was submitted for metallurgical examination.

Vibration aggrevated failures have been a common occurrence on the charging pipes at Zion-2. A study is underway to determine the feasibility of installing pressure pulsation damping in the positive pump discharge piping.

The released primary coolant was collected in the floor drains and routinely processed with other liquid radioactive wastes. There was no danger to the plant or to the health and safety of the public.[7]

UNPLANNED RELEASES

Oconee 1&2

A sample from a waste gas tank at the Oconee Nuclear Station Units 1 and 2 had been analyzed and a release rate of 40 CFM had been determined from the analysis. However, during discharge, an alarm was received from the vent gas monitor; release of the waste gas tank was terminated.

The waste gas tank had been sampled with the correct 100 ml container, but when entering information to the computer to calculate the release rate, a volume of 3300 ml, used in several procedures, was used instead of the 100 ml sample value. Subsequent recalculation with the correct volume indicated the correct release rate should have been 8.6 CFM. However, the actual release rate was still only 9% of the one-hour release rate limit. Because there was no radiation exposure and the release was within the limitations of the technical specifications, it was concluded that the health and safety of the public was not affected.[8]

Surry 1&2

With both units of the Surry Power Station in the cold shutdown condition, a tube rupture occurred in a component cooling heat exchanger. The rupture resulted in the release of approximately 8000 gallons of low level radioactive component cooling water to the service water system and ultimately to the James River. The leak rate was estimated to be 170 gal/min. Investigation of this failure and resulting large leak revealed that the component cooling system had been undergoing minor dilution for a 66-day period. Officials estimated that the dilution over this period would have been the result of a leakage of at least 33,500 gallons of low level radioactive water. This release, too, was to the James River.

Only one tube had failed in the heat exchanger. It was presumed that the slow leak was caused by gradual degradation of this tube; the tube was plugged. It was the first instance of a tube failure in the component cooling heat exchangers.

After the exchanger was returned to service for a short time, component cooling system leakage was again discovered; there were pinhole leaks in two tubes. The two leaking tubes resulted in an additional 2445 gallons of low level radioactive water being released to the James River. The failed tubes in the component cooling water heat exchanger were plugged.

Eleven days later, a radiation monitor that senses service water leaving the component cooling heat exchangers alarmed. The heat exchanger was immediately isolated and pinhole leaks were observed in two tubes. They had been leaking for more than 11 hours, which meant there had been an additional release of 349 gallons of low level radioactive component cooling water to the James River.

Preliminary results of an analysis of a previously failed tube extracted from the heat exchanger indicated the failure was mechanical in nature and not corrosion related.

Procedures have been instituted to prohibit the use of component cooling system pump and heat exchanger combinations which could stress the heat exchanger tubes and cause further failures. Service water radioactivity is being logged on two hour intervals to ensure that trends are detected in a timely manner. Two tubes have been removed for further inspection.

An insignificant amount of radioactivity was released to the environment and all radioactivity concentrations were within 10 CFR 20 limits. This occurrence did not affect the safe operation of the station or the health and safety of the general public.[9]

STEAM GENERATOR TUBE DETERIORATION

In a continuing program of eddy current testing of the steam generator tubes at the Surry Power Stations, Units 1 and 2, a total of 10,881 hot leg side tubes and 1689 cold leg side tubes have been tested; 195 tubes had wall thickness deterioration of greater than 50% so these tubes were plugged.

Tube wall deterioration of the steam generators at Surry 1 and 2 is believed to have been caused by sheet sludge deposits and deleterious effects of sodium-phosphate chemistry control. However, this phenomena is a generic problem and its solution is not completely understood.

In order to prevent recurrence, steam side chemistry control is being changed from phosphate treatment to all volatile treatment. An all volatile treatment specification has been provided by the nuclear steam supply system manufacturer, the Westinghouse Electric Corporation.

Plugging of tubes in the steam generators resulted in only a negligible reduction of available heat transfer area. There were no safety implications associated with the tube plugging, and this occurrence did not affect the safe operation of the station or the health and safety of the general public.[10]

DIESEL GENERATOR PROBLEMS

A number of problems were experienced with the three diesel generators at the Edwin I. Hatch Nuclear Plant, Unit 1. One diesel generator would start and operate a short time, but would not come up to speed because a timer (Agastat) was cutting out before the diesel reached rated speed. The timer, which had been set for 7 seconds, was tested and found to trip in 4 seconds. In addition to the timer problem, the booster for the governors of both diesel generators was rusted on the air side. Without the booster, the diesel could not rotate fast enough to allow the shaft-driven pumps to supply sufficient oil to the governor. The vendor, Fairbanks Morse, recommended cleaning and increasing the port size from 0.025 inches to 0.050 inches. The larger port allowed air to enter the booster faster and open the fuel rack so the diesel generator would come up to speed before timer closure.

During a loss of off-site power test, one diesel started automatically and picked up its load on the bus. However, after one minute of operation, the diesel shut down. Investigation revealed that there was approximately 50 gallons of water in the diesel day tank. The day tanks for the other two diesel generators were checked and found to contain less than two gallons of water.

The day tanks are supplied from underground storage tanks located external to the diesel generator building. Water had accumulated in the access area to the storage tanks where the transfer pumps and fuel oil sample penetrations are located; the cap on the sample penetration pipe, located below water level, was only hand tight. Water also could have leaked into the storage tank through the pump seals which were under water. In addition, the storage tanks contained a manhole which could leak. It was found that three gallons of water had leaked into each storage tank.

The water detector of the day tank that contained most of the water, was inoperative. The detector was repaired. Corrective action will involve raising the access opening to approximately 12-inches above grade. In addition, the hatch cover will be made water tight.[11]

Point of Contact:
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CURRENT EVENTS

POWER REACTORS

UNITED STATES NUCLEAR REGULATORY COMMISSION

EVENTS SELECTED FROM REPORTS SUBMITTED TO THE UNITED STATES NUCLEAR REGULATORY COMMISSION AS OF:

MARCH 1975

FUEL MISPOSITIONED IN REACTOR CORE

While performing core verification before replacement of the reactor head at Unit 1 of the Quad-Cities Nuclear Power Station, a fuel assembly was found to be in its proper core location, but misoriented 180 degrees. The misoriented fuel assembly was an initial cycle (7x7) fuel assembly with approximately 8000 MWD/T of exposure. For a fuel assembly in this exposure range and with local peaking factor increased by a potential of 35% because of misorientation, it was estimated that the peak linear heat generation rate (LHGR) was about 17 kW/ft. With this heat generation rate, the fuel assembly would not have approached the 1% plastic strain limit or departed from nucleate boiling.

Upon review of video tapes of the core verification to assure there were no other loading errors, it was found that three other peripheral fuel assemblies were not fully seated because the spring clips were hung-up on the core upper grid. At the reduced power level of a peripheral assembly (approximately 60% of the power level of an average assembly), there was no possibility of departure from nucleate boiling even if the assembly received no forced circulation.

The misoriented assembly was replaced with an assembly of the same type and approximately the same exposure as removed from the core during the previous refueling. The three spring clips on the peripheral assemblies were replaced and the assemblies returned to the core. These reloaded assemblies were subsequently verified for proper identification, orientation, and seating.

To prevent repetition, the core verification procedure was changed to require a separate verification of bundle orientation and bundle height before fuel assembly identification numbers were verified.

Unit 1 was returned to commercial power operation and the off-gas release rate and off-gas response to power change was identical to prior conditions before removal of the misoriented fuel assembly. This observation led to the conclusion that no gross fuel failure occurred as a result of fuel misorientation.

It was concluded that no safety limit was exceeded and that there were no adverse effects on the health and safety of the public.[1]

UNPLANNED INSERTION OF CONTROL ROD

Unit 1 of the Oyster Creek Nuclear Generating Station was at a steady state power of 647 MWe and a weekly control rod exercise surveillance was being performed. A control rod had been properly inserted one notch from position 48 (fully withdrawn) to position 46. When an attempt was made to return the rod to position 48 using the manual rod control switch the rod inserted to position 28. The rod stopped only after several attempts to withdraw it using "notch override" in conjunction with the manual rod control switch, and finally by reducing the control rod drive water pressure.

The unplanned insertion caused the linear heat generation rate in the fuel assemblies surrounding the rod to increase sharply in the upper position of the core as the control rod approached and stopped at the same position as two adjacent rods.

After return to the original rod pattern, the control exercise surveillance was continued, and operation of the manual rod control system was satisfactory with no abnormal indications.

Later, a relay thought to be a possible source of the malfunction was removed from the manual rod control system and bench-tested. Out of 400 operations, the relay failed to reset two times, confirming it as the intermittently inoperable component. The relay was replaced with a spare and the manual rod control system was returned to service.

After estimating the heat generation rate, it was concluded that no core thermal-hydraulic limits were exceeded that could cause fuel damage. This estimate was confirmed by observation of the off-gas monitors where no increase in activity was noted.

The average planar linear heat generation limits were exceeded for approximately fourteen minutes. Under loss-of-coolant accident conditions, this might possibly have reduced the effectiveness of the emergency core cooling system.[2] Because there was no increase in off-gas rate, there was no hazard to the health and safety of the public.

POSSIBLE GENERIC PROBLEM WITH SAMPLE
LINES WITHIN CONTAINMENT PENETRATIONS

A pool of reactor coolant water was discovered on the floor of the pipeway in the primary auxiliary building of Unit 2 of the Point Beach Nuclear Plant on five occasions during a 10-day period.

There are three sample lines passing through the penetration. The penetration steel shell was air tested and was determined to be breached at some point within the containment concrete wall, permitting water within the steel penetration shell to permeate through the concrete and exit from the floor joint in the pipeway. The reactor coolant system hot leg sample line was leaking within the boundary of the penetration envelope. Two valves within the containment were closed to isolate the leak. A more conservative containment boundary was established by cutting the 3/8-inch sample tube close to where it entered the penetration within the containment and capping both ends of the cut tube. The pressurizer liquid sample line also was leaking within the penetration; it was isolated by closing two valves, and the line was subsequently capped.

The penetration was opened for examination during a refueling outage. The hot leg sample line was found to have cracked within the penetration at a point approximately two-thirds of its length from where the pipe entered the penetration from the containment side. During sampling operations, leakage at the crack led to overpressure and a rupture leak of the penetration. The penetration assembly was breached at a weld where the cylindrical shell joined a backing plate on the outside of the liner plate. The penetration assembly was successfully repaired, tested and returned to service.

There was insufficient provision for thermal expansion of the pipe during cyclic sampling operations. The four foot length of pipe within the penetration is normally subjected to a rapid temperature rise of approximately 500°F during taking of a hot leg sample.

The pipe crack had characteristics of fatigue failure, and failure apparently occurred at the point of maximum bending of the tube following rapid expansion, with the pipe ends essentially fully restrained by the penetration assembly.

A review of the containment penetrations indicated ten possible sample lines within four assemblies that are subject to significant and repeated thermal cycling at the two units.

It was estimated a total of 15 gallons of leakage occurred in the 10 day period of penetration leakage. However, each time the liquid was found it was mopped up and deposited in the plant radioactive waste treatment facilities. No detectable radioactive release was measured by plant monitors throughout this event, and it was concluded that these occurrences did not constitute a hazard to the health and safety of the public.[3]

HIGH GASEOUS RELEASE RATE

Prior to January 10, the Pilgrim Station, Unit 1 was operating at less than 90% power, and the release rate of halogens and particulates with half-lives greater than eight days was less than the technical specifications limit. On January 11, the station was shut down for maintenance of a recirculation pump seal. From time of shutdown to January 14, the release rate from the reactor building vent exceeded the technical specification by about 13 percent. It was concluded that there had been a limited deterioration of fuel cladding.

Following shutdown of a reactor with perforated fuel, an iodine spiking phenomenon would occur from the reduction in reactor coolant pressure. Iodine would diffuse from the deteriorated fuel cladding into the reactor coolant system. In this reactor shutdown, the reactor coolant iodine inventory (mainly iodine-131), spiked to a level over 100 times the level during full power operation. During most of the shutdown, the reactor cleanup system was out of service for repair, and coolant iodine activity remained much higher than usual throughout the outage. With the plant in a shutdown condition, the usual procedure is to vent the reactor head to the drywell sump. When reactor activity increased, air presumably saturated with iodine passed through the reactor head vent and ultimately exited from the station through the reactor building vent.

On January 14, the reactor building vent release rate was reduced to 41% of the allowable technical specification limit by routing drywell air through the standby gas treatment system and charcoal filters.

A special procedure has been placed in the control room stipulating the operating steps to be performed during periods of unusual iodine conditions. A detailed broad-scope investigation of iodine release sources, covering startup, shutdown, and steady state operation, was initiated.

The air exiting the reactor building vent was much lower in activity than permissible to breathe without respiratory protection. Activity, after leaving the vent, is further dispersed and its concentration beyond the site boundary where the public would be located, is much less than at the vent.

The concentration calculated at the site boundary was 2×10^{-13} µCi/cc, 45,000 times less than a worker is allowed to breathe and 500 times less than the allowable annual average concentration for the general public. Therefore, it was concluded that this event did not pose a threat to the health and safety of the public.[4]

UNCONTROLLED LIQUID RELEASE

While Unit 1 of the Oyster Creek Nuclear Power Plant was being refueled, the hotwell of one of the condensers was flooded to search for tube leaks in the north and south water boxes. As part of the operation, each water box had to be drained for personnel access. This was accomplished by cracking the backwash discharge valves and opening the water box vent valves. The backwash discharge valves were not returned to the closed position before flooding the hotwells and because of the unexpected magnitude of tube leakage, the condensate from the hotwell flowed into the water boxes and out the backwash valves to the discharge tunnel at an estimated flow rate of 3 gpm. Thirty-three leaking tubes were plugged, reducing the tube leakage rate to approximately 1 gpm. The leakage rate in the south side water box was very small, and did not contribute significantly to the release. About 5 hours after completion of the tube plugging, the significance of the flow through the backwash discharge valves was realized, and the valves were closed. It was estimated that there had been an uncontrolled release of approximately 4000 gallons of condensate to the discharge canal.

The water remaining in the water boxes was pumped to the radwaste facility for processing. Revisions were to be made to plant operating procedures to prevent recurrence of this event.

Water samples were collected from the intake and discharge structure and the discharge canal prior to and after dilution with Oyster Creek, and it was determined the concentrations of effluents released from the site were less than the maximum permissible concentrations of 10 CFR 20.

Therefore, this event did not adversely affect the health and safety of the public.[5]

PERSONNEL ERROR CAUSES INCREASE IN CONTAINMENT INSTRUMENT AIR PRESSURE

Unit No. 1 of the Surry Power Station was in the intermediate shutdown condition when it was noted that containment instrument air pressure was the same as station instrument air pressure. Normally, containment instrument air pressure is about 10 psi lower. A check of containment isolation valves revealed two valves were open.

In establishing the valve lineup, the operator assumed all valves beginning with the digit "2" were associated with Unit No. 2. He did not realize there were two valves in series from Unit No. 2 station instrument air system to Unit No. 1 containment. The position of these valves was not verified by checking valve tag numbers.

The importance of following procedures and verifying their actions are in accordance with procedures was stressed to the operator. A change to the procedures now includes a statement that valve identification tags will be visually checked and the valve number verified.

There were no safety implications associated with this occurrence because there were no accident conditions requiring containment isolation. Therefore, this event did not affect the safe operation of the station or the health and safety of the general public.[6]

MULTIPLE LEAKS IN REACTOR BUILDING SPRAY SYSTEM

On November 7, a leak was discovered in a reactor building spray system of Arkansas Nuclear One, Unit 1. The plant was being shut down following a hot functional test of the primary coolant drain line when the leak was detected. A segment of the line including the leak was replaced and the plant returned to operation. On November 13, a second leak was detected adjacent to the new weld in the original pipe as part of the original repair. Three subsequent leaks were discovered in the spray pumps suction crossover line. Samples of the pipe containing each of the first three pipe leaks were forwarded to Bechtel for metallurgical analysis.

The three leaking pipe sections showed very similar crack morphologies. All exhibited intergranular cracking roughly parallel to circumferential butt welds in the continuous sensitized region of the heat affected zone. In all cases the cracking began on inside diameter surfaces approximately 1/4-inch from the root of the weld. The microstructure of the pipe showed carbide precipitation.

Intergranular stress-assisted corrosion cracks of Type 304 stainless steels at temperatures near ambient have been rare. Southwest Research Institute has been retained to review the analysis by Bechtel and to report their findings.[7]

STEAM GENERATOR TUBE FAILURE

A steam generator tube failure occurred with Unit No. 1 of the Point Beach Nuclear Plant at 100% power. The failure was progressive over an interval of approximately 48 minutes. The failure was first indicated on the air ejector monitor, and later on the blowdown monitor. This was followed by increased pump flow until all three pumps were operating at a combined flow rate of 125 gpm to maintain reactor water level.

Reactor power was gradually reduced to 25% before the unit was manually shut down. This method of power reduction kept releases as low as possible, safety injection was avoided, and no safeguards equipment was required. Secondary system pressure and steam generator levels were controlled throughout the event without actuation of relief or safety valves.

The radioactivity of water in the steam generator reached a maximum of 5 μCi/cc. All radioactive water was contained in the hotwell, steam generator and waste collection tank and processed by the radwaste evaporator. No liquid releases exceeded limits, and a preliminary analysis indicated the gaseous release limits of 10 CFR 20 were not exceeded. It can be concluded that this event did not affect the health and safety of the public.

Subsequent tube inspection of the hot and cold leg sides of both steam generators revealed 143 tubes with a wall reduction greater than 30%. All tube wastage occurred on the hot leg side within six inches of the tube sheet. All tubes with wall reductions greater than 30% will be plugged before the unit returns to power operation.[8]

OILY FILM ON POWER CABLE TERMINATIONS

During construction of the North Anna Power Station, Units 1 and 2, verification checking of the emergency switchgear prior to energization for initial operation revealed an oily film on some 4160V and 480V power cable terminations. The oil was being secreted between termination tape layers; a check of all power cable terminations revealed 553 terminations in safety related systems exhibited a similar condition.

All power cable terminating was stopped. Materials used to make these terminations and a sample of secreted oil were sent to a laboratory for analysis.

The results of the analysis indicated the oil could only have originated from two of the terminating materials: John-Mansville Type NSC Duxseal or Bishop Electric Filler Tape #125. Duxseal was believed to be the major contributor of the problem.

These two materials have been removed from the approved materials list. The written procedures for making electrical terminations have been revised to identify acceptable procedures and materials to be used. All power cable terminations at North Anna were reworked with approved termination materials.[9]

D[illegible] ES EL

Approximately 45 concret[illegible] from the two top rows of a removable concrete block wall buil[illegible] he containment structure at Unit 1 of the Surry Power Station. [illegible] me of wall collapse, the reactor head had been removed for refue[illegible] the upper internals and all fuel had been removed from the [illegible] block fell into the reactor cavity approximately three feet from the reactor vessel. Other debris, ranging in size from approximately two-inches in diameter to small chips, were deposited primarily in the southeastern corner of the reactor cavity, inside the reactor vessel, and on the upper internals which had been placed alongside the reactor vessel in its refueling storage position.

When attempting to remove the remainder of the concrete wall by raising a section several inches, the upper rows of concrete blocks separated from the wall and fell approximately 15 feet to the operating floor level of the containment vessel. One block and small pieces of debris fell into the reactor vessel.

All concrete particles were removed. A videotape survey following the cleanup operation verified the thoroughness of the cleanup procedure. The reactor vessel and associated system were not damaged by this incident. The concrete wall is being rebuilt in a fashion that will preclude a similar occurrence. This event did not affect the safe operation of the station or the health and safety of the public.[10]

ENERGIZED WELDING CABLE MELTS LIQUID SAMPLE LINE

An energized welding cable had been draped over the pressurizer liquid sample line at Unit 2 of the Prairie Island Nuclear Generating Plant. As the plant was heated and samples were drawn from the line, the line melted through the insulation of the welding cable. The conductor of the cable electrically shorted to the sample line and caused the tubing at the point of contact to melt into two pieces. The portion of tubing to the containment was red hot approximately one foot from the melt point; the portion of line to the sample room was red hot for about 50 feet. It took several minutes to dislodge the fused welding cable from the sample line.

The fuel in Unit 2 was not irradiated, so no contamination resulted. All welding cables were inspected to assure they were not lying on hot or potentially hot piping and to confirm their insulation was intact. The sample line tubing was replaced.[11]

TEST REACTOR PROBLEMS

During shutdown of the General Electric Test Reactor at the Vallecitos Nuclear Center, a control rod was found split four to six inches in length in one of the seams of the stainless steel cladding. Inspection capabilities in the canal were limited, so the poison section was to be transfered to remotely-operated hot cells for a more complete examination. The failure appeared to be in the corner weld area of the cladding.

During the shutdown, a control rod failed to disengage from the control rod drive during a rod drop time test. An inspection of the control rod drive revealed the self-locking nut at the bottom of the rod which actuates the ball coupling was out of position. As a result, the rod could not travel a distance sufficient to release the ball coupling mechanism. After proper adjustment of the lock nut, the control rod performed within specifications. Subsequent inspections revealed the lock nut to be properly positioned on all other control rod drives.

Later, an inspection of the control rod poison section revealed small separations in the weld seams of the stainless steel cladding and slight swelling of the boron stainless steel poison material in three poison sections.

Two poison sections will continue to be used, as past experience with this problem has demonstrated that the swelling has had no effect on the ability of the control rods to perform within the limits of the technical specifications (the sections exhibited swelling of only 10 to 40 mils, and separated seam welds of 1.5 and 2-inches, respectively). The poison sections were reversed end-to-end when reinstalled so that the ends exhibiting swelling will receive practically no neutron exposure.[12]

There was no release of radioactivity and the health and safety of the public was not affected.

Point of Contact:

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CURRENT EVENTS

POWER REACTORS

UNITED STATES NUCLEAR REGULATORY COMMISSION

EVENTS SELECTED FROM REPORTS SUBMITTED TO THE UNITED STATES NUCLEAR REGULATORY COMMISSION

APRIL-MAY 1975

LOSS OF MAIN COOLANT PUMP SEAL

The H. B. Robinson S. E. Plant, Unit 2, was operating at 100% power when leakage from the first stage shaft seal of one of three main coolant pumps resulted in an alarm. The reactor power level was reduced to 36%, the leaking pump was shut down, and the reactor tripped from a high steam generator flow signal. About ten minutes later, the two remaining main coolant pumps were shut down and the component cooling water return line was isolated. Approximately two hours later, it became necessary to equalize temperature in the reactor system, so the pump with the leaking first stage shaft seal was restarted. The pump was operated approximately two hours, but was shut down when the second stage seal separated and the pump was now discharging a high volume of primary coolant to the floor of the containment building.

Approximately 135,000 gallons of primary coolant water was discharged into the containment structure from the leaking shaft seals. The liquid level of the pressurizer vessel was maintained by using three charging pumps at high system pressures, and by intermittent manual actuation of the safety injection system at pressures below 1500 psig. The leakage rate through the shaft seals reached a maximum of 500 gpm. The plant was brought to a cold shutdown condition by natural circulation and by the residual heat removal cooling mode. Pressure in the containment building reached 2 to 4 psig, but was reduced by normal temperature loss and with the containment purge system. Radioactive releases were within licensee limits. Waste water was transferred to water storage and holdup facilities.

Westinghouse Electric Corporation is investigating the cause of seal failure, evaluating the cooldown rate of the coolant system and the effect of flooding the lower reactor vessel.[1]

IMPROPER VALVE LINEUP DEFEATS REACTOR INSTRUMENTATION

FitzPatrick

During a routine surveillance test at the James A. FitzPatrick Nuclear Power Plant, the rack isolation valves of four sets of drywell high pressure instrumentation for both safety systems were found closed. Their associated root valves at the four drywell penetrations also were closed. Because the root valves are not used in surveillance testing and the position of the root valves were not on a valve line-up sheet, these valves were assumed to be closed for the past seven months. A valve check of the instrument racks three months earlier had indicated the rack valves were open, but the fact the root valves were closed negated the design function of the drywell high pressure instrumentation. The isolated valves were sealed open to prevent closure, and this condition was added to the valve check-off lists for operations, instrument, and control surveillance. The position of the valve is to be checked prior to plant startup and during instrument surveillance testing.

After discovery of the closed instrument valves, other reactor protection system instrumentation valves were inspected, and four other valves for variable monitoring, not of safety significance, were found closed and were opened.

Even though the high drywell pressure signal had been isolated, the desired functions of the safeguard systems for all accidents were not affected because of the availability of redundant systems, so there was no hazard to the general public as a result of this procedural failure.[2]

Hatch

On returning the Edwin I. Hatch Nuclear Plant to a low power level of operation following a scram, Yarway Corporation level switches that initiate core cooling systems from a low level water signal were reading unusually high on scale. Investigation revealed two Yarways piped in parallel had their equalizing valves open, causing the high upscale indications. The equalizing valves were closed and proper indication was restored.

The equalizing valves apparently were not closed after the instruments had been functionally tested. The normal startup procedure has been revised to reference valve lineup procedure, and the instrument check procedure has been revised to include the expected reading of these instruments for verification of magnitude of correct approximate reading.

Since the plant had not been to high power levels and because the improper valving was discovered at low level operation following the outage, it was concluded that the health and safety of the public was not endangered.[3]

Quad-Cities-2

With Unit 2 of the Quad-Cities Station at approximately 90% power, a "reactor vessel low pressure" alarm was received in the control room. A check of a redundant channel indicated reactor pressure to be normal. Investigation determined the sensor with an alarm indication had been valved from service, and that reactor pressure was normal.

Earlier in the day, a surveillance test had been completed that required isolation of the pressure switch. With completion of surveillance, the instrument technician left the switch valved out.

This was the first occurrence of a switch being valved out at Quad-Cities-2. Analysis of possible consequences led to the determination the core spray system and the residual heat removal system would have functioned properly in event of an emergency core cooling initiation signal. Thus, there were no safety implications from this occurrence, and the health and safety of the public was not endangered.[4]

POOR CRAFTSMANSHIP AND PERSONNEL ERRORS

Quad-Cities-2

During scheduled inspection of the twenty jet pumps at Quad-Cities Station, Unit 2, the beam bolt retainer cups and the 0.5-inch cap screws were found to be missing from two jet pumps. The restrainer adjusting screw on the shroud side of another jet pump was also missing. The restrainer gate keepers on five jet pumps had their welds intact, but were not fused to the restrainer gate.

The apparent cause for all deficiencies was attributed to faulty installation and workmanship. Vibrational forces on inadequately installed components could cause these components to dislodge from their normal positions.

The missing beam bolt retainer cups and cap screws will not be replaced as these pieces were important only during initial assembly or removal of the pumps. The restrainer adjusting screw was installed and tack welded to its holding clamp. As a result of the faulty tack welds on the jet pump restrainer gate keepers, the restrainer gate bolts were retorqued and new tack welds were placed and verified. A list of loose or missing parts was compiled so a search to retrieve the loose objects could be completed prior to returning the unit to operation.

The missing jet pump hold-down components did not lead to jet pump failure or to loss of jet pump operational integrity. There were no failures of any jet pump hold-down components and there was no unsafe condition during previous periods of reactor operation. This event did not affect the health and safety of the public.

The problems discovered on this inspection were similar but less severe than those discovered following a jet pump failure of Unit 2 in August 1972. At that time, a jet pump assembly had become dislodged from its normal position and rotated in the vessel. Extensive inspections and repairs were performed on all Unit 2 jet pumps and they since have operated satisfactorily.

An extensive inspection of all Unit 1 jet pumps during the first refueling outage in April 1974 revealed a large number of jet pump discrepancies. These included beam bolt torque test failures, sheared restrainer gate bolts and keepers, and missing and cracked restrainer gate bolt keeper tack weld. A missing restrainer gate wedge had indications of wear in the vicinity of the wedge, indicating possible vertical movement of the wedge.

All of the jet pump problems that have occurred at Quad-Cities Station have been attributed to faulty craft installation and workmanship during the initial construction of both units.[5]

Three Mile Island-1

Three Mile Island Nuclear Station, Unit 1, was at 99% power when a high pressure injection pump failed to start on signal from the control room. There was a loose terminal on a Westinghouse 50-DH-P350 breaker. The breaker was replaced and the pump operated satisfactorily.

This incident prompted further investigation into the craftsmanship and expected reliability of the engineered safeguards electrical circuits. Six of 20 motor control center units (ITE Imperial Corporation Series 9600) had wiring and/or connector deficiencies. Wire of smaller guage than required by the manufacturer's specifications, strands broken from multiple strand wire, poorly crimped lugs, and loosely-bolted electrical connections were discovered. The apparent cause for each deficiency was poor workmanship either during manufacture or during installation. All deficiencies were corrected.

The connector and wiring problems in the engineered safeguards motor control center did not present a threat to the health and safety of the public. There was no evidence of overheating nor indication of imminent failure of a component. If failure would have occurred, operable redundant safety systems were available.[6]

Fort Calhoun-1

With Unit No. 1 of the Fort Calhoun station in a refueling shutdown condition, a high pressure safety injection valve failed to open on switch command from the control room. Investigation determined the reversing interlock of the General Electric combination breaker/starter was not making proper contact. The reversing interlock was disassembled and inspected; a normally open contact had been installed instead of a normally closed contact.

Preventive maintenance had been performed on the breaker/starter and, evidently, the unit was improperly assembled. The maintenance procedure for inspection, disassembly, cleaning, lubrication and reassembly was adequate in every respect except no functional test was performed after completion of preventive maintenance.

The interlock was properly assembled and the valve functioned normally. There was no danger to the health and safety of the public because the reactor was in a shutdown condition and redundant systems were available.[7]

Calvert Cliffs-1

Unit 1 of the Calvert Cliffs Nuclear Power Plant was at 100% power, and a planned discharge of the reactor coolant waste monitor tank (RCWMT) was in progress. A release permit had been obtained and the discharge was being continuously recorded on the radiation monitoring system.

Coincident with discharge of the RCWMT, the miscellaneous waste receiver tank (MWRT) was also being pumped out. After release of the RCWMT contents, the operator discovered that the inlet stop valve of the RCWMT which is also an influent path from the MWRT had been left open. Therefore, the entire contents (4000 gallons) of the MWRT had been inadvertently discharged through the RCWMT while it was being released.

Measurements of the discharge from the radiation monitoring system were not greater than expected values. It was not possible to obtain a representative RCWMT sample because the tank had been refilled for a future planned release. Based on past analyses, a typical concentration of the MWRT is about $1x10^{-5}$ µCi/ml gross beta-gamma concentration. An assumed concentration of this magnitude would be corroborated by the monitored discharge data. The assumed activity of the release was of little significance with respect to the technical specifications.

To prevent recurrence, signs have been conspicuously posted in the area of the RCWMTs stating the tank influent valves must be shut prior to initiating a discharge. The importance of adhering to written procedures has been reiterated to all operations personnel.[8]

Oconee-2

During replacement of purification demineralizer resin at Oconee Nuclear Station Unit 2, the drain valve for Unit 1 purification demineralizer was inadvertently opened instead of the drain valve for Unit 2 purification demineralizer. The control operator immediately identified a decreasing level indication in the letdown storage tank and monitoring of other instrumentation verified tank level to be decreasing. The Unit 1 purification demineralyzer drain valve was shut, and the leakage isolated.

Valves at Oconee Nuclear Station are normally identified by black identification tags. However, in this instance, the valve had been labeled with a marker. Subsequent wetting made it difficult to distinguish whether the valves were for Unit 1 or Unit 2. The condition of the valve identifier contributed to the failure of the operator to adequately identify the valve to be opened.

The prompt and timely action by the control operator detected the decreasing letdown storage tank level before an alarm sounded. Little, if any, resin had been transferred from the purification demineralizer. The resin sluice line and the spent resin storage tank were monitored during the discharge and no increases in radiation level were detected. With this information, it was concluded the health and safety of the public was not affected by this incident.[9]

Zion-2

Unit 2 of the Zion Station was operating at 857 MWe when a reactor trip occurred because of low level (25%) in a C steam generator coincident with a feed flow/steam flow mismatch. Safety injection occurred 25 seconds after the trip from the high rate of steam flow together with a low-low Tavg (540°) steam generator temperature. Safety injection was terminated after 90 seconds when unit parameters had stabilized.

Prior to performing a channel calibration on steam flow loops, the operator was mistakenly instructed to select loop 522 for steam generator level control rather than loop 523. When a technician started to calibrate the feedwater regulating valve for the steam generator, the valve closed, causing the low steam generator level and feed flow/steam flow mismatch.

The operator attempted to manually return the steam generator level to a correct value, overfed and thereby subcooled the system. The high steam flow signals were artificially induced by the channel calibration procedure.

The inadvertent safety injection was caused by operator error in misreading the procedure. The personnel involved have been instructed in the correct procedure for steam generator level control calibration and to double check which channel is selected.

The safety injection system operated satisfactorily and correctly terminated upon recovery of pressurizer level. Inspection of the reactor coolant system did not reveal damage to the system and it was concluded the health and safety of the public was not affected.[10]

UNMONITORED RELEASE OF CONTAMINATED LIQUID

Unit No. 1 of the Millstone Nuclear Power Station was operating at a steady state power level of 100% while the liquid radwaste concentrator was undergoing a blowdown operation and one of the house heating boilers was being manually placed in operation. During the process of placing the boiler on line, liquid from the boiler makeup deareating tank overflowed to the floor of the boiler room. A man leaving the boiler room found his shoes were contaminated from the water on the boiler room floor. The boiler was removed from operation and barriers were established to limit the spread of contamination.

This boiler was supplying steam to the Unit 2 heating system. Because of possible contamination, all Unit 2 construction workers were ordered to leave the site after completing personnel radiological measurements.

A radiological survey of Unit 1 revealed approximately 1200 square feet of floor area contaminated to a level of 80,000 dpm/100cm^2, 100,000 dpm/100cm^2 in the area of the heating steam condensate surge tank, and 80,000 dpm/100cm^2 in the area of the heating steam condensate recovery tank. Unit 2 heating steam piping was measured at 1 mr/hr, with traps at 5 to 6 mr/hr.

The contaminated water originated with the blowdown operation of the radwaste concentrator. Heating steam to the ring sparger of the radwaste concentrator had been properly valved off, but the isolation valve leaked and passed high activity concentrate to the condensate return tank. The discharge from the condensate return tank is monitored for conductivity and water of low concentration is returned to the boiler makeup deareating tank. High concentration discharge is diverted to the radwaste floor drain system after indication of conductivity to the radwaste operator and panel alarm annunciation. The conductivity sensor was found mis-wired and, thus, permitted high activity concentrate to enter the heater boiler makeup system without alarm indication. This instrument loop had undergone maintenance work two months earlier and had not been properly checked when completed.

Spillage of contaminated water to the boiler room floor from the boiler makeup deareating tank occurred during the manual startup of the house heating boiler. The contaminated water on the boiler room floor flowed to an unmonitored sump that discharged to the storm drain system.

An estimated 3,000 gallons of contaminated water was released unmonitored to the storm drain system. The activity of water remaining on the floor was analyzed to be 1.18×10^{-2} μCi/ml gross beta. With dilution, the calculated average concentration at the point of release was 1.4×10^{-6} μCi/ml. The average allowable daily discharge limit for Millstone is 1.0×10^{-6} μCi/ml. There were no personnel directly contaminated as a result of this occurrence. However, a total of 12 pairs of work shoes were not returned to employees because of fixed contamination.

Subsequent surveys of the Unit 2 house heating piping system indicated contamination throughout the system; all flush water and boiler drains were routed to the Unit 1 radwaste system for processing.

The mis-wiring of the conductivity sensor was corrected and the conductivity instrument loop was successfully tested. Unit 1 building floor drain sump was diverted to discharge to the radwaste floor drain system instead of the storm drain system for decontamination of the boiler room and adjacent floor areas. The Unit 2 heating system piping was drained, steam cleaned and refilled. Activity levels were reduced to barely above background. Local floor contamination from leakage of heating system valve packing was decontaminated. Instructions were issued that all sumps must be sampled and, if found to be contaminated, pumped to the Unit 1 radwaste system.[11]

CRACKS IN FEEDWATER SPARGERS

During a refueling shutdown at Unit 2 of the Quad Cities Nuclear Power Station, a liquid penetrant test on the four feedwater junction boxes revealed evidence of cracking. The test had been performed as a result of a request of General Electric Co. because of concern over cracking in several feedwater spargers installations of the same design.

There were several cracks in the heat affected zones on the piping side on each of the four spargers. After removal of the spargers, further dye penetrant examinations of the feedwater nozzle cladding detected numerous linear indications. All relevant indications were removed by grinding.

Cracking of the feedwater spargers was attributed to flow-induced vibration compounded by stresses induced by thermal gradients between the feedwater piping and reactor vessel internals. Leakage between the sparger and the feedwater nozzle also contributed significantly to vibration of the sparger assembly and imposed thermal stresses on the nozzle.

Feedwater spargers of a new design utilizing an interference fit to eliminate leakage and thus reduce vibration were to be installed prior to completion of the refueling outage.

The safety implications of this event were inconsequential because the reactor was shutdown. Although minor leakage was present, the feedwater spargers were still capable of performing their design function. There was no effect on the safe operation of the plant or to the health and safety of the public.[12]

Point of Contact:

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and Program Control
U. S. Nuclear Regulatory Commission

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CURRENT EVENTS

POWER REACTORS

UNITED STATES NUCLEAR REGULATORY COMMISSION

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JUNE-JULY 1975

DEFICIENCIES IN DESIGN OF PRIMARY SHIELDING

During two recent reactor power ascension programs, at a pressurized water reactor (PWR) and a boiling water reactor (BWR) facility, radiation in certain areas was in excess of predicted or design values. Each plant involved different architect-engineers and a different type of radiation.

FitzPatrick

During drywell entry with the James A. FitzPatrick Nuclear Power Plant at 1.5% power, unexpectedly high radioactivity levels were discovered at upper elevations in the drywell. Levels from 5 rem/hr neutron to 20 rem/hr gamma were measured near the reactor vessel level reference leg piping penetration. Investigation of the biological shield around the reactor vessel disclosed hydrogenous material had not been used for shielding around two instrument penetration inspection doors and six reactor vessel weld inspection doors.

It was determined that nine-inches of "Permali" (80#/ft^3) and four-inches of borated (3% weight) "Permali" would be required in addition to nine-inches of steel at the inspection doors. Also, long range plans have been made to shield the recirculation pump suction penetrations, the jet pump penetrations and the area about the containment spray header.

During an NRC inspection, it was observed that seven of the doors in the biological shielding would, upon opening, strike drywell piping. These doors provide access to the jet pump supply vessel nozzles, and the doors could strike the reactor water cleanup return line or two of the main steam lines. These pipes are considered to be critical as a rupture could lead to a loss of coolant accident. The doors with additional shielding to be added will be pinned shut with hardware designed to withstand the pressure transient of a recirculation line break. The doors to six penetrations at the top of the biological shield are to be removed.[1]

Calvert Cliffs-1

When reactor power was increased into the power range (greater than 2% power) for the first time at the Calvert Cliffs Nuclear Power Plant, Unit 1 excessive radiation levels (approximately the same as predicted for 100% power) were noted on the outside surfaces of the containment structure. In addition, if radiation levels taken at 20% power were extrapolated to 100% power, all normally accessible areas inside containment would have had greater-than-design radiation levels.

The high radiation levels were caused by neutron and gamma streaming from an annulus between the reactor vessel flange and the primary shield wall and the annulus around the reactor coolant piping where it penetrates the primary shield wall. To a lesser extent, radiation was also measured at the access opening at the base of the primary shield. The reactor vessel - primary shield annulus is approximately 2.5 ft. wide, and radiation in the vessel cavity, scattered by the vessel wall and primary shield concrete, was streaming out of the large gap. Subsequent scattering and direct penetration by the streaming radiation contributed to the high radiation level at the 69-ft. elevation level outside the secondary shield and at the equipment hatch.

Radiation streaming also occurred from large openings in the primary shield for the six reactor coolant piping-nozzle connections. These openings are conical in cross-section with an insulation-air gap of approximately 10-inches at the inside surface and 24-inches at the outer surface. The highest radiation levels outside the primary shield were in the vicinity of the cold legs at the discharge of the reactor coolant pumps.

A high radiation level near the bottom of the primary shield was caused by a 2.5 ft. square personnel access opening that extends through the primary shield into the reactor cavity. The access hole is sealed at the inside by a steel door which did not provide a significant amount of shielding.

Temporary shielding installed outside the equipment hatch reduced radiation levels to less than 0.5 mrem/hr at 20% power. Restrictions on personnel access to some areas and to the containment structure have been instituted to minimize personnel radiation exposure.

Temporary shielding was also installed above the gap between the reactor vessel flange and the primary shield wall and at the personnel access opening at the bottom of the primary shield. Bagged crystalline boric acid (H_3BO_3) was stacked on the support grating which spans the 2.5 ft. gap between the primary shield at the reactor vessel flange. The addition of this shielding reduced radiation levels in this area by a factor of 50-100. The reactor coolant piping nozzle shield was insulated with rectangular sections of polyethylene installed around the reactor coolant pipes just outside the primary shield walls.

Action was initiated to design a permanent shield for the area between the reactor vessel and primary shield and for the reactor coolant piping nozzles.[2]

DAMAGE TO FUEL ASSEMBLIES

Humboldt Bay

During transfer of an irradiated fuel assembly from the transfer basket position in the spent fuel pool at Unit 3 of the Humboldt Bay Power Plant to a pool storage location, the fuel assembly was disengaged from the fuel grapple and fell approximately six feet to the spent fuel pool floor. It then tipped over and fell into the ten-foot deep spent fuel cask pit in the corner of the pool.

An air sample was normal, and the grapple was examined and found to be functioning properly. It was concluded the fuel assembly had not been grappled properly or properly checked prior to movement of the fuel bundle. The only damage to the fuel assembly was that the channel had been forced down over the fuel bundle nose piece and was split in at least two corners from the channel bottom for about eight to ten-inches.

Two days later, when attempt was made to recover the fuel assembly from the cask pit, and as the fuel assembly was lifted toward the vertical position, the channel came off and fuel rods fell out of the bundle. The remaining portion of the bundle was lowered and the refueling building was evacuated until an air sample showed no abnormal airborne concentrations.

The tie rods and/or tie rod keepers apparently had sheared during the drop, allowing the bundle to separate. It was planned to recover the fuel assembly after the refueling outage at which time a complete examination of the fuel bundle would be completed.

There were no personnel exposures, injuries or off-site consequences as a result of this event.[3]

Turkey Point-4

During refueling at Turkey Point Station, Unit 4, an observer noted damage to the side of a fuel assembly as it was being lowered to the reactor core. Containment air particulate, gaseous radioactivity and area radiation detectors showed only background radiation levels.

The first grid above the bottom nozzle of the fuel assembly was damaged, and the seventh and eighth fuel rods from the southwest corner of the fuel assembly were distorted. These two fuel rods had been pushed back and out of line with other fuel rods in the outside row. There was no evidence of breach of fuel cladding integrity. However, damage to the grid and deformation of fuel rods made this assembly unacceptable for further use in the reactor core.

Apparently, when the spent fuel pit (SFP) side lifting frame was upended, the lifting frame struck the fuel assembly and pushed it into the lifting frame pulley mounted on the west wall of the SFP transfer canal. The location of the pulley was consistent with damage to the fuel assembly.

The licensee concluded that procedural deficiencies were the cause of the occurrence; procedures did not specify the fuel assembly must be lifted to the "full-up" position by the SFP bridge crane before the SFP bridge was moved from the SFP rack position. Procedures did not specify that fuel assemblies must not be moved over the SFP side lifting frame area until the lifting frame had been upended and ready to receive a fuel assembly. The procedures have been revised accordingly.

There were no injuries to personnel and no exposure of personnel to radiation or concentrations of radioactive material as a result of this occurrence, and it was concluded neither reactor safety nor the health and safety of the public were jeopardized.[4]

Quad-Cities-2

A series of Local Power Range Monitor (LPRM) high alarms occurred during power ascension of Unit 2 of the Quad-Cities Nuclear Power Station following a forced outage. The unit nuclear engineer was informed by telephone of these alarms, and each time recommended rod position changes that cleared the LPRM alarms. After two changes of rod configurations, a high offgas alarm indicative of possible fuel damage was received and plant load was decreased.

The increased offgas was a result of failure of the fuel cladding. The maximum release rate was estimated to be 1.5 Ci/sec, a factor of four higher than the steady state rate before the fuel clad failure.

The cause of the occurrence was a combination of in-sequence rod patterns that produced abnormally high peaking at the bottom of the core because of a low xenon condition followed by a power increase on flow. The net result was a local power level increase at a rate that would not allow fuel pellet cladding stresses to relax without cladding failure. Operating personnel could have minimized the damage had they more thoroughly understood reactor conditions and inserted enough rods to completely clear the high peaking.

Fuel failure from rapid power increases have been experienced at both Quad-Cities and Dresden stations as a result of rod withdrawal errors. Although differences exist in the circumstances of these incidents, the cumulative experience indicates that significant fuel failure may result if the local rate of power increase is excessive.

To prevent recurrence, the most recent maximum power distribution data will be provided to the reactor operator for reference during startup to serve as a guide in determining if the previous cycle maximum local power densities are being approached too soon. Written instructions from the nuclear engineer will be approved by the operating engineer and included in the daily log for rod maneuvers which have potential of exceeding the previous maximum power densities. Increased efforts will be made to more accurately determine when control rod sequence will require modification to stay within the previous power envelope, especially on xenon-deficient startups. Consideration will also be given to the possibility of reduced rates of power ascension or power soaks following outages of 24 hours or more in order to allow buildup of a larger xenon inventory during non-emergency load conditions.[5]

Surry-2

During inspection of fuel assemblies for the first refueling operation of Unit No. 2 of the Surry Power Station, gas bubbles were noted coming from one of the outer fuel rods, and it was established the cladding was perforated by local hydriding. The defect area was approximately 0.1 inches in diameter, with the surrounding hydride area being approximately 0.25 inches in diameter.

Reactor coolant activity levels during the first cycle had showed a slight increase, typical of a few failed rods, about two months after the beginning of operation.

Westinghouse Electric Corporation concluded the fuel assembly could be operated through its end of cycle 2 design burnup as scheduled. A review of previous operating experience in other reactors with known defected fuel revealed no evidence of propagation of similiar failures, and there was no evidence that similiar perforations led to gross failure of an effected rod.

A review of Quality Control/Quality Assurance records of the fuel assembly revealed no deviations or discrepancies that contributed to this defect, and inspection of other fuel assemblies revealed no other defected fuel rods.[6]

Also at Surry 2, when a fuel assembly was being removed from its core location, two adjacent locking fingers on the fuel handling crane failed to engage the top nozzle, so the fuel assembly was supported only by the remaining two fingers. When the assembly was pulled clear of the core, it was free to pivot about the axis formed by the two engaged fingers. Coolant flow, caused the lower end of the fuel assembly to drift and to bind in the crane mast. The binding caused an increase in load, and the crane operator ceased fuel withdrawal before an overload condition was reached.

Unaware of the cause of increased load, the crane operator lowered the fuel assembly. However, the bottom of the fuel assembly had now drifed over another fuel assembly in a different core location, and the bottom nozzle came to rest on the top nozzle of the stationary fuel assembly. Upon contact, the crane operator noted a decreased in load and stopped the crane. Two of the bottom pedestal feet of the fuel assembly were partially resting on the hold-down springs of the stationary fuel assembly.

Subsequent inspections established the hold-down springs of the stationary fuel assembly had been plastically deformed with a permanent set of 1.0 and 1.1 inches, respectively. No additional damage to either fuel assembly was observed.

As a result of a Westinghouse analysis of the possiblity of adverse consequences of continued operation with the damaged in-place fuel assembly, it was concluded that the remaining hold-down capability was adequate to prevent the assembly from lifting off the lower core plate during normal power operation. In addition, it was concluded that a postulated reactor coolant pump overspeed transient condition of 110 percent or less would not lift the assembly to the extent that further plastic deformation of the hold-down springs would occur.

The refueling operation was completed and the reactor was returned to service.[7]

PERSONNEL ERRORS

Dresden-2

With Unit No. 2 of the Dresden Nuclear Power Station at 55% power, it was discovered during a main steam isolation valve (MSIV) timing surveillance test that the reactor protection relay was de-energized. This relay is energized by the "<10% closure" limit switches on MSIV's 1C and 2C. Investigation of the 1C limit switch revealed the internal workings of the switch were missing.

During a refueling outage, all MSIV limit switches had been removed for inspection and cleaning. Inadvertently, the 1C limit switch was never reinstalled. When the work package for limit switch maintenance was subsequently reviewed, all signatures were present. The safety-related work request package had required a maintenance functional test, two post-maintenance operational tests, MSIV 10% closure tests and a MSIV closure timing test.

Absence of the limit switch simulated a "fail safe" condition toward a full scram. Therefore, the health and safety of plant personnel and the public were not jeopardized as a result of this occurrence.

The unit was operated for four days without the limit switch in the circuit. When the unit was shut down, the switch was installed and proper operation verified.[8]

Oconee-2

A quench tank low level alarm was received in the Oconee Nuclear Station Unit 2 control room with the plant at 100% power. The alarm was acknowledged. Approximately 20 minutes later, the control operator observed a low quench tank level of 40-inches. Corrective action was taken and normal quench tank level was restored 45 minutes after the initial alarm.

Immediately prior to this incident, the alarm next to the quench tank low level alarm had been alarming intermittently. The operator heard the audio portion of the quench tank alarm, looked up, and mistakenly thought this alarm was the intermittent alarm again. The apparent cause of this event was improper identification of an alarm because of proximity of alarm panels.

This incident did not affect the safe operation of the unit, and the health and safety of the public was not endangered.

Personnel involved in this incident were reminded of the importance of considering each alarm as a new and different alarm.[9]

Dresden-1

An operator inadvertently started a wrong pump and transfered liquid radwaste from the resin vault to the radwaste contractor's treatment facility at Unit 1 of the Dresden Nuclear Power Station. The licensee did not become aware of the event until two days later (contractor personnel did not work over the weekend). The pump ran until the resin vault emptied and liquid waste overflowed the contractor's tank to the ground.

An estimated 19,500 gallons overflowed the tank. Surveys of soil samples indicate the surface water overflow was confined within the reactor plant boundaries. The licensee planned to remove and dispose of approximately 1,000 cubic yards of soil.[10]

Maine Yankee

During startup of the Maine Yankee Atomic Power Plant, all three safety injection tank motor-operated isolation valves were not opened during plant heatup. These valves are part of the Emergency Core Cooling System (ECCS) valve checklist, and this checklist is to be completed prior to reaching a reactor coolant system temperature and pressure of 210°F and 400 psig.

The condition of safety injection isolation was detected by the control room operator during routine review of main control board valve position indicators. At this time, the reactor coolant system was at 370°F and 700 psig.

Personnel responsible for completing the checklist had noted the locked handwheels, but mistakenly assumed the values to be locked open when, in fact, they were locked closed. The three safety injection tank motor-operated isolation valves were immediately opened. The entire ECCS valve checklist was recompleted with no further discrepancies noted.

The ECCS valve checklist has been revised to require independent check of main control board ECCS valve positions prior to exceeding 210°F and 400 psig. Review of this incident by plant personnel led to the conclusion the incident presented no significant health or safety hazard to the general public.[11]

Turkey Point-4

Unit No. 4 of the Turkey Point Station was being returned to service after shutdown, and reactor heatup was in progress. A quality control inspector discovered a disconnected mechanical linkage on the equalizing valve for the outer door of the personnel airlock. Further investigation showed the valve to be in the open position and establishing a flow path from containment to atmosphere whenever the airlock inner door was open.

Containment integrity had been administratively verified prior to plant startup by completion of the prestart check-off list. However, personnel conducting the checkoff were not aware the linkage was disconnected because both valve and linkage were hidden from view behind a vertical steel cover plate. The valve operating handle and position indicators were visable in front of the steel plate, so, personnel thought they were checking the valve shut when, in fact, it was staying open.

A checkpoint was added to the appropriate check-off list to require verification that mechanical linkages for the airlock inner and outer door equalizing valves were connected.

Breach of containment integrity occurred for only a brief period when the inner airlock door was opened concurrent with movement of fuel inside containment or heatup of the reactor coolant system above 200°F. The flow path through the two-inch equalizing valve permitted only a small amount of air flow from containment to atmosphere. Therefore, the health and safety of the public were not adversely affected.[12]

FAILED LIGHT BULB PREVENTS DIESEL FROM STARTING

With the Yankee Nuclear Power Station at full power operation, the No. 3 Diesel Generator DC control circuit pilot light located outside the diesel cubicle was observed to be out. It was fused to its socket. The pilot light located on the control room diesel panel also was out, and an attempt to start the diesel failed.

The apparent cause of bulb failures and the failure of the diesel to start was a short circuit within the pilot light, resulting in a blown fuse in the DC control circuit.

The defective pilot light and holder were replaced and new fuses were installed in the DC control circuit. The diesel was successfully test run.

Immediately after the failure of the diesel generator to start, two redundant diesel generators, were started and run for 5 minutes to verify their operability. Hence, this event did not jeopardize the health and safety of the public.[13]

ABNORMAL DEPRESSURIZATION OF PRIMARY SYSTEM AND RELEASE OF GASEOUS ACTIVITY

Unit 1 of the Zion Station was in a hot shutdown condition, and valves of the excess letdown system were being lined-up to service a relief valve to the pressurizer relief tank (PRT) that had been weeping. When the reactor coolant drain valve was opened to establish excess letdown flow, high seal water flow and high outlet temperature indications were noted on two reactor coolant pumps. Reactor vessel flange leakoff temperature increased rapidly, and pressurizer level and standpipe level alarms were received from three reactor coolant pumps.

The licensee thought a pump seal had blown, so safety injection was manually initiated and the reactor coolant pumps were deenergized. Closure of the reactor coolant loop isolation valves caused almost immediate stabilization of reactor systems.

In the twenty minute excursion, reactor pressure decreased from 2235 to 1560 psig, containment pressure reached approximately 1 psig and a containment humidity change of 10% was noted on one detector. Approximately 3 to 4 inches of coolant had accumulated on the containment floor, and the rupture disc (100 psi burst pressure) on the pressurizer relief tank ruptured.

A manual drain valve in one loop of the reactor coolant system that had been inadvertently left in the open position. This caused the abnormal conditions and leakage.

The position of the valve had not been listed in the abnormal valve line-up when opened, or added as a temporary change to the drain or to the fill procedure. After the loop was refilled, the valve was not reclosed.

Release of gaseous activity originated from the auxiliary building ventilation system when approximately 2,000 gallons of liquid was erroneously pumped from the containment sump to the auxiliary building floor drain analysis tank. The containment sump valves had not been repositioned prior to reset of safety injection.

The maximum release rate was calculated to be 69,000 μCi/sec (Technical Specification limit is 60,000 μCi/sec) for a total release of less than 0.5 curies. The safety of the public was not endangered because of short release duration, the direction of release, the short half-life and the total magnitude of the release.

Permanent changes have been made for the check-list of valves for reset of safety injection and to the drain and fill procedure to preclude recurrence of these events.[14,15]

Point of Contact:

Theodore C. Cintula
Office of Management Information
and Program Control
U. S. Nuclear Regulatory Commission

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CURRENT EVENTS

POWER REACTORS

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EVENTS SELECTED FROM REPORTS SUBMITTED TO THE UNITED STATES NUCLEAR REGULATORY COMMISSION

AUGUST - SEPTEMBER 1975

CRACKS DISCOVERED IN COLLET HOUSINGS OF CONTROL ROD DRIVES

During a refueling outage at Unit 3 of the Dresden Nuclear Power Station and while overhauling a control rod drive, a crack was discovered in the collet housing short tube. Four other control rod drives were available for scrutiny; inspection revealed each of their collet housings to be cracked. In each case, the cracks occurred in the collet housing short tube below the water ports in the area of increased wall thickness. Subsequent inspection of eighteen control rod drive mechanisms revealed that eleven rods displayed some indications of cracking in the collet housing area.

General Electric Company's Nuclear Energy Division was advised of this possible generic problem. Examination of their test control rod drive mechanisms revealed cracks of the collet housings nearly identical to the four control rod drives examined at Dresden-3.

General Electric had been aware of similar cracking on test collet housings of control rods that had been scram-cycled 2000 times, and more severe cracking on mechanisms scram cycled more than 4000 times. However, there were no indications that cracking would develop within the expected lifetime of 200 scrams for the control rods at Dresden-3.

The collets with cracked housing were replaced with new assemblies. Future actions will be determined by the outcome of tests now in progress.

At present, General Electric and Argonne National Laboratory are conducting independent metallurgical tests to determine the cause of cracking. Although it has not been substantiated, the cause of cracking may be related to the temperature cycle a control rod drive experiences during a reactor scram.

The 2000 and 4000 cycle scram tests performed at G.E. demonstrated the probability of total collet housing failure to be quite remote. The collet housing does not function as a pressure barrier and is subject to stress vastly less than the yield strength of collet housing metal. In a supposed possible worst conditions accident, a number of collet housings failing simultaneously, localized core damage could result from abnormal rod patterns and power levels. However, even in this unlikely event, a standby liquid control system would be available to reduce reactivity and maintain the reactor in a shutdown condition; all radioactivity would be contained within the reactor vessel or the standby gas treatment system; and there would be no danger to plant personnel or the public.[1]

STEAM GENERATOR TUBE LEAK

At Unit 2 of the Point Beach Nuclear Plant, operating personnel noted an upward trend on the air ejector radiation and blowdown monitors, indicative of primary-to-secondary steam generator leakage. The primary-to-secondary leak rate was calculated to be 0.23 gpm, a rate near the normal average of 0.2 gpm, but operating personnel began securing systems in anticipation of a blowdown/shutdown. Five and one-half hours later, the primary-to-secondary leak rate had increased to 0.4 gpm, and four and a half hours after that, the blowdown monitor alarm was received. Thirteen and one-half hours later, an orderly shutdown of Unit 2 commenced at a rate of approximately 100 MW/hour. Subsequent eddy current inspection identified a failed tube in the "B" steam generator. The failed tube was on the periphery of the tube bundle slightly above the top of the tube sheet, and the appearance of a relatively clean cut and roughly circular hole indicated a manufacturing defect or the result of damage following manufacture. The failure appeared to be random in nature and not connected with previous generic problems of wastage in the kidney shaped high heat flux zone of the hot leg.

Two tubes, in addition to the leaking tube, were discovered to have significant defects. One, a 44% defect, was located at the third support. A second, with a 58% defect, was located approximately one-inch above the sixth support. These tubes had previously been measured with a 20 to 30% defect, and a 40% defect respectively. The failed tube had never been examined in service.

Of the 712 tubes tested during the eddy current program, 150 appeared to exhibit a loss of ovality of 0.002-inch or greater. The steam generator manufacturer has advised that tube vibration from crossflow of water on a tube may be a contributing factor to the loss of ovality. There was no measurable metal loss with loss of ovality.

The switch to all volatile water chemistry treatment at both Units 1 and 2 appears to have inhibited the tube wastage problem previously discovered in the kidney-shaped high heat zone of the steam generator hot legs. No new indications of wastage in this heat zone were observed during the inspection. In addition, although sludge depths of up to four inches were measured on the tubesheet by eddy current examination, this sludge appeared to be harmonious with the tubing. Sludge lancing, therefore, was not performed during this outage.

A secondary-to-primary 800 psig leak test was performed with satisfactory results.[2]

FAILURE OF SAFETY RELIEF VALVE

With a reactor power of approximately 10% at Unit No. 2 of the Brunswick Steam Electric Plant, the "B" safety relief valve inadvertently opened. An attempt to close the relief valve by placing the control switch to close failed. (A violation of the emergency instructions occurred when the reactor was not manually shut down when it was determined that the relief valve was stuck in the open position.) Concurrent with attempt to seat the relief valve, an attempt was made to initiate torus cooling with one of the residual heat removal loops, but the service water supply valve to the heat exchanger failed to open. A redundant loop was immediately placed in the torus cooling mode.

When the decision was made to shut down the reactor, the High Pressure Coolant Injection (HPCI) operated for only a limited time because of high torus level. When it was apparent that manual operation of the HPCI could not supply clean water to the reactor, the main steam isolation valves were closed. This action resulted in a reactor scram. Reactor pressure decreased rapidly, and continued to decrease until the pressure reduction was stopped at 72 psi by apparent seating of the relief valve. There was no damage to the torus structure or relief valve discharge pipes, and inspection indicated all components reacted normally to the discharge failure. A specific cause for the blowdown incident was not discovered. All relief valves were actuated successfully at 50 psi during subsequent reactor heatup, and all relief valves met capacity checks successfully. No problem with valve operation was identified.

Seven days later, with the reactor at 8-9% power, and at 600 psi pressure, it was observed that the temperature of the discharge of the same relief valve was abnormally high. The relief valve was cycled three times but did not reseat. Adjacent valves were cycled in an attempt to shock close the open relief valve, but the valve still did not reseat. Reactor pressure was at 475 psi and decreasing so the reactor was manually scrammed.

During the blowdown, several attempts were made to reseat the relief valve: once at 184 psi, once at 82 psi, and once at 49 psi. Two and a half hours after the relief valve inadvertently opened, the valve appeared to reseat with reactor pressure at 20 psi.

Two or three days prior to the first depressurization, a ground alarm had been received in the control room. The ground circuit was subsequently discovered in the conduit for the relief valve that had inadvertently opened. A screw on the conduit cover had pierced the insulation at the connection between the remote cabling and the solenoid wiring. The connection was reinsulated and a small burr on the end of the screw removed.

Between the first and second depressurization, all Target Rock relief valve solenoid pilot operators had been rebuilt. Upon entering the drywell after the second depressurization, the solenoid operator of the relief valve that lifted was found to be stuck in an intermediate position so it was both blowing air into the valve air operator and venting air from the operator. A second ground was found to be caused by water in the solenoid housing caused from condensation in the instrument air system. The ground was repaired and the air lines blown dry.

All relief valve solenoid operators were removed, and during bench testing it was found the solenoids were initially energizing at 90 volts, but the valve did not drop out until a value of 6 to 8 volts DC and when almost zero holding current was reached. These low values of hysteresis current could make solenoid operation susceptible to spurious grounds, leakage paths, or phantom circuits.

Five of the eleven solenoids were found to have their O-ring partially out of their seat. However, further testing of the valve solenoid showed the O-ring could be recaptured in its seat by continued operation (approximately twenty times). A burr on the plungers contributed to the O-ring sticking in the full open position.

Inspection of the valve solenoids revealed all to have dirt in the body area, and the lubricant used to assemble the valves had turned black from valve heat. Rust was found in several of the valves, and at some joints the teflon tape had deteriorated. Dirt was found around the solenoid pilot seats and plungers, and seven of the valves had piston seat O-rings in various stages of being dislodged from their seats.

The solenoid valves were cleaned and reassembled with new body internals and lubricant. A leak check of the valves indicated zero piston and poppet seat leakage, but all ten valves had some pilot seat leakage. After new plungers were installed, pilot leakage was detected to be coming around the pilot seat and through porosity in the valve body. Six valves were made leak tight by resetting the pilot seat, and four valves were rejected because of body porosity. The latter were replaced with new valves.

The eleven solenoid valves that passed inspection were installed and functionally tested satisfactorily at 250 psi reactor pressure, and again at 930 psi and 20% power.

The insulation of the Target Rock relief valves was modified to maintain the air actuator and solenoid valves at a lower temperature. After unit startup, the solenoids were operating at less than 210°F, a temperature safe for prolonged operation.[3]

EXCESSIVE REACTOR COOLANT SYSTEM COOLDOWN RATE

During the course of a routine shutdown for maintenance of the Oconee Nuclear Station Unit 3, when reactor power had decreased to approximately 15%, a system transient occurred that resulted in the opening of a pressurizer relief valve.

The power actuated relief valve had correctly opened when reactor coolant system pressure reached 2255 psi, but failed to close when pressure dropped below 2220 psi. The open/close lights in the control room did not indicate that the valve was open. As reactor coolant system pressure dropped, the reactor tripped on low pressure, and the High Pressure Coolant Injection (HPCI) system actuated. Reactor coolant system temperature and pressure were 480°F and 720 psi, respectively, when depressurization terminated. The initial drop of temperature exceeded the allowable cooldown rate of 100°F/hr. by 1°F/hr.

The relief valve was stuck open because of heat expansion and boric acid crystal buildup on the valve lever. The crystals rubbed against the solenoid brackets and bent the solenoid spring bracket. The valve was repaired and reinstalled. The cause for malfunction of the valve position indication was not observed when the repaired valve was reinstalled. Possibly, this malfunction could have been caused by the solenoid plunger sticking at slightly less than the full open position, or by crud buildup around the plunger-operated minature control switch to the open/close lights.

The transient and associated events also caused the quench tank rupture disc to blow, mirror insulation to be separated from the bottom nozzle of the pressurizer, and the release of approximately 1500 gallons of reactor coolant to the reactor building sump.

The release of coolant did not cause any significant increase of radiation level in the reactor building, and no radioactivity was released into the environment. The excessive cooldown rate associated with the transient was evaluated, and it was determined that the operability of the reactor and the health and safety of the public were not affected. No other system limits were exceeded.[4]

LOW FLOW FEEDWATER LINE SEVERS AT 6x4 REDUCER

While the power level was increasing at Unit 2 of the Quad-Cities Station after an outage, and with both main and low flow regulating valves partially open, a feedwater vibration alarm was received in the control room. The unit was manually scrammed, feedwater pumps were tripped and the feedwater regulating station was isolated. Reactor vessel level was controlled with the Reactor Core Isolation Cooling System (RCIC).

The low flow feedwater line had severed at a 6- to 4-inch reducer on the downstream side of the low flow regulating valve. Inspections also revealed cracks in the low flow piping at the low flow riser junction to the main feedwater line and in the reducer upstream of the regulating valve.

The initial cause of cracking was operational vibrations at the feedwater regulating station, and the break was attributed to vibrations at the feedwater regulating station during transfer of flow from the low flow valve to the main feedwater regulating valve.

At no time was safe operation of the reactor threatened; all reactor parameters responded satisfactorily. The total amount of water released as a result of this occurrence was estimated at 12,500 gallons: 8500 gallons from the severed line and 4,000 gallons from the service water deluge system. This water was discharged from the site on a batch control basis, and activity at the release point in the discharge bay was less than the Technical Specification limit.

The low flow feedwater line had failed previously on June 10, 1974, when the low flow regulating valve ruptured. This rupture, also, was believed to have been partly caused by vibration during normal service, but the main cause was improper machining of the valve body for weld preparation.

Corrective actions to prevent future recurrence include the installation of a "drag valve" to replace one of the main feedwater regulating valves to provide more adequate flow control over a wider range of flow conditions and reduce flow induced vibrations at the regulating station. Also, the low flow control valve line is planned to be repiped to a less rigorous path as another measure to reduce flow induced vibrations.[5]

UNPLANNED RELEASE FROM SITE BOUNDARY

With Unit No. 1 of the Calvert Cliffs Nuclear Power Plant at steady state conditions at approximately 99% power, the control room received a high alarm from the waste area ventilation radiogas monitor. The main vent radiation monitor was also reading above normal. Investigation revealed gaseous radioactivity was being released to the auxiliary building ventilation system.

The radioactive gas was leaking from a waste gas compressor and from the volume control sample hood. The valve had not been completely closed following sampling, allowing leakage through a section of excessively perforated surgical rubber tubing into the primary sample hood and into the waste area ventilation system. This caused the monitor alarm and also vented the volume control tank vapor space to the waste gas system.

Approximately 46 Ci of Xe-133 and 5 Ci of Xe-135 were released during the incident. This release is less than 1% of the Technical Specification release rate limit for noble gases. Two individuals were slightly contaminated while investigating the source of gaseous activity, but they were readily and completely decontaminated. It was concluded this incident did not constitute an undue hazard to the health and safety of plant personnel or to the general public.

The diaphram of the waste gas compressor was replaced. The section of surgical rubber tubing on the volume control tank sample point, which had been repeatedly perforated by the gas sampling syringe, was replaced. The importance of regularly replacing used gas sampling membranes and tubing, and of proper operation of sample system valves was emphasized to all plant radiation safety and chemistry technicians.[5]

RELEASE IN EXCESS OF TECHNICAL SPECIFICATION LIMITS

Over a period of several weeks, containment structure internal pressure gradually increased to 0.9 psig at the Calvert Cliffs Nuclear Power Plant Unit 1, and it was decided to deliberately vent excess containment pressure to the atmosphere.

Based on radioactivity measurements of the containment atmosphere, a maximum release rate of 49,550 cfm would ensure compliance with Technical Specifications. Using the containment purge fan, rated at 50,000 cfm, would have resulted in the allowable release rate being exceeded, so it was decided to vent through the containment purge isolation valves without operating the fans. These valves were opened for four minutes, and containment pressure decreased to 0.05 psig. Review of pressures recorded during venting indicated the actual release rate to be 51,300 cfm during the first minute of venting, exceeding the limit by 4%.

It was estimated the release resulted in less than $5x10^{-3}$ mrem to an individual at the site boundary. Therefore, this incident did not constitute an undue hazard to the general public.

During future containment ventings, either one of the purge isolation valves will be throttled, or an alternate means for more slowly venting the containment will be provided.[7]

TRANSFER OF REFUELING WATER TO CONTAINMENT BASEMENT

During performance of a periodic test for safeguard system valve operation at Unit No. 1 of the R.E. Ginna Nuclear Power Plant, a flow path from the refueling water storage tank (RWST) to the containment was inadvertently established, and containment integrity was violated.

An operator, while following a checksheet, closed valve MOV-851B and erroneously reopened it before the next step to stroke MOV-850B and initialed the procedural step "close MOV-851B". He then noted it was time for his hourly readings and requested another operator to take them for him. Returning to the procedure he saw that the next step after the last step he had initialed was to open MOV-850B. Upon the opening of MOV-850B with MOV-851B open, flow was established from the RWST to sump B.

Upon receipt of alarms, the operator immediately secured the flow path. It was estimated containment had been violated for approximately 3 minutes and about 12,000 gallons of refueling water was transferred to containment. There were indications that approximately 1-inch of water had been on the containment floor. No damage to the safeguards equipment was noted and the water was processed according to normal procedures.

There was no danger to the plant or to the health and safety of the public. The control room operator was reprimanded and, because of the nature of this occurrence, precautions have been implemented so that control room personnel will not have simultaneous responsibilities relative to normal duties and routine operations.[8]

UNREQUIRED ACTUATION OF EMERGENCY SYSTEMS

With Unit No. 2 of the Millstone Nuclear Power Station in the power ascension phase, the cabinet for channel "C" of the Engineered Safeguards Activation System (ESAS) was deenergized for maintenance. All other safeguards channels were energized. The technicians performing the maintenance then noticed the positive logic power supply fuse light for ESAS channel "D" was out; this condition was indicative of a blown fuse. The fuse indicator light bulb was replaced, but the bulb did not energize. The fuse was then removed, resulting in a loss of channel "D" ESAS power because the fuse was actually not blown. With channels "C" and "D" deenergized, a 2-out-of-4 logic condition was established, resulting in generation of all engineered safeguards actuation signals. This included the loss of the normal power signal and caused both diesel generators to start, with load shedding to occur from the emergency buses.

The actuation of the ESAS components did not adversely affect the rest of the plant or the health and safety of the public.

As a result of the ESAS transient, it was discovered that a blown fuse of a power supply for automatic closure of one of the diesel generators onto an emergency bus was undersized. Power was unavailable to this bus for a period of about 12 minutes.

The "B" service water pump failed to start. Because of an administrative error, the pump was aligned to Unit 1. A wiring error was subsequently discovered in the water pump control circuit that prevented proper sequencing of the service water pump.

Also, two of the containment air recirculation fans did not start on slow speed. The problem was traced to a loose relay to the control of both fans.

All of the discovered malfunctions were repaired and tested to verify their correct operation.[9]

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OCTOBER 1975 - FEBRUARY 1976

FAILURE OF REACTOR COOLANT PUMP SEALS

During startup activities from a hot shutdown on September 20, 1975 at Unit No. 1 of the Fort Calhoun Station, an increase in containment sump levels indicated a leak from the upper vapor seal region of reactor coolant pumps C and D. Although it was within Technical Specification limits, the plant was brought to a cold shutdown and the vapor seals of the two reactor coolant pumps were replaced.

After completion of vapor seal replacement, the pumps were pressurized for a leak check and, at pressure, it was discovered the seal pressure breakdown for pump D was incorrect; both first and second stage seals did not indicate a pressure drop. Upon removal of the seal cartridge, it was discovered that five of the eight lower breakdown device cap screws had backed out and damaged the seal coolant recirculation impeller and the bottom supports of the lower breakdown device. All parts were recovered.

After reassembly of the seal, reactor coolant pumps A and C did not indicate a correct pressure breakdown across the seals, so the seals for both pumps were replaced.

Cause for the initial leakage from vapor seals of pumps C and D could not be determined. However, the problem with the D pump seal caused by the backed out cap screws was the direct result of an inadequate maintenance procedure covering the rebuilding of reactor coolant pump seals. A lock wire had not been installed on the pump seal, and the maintenance procedure covering the rebuilding of the seals was too general.

The subsequent improper breakdown of seal pressure across the A and C pump seals was attributed to independent causes; the upper shaft sleeve retaining pin clearance of pump C was greater than normal and allowed relative movement between the upper and lower shaft sleeves. This resulted in unloading of contact forces between the rotating and stationary faces of the bottom two seals. The improper pressure breakdown for pump A was the result of crud blockage in the leakoff path within the pressure breakdown device. After examination of the seal, it was postulated that this condition might have corrected itself if the system had been brought to a higher pressure before shutdown.

Initial leakage through the vapor seal of the pump allowed reactor coolant leakage to the containment atmosphere. However, a certain leakage is permissible under the Technical Specifications, and at all times the measured leakage was below the permissible limit.

The loose parts and damage found to the D pump seal did not jeopardize system integrity because all parts were contained within the cavity and were recovered.

The maintenance procedure has been revised to include more specific information for seal rebuilding and for proper checks for upper shaft sleeve pin clearance.[1]

VIBRATION CAUSES LOW FLOW FEEDWATER LINE DAMAGE

While decreasing load in preparation for shutdown of Unit 2 of the Quad-Cities Nuclear Power Station on August 31, 1975, a feedwater vibration alarm indicated excessive vibration. Because of an increase in reactor vessel water level, the unit operator started closing the feedwater regulating valve. However, before he was able to fully close the valve, the reactor scrammed from a turbine trip.

The reactor vessel water level was controlled, after the scram, by the feedwater system until the personnel investigating the source of vibration reported a leak in the feedwater system. The feedwater system was then isolated from the reactor vessel.

The leakage was caused by severance of two 3/4-inch feedwater drain lines and the 3/4-inch bypass line around the inlet valve for the high pressure heater. Also, the feedwater regulating valve was found to be in the full open position.

The three lines broke because of high vibration of the feedwater system. Vibration also caused the loss of the feedback spring on the valve controller. This caused the feedwater regulating valve to go to the fully open position.

The feedwater low flow drain lines were welded and braced, and the high pressure heater bypass line was replaced from the elbow to the weldolet on the heater side.

The piston-cylinder air actuator on the feedwater regulating valves was replaced with a diaphragm operator in attempt to reduce oscillations of the feedwater regulating valves.

All water from the breaks of piping was processed by the radioactive waste system; there was no excessive exposure to plant personnel nor adverse effect on health and safety of the public as a result of this occurrence.

There have been several cases of excessive vibration of the feedwater system at the Quad-Cities Station. In July 1975, the low flow feedwater line severed at a 6-to-4-inch reducer on the downstream side of the low flow regulating valve. In June 1974, the 4-inch low flow feedwater valve failed. In September 1974, the 4-inch feedwater bypass valve had a crack about three inches long in the bottom of the valve, and cracks in the welds of the bypass valve and pipe reducers.

Excessive vibration problems have been under investigation by a company task force, outside consultants, and engineers from Sargent and Lundy.[2]

OTHER CRACKS IN REACTOR PIPING

QUAD-CITIES 2

On October 14, 1975, Unit 2 of the Quad-Cities Nuclear Power Station was in a cold shutdown condition and ultrasonic testing of the bypass piping around the recirculation pump discharge valves was being performed in accordance with an NRC Bulletin. A crack was found in the heat-affected zone on the 4-inch pipe side of a pipe-to-weldolet weld used to connect to the 28-inch discharge header on the downstream side of the bypass valve.

Although a mode of failure had not been established, the apparent cause was believed to be the same as that which caused cracks in recirculation bypass lines in the past: intergranular stress assisted corrosion.

Early detection of the crack prevented a leak. No radioactivity was released to the environment, so this incident did not present a health hazard to the public or plant personnel.

The existing recirculation pump discharge valve bypass piping of both loops was to be permanently removed and capped.

There have been crack indications in the bypass lines of the Quad-Cities station in the past. On September 16, 1974, there was a crack at a weld on the B loop of Unit 2 which was corrected by replacing the weld and a short section of pipe.

During a second ultrasonic inspection at Unit 2 on December 23, 1974, two cracks were found on bypass loop A and one on bypass loop B; the A and the B loop recirculation pump discharge valve bypass piping was replaced.

On January 10, 1975, at Unit 1, a crack was found in the recirculation pump discharge valve bypass piping on the A loop weldolet running along the 4-inch side of the weld. In addition, there was a crack on the B loop weldolet running 1/2-inch to 3/4-inch from the weld bead. Both the A and the B loop recirculation pump discharge valve bypass piping were replaced.

Similar cracks were found at Dresden, Millstone, Peach Bottom Unit 3, Monticello and the Edwin I. Hatch Nuclear Power Stations.

The pipe that failed in all cases was 304 stainless steel, four-inch diameter, with a wall thickness of 0.377 inches.[3]

DRESDEN-2

While a local leak-rate test was being conducted with Unit 2 of the Dresden Nuclear Power Station at 700 MWe on October 7, 1975, the test failed, and inspection revealed a throughwall crack on the 18-inch drywell/torus nitrogen purge line. The crack occurred at an 8- to 18-inch tee connection, and extended 180° around the 8-inch connection on the 18-inch line, crossing the welded intersection, and extending approximately seven inches along the 8-inch line.

It was assumed the crack occurred during a drywell inerting process when the heating steam boilers, which vaporize liquid nitrogen before admission to the drywell, failed temporarily. Because a previous heating steam boiler alarm had not cleared, the boilers were inoperable for approximately 15 minutes before the problem became evident. During this interval, liquid nitrogen passed through the vaporizer directly, and impingement on the steel tee connection caused a rapid and uneven contraction, resulting in the throughwall cracking.

The throughwall crack constituted a breach of primary containment. However, no abnormal makeup of nitrogen was required, so it was suspected that leakage was minimal. Secondary containment was in effect, and the pressure suppression system and all emergency core cooling systems remained operable.

The immediate corrective action was an orderly unit shutdown at the rate of 100 MWe an hour. After extensive magnetic particle examination, a 20-inch section of pipe containing the tee connection was replaced. The new welds were radiographed and a successful local leak-rate test was completed.

A thermocouple and strip chart recorder were installed on the vaporizer discharge for rapid isolation of the vaporizer to prevent a similar failure. A special operating procedure for startup was written, adding precautionary measures to the existing inerting procedures.[4]

FAILED FUEL ASSEMBLY

During cycle 4 core loading in December, 1975 at Unit No. 1 of the Point Beach Nuclear Station, personnel noted something protruding from the side of a fuel assembly as it was being lowered into the fuel assembly upender. The assembly was moved to the spent fuel pit for examination.

Near grid 1, rust marks were on the grid and on rods 12 and 13. The clad of these two rods was worn so that the fuel springs were visible behind slots in the grid. A fuel fragment was observed lodged between rods 13 and 14. There were gouge marks in rods 12 and 13 adjacent to the grid tab, and a hole was visible in rod 12 at the grid tab.

In the vicinity of grid 2, the cladding of rod 12 was separated with no cladding or fuel behind the upper part of the grid. Rod 13 had a cut mark near the upper edge of the clad and a hole on the left side. A fuel fragment was visible between rods 13 and 14.

Between grids 2 and 3, there were several holes at the contact points of the grid springs on rod 12; no fuel was visible. There was a split in rod 13 and no fuel was visible except at the top end of the split.

At the top of grid 3, there was an open cut in the cladding of rod 12 adjacent to the vane; the vane was severely worn. Rod 13 was completely separated just above the grid. Another fuel fragment was visible on top of the grid.

Below grid 3, holes were visible in rod 11. There was a large hole in 12, with a large fuel fragment sticking out. A section of cladding from rod 13 was missing. No fuel was visible at the top edge of this section.

Many small fuel fragments were visible behind grid 4 and rods 12 and 13.

Between grids 4 and 5, the top 11 inches of rod 13 were missing. The end of rod 13 was bent to a horizontal position about two inches long.

The 11-inch section of rod 13 was found lying diagonally across another fuel assembly, and was recovered.

Westinghouse Electric Corporation believes the initiating factor for fuel failure was water impingement when the fuel assembly was in its original position in the reactor core.

Water impingement at the corner or near the corner fuel rods has led to vibration and fretting wear in foreign reactors. This fuel assembly occupied a corner position in cycle 2. It is postulated a small hole from fuel rod vibration occurred at this time.

The initial escalation to power at the beginning of cycle 3 was at a rate higher than the present operating guidelines, and the cycle 3 position subjected the assembly to a measurably higher power rating than its cycle 2 position. During initial escalation to power at the beginning of cycle 3, a sharp increase in reactor coolant activity was noted between power levels of 40% to 50%. It was presumed the fuel rods containing holes in the clad became water-logged in the shutdown and burst from steam pressure during the power escalation phase.

The potential for additional fuel failures is minimized by new guidelines governing the rate of power escalation following a cold shutdown. The controlled power escalation will allow fuel rods which may have absorbed water from pinhole leaks to expel the water before a substantial increase of steam pressure.

Attempts have been made to locate and remove all loose pellets from adjacent fuel assemblies and the lower core support plate, and apparently no loose pellets remain in the reactor vessel or on fuel remaining in the core.

Based on a safety evaluation, operation of cycle 4 core is not considered to pose a hazard to the health and safety of the public.[5]

HYDROGEN EXPLOSIONS

On November 5, 1975, the Cooper Nuclear Station was in steady state operation at 60% power, and station personnel were removing the manhole cover to the sump below the elevated release point to investigate a pressurization of the sump, a hydrogen explosion occurred when the air sampler was turned on. An orderly shutdown of the reactor was initiated.

Two persons were burned, and after cleaning the burned areas and finding both free of contamination, one patient was retained in the hospital and treated as a burn patient, and the second worker was released.

During investigation of the source of hydrogen gas, it was determined that an isolation valve in the off-gas system was in the closed rather than the normal open position. This caused the discharge of off-gas from the steam jet air ejector to be routed through the loop seal drain line to the sump and back to the dilution fans prior to being discharged at the elevated release point.

The valve was found in the closed position although the control room valve position indicating lights and the control switch showed the valve to be open. Personnel, who had been making wiring changes to this valve for additional off-gas treatment equipment, thought they had verified the proper position of the valve by noting the position of the slotted notch at the top of the stem. However, the butterfly valve gate was not aligned parallel to the slot as they had believed.

The explosion occurred when the air sampler was turned on to monitor the gaseous activity release from the sump. Hydrogen from the off-gas line exploded as it was drawn through the air monitor; it was ignited by the arcing of the brushes of the sampler motor. An explosive mixture meter had not been used to sample the gases from the sump; the meter previously had been used when opening the sump, but no indication of hydrogen had been found.

The sump at the base of the elevated release point was inspected and found to be damaged. The top of the metal lined sump had separated from the side wall liner. Repair was made and the sump air tested.

Station operation with improper position of the valve resulted in by-passing the absolute filters in the off-gas system. The stack gas activity prior to the explosion was calculated to be approximately 680 μCi/sec; after explosion, the stack gas activity was calculated to be 235 μCi/sec. Therefore, a ground level release of approximately 445 μCi/sec occurred from the time of accident until reactor shutdown.

Although the ground level release was unplanned and unmonitored for a period of time, there were no indications that abnormal conditions existed outside the site boundary. Therefore, it was considered this occurrence presented no adverse potential consequences from the standpoint of public health and safety.[6]

Two months later, with the Cooper Nuclear Station at 83% power, an alarm in the control room indicated a low flow condition at the discharge of one of two off-gas dilution fans. The alarm automatically started the alternate dilution fan. It was then noted the elevated release point (ERP) recorder had indicated a gradual decrease in flow rate from approximately 2800 CFM to 2200 CFM over a period of several hours. There was no increase in flow rate after the alternate dilution fan was started. The standby gas treatment (SBGT) system fans were started, but there was not indication of increase ERP flow, and the SBGT flow was low.

Inspection of the off-gas building did not reveal the sources of the problem. However, it was noted the constant air monitor (CAM) was showing an increase in activity, and the building did not appear to be at its normal negative pressure.

After inspecting the ERP and observing no indication of the problem, personnel returned to the off-gas building. Upon reentry, they noted an unusual odor, and the constant air monitor was off scale high. The off-gas building was immediately evacuated and an explosion in the building occurred shortly thereafter. Reactor power was immediately reduced and then the reactor was shutdown.

The 32-foot by 48-foot metal building was completely destroyed with the exception of some heavy metal framework. The dilution fan room ceiling and upper walls (constructed of reinforced concrete) were severely damaged.

A partially melted ice plug was found at the bottom of the ERP several days after the explosion. It was postulated the ice plug had formed at the top of the 325-foot elevated release point pipe and reduced the discharge area from 153 sq. in. to approximately 12 sq. in. The ERP is uninsulated pipe. The bottom 66 feet is constructed of 30-inch diameter pipe with a divider. The pipe then is reduced to an 18-inch diameter until the last 15 inches, where it is further reduced to a 14-inch diameter at point of discharge. All pipe has a 3/8-inch wall thickness.

The ice plug and subsequent reduction in ERP pipe discharge area resulted in back pressure that created the off-gas dilution fan low flow condition. The starting of the standby gas treatment system compounded the problem by creating additional back pressure at the ERP.

The progression of ERP blockage and flow reduction was not easily discernible. The ERP flow monitor, a Pitot-Venturi type sensor device, did not indicate an unusual flow reduction. This instrument had not been reliable and after the explosion and complete ERP flow loss, the recorder still indicated a flow of 2000 cfm.

The hydrogen concentration apparently increased until an ignition source within the room caused the explosion. There were several electrical devices including limit switches and solenoids that were not of explosion-proof rating.

The event presented no adverse potential consequences from the standpoint of public health and safety. Although there was an unplanned and unmonitored radioactive release with the explosion of the building, there was no indication of abnormal conditions outside the site boundary.

A new off-gas building has been erected. The upper 10 feet of the elevated release point has been heat traced and insulated to preclude the formation of another ice plug. Also, another 10-foot section of the ERP around the ERP flow monitor location and the sensor flange was heat traced and insulated to improve flow monitoring reliability.

The dilution fans were removed from the direct path of the process flow stream and now take suction from the building room air only. Piping in the off-gas building that can potentially carry an explosive mixture is now designed to stand an explosion. The ERP flow pitot-venturi sensing device has been modified to improve flow monitoring reliability.[7]

EXPLOSION IN STACK FILTER HOUSE

A hydrogen explosion occurred at Unit No. 2 of the Brunswick Steam Electric Plant while at 85% power. On January 19, 1976, during an attempted blowdown of the stack monitor sample line an increase in radiation activity of the stack monitors was noted, although off-gas loop seals had been determined to be filled. Two people were dispatched to the filter house and saw an alarm on the local area alarm monitor, and water was on the floor with a heavy mist overhead. They spent about 30 seconds in the building and, upon exit, discovered they were contaminated. They were subsequently decontaminated.

About 2-1/2 hours later, the filter pit area was reentered, and the loop seals were refilled with water although it could not be determined if the seals had blown their original water supply.

About 4 hours later, two off-gas annunicators alarmed. A security guard reported to the control room there had been an explosion in the filter house and that the house was on fire.

The fire was extinguished with no apparent structural damage to the filter house. However, the hatch cover hinges were bent from the explosion.

Investigation revealed that removal of a filter cell concrete plug during subfreezing temperatures had permitted moisture buildup on the high efficiency particulate filter (HEPA). Additional moisture buildup also occurred because the HEPA filter demister was improperly positioned and did not allow proper water removal from the process stream.

As a result of the moisture loading, the increased pressure differential across the HEPA caused an increase in system backpressure that caused water to be blown from an undetermined number of off-gas loop seals. The blown seals allowed both airborne activity and hydrogen gas to the filter house where the hydrogen gas was ignited, presumably by an arc from a relay contact.

The operating group had no warning of the occurrence because excess differential pressure across the filter was not annunciated.

The source and sequence leading to the off-gas explosion has been accurately identified, and corrective measures have been implemented to preclude occurrence of further off-gas explosions in a similar manner.[8]

CONTROL ROD DRIFT

During a control rod drive scram time periodic test at Unit 2 of the Brunswick Steam Electric Plant on September 25, 1975, a control rod scrammed from position 48. Following the rod scram, the operator withdrew the rod to position 06. When the control switches were released, the rod continued to drift beyond position 06 to position 48. The rod was inserted again to position 00 but five times drifted out to 48.

Suspecting a problem with the hydraulic control unit, the insert and withdraw riser valves were closed after positioning the rod at 00. However, the drive continued to drift to position 48. The valves were reopened, and the drive was exercised by notching in from position 48 to 46. After two to three notching exercises, the drive successfully latched at position 46. The drive was then fully inserted and observed to stay full in. Then, the drive was withdrawn to position 48 and left there.

While the control rod was drifting, it was noted there was no control rod drive hydraulic fluid flow and the withdraw and insert lights were not lit. The time to drift from full in to full out was estimated to be 90-120 seconds. During subsequent operation of the control rod drive, it was observed to double notch out and to insert sluggishly.

Based on the control rod performance, it was concluded that foreign material had entered the collet piston area which prevented reseating of the collet piston and closure of the collet fingers.

The sluggish insert motion was indicative of directional control valve failure.

As a result of proper rod latching following the drift, it was concluded the interference material at the collet piston had been eliminated during the sequences of rod exercising. Demonstration of proper collet finger operation under a scram condition was terminated after six successful scram insertions. However, numerous double notches were encountered during withdrawal, apparently caused by directional control valve failure. Also, during testing, withdraw stall flow decreased from an original value of 1.5 GPM to 0.2 GPM. The insert speed control needle valve was adjusted and the drive water supply, under-piston water to exhaust, and the over-piston water to exhaust filters were replaced; the withdraw exhaust and settle valve was replaced. Four scram tests were completed successfully; the control rod successfully notched from 00 to 48 with no indicated deviation from normal drive performance.

Failure of a single control rod to position is not considered by the licensee to lead to a compromise of reactor safety systems. The failure of a control rod to insert under a scram condition is considered in the plant safety analysis as a worst-case situation. The apparent failure of the control rod was detected by performance of periodic tests which are designed to provide such detection.[9]

LOSS OF POWER AND SUBSEQUENT REACTOR BLOWDOWN

On September 13, 1975, Unit 1 of the Pilgrim Station was being shut down for replacement of a flange gasket on a pressure reducing valve when, at 17% power while switching the turbine generator off-line, two 345-kV power switchyard breakers malfunctioned. This resulted in loss of power to the emergency busses, and to non-vital equipment including the reactor feedwater pumps. However, offsite power was available to the Core Spray Cooling System (CSCS); but it was not needed.

The malfunction of the breakers caused a reactor scram to occur; the emergency diesel generators started and restored station power to the safety related busses, as designed.

Primary and secondary containment isolation occurred immediately following the scram and a Reactor Core Injection Cooling (RCIC) system flow of 400 gpm was established in the test mode.

Approximately 10 minutes after primary containment isolation occurred, one relief valve opened automatically at its design pressure. Another relief valve was opened manually to augment relief of the pressure vessel, and coolant from the RCIC system was injected into the vessel at the full flow rate.

When the reactor pressure decreased to 800 psi, the manually operated relief valve was closed. However, the relief valve operating in the automatic mode failed to reseat with return to proper reactor pressure. Reactor vessel inventory continued to decrease and caused initiation of the Core Standby Cooling System (CSCS) - High Pressure Coolant Injection (HPCI), Low Pressure Coolant Injection (LPCI), Residual Heat Removal (RHR) system, and the Core Spray System - approximately 21 minutes after the loss of station power.

The CSCS system responded and maintained coolant level until the relief valve subsequently reseated at a pressure of 275 psi.

The minimum reactor vessel level during the transient was the CSCS initiation level (greater than 60 inches above the top of the reactor fuel). During the reactor depressurization, the temperature of the vessel exceeded the maximum cooldown rate of 100°F/hr. However, the actual rate of cooldown was less severe than a previously analyzed transient at Pilgrim, and analysis of the vessel temperature transient was not required.

A preliminary inspection of the torus showed no abnormal conditions. However, a more detailed inspection below the normal water level of the torus showed the lower restraints of two discharge lines were each missing their top structural member, an 8-inch channel section. The other two relief valve discharge line restraints showed indication of movement at the point of contact between the pipe and the channel. One discharge line had damage to the upper structural supports and to the 12-inch discharge pipe.

The relief valve that failed to reseat was disassembled and inspected. Failure was attributed to pilot valve leakage; flow of steam had eroded the pilot valve assembly, and erosion permitted an increase of pressure on the actuating side of the second stage piston and, thereby, reduced the closing forces on the second stage piston.[10-12]

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CURRENT EVENTS

POWER REACTORS

UNITED STATES NUCLEAR REGULATORY COMMISSION

EVENTS SELECTED FROM REPORTS SUBMITTED TO THE UNITED STATES NUCLEAR REGULATORY COMMISSION

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ISOLATION CONDENSER TUBE FAILURE

With Unit No. 1 of the Millstone Nuclear Power Station operating at 100% power, the fire suppression deluge system on the main transformer in the switchyard initiated without being required to do so. The water from this system apparently combined with salt residue on the transformer insulator causing an electrical arc-over. The arc was sensed by the protective circuitry as an electrical fault, so the main generator breaker tripped open. This, in turn, caused the reactor protection system to initiate a trip from 100% power. The disturbance on the electrical system at the site also resulted in a reactor trip of the Unit 2 reactor from about 80% power. Unit 2 experienced no problems as a result of the trip.

At Unit 1, an operator in the area of the isolation condenser noted that an internal rumbling started about one minute after the trip; he presumed the isolation condenser had gone into service. He also noted that the smaller piping attached to the isolation condenser was vibrating. Other personnel noted "puffs" of steam coming from the vent of the isolation condenser. One operator noticed the lights on the isolation condenser condensate return valve momentarily lose the full closed indication; there was no reason for the valve to open automatically because a reactor pressure of 1085 psig was not sustained for 15 seconds. The isolation condenser steam inlet valve is normally open, and opening of the condensate return valve would have established flow of reactor steam through the isolation condenser.

The isolation condenser is an 11-foot diameter shell with two U-tube bundles, each with 121 stainless steel 1-inch O.D. tubes. It is a high pressure residual heat removal unit used as a backup to the main condenser, and is designed to reject all residual heat for a period of 5 minutes after a reactor trip. The unit functions by taking steam from the reactor, condenses it on the tube side of the isolation condenser, and returns the condensate to the reactor. With this heat exchanger, residual heat removal and reactor cooldown can be accomplished without use of other heat sinks such as the main condenser or torus. The shell side of the condenser contains greater than 15,500 gallons of water which absorbs residual heat by boiling at atmospheric pressure.

Because of the momentary anomaly with the indication lights, an operator was sent to check the position of the isolation condenser condensate return valve; it was found in the full closed position.

Eight minutes after the reactor trip, the main condenser was valved in to act as the prime heat sink. Reports from the area indicated the amount of steam coming from the isolation condenser vent had now dropped off considerably.

Recovery from the reactor trip proceeded smoothly, with the only off-normal condition being the continuing temperature change in the isolation condenser. Although the temperature change was being monitored, it was presumed that the isolation condenser temperature was stabilizing since the condensate return valve was known to be in the closed position. However, as a precaution from the continued issuance of both steam and water from the isolation condenser vent, the area was secured to minimize the potential from contamination. It was thought the first condensate return valve might be leaking, and the second in-line isolation condenser condensate return valve was closed to eliminate the boiling in the isolation condenser. About fifteen minutes later (65 minutes after the trip) an alarm was received from the isolation condenser vent radiation monitor. The alarm, together with reports of steam and water still coming out of the vent, caused the operator to shut the isolation condenser steam inlet valves; steam from the isolation condenser started to decrease at this time.

After the incident, the isolation condenser shell side was entered and a visual inspection revealed that one of the stainless steel tubes had failed; the hole in the tube was approximately one inch wide by two inches long. No physical damage to adjacent tubes was noted.

A review of trip sequence and plant parameters revealed no reason for initiation of the isolation condenser or tube failure. Pressure in the reactor never approached the isolation condenser initiation setpoint, and a review of isolation logic and relays showed no isolation signal had been received. No thermal shocks had been noted.

Observations made by an operator in the immediate area of the isolation condenser at the time of the reactor trip, personnel reporting "puffs" of steam from the isolation condenser vent, and a review of the vent radiation monitor recorder indicated the tube failure occurred almost immediately after the reactor trip.

The failed tube allowed reactor steam to enter the shell side of the isolation condenser for approximately 65 minutes. Actions taken during this time were based on the initial evaluation that the isolation condenser condensate return valve was leaking and that tube integrity had not been impaired.

A preliminary examination of the failed tube indicated the cracking originated on the inside surface (primary waterside). The cracking was transgranular and branching, characteristic of stress-corrosion cracking. Many secondary cracks, some penetrating up to 90% of wall thickness, were found in both the bent and straight sections (near the support plate) of one tube. The fracture surfaces were covered with rust, and most cracks were filled with corrosion products. The crack appearance suggests these cracks did not occur during recent usage, but that they had been present in the tube for some time.

There were no evidence of chlorides either in the cracks or in adjacent corrosion deposits. One slight indication of fluoride was found. The cracks did contain significant amounts of silicon, calcium, and aluminum. None of these elements would be expected in the primary water. Their presence suggest $CaSO_4$ during a past intrusion of the primary cooling system.

A microscopic examination of an intact tube failed to reveal any indications of stress-corrosion cracking on either tube surface along the entire sample length.

After plugging the failed tube, the shell side was filled with water and leak-inspected, no additional leaks were found.

The majority of inlet ferrules, all 121 ferrules on the north end and 107 ferrules on the south end, designed to minimize thermal stresses on the tube-to-tube sheet welds, were found to have collapsed. They were to be replaced. In the outlet, only a few collapsed ferrules were found.

The north side heat shield was found to have bent mounting studs and some misalignment and the south side heat shield mounting studs were broken and the shield had been pulled away from the tube sheet. Heat shield deformation and bolt failure was attributed to thermal stress. They will be repaired. The outlet pipe thermal shield on the south side was found have a cracked weld and will be repaired.

Because non-destructive eddy current examination of the tubes revealed numerous indications ranging from 10% to 90% of through-wall thickness, it was decided to retube the isolation condenser with 0.065-inch wall thickness Inconel 600 material.

Instrumentation changes to prevent recurrence included continuous monitoring of the shell side temperature with an alarm, a prescribed action in event of alarm actuation, and adjusting the isolation condenser vent monitor setpoint close to the steady state background.

At the time of the incident, the potential for minor offsite contamination was recognized and technicians were dispatched to the offsite monitoring station; no measurable offsite air activity or contamination was detected. However, the tube break caused minor contamination of approximately one acre inside the fenced area. The roadways and open areas were scraped and the dirt contained for storage. By the next day, all areas were clean with the exception of the inaccessible condensate storage tank moat. The rapid decay of the activity indicated the predominate isotopes were short lived.

No measurable air activity or contamination was found offsite, most of the released isotopes, were of short half life and no reportable radiation exposures occurred. The incident posed no hazard to the health and safety of the public.[1,2]

HPCI SYSTEM PROBLEMS

Quad-Cities 2

When testing the High Pressure Coolant Injection (HPCI) system because of failure of the Reactor Core Isolation Cooling (RCIC) system at Unit 2 of the Quad-Cities Nuclear Power Station, it was discovered the HPCI system was also inoperable. The auxiliary oil pump kept tripping and the HPCI turbine would not start.

Because both the HPCI and RCIC were not functional, an orderly shutdown of the reactor is required by the technical specification and was initiated from 506 MWe.

Investigation revealed a flexible line inside the oil storage tank for the high pressure oil discharge had broken and caused the auxiliary lube oil pump to trip. The flexible line was enclosed in a wire mesh to increase its strength. The wire mesh was also broken.

The broken oil line was replaced with the same type of line.

The HPCI system is one of the four Emergency Core Cooling Systems that provide emergency cooling water to the core over a wide spectrum of line breaks. Because the low pressure systems were operable, and unit shutdown had been initiated after the RCIC system was found inoperable, the safety implications were minimal, involving principally the availability of redundant systems.[3]

Duane Arnold

During a manual start of the HPCI system, operating personnel at the Duane Arnold Energy Center noted a high pressure indication in the HPCI turbine exhaust line; they manually tripped the HPCI turbine. Operating personnel had been closely monitoring the turbine exhaust pressure because a rupture disc had blown during similar testing the previous day.

Subsequent investigation determined the disk of the HPCI Swing Check Valve had become separated from the hinge arm and was lying on the bottom of the check valve. The disk retaining nut and washer were missing. However, the missing nut and washer were later found in the torus.

The HPCI Stop Check Valve was disassembled in the search for the missing nut and washer. Although the nut and washer were not found in the stop check valve, it was observed that two tack welds between the valve disk and the disk retaining nut were broken.

The disk apparently separated from the swing arm in the 16-inch HPCI Swing Check Valve because, during manufacture, the retaining nut had not been welded to the disk stud in accordance with the design drawing by Anchor Valve Company.

The apparent cause of the broken tack welds between the valve disk and the disk retaining nut in HPCI Stop Check Valve was a design deficiency. The two tack welds apparently were insufficient to secure the nut and disk under normal operating conditions.

The detached disk in the HPCI Swing Check Valve could have prevented performance of the HPCI subsystem; the disk could have lodged against the discharge of the valve causing overpressurization of the HPCI turbine exhaust line and a subsequent trip of the HPCI turbine.

If the valve disk in the HPCI Stop Check Valve would have become separated from the valve stem as a result of the broken tack welds, the above analysis would also be applicable. The design function of the HPCI Subsystem is only required when normal makeup water to the reactor is not available. If operation of the HPCI system is required and the system does not perform, the Automatic Depressurization System (ADS) in conjunction with the Low Pressure Coolant Injection (LPCI) and the Core Spray System are available for reactor cooldown. This event did not present a hazard to the health and safety of the public.

It also should be noted that the detached disk in the HPCI Swing Check Valve would have prevented the valve from acting as a boundary isolation valve. However, in the as-found condition, the HPCI Stop Check Valve would have performed the isolation function and would have isolated the HPCI turbine exhaust line even if the HPCI Swing Check Valve did not.

Corrective action was to tack weld the retaining nut and disk stud in the HPCI Swing Check Valve in two locations in accordance with an approved design change. The valve disk and retaining nut in the HPCI Stop Check Valve were tack welded in four locations in accordance with vendor recommendations and an approved plant design change.

Similar Swing Check and Stop Check Valve installations in the RCIC were inspected to ensure the disk retaining nuts were adequately secured. The disk retaining nut in the RCIC Swing Check Valve was properly secured with a pin. Two tack welds were added to provide additional assurance the nut would remain secure. The RCIC Stop Check Valve disk retaining nut was found secured with two tack welds; two additional tack welds were added.[4]

INADVERTENT ISOLATION OF REACTOR INSTRUMENTATION

Quad Cities-1

Unit No. 1 of the Quad Cities Nuclear Power Station was at 512 MWe while a routine surveillance test of the Reactor High Pressure scram switches was in progress. When the instrument mechanic attempted to isolate one of the switches prior to calibration, he discovered it was already isolated.

The switch apparently had been left isolated after completion of the previous month's testing, since no maintenance had been performed on the switch.

The safety significance of this occurrence was minimal; redundant pressure switches were operable. The surveillance test found the other three switches to be operational and they would have tripped within prescribed limits.

Seven days later, with the reactor at 541 MWe, a monthly surveillance test of the Emergency Core Cooling System (ECCS) pressure switches was made. One pressure switch was discovered to be isolated. Apparently, the isolation valves for the pressure switches had been inadvertently left in the closed position since the last surveillance test.

A redundant pressure switch was operable; ECCS systems would have performed their required function. The safety implications of both cases of inadvertent isolation were minimal, and the public health and safety were not affected.

An additional requirement was added to the surveillance procedures to place wire security seals on safety related instrument stop valves. This additional step should eliminate valving errors in the future.[5,6]

TROJAN

With the Trojan Nuclear Plant at 30% power, it was noted the steam flow indications for one of the steam lines were constant while indications for other loops were fluctuating. Investigation revealed both flow transmitters for the steam line were isolated.

The recorder charts indicated the sensors had been isolated fo. three days. During that period, reactor power varied between 0 and 30 percent. Apparently the steam flow indicators had not been returned to service following maintenance, and the continued operation in this period was a violation of the limiting conditions of operation.

Although automatic protection of the plant to steam line breaks was reduced, adequate protection still remained. A steam line rupture downstream of the main steam check valves would have actuated a high steam line flow signal on the other three steam lines (logic is 2 of 4) to produce a safety injection signal. It was concluded that there was no danger to the health or safety of the public.

To prevent recurrence, the importance of returning safety-related instrumentation to service as rapidly as possible was stressed. The operators were instructed in the importance of recording when a safety related instrument is removed from service and placing the applicable reactor protection channel in the "trip" condition.[7]

PROBLEMS DURING FUEL MOVEMENT

Crystal River

While transferring the 55th new unirradiated fuel assembly from its shipping container to the inspection location at the Crystal River Nuclear Plant, it fell approximately five feet to the floor. The wire cable for the fuel handling tool had pulled out of its swaged fitting.

The cable was certified to support 2,400 pounds; the fuel assembly weighed 1,550 pounds.

Some of the fuel pins were bowed, but none had ruptured. Some spacer grids were broken, the lower end fitting was bent, and some welds on the fuel handling tool were cracked.

After the fuel assembly drop, radiation and contamination surveys indicated there had been no release of radioactive material. Therefore, the drop did not cause exposure to employees or present a hazard to the public. All fuel handling slings were to be evaluated and consideration given to eliminating the use of swaged connections. Until this evaluation is completed, a different type of fuel handling tool that does not require the use of slings was to be employed.[8]

Surry-1

Unit No. 1 of the Surry Power Station was in a refueling shutdown following fuel movement and replacement of the upper internals package. The manipulator crane was being moved in preparation for latching the full length control rods. During movement, the manipulator outer mast was inadvertently driven into the upper internals package and damaged the drive shaft at core location P-8. The drive shaft was not latched to its control rod at the time of impact.

The impact caused a bend in the drive shaft and a minor displacement in straight edge measurement of the upper guide tube.

It was concluded that the drive line was acceptable for reuse. Controlled tests indicated that guide tube misalignment would not have significant effect on drive line operation. Westinghouse Electric Corporation reviewed the occurrence and agreed that the continued use of the component would not significantly affect operation of the system.

As final assurance of adequacy of the drive line, an extensive rod drop test program was to be conducted on this rod prior to reactor startup. In addition, the drive line was to be inspected during the next refueling outage to determine if abnormal wear was occurring.

This occurrence did not affect the health and safety of the public.[9]

CONTROL ROD PROBLEMS

Palisades

With the Palisades Plant at 80% power, a control rod dropped into the core. A turbine runback further reduced plant power to 70%, and administratively plant power was further reduced to 50%. An attempt to retrieve the dropped rod failed.

The apparent cause of the control rod drop was a shorted clutch coil. When the clutch coil is energized, the upper and lower clutch jaws are held together and maintain rod position at the set location. When the clutch is deenergized, the lower portion of the jaw separates from the upper, and the control rod falls by gravity to a more safe position. The shorted clutch coil did not allow the rod to be retrieved.

Plant operation can continue with one inoperable control rod. However, it was decided to shut the plant down because of problems of high seal leakoff temperature in another control rod drive mechanism.

Core flux tilts were calculated to be within the limits of the technical specifications. The shorted clutch coil was replaced. There was no hazard to the health and safety of the public.[10]

Robinson-2

The H. B. Robinson Steam Electric Plant, Unit 2, had reduced power to perform weekly surveillance tests. These tests were completed successfully and a power level increase had commenced. The Rod Exercise Test was in progress. These tests check operability of the full length control rods by inserting and withdrawing them 19 steps and observing the rod position indication response.

While withdrawing shutdown Bank "A," an alarm was received on the control panel. This alarm prevented step movement of the entire bank of twelve control rods. A decision was made to proceed with a normal reactor shutdown as far as practicable.

With the reactor at approximately 9% power, a turbine trip occurred from a high water level in a steam generator. Shortly, the reactor was manually tripped; all rods inserted satisfactorily.

The alarm resulted from a defective fuse in the AC power supply to a rod control cabinet. The fuse was improperly assembled during manufacture, causing intermittent continuity. When discovered, the fuse link had not burned apart, but was not making solid contact with one end of the fuse housing. This disabled one of the three phases from the AC power source to the power cabinet. When rod movement was attempted, the phase monitoring card in the cabinet sensed the loss of the AC phase and initiated the alarm.

A replacement fuse was installed. It was believed that this was an isolated case of failure. Other fuses were not inspected because of possible link damage from twisting.

The reactor control rods and shutdown rods were all capable of tripping throughout the duration of the occurrence, and all reactor trips were operable to provide the fullest protection possible. At no time was reactor shutdown capability reduced by the presence of the inoperable rods. This occurrence did not create or threaten to create any hazard to the plant or the public.[11]

TAPED REACTOR SPRAY BUILDING NOZZLES

It was reported that several of the reactor building spray system nozzles at the Rancho Seco Nuclear Generating Station had, at some earlier date, been covered with tape which had not been removed. Investigation revealed that four of the nozzles had their spray openings covered by tape, and 12 other nozzles had tape on them which did not block the spray opening and did not affect their performance. Discussion with maintenance personnel led to the conclusion that tape was placed over the nozzles to protect them during painting activity. At completion of the work, which was done while the plant was still under construction in mid-1974, the outside contractors doing the painting failed to remove the tape.

The four inoperative nozzles represented only 2% of the 199 nozzles of the reactor spray system. Several periodic surveillance tests have been performed on both spray systems and the systems passed all requirements of the tests. Therefore, it was concluded that the health and safety of the public was not endangered by the taped nozzles.[12]

OCCUPATIONAL EXPOSURES

Indian Point

Unit Number 2 of the Indian Point Station was in cold shutdown condition, having been shut down five days earlier for a refueling outage. An individual had been assigned to determine the lighting requirements in the general sump area beneath the reactor vessel in preparation for installation of a pump.

Gamma field measurements made several hours after shutdown and on the following day showed general radiation levels in the sump area ranging from 30-150 mR/hr. However, between the time of the last field survey and the time the individual entered the area, thimbles which housed the fixed and movable in-core detectors had been withdrawn from the reactor vessel. Withdrawal of the thimbles is required for the refueling procedure and is mechanically performed at an area far removed from the reactor vessel sump level. Unaware that the radiation field had increased considerably as a result of thimble withdrawal, the individual proceeded to the sump level. Upon reaching the sump level he checked his self reading pocket dosimeters (0-200 and 0-500 mrem), found them off-scale and immediately exited the area. Immediate processing of the film badge indicated the individual had received a whole body radiation dose of 10.06 rem for the quarterly period of April 1 through June 30, 1976.

It was subsequently determined that the maximum radiation field to which this individual was exposed was approximately 600 R/hr. Based on retracing the individual's steps in the identical Unit No. 3 (not yet critical), it was estimated that he spent approximately 100 seconds in the area.

The immediate corrective action to prevent recurrence included locking of the access hatch, conspicuously posting a warning sign at the entrance, partial reinsertion of the thimbles into the reactor vessel, thereby lowering the radiation levels from 600 R/hr to 50 R/hr, and placing a gamma monitor in the area to alert individuals to any increase in radiation fields above the postulated levels.

In view of the unusually high radiation level that can exist in this area, a long-range investigation was initiated to determine other corrective actions for controlling personnel access which could be used in addition to controls already implemented.

A design review of Units Nos. 2 and 3 did not find any similar situations where an operation at one location could significantly affect radiation levels at a different location. Because an unusually high radiation level can exist in this area and not be immediately apparent, the utility contacted all similar operating units in the U.S. and the vendor to advise them of this incident to prevent recurrence at another site.

10 CFR Part 20 requires that an individual's total accumulated exposure be limited so as not to exceed 5(N-18) where N is age of employee in years. Within this limit the allowable exposure in any one year is 12 rem. For this employee, who was 32, the total permissible accumulated dose was 70 rem, his actual accumulated dose had been 16.98 rem, including the dose received in this incident. To assure that the employee's annual allowable exposure did not exceed the 12 rem limit, he was not to be assigned to further work involving potential radiation exposure for the balance of the year.[13]

Zion-1

Unit Number 1 of the Zion Generating Station was in its first refueling operation. When the refueling cavity was partially flooded, excessive leakage was noted from the refueling cavity into the reactor cavity. In an attempt to discover the leakage pathway, an inspector entered the reactor cavity and, after remaining for 1 to 1-1/2 minutes, noted he had accumulated an exposure of 200 to 250 mrem. He wished to inspect the platform area of the annulus between the reactor vessel and the concrete shield wall, and decided he could make a rapid inspection and maintain his accumulated exposure under a 500 mrem limit.

He proceeded to this area, but during inspection noted the meter was pegged full scale; he immediately left the reactor cavity. The total elapsed time on the platform was estimated to be 1 to 1-1/2 minutes. His film badge was sent for immediate processing; his exposure was estimated at 8.05 rems.

The exact level of radiation throughout the area was not known because the 58 incore detector thimbles were withdrawn from the reactor vessel into their guide tubes as required for refueling operation. A subsequent survey indicated a range of at least 200 R/hr in the platform area.

This was the only exposure for the individual during the quarter.

This entry was in direct violation of approved Zion Radiation Protection Procedure. To prevent recurrence, the importance of following approved station procedures was stressed to all station personnel. To preclude ready access to the reactor cavity area during periods of cold shutdown, administrative controls were established to have all accessess to the cavity padlocked. These padlocks were to be removed prior to proceeding to criticality. These administrative controls were to include Management verification.[14]

HUMBOLDT BAY In preparation for cleanup line repairs at the Humboldt Bay Power Plant, a foreman and worker made four trips to the lower drywell area for removal of flux wire guide tubes and the installation of copper "freeze seal" cooling coils. The radiation fields in the lower drywell area ranged from 200 mR/hr to 10 R/hr.

After the foreman's second trip into the lower drywell area, his highest range pocket dosimeter (range 0-1R) was beyond full scale (above 1R with the hairline still visible). The other individual who was performing essentially the same work and in essentially the same location, had a total indication of 1000 mrem at this time. From this measurement, a preliminary calculation indicated the highest dose the foreman could have received was 1200 mrem. It was decided that it would be proper for the foreman to continue the job. Both individuals made two additional trips to the lower drywell to complete the job, and each time their dosimeters pencils indicated they had received the same doses within 50 mrem.

The next day the foreman was issued a new film badge and worked in a radiation area until his total estimated dose for the two days was 2550 mrem. When the film badge results were received, it was learned that the foreman's first badge read 3500 mrem and his second film badge was 95 mrem. The individual who had worked with the foreman in the lower drywell had a badge reading of 2300 mrem.

The most probable cause of the overexposure was the assumption that two men working side by side receive approximately the same exposure and, based on that assumption, permitting the individual to return to work after his pocket dosimeter had exceeded full scale and before his film badge result was known. A contributing factor was that the foreman was not wearing a higher range dosimeter pencil for a backup dose estimate.

To prevent recurrence, a procedure was to be initiated in which the proper actions to be taken when a pencil dosimeter goes beyond full scale would be defined, and a list of pocket dosimeter ranges to be used while working in various radiation levels would be provided. The new procedure was to be reviewed with all plant radiation protection personnel and issued in the plant manual following review.

Point of Contact:

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CURRENT EVENTS

POWER REACTORS

UNITED STATES NUCLEAR REGULATORY COMMISSION

EVENTS SELECTED FROM REPORTS SUBMITTED TO THE UNITED STATES NUCLEAR REGULATORY COMMISSION

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EMERGENCY DIESEL GENERATOR PROBLEMS

SURRY-1

A routine start of the emergency diesel generators from the control room of Unit 1 of the Surry Power Station damaged the number 1 diesel generator. The EDM-GM Turbo Vee 20, 3810 Bhp engine had a crack in #17 cylinder head which extended between two exhaust valve seats and into the water jacket. The cylinder wall was ruptured, the piston broken and the connecting rod bent. The cylinder head is an area of high heat stress and this was the most probable cause of the crack. The crack permitted water from the water jacket to drip into the cylinder. The engine had not been operated for twelve days, and this time frame allowed sufficient water to accumulate in the cylinder to form a hydraulic lock. As the piston started the compression stroke during starting, the noncompressability of the water caused the bend in the piston connecting rod and ruptured the cylinder wall. The broken piston resulted from the bent connecting rod allowing the piston to bottom out and striking the cylinder wall on the return stroke. The other cylinders were inspected and no damage or indications of water were found.

The engine was repaired by replacing all damaged parts. The starting procedure was modified to insure the diesel would be rolled with the cylinder test cocks open to check for flooded cylinders prior to manual start.

About three weeks later, in preparation to start the number 1 emergency diesel generator, water was observed dripping from the air box drain. Investigation revealed water had entered the air box from #1 cylinder via the cylinder inlet ports.

The crack in #1 cylinder head extended from an exhaust valve seat approximately three-fourths of the distance to the injector well and through to the water jacket. The crack permitted water from the water jacket to drip into the cylinder. The piston was near the bottom of the stroke which uncovered the air inlet ports and allowed water to enter the air box and exit the engine via the air box drains.

The cylinder head was replaced. Because inspection after the last incident failed to detect the cracked head, a more stringent inspection was conducted to ensure no other cylinder heads of this engine were defective.

About six weeks later, during preparation to test the starting of number 1 emergency diesel generator, water was detected in #7 cylinder. The crack extended between the two exhaust valve seats and through the water jacket. Inspection of the engine prior to starting permitted the detection of water in the cylinder and prevented further damage to the engine.

This was the sixth cylinder head on this engine to be found with a crack in a three month time period. The location of #7 head on the engine does tend to eliminate the presumed causes of either cylinder heat imbalance or heat stress as a result of an engine overheat.

It now appears that all failures were the result of a previous engine overheat condition that may have heat stressed the cylinder heads to a point where premature metal fatigue from vibration is causing the cracks to appear between the exhaust valve seats. This is an area of high heat and vibrational stress.

To ensure reliability of this engine, weekly testing of the engine will continue. New cylinder heads have been ordered and total replacement should preclude additional failures.

In each instance, the backup emergency diesel generator was demonstrated to be operable. In addition, the manufacturer's representative indicated that the number 1 diesel engine would have operated and performed its intended function had it been necessary, so no hazard to the safety or health of the general public existed.[1-4]

DRESDEN-2

On March 17, 1975, the Diesel Generator failed to start at Unit 2 of the Dresden Nuclear Power Station and the diesel was taken out of service. During subsequent testing, the diesel again failed to start and the air start motors were replaced and sent to the manufacturer (Ingersoll-Rand) for examination. No defect could be found.

On April 15, the diesel generator was being returned to service after repairs when the pinion gears and ring gear jammed. No cause for the failure could be pinpointed.

The diesel generator failed to start again on June 4 after successfully starting for a monthly inspection. The diesel generator was then started successfully a number of times in an attempt to isolate the cause of failure. The diesel generator had started 12 times without incident when, on June 12, it failed to start twice in four attempts. The same day, with a factory representative present, the diesel started six consecutive times.

On November 14, vendor representatives were summoned to the plant to exhaustively investigate the air start system. The ring gear was examined in detail and found to have two small, slightly gouged and burred areas. A series of 22 tests were performed, consisting of rotating the ring gear manually and engaging the pinion gears from the control switch with the main air valved out, simulating an actual start. At the two gouged and burred areas, the pinion gears failed to engage three out of six times, while at all other points on the ring gear the tests were satisfactory.

The ring gear was dressed in these areas with a hone and file. No diesel generator starting failures have occurred since the burrs were removed from the ring gear.[5]

CRACKS IN REACTOR PIPING

DRESDEN-2

An inservice inspection at Unit No. 2 of the Dresden Nuclear Power Station revealed an unacceptable ultrasonic indication in the isolation condenser safe-end. Removal of the 14-inch diameter safe-end and subsequent dye-penetrant examination of the inside pipe surface confirmed the existence of the cracks.

The cracked safe-end was sent to Battelle Columbus Laboratories for metallographic analysis. This analysis revealed one circumferential crack at the 7:00 position and four axially-oriented cracks at the 1:00, 4:00, 4:45 and 5:00 positions. The depth of the circumferential crack was 0.261 inches, while the axial cracks ranged in depth from 0.255 to 0.500 inches. The circumferential crack was located approximately 3/8-inch from the safe-end-to-pipe weld and was 0.60 inches long at the I.D. surface. The axial cracks ranged from 0.23 to 0.43 inches in length and extended to within 1/16-inch of the safe-end-to-pipe weld.

The metallographic examination revealed similar features in both the axial and circumferential cracks. They initiated at the I.D. surface and propagated intergranularly in the heavily sensitized microstructure. The fractured surfaces showed no indication of chlorides, fluorides, sulfides, or other possible corrosives. There were moderate residual stresses from welding and possibly from inner surface grinding (up to 5 mils of cold working were observed). The mechanism for cracking was intergranular stress corrosion and has previously occurred at Unit 2 in the High Pressure Coolant Injection (HPCI) safe end, the 10-inch core spray piping, and the 4-inch recirculation bypass piping.

The unclad cracked isolation condenser safe-end was type 316 stainless steel. It was approximately 5-inches long, with a 14-inch O.D. at the piping end (0.56-inch wall thickness) and a 16-inch O.D. at the nozzle end (1.08-inch wall thickness). The safe-end was furnace-sensitized during the post-weld stress relief treatment of the pressure vessel.

The safe-end is to be replaced with a forging of type 316L stainless steel. The indications were not through wall and in no way affected system operation. There was no effect to the health and safety of the public.

Also, a final report was received on the metallographic examination on the 10-inch diameter stainless steel core spray piping weldments at Unit 2. The cracks were discovered in January 1975 and four of the eight welds were examined in detail by Argonne National Laboratory.

Their report concludes that the cracks were generally circumferential and were located in the heat-affected zone near the welds. None of the cracks propogated through the welds, but were limited to a penetration of about 0.2 inches. The mode of failure was strictly intergranular stress corrosion that initiated at the inside pipe diameter surface and propagated toward the outside diameter.

The corrective action taken to prevent recurrence was to replace the stainless steel portion of the core spray piping from the vessel nozzle to the second isolation valve with carbon steel pipe. The reactor vessel core spray safe-ends were replaced with type 316L stainless steel with an inside diameter clad of 308L weld material.[6-7]

QUAD-CITIES-1

A dye penetrant examination of the feedwater spargers at Unit 1 of the Quad-Cities Nuclear Power Station revealed one indication of cracking in each of two spargers. The test was being performed, after a negative visual inspection, upon request of the General Electric Company, which was concerned over the occurrence of cracking in several feedwater spargers of similar design.

The sparger crack indications were a 1.5-inch linear indication on the 60° sparger and a 2-inch linear indication on the 150° sparger. Both indications were through the junction box-to-thermal sleeve weld.

After removal of the spargers, a dye penetrant examination of the inner bend radius revealed numerous linear indications on all four nozzles. The indications averaged two inches in length; the longest indication was five inches. Maximum indication depth was 5/32 inch into the base metal. The majority of the indications were segregated on the upper half of the nozzles. The cause of sparger cracking was attributed to fatigue caused by flow induced vibration, and compounded by stresses induced by inherent thermal gradients between the feedwater piping and reactor vessel internals. Leakage between the sparger and the feedwater nozzle contributed significantly to vibration of the sparger assembly and also imposed thermal stresses on the nozzle.

New feedwater spargers designed and manufactured by General Electric Company have been installed. These spargers have an interference fit to eliminate leakage and thus reduce vibration and thermal induced stress cycling.

The safety implications of the event were minimal because the reactor was shutdown for refueling and although minor cracking was present, the feedwater spargers and nozzles were still capable of performing their designed functions. There was no effect on safe plant operation nor on the health and safety of the public as a result of this occurrence.[8]

SMALL FIRE DURING CONSTRUCTION

During modification of an existing grating in the drywell at Unit No. 1 of the Browns Ferry Nuclear Plant, weld slag fell onto a 16-inch I-beam installed on a 45-degree angle. The slag ran down the beam and ignited four lengths of breathing air hose in a plastic wrapper and an electric extension cord at an elevation 17 feet below the welders. Ignition occurred after the craftsmen installing the grating had left the area.

The roving fire watch was notified of smoke coming from the reactor building in the vicinity of the TIP (Traversing Incore Probe) room. The fire watch was unable to find the source of smoke and called the control room to request operator assistance. Three operators arrived almost immediately and determined the smoke was coming from within the drywell. The fire alarm was sounded and the fire was promptly extinguished following the arrival of the fire brigade. It was extinguished by using dry chemicals and demineralized water. There was no damage or detriment to any system operating ability as a result of this event. This event will not cause delay in returning the Browns Ferry Units to service.

To prevent recurrence, the concurrence of a senior licensed operator or a certified Quality Control Inspector will be required when the foreman determines that a fire watch is not required at the welding site.[9]

ERROR IN FILING OF PLANT DRAWINGS

With the Cooper Nuclear Station at 81% power, one of the reactor recirculation pumps tripped. This was the first trip of this type at Cooper and a check of the control circuit indicated no malfunction, so a cause for the trip could not be determined. About two weeks later, a second reactor recirculation pump trip occurred. This time, the licensee found that a ventilation temperature switch was tripping from vibration induced by a motor generator drive motor. The trip of the ventilation temperature switch caused the reactor recirculation pumps to trip. The temperature switch was disconnected and was to be replaced by an improved type of switch.

During an unannounced inspection, the NRC inspector had planned to review the recent pump failures and asked one of the plant engineers to review the trip circuit diagram logic for the pumps with him. When the engineer began to explain the circuit, he noted what he though was an error in the print. The drawing (Revision 11) showed the pump could be tripped by the temperature switch and a lube oil pressure switch. The engineer believed there should also be another contact in the circuit to also provide a pump trip.

An identical drawing (Revision 10) in the engineering stick file did show another contact in the trip circuit. Examination of the pump trip circuit showed the circuit to be actually wired in conformance with Revision 10 of the drawing. The engineer and the inspector then attempted to determine the origin of changes in Revision 11 of the drawing. They found the above change and 14 additional changes on separate drawings had been transmitted to the licensee by the Architectual Engineer (Burns and Roe, Inc.). The transmittal letter noted the drawings were "approved for construction."

The licensee's Document Control Department apparently processed these drawings as an "as-built" revision and placed them into the drawing system. Revision 11 drawings had been intended to illustrate plant changes required for a modification planned for the forthcoming refueling outage. These drawings should have been clearly identified for "construction only" and should not have been placed in the drawing system.

The remaining 14 drawings that accompanied the transmittal letter will be reviewed to determine if these drawings were also modified erroneously. The licensee will determine if other drawing transmittals were made which resulted in drawing changes that were made in error.[10]

INADVERTENT CONTAMINATIONS

FITZPATRICK

While mowing the lawn on the east side of the Administration Building of the James A. FitzPatrick Nuclear Power Plant, the janitor discovered an area of ground that was especially soft, and vapors could be seen rising from the ground. A radiation survey indicated readings above the background level. A backhoe was immediately brought to the area and the area was roped off. A small hole was dug and a sample of water and mud were taken for analysis.

The source of leakage was a flange in a bondstrand pipe that carries water from the Waste Sample Tanks in Rad Waste to the Condensate Storage Tanks that are located outside of the Administrative Building. A sump pump was located in the area to keep the hole free of water so that repair of the pipe could be made.

The leak was repaired by replacing the section of bondstrand with type 304 stainless steel pipe. As a final solution, the entire length of bondstrand will be replaced with stainless as soon as practicable. The Architect/Engineer (Stone & Webster Engineering Corp.) has been requested to investigate all underground piping that does or could be used to transport radioactive water.

An estimated 1000 cubic yards of dirt will have to be shipped offsite for burial.

It was estimated that the total activity released from the time of discovery until the leak was stopped was 418 mCi. It is highly unlikely that there was a significant release prior to excavation because there were no peripheral drains to transport the water directly to the sewer. Surveys of the lawn indicated no activity above normal background ten feet away from the leak at the time of discovery.[11]

CONNECTICUT YANKEE

When the Haddam Neck Plant of the Connecticut Yankee Atomic Power Company was shutdown for refueling operations, a small through wall leak was discovered in the sump area into the safety injection cubicle. Nine days later, a second wall leak was noted coming into the lowest level of the radwaste building.

After an extensive unsuccessful search to locate the source of leakage, it was decided to investigate the waste liquid steam generator blowdown discharge piping where it joins the service water effluent line. This required core drilling through the 12-inch reinforced concrete floor. The source of leakage was then identified as a fillet weld on the 24-inch service line that had eroded and was allowing leakage to the area below the drumming room floor.

The waste discharge pipe directs steam generator blowdown and intermittent radioactive waste liquid effluent into the service water discharge which eventually flows into the discharge canal.

With the change in steam generator chemistry control from phosphate to all volatile treatment, an increase in steam generator blowdown was required. It is believed that this continuous blowdown of increased volume caused a rapid deterioration of the piping material where the hot blowdown water contacted the relatively cold service water effluent.

A repair consisting of a saddle and sleeve was welded over the defective areas. The plant engineering group will evaluate a design that includes a heat exchanger to cool the steam generator blowdown to prevent thermal shock and a change in piping configuration which will place the piping connection above ground where it will be visible.

There was a release of radioactive tritium. Through underground seepage, the tritium found its way to the lowest point in the area, the containment external sump, and from there to the discharge canal. Samples of the mud and water in the area of the leak showed the concentration of all radionuclides within the limits of 10 CFR 20, Appendix B, Table 1, column 2.[12]

EXPOSURES

ZION 1

Two contractor personnel were working together reinstalling insulation at the piping elbow of a Resistance Temperature Detector (RTD) line of Unit No. 1 of the Zion Generating Station. They each were wearing film badges and indirect reading 0-200 mR pocket dosimeters. They were under the occasional surveillance of a contract radiation protection technican, who was timekeeping to estimate accumulated worker dose. At the end of their shift, both worker's dosimeters were found discharged. The timekeepers estimate of dose recieved was approximately 270 mrems and 320 mrems, respectively.

One film badge was sent for processing as a routine check of timekeeping accuracy. An exposure of 3,460 mrem was indicated on the film. Subsequently, the second worker's badge was sent for processing; the film read 3,390 mrem. This brought their respective current calendar quarter whole body doses to 3,870 mrems and 4,310 mrems.

A subsequent survey indicated a high radiation level existed only in a localized area near the piping elbow. An adequate survey prior to issuance of a work permit and recognition of the potential hazard by requiring a high range self-reading dosimeter may have prevented the overexposures.[13-14]

Point of Contact:

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CURRENT EVENTS

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LOW VOLTAGE ON SAFETY-RELATED EQUIPMENT

On July 5, when decreasing load for repair of a leaking feedwater regulating valve at Unit No. 2 of the Millstone Nuclear Power Station, a reactor trip occurred from a steam generator transient. The in-plant electrical loads had been transferred to the reserve station service transformer prior to the trip in preparation of a normal shutdown so plant systems would receive power from the preferred source - the grid transmission network. At the time of the trip, both Units 1 and 2 were in operation with Unit 1 carrying 680 MW and Unit 2 at approximately 100 MW. The pre-trip voltage of the 345 KV grid was approximately 352 KV (the normal operating voltage on the 345 KV system is 359-361 KV). The very light load condition of the grid was the effect of the end of a holiday weekend and the entire state of Connecticut was being supplied by the two Millstone units and one small conventional plant.

As a result of the trip, the 345 KV grid dropped to 335 KV, and remained at this voltage for over an hour. The capacity of the remaining two plants could not maintain a proper grid voltage level. The central load dispatcher was aware Unit 2 was going off line but apparently was not monitoring the grid condition or aware of the required additional generating capacity needed to sustain the grid at an acceptable working voltage.

At Unit 2, in accordance with normal post-trip procedures, personnel started various auxiliary equipment associated with the plant shutdown; however, certain non-safety 480 V equipment did not start. This equipment included the "A" charging pump, three of six turbine generator bearing oil lift pumps, the "A" steam generator feed pump auxiliary oil pump and the main turbine turning gear motor and the AC motor oil suction pump. Investigation revealed each of the motor controllers on the motors that failed to start had a blown control power fuse.
The control power fuses were replaced and the equipment was started as desired.

The reserve service transformer had tap settings for normal 345-4.16 KV and 4160-480 volt transformation ratios. The degradation in grid voltage resulted in a ratioed degradation on all transformer buses.

Apparently, the low control voltage was insufficient to actuate the main line contactors and as a result, the control power fuses were blown. The contactors require approximately 80% of rated voltage to operate, and the problem may have been compounded by inherent cable voltage drops to individual contactors.

The licensee concluded that under similar low voltage conditions, the operability of 480V Engineered Safety Feature Actuation Systems (ESFAS) equipment might not be assured and measurements were taken to determine a minimum voltage above which the 480 V safety related equipment would start. Testing of two motors selected as worst case situations found satisfactory performance at all bus voltages above 410 V. The preventive action was to raise the setpoint of the ESFAS "loss of power" undervoltage relays to assure that the plant would be separated from the grid and emergency power system operation would be initiated before control voltage fell below that required for contactor operation.

However, sixteen days later, with the plant at 100% power, a 1500 HP circulating water pump was started. The voltage drop from the pump motor inrush current apparently drew the ESFAS bus below the new elevated undervoltage trip point and caused the engineered safeguards actuation system (ESAS) to sense a loss of normal power (LNP) condition.

A LNP should cause the emergency buses to deenergize, a load shed signal to strip the buses, the diesel generators to start and come to speed at no load conditions and the required safety related loads to sequentially pull in on buses that are now being powered by the diesel generators. A reactor trip occurred as designed due to the load shed deenergization feature of the emergency buses.

However, actuation of the undervoltage sensor now initiated a function to prohibit offsite power from being available to the safety related 4160 volt buses (an assumed undervoltage grid situation). Both emergency diesels started and when they attained their rated speed and voltage, they were connected to their safety related buses.

The only significant loads to be sequenced onto the diesels were the service water and reactor building closed cooling water (RBCCW) pumps. However, inrush current caused the bus voltage to drop below the new undervoltage trip point settings for each ESAS load; these loads were then tripped off from the bus. Thus, on completion of load sequence, the emergency buses were energized, but the service water and reactor building closed cooling water pumps were not operating because of the additional load shed signals.

On recognizing the situation, the undervoltage bistables were then immediately reset to their previous setting of 2912 V and the reserve station service transformer was connected to the emergency buses. The service water and RBCCW pumps were restarted successfully. The total time the emergency buses were incapable of accepting emergency loads was approximately five minutes.

Other plant systems responded properly, and at all times the plant was maintained in a satisfactory hot shutdown status.

As a result of the plant trip, a seal which had been degrading on the reactor coolant pump failed.

The purpose of the load shed feature was to ensure the diesels can quickly come to speed and energize the buses without sustaining an overload condition. It is only necessary upon initial transfer of the bus loads to the diesel generator. Subsequent operation of the load shedding feature could be detrimental to supplying power to the safety related equipment since it can cause inadvertent shedding of these loads on momentary voltage transients.

A subsequent investigation to verify the calibration of the ESAS under-voltage relays determined there was a design error in the test circuit. This error led to an actual undervoltage (UV) calibration setpoint of approximately 5% higher than anticipated (approximately 4000 volts on the 4.16 KV bus).

By design, there was no adverse consequence from plant shutdown without AC emergency power. Redundant safety features such as a steam turbine driven auxilliary feedwater pump and DC power assure safe shutdown capability without AC power on the emergency buses under normal conditions.

However, the coincident occurrence of a postulated design basis accident together with inability of AC powered safeguards equipment to automatically energize and function successfully is not theorized in the safety review of nuclear power plants. This incident brought attention to existence of a new type of possible common mode failure; consideration of this and related conditions were analyzed and corrected prior to plant startup.

Specifically, in the condition of temporary loss of operability of the safety related 480 V equipment, Millstone Unit 2 had insufficient capability to cope with all postulated credible design basis accident conditions. Though this is an undesirable condition, no immediate hazard existed as serious postulated design basis accidents have a low probability of occurring because of conservative design margins.

To protect plant equipment against all credible undervoltage conditions and to insure the correct operation of all safeguard equipment, the licensee performed design modifications to the UV trip logic which (1) prevent the emergency buses from load shedding after the diesels have started, (2) replace the single UV trip setpoint with a dual setpoint logic, one setpoint of which has an eight second delay (this second design change allows for grid transients while preventing sustained reactor operation under a degraded voltage condition), and (3) change the plant transformer taps to optimize the in-plant voltage.

The NRC has held meetings to address the potential generic implications of the events and equipment failures and of grid stability and control of load sharing with representatives of various licensees. Solutions to prevent this type of problem from recurring are being resolved on a plant-by-plant basis.[1-5]

INADVERTENT RELEASE OF TRITIUM

During a routine pumpdown of the fuel oil storage tank sump at the Vermont Yankee Nuclear Power Plant, the operator noted an unexpected increased water level in an adjacent area. Investigation revealed water was entering from an electrical conduit that was in communication with the condensate storage tank (CST) moat. Examination of the CST moat revealed an elevated water level.

Pumpdown of the fuel oil storage tank was terminated and the CST sump pump was started to transfer water from the moat to radwaste storage facilities. During the pumpdown, a station operator observed flow from the CST overflow pipe although the control room indication of CST level was a normal 85%. A sample of water indicated the presence of tritium at a concentration of 5×10^{-3} µCi/ml.

Additional investigation revealed a second flow path existed between the flooded subterranean portion of the CST moat and a pipe chase. The chase contained a drain that allowed contaminated water to leak unmonitored to the Connecticut River.

The cause of the inadvertant unmonitored release was the two leakage paths from the CST moat to the storm drain system and the overflow of the CST. The maximum water level of the CST moat was approximately 20 inches above the moat floor level. The first leakage path was a non-watertight electrical junction box located one foot above the floor level inside the CST moat. Conduit from the junction box runs below ground level from the fuel oil transfer pump room, to the fuel oil storage tank sump from which rain water is routinely pumped to the storm drain after only a sample analysis for the presence of oil.

The second leakage path was from seepage around pipe penetrations in a chase that runs through the CST moat sump wall. The drain line for this chase discharges to the same storm drain system as the fuel oil storage tank sump.

It is estimated a total of 1.6 curies of tritium was released in a 46 hour discharge period. The fully diluted rate of tritium discharge would be unobservable from normal variation of background tritium concentration in the river water from month to month. The net environmental impact was negligible and full use of the river (i.e., water supply, swimming, fishing, etc.) was in no way impaired by the incident and there was no hazard to the general public.

Tritium acts chemically as normal hydrogen and cannot be removed by radioactive waste treatment. Vermont Yankee voluntarily elected to recycle tritium effluent for reuse in the plant rather than make periodic discharge of the effluent to the river within federal and state allowable limits. By doing so, the significance and risk of an unmonitored spill is increased as the inventory of tritium builds with continued plant operation.

After four years of operation, the 1,500,000 gallon recycle water reservoir contains approximately 30 curies of tritium. Had this quantity of tritium been released within regulatory limits over the past four years, approximately 28 curies more of tritium would have been released to the environment.

Adequate precautions have been taken to ensure this incident is not likely to be repeated. In addition, a review was made to identify all plant equipment and structures that can potentially result in an unmonitored flow path of radioactive liquid to the river.[6]

INADVERTENT VALVE ISOLATIONS

Fort Calhoun

With Unit 1 of the Fort Calhoun Station at 99% power and with steam generator blowdown in progress, both steam generator blowdown radiation monitors indicated a no flow condition. As soon as the no flow condition was discovered, valve HCV-2508 was found to be closed. The valve was immediately opened to restore steam generator blowdown sample flow to the blowdown radiation monitors. It was then noted the "no flow" alarm for the "B" steam generator would still not clear even though proper sample flow was now indicated.

The steam generator blowdown monitors are used to detect primary to secondary leakage. Although isolated, the condenser offgas radiation monitor was operable and available to detect primary to secondary leakage if it had occurred. The steam generator blowdown sample system provides an alarm should sample flow through either blowdown radiation monitor be lost. The alarm is both visual and audible and must be acknowledged to be cleared.

On the day prior to the event, a maintenance order was implemented to remove lead bricks (shielding) from around the monitors and to replace the bricks after a shielding support table was moved into position. During removal of the lead shielding, both radiation monitors alarmed because of the increase in background radiation and automatically terminated steam generator blowdown. Steam generator blowdown was restored after shielding relocation work was completed, but the alarm at local panel AI-107 was not acknowledged by the auxiliary building operator.

On the day of the event, the auxiliary building operator could not verify sample flow because the relocated monitor shielding blocked access. When the shielding was removed, he then discovered that a no-flow condition existed on both blowdown radiation monitors. Flow was immediately restored by opening HCV-2508. However, the "no flow" alarm for B steam generator would not clear even though proper sample flow was indicated. A technician investigating the failure of the alarm to reset, determined the monitor shielding rearrangement had placed the lead shielding too close to the coil of the alarm sensor and thus, activated the alarm. After rearranging the shielding, the alarm cleared.

The individual responsible for closing HCV-2508 could not be identified.

Control room operators permitted an unacknowledged alarm to persist without requiring prompt action from the auxiliary building operator. The control room operators had reasoned incorrectly that the alarm was caused by the inability to reset the first alarm and was not due to a separate valid alarm.

To prevent recurrence, auxiliary building operators are now required to tour the primary sampling room every two hours, to visually verify sample flow to the steam generator blowdown radiation monitors and to check the alarm status. The operating staff has been cautioned as to the importance of prompt response to alarm conditions.[7]

Oconee-2

During startup of Oconee Nuclear Station Unit 2, one of four Reactor Protective System (RPS) Channels (Channel "B") failed to trip as required when the reactor coolant pressure reached 1720 psi. Investigation revealed the root valve for the pressure transmitter had inadvertently been left closed. This resulted in isolation of the transmitter and prevented the channel from tripping when the setpoint was reached. The valve had been left open as required following calibration of the pressure transmitter a month earlier, but had been closed at some subsequent time before unit startup.

Although RPS Channel "B" failed to trip as required in the shutdown bypass mode, the other three RPS channels tripped when the 1,720 psi setpoint was reached. The Reactor Protective System utilizes a two out of four redundant logic, and would have been disabled only if two other channels were inoperable. It is concluded that this occurrence did not impair the operability of the Reactor Protective System, and therefore, the health and safety of the public was not affected.

Station procedures are currently being revised to assure, following refueling outages, instrumentation is checked for proper operation prior to unit heatup and to assure, following performance of maintenance, instrument valves are returned to their pre-maintenance position.[8]

St. Lucie

While pumping water from the primary water tank to the spent fuel pool at Unit 1 of the St. Lucie Nuclear Power Plant, operations personnel discovered the refueling water tank (RWT) was overflowing. The valve lineup was checked and a crossover valve between the RWT and the spent fuel pool system was found open. The valve was immediately closed.

Leaving the valve open caused dilution of the boron concentration in the RWT to 1,653 ppm. The Technical Specifications requires a minimum boron concentration of 1,720 ppm. Concentrated boric acid was added and a sample taken one hour later indicated a proper boron concentration had been restored.[9]

Zion-2

At the Zion Station, service water to the Unit 2 lube oil cooling for the main turbine, feedwater pumps, condensate pumps and heater drain pumps was isolated through an operator valving error. The operator had been instructed to isolate the service water return line to the discharge tunnel for Unit 1; however, he closed the isolation valve for Unit 2. He was not sure of the valve location and could not identify the valve number clearly. Valves performing the same function at Zion have identical valve numbers and are differentiated only by the prefix number for the respective unit.

Approximately 2 hours later, an instantaneous puff of fire was seen from the bearing area of the main turbine generator. The unit was safely shutdown; however, the #1 and #5 bearings on the turbine were damaged.

The pump had just been returned to service after a turbine bearing repair. It had been presumed that bearing temperature alarms and pump vibration were caused by the recent repairs; the alarms were ignored and were not reset. Also, the trend alarm typewriter was out of paper and thus was ineffective in indicating the steady increase in bearing temperature.

A planned outage originally scheduled to modify the condensate system was advanced to incorporate repairs to the turbine.[10]

FAILURE OF FLEXIBLE METAL HOSE

During the initial approach to power at the Beaver Valley Power Station, it was noted that air pressure in the containment vessel was 9.39 psia when the maximum permissable was 9.36 psia. Upon checking, it was determined that both air partial pressure and moisture content were increasing. The reactor was shutdown and station cooldown was commenced so personnel could enter the containment.

The source of air leakage was the failure of a Swagelock flexible stainless steel metal hose that was installed between a pressure transmitter root valve and the isolation valve of the pressure transmitter.

The sensing line was replaced with a rigid stainless steel instrument line. The rigid line was dye checked and hydrostatically tested and when the plant was returned to operation, a visual inspection was made to insure no leakage.

The health and safety of the public was not jeopardized as all leakage was contained within the containment. No excessive exposures were received by plant personnel. An inspection was made of all high pressure stainless steel instrument lines including those in the reactor coolant system, charging system, boric acid system and safety injection system to assure that no metallic hoses were installed. None were found.

Installation of the flexible metallic hose was the result of an engineering decision made by unauthorized personnel. The change to the flexible metal sensing line was made by construction craft personnel who relied on the craft supervisor's ability to interpret an engineering data sheet. Apparently, the problem was compounded by the normal pressure rating system for hoses; i.e., the listing of both a working pressure and a burst pressure.

Project documentation is continuing to be reviewed to assure that no further unauthorized installations have been made.[11]

DISCHARGE WATER TEMPERATURE EXCEEDS ENVIRONMENTAL LIMIT

Unit No. 1 of the Three Mile Island Nuclear Station was operating at 100% power, the river water intake temperature was 78.4°F and a 2°F differential temperature was being maintained between plant inlet and outlet.

However, a severe thunderstorm which accompanied a cold front caused the local ambient air temperature to sharply drop from approximately 83°F to 72°F in twenty minutes. Although attempting to respond to the change, the operator was unable to anticipate the abrupt change on the mechanical draft cooling water characteristics. As a result, the Federal Power Commission requirement to maintain a delta T between 0°F and 3°F was exceeded for nearly thirty minutes. The maximum temperature difference was 4°F.

It was not believed the maximum temperature differential of 4°F caused environmental damage because this condition lasted only a short time and was not so severe as to greatly alter the ambient temperature of the river. Accordingly, a change to the Environmental Technical Specifications and the Federal Power Commission requirements will be evaluated to determine whether short term departures from the 3°F delta T coincident with appropriate action levels would provide adequate environmental protection.[12]

ERRORS IN COMPUTER PROGRAMS

Westinghouse

Westinghouse Electric Corporation Pressurized Water Reactors (PWRs) have been advised of a generic error in the nonconservative direction in their Emergency Core Cooling System (ECCS) analyses following a presumed loss-of-coolant accident (LOCA).

The ECCS analysis had been performed with the assumption that the primary coolant in the upper head region above the reactor core is at the cold leg temperature (reactor coolant return flow). Recent tests have indicated the more conservative assumption should be made that the temperature of the primary coolant in the upper head region of the reactor is the hot leg temperature. This analytical change would result in an increase in the maximum calculated peak fuel clad temperature following a postulated accident.

Perhaps typical of the numerical and descriptive changes this reanalysis has had on the nuclear power plants can be illustrated by example of the Indian Point Units.

The ECCS analysis originally performed for Indian Point No. 3 yielded a calculated maximum peak clad temperature of 2,168°F. The calculation with the higher temperature of the hot leg coolant resulted in a 40°F increase in the calculated maximum peak clad temperature to 2,208°F.

Westinghouse then evaluated the effect of a change in the nuclear heat flux hot channel factor (F_q) and determined a decrement of 0.01 in F_q results in a 10°F reduction in peak clad temperature. For Indian Point-3, the new analysis resulted in a F_q limit of 2.312 (a change in F_q of -0.008) and the corresponding peak clad temperature would be reduced to 2,200°F.

The new F_q limit is sufficiently large to require no additional analysis or surveillance for the remainder of the present cycle. No additional action, either analytical or administrative, is required for the remainder of the cycle.

Westinghouse also determined that an additional penalty of 10°F must be applied for each 1% of steam generator tubes that are plugged. Indian

Point No. 2 has three percent of their steam generator tubes plugged, so an additional 30°F penalty must be applied.

The ECCS analysis for Indian Point No. 2 had yielded a calculated maximum peak clad temperature of 2,115°F. Applying the two penalties (40°F + 30°F) the calculated maximum peak clad temperature becomes 2,185°F. Because the final acceptance criteria permits a maximum peak clad temperature of 2,200°F, a sufficient margin still exists and no operating or Technical Specification changes were necessary.

As a contingent calculation of the assumed increase in upper head region temperature, the reactor vessel thermal stress was reevaluated. It was determined that the new calculated stress values still satisfy the reactor vessel design criteria and no changes were required.

Westinghouse also informed licensees with an identified rod bowing problem that departure from nucleate boiling (DNB) penalties are to be higher than previously reported.

Fuel rod bowing has been under generic review by the NRC staff and has focused on information supplied by Westinghouse. Previously, based on empirical models, the NRC issued an interim licensing position that concluded generic design margins were adequate to offset bow effects for 15x15 fuel design with linear core densities exceeding that corresponding to 100% power.

However, recent data on the effect of fuel rod bow on DNB has resulted in larger DNB penalities. The NRC now requires the Nuclear Enthalpy Hot Channel Factor ($F_{\Delta H}$) be reduced to account for loss of DNB margins or that existing margins be used to demonstrate that the $F_{\Delta H}$ penalty is not required.

Although Indian Point-3 had demonstrated a margin, by administrative action, the first cycle operation will include a 0 to 4% penalty directly proportional to core average burnup.

At Indian Point Unit-2, the two lead burnup assemblies had previously been scanned and the two rod segments per face, between neighboring grids, exhibiting the largest rod bow were chosen for detailed measurement. Of a total population of 2,880 rod segments, only 0.4% of the segments exhibited measurable rod bow (0.02 inches). As a result, no DNB penalties for Unit 2 were deemed necessary.[13-14]

Combustion Engineering

As part of an on-going review of LOCA (loss-of-coolant accident) computer codes, Combustion Engineering, Incorporated, recently discovered several small errors in STRIKIN-2, the code used to calculate hot rod clad temperature and clad oxidation percentage.

As a result of the STRIKIN-2 corrections at Maine Yankee, the peak clad temperature has increased from 1,887°F to 1,953°F and the peak local clad oxidation increased from 6.92 to 8.91%. The LOCA analysis values of peak clad temperature and peak local clad oxidation would change from 2,094°F to approximately 2,175°F and from 15.98% to 17.75%. These new results were well below limits of 10 CFR 50.46 and do not create a safety concern.

However, at Unit No. 1 of the Calvert Cliffs Nuclear Power Plant, the corrected calculation justified reactor operation up to a peak linear heat rate (PLHR) of only 14.9 KW/ft. However, at that time, reactor operation was limited to 15.2 KW/ft. for existing burnup. The incore detector alarm setpoints were immediately lowered to ensure reactor operation did not violate the more conservative PLHR limit. Calvert Cliffs was subsequently notified by the NRC to incorporate a 1 KW/ft. uncertainty penalty. Consequently, reactor operation is presently limited to a PLHR of 13.9 KW/ft.[15-16]

Point of Contact:

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5. ADVISORY COMMITTEE ON REACTOR SAFEGUARDS, 197th GENERAL MEETING, SEPTEMBER 10, 1976.

6. LER 76-22, Docket No. 50-271, August 5, 1976.

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11. LER 76-41, Docket No. 50-334, June 30, 1976.

12. LER 76-28, Docket No. 50-289, August 20, 1976.

13. LER 76-28, Docket No. 50-286, August 18, 1976.

14. LER 76-13, Docket No. 50-247, August 17, 1976.

15. LER 76-7, Docket No. 50-309, June 22, 1976.

16. LER 76-29, Docket No. 50-317, June 23, 1976.

CURRENT EVENTS

POWER REACTORS

UNITED STATES NUCLEAR REGULATORY COMMISSION

THIS COMPILATION OF SELECTED EVENTS IS PREPARED TO DISSEMINATE INFORMATION ON OPERATING EXPERIENCE AT NUCLEAR POWER PLANTS IN A TIMELY MANNER AND AS OF A FIXED DATE. THESE EVENTS ARE SELECTED FROM PUBLIC INFORMATION SOURCES. NRC HAS, OR IS TAKING CONTINUOUS ACTION ON THESE ISSUES AS APPLICABLE, FROM AN INSPECTION AND ENFORCEMENT, LICENSING AND GENERIC REVIEW STANDPOINT.

1 OCTOBER - 31 DECEMBER 1976

(Published Mid-March 1977)

UNPLANNED CRITICALITY

Millstone Point Unit No. 1 of the Millstone Nuclear Power Station had been shutdown for a scheduled refueling outage and maintenance. The reactor pressure vessel head and internals had been removed, the refueling cavity was filled with water and fuel loading was in progress. Five hundred and forty-three (543) of the 580 fuel assembly total core complement had been loaded and the licensee was proceeding to conduct a shutdown margin test. Administrative requirements specified such testing to be completed once each operating shift after 36 fuel assemblies had been loaded, and these tests were being done on a routine basis. The shutdown margin test is performed by full withdrawal of the highest worth rod and partial withdrawal of the diagonal rod to a predetermined position that demonstrates a safe specified shutdown margin.

Administrative controls for fuel loading and unloading required movement of the highest worth control rod, 46-23, at the existing core configuration to the fully withdrawn position followed by re-insertion of this rod to notch position 10 (21% withdrawn), a position determined by calculation. The diagonal control rod, 42-19, was then also to be withdrawn to notch position 10 followed by full withdrawal of the high worth rod to notch position 48 with the reactor remaining subcritical, thus demonstrating an adequate shutdown margin.

Although specific instructions were provided specifying the correct control rods and movement sequence, the licensed reactor operator incorrectly selected one of the four directly adjacent control rods, rod 46-19 instead of control rod 42-19, the correct and designated rod, and withdrew this rod to notch position 10. Without recognition of the selection error, the high worth rod was then withdrawn.

A reactor trip occurred when control rod 46-23 was being notched out from position 14 to 16 (27% withdrawn). The duration of the resultant transient was approximately seven seconds and the high flux condition was terminated by the Reactor Protection System (Intermediate Range Monitors (IRMS)), which were in the most sensitive range position. Four IRM channels tripped and terminated the event.

At the time of the occurrence, the Rod Worth Minimizer (RWM), a plant feature that provides automatic supervision to assure that out of sequence control rods will not be withdrawn or inserted, had been bypassed and was not programmed for the shutdown margin test sequence. The reactor mode switch was in the startup mode, a condition which permits the withdrawal of more than one control rod.

The operator had performed the shutdown margin test by himself at the control room console with the prior authorization of the Shift Supervisor, a licensed Senior Reactor Operator. The circumstances of the reactor trip were reported to the Shift Supervisor who attributed the trip to be the result of "electronic noise" and therefore, not meaningful. A second test, under the direction of the Shift Supervisor, was performed contrary to procedural requirements concerning evaluation of instrumentation. Again, the operator introduced the identical human error in erroneously selecting control rod 46-19 and positioning it at notch 10. Subsequent movement of the high worth rod from notch 10 to notch 12 (25% withdrawn) resulted in a flux increase and the high worth rod was immediately re-inserted by the operator to avert a second trip. Following recognition of the previous rod selection errors, a third shutdown margin test using the correct and designated rods was successfully completed and the reactor remained subcritical.

During the next two and one-half hours, fuel loading was resumed and an additional eleven assemblies were loaded into the core. Contrary to procedural requirements, the event was not reported to appropriate management personnel until their arrival for the scheduled work day. Additionally, testing and refueling operations were permitted without assessment of potential overexposure to personnel, or possible fuel damage as a result of the event.

A visual inspection of fuel assemblies surrounding the high worth control rod disclosed no apparent damage and provided further verification of calculations that the event was of no consequence with respect to fuel and cladding integrity.

The thermal evaluations for the core area of interest indicated a center line differential temperature of less than 7°F and an increase in fuel enthalpy of less than one calorie per gram.

Thermoluminescent dosimeters of all personnel on site involved with Unit No. 1 revealed no gamma exposure outside of that expected; no neutron exposure was indicated either. The five area radiation monitors and the continuous air monitor showed no increase in the background radiation; none alarmed nor was the standby gas treatment system initiated. The reactor building exhaust plenum monitor recorder and the stack gas monitor recorder also showed no change in radiation level or background. No work was being conducted in the drywell at the time of the event, and no radiation detectors alarmed. However, contrary to 10 CFR Part 20, Section 20.203, required drywell access control had not been adequately provided.

Refueling operations were suspended pending a complete review of the event. Existing refueling related procedures were revised to further preclude the possibility of similar occurrence. A number of new procedures were generated to further define precautions and actions to be taken during refueling activities. A re-training program was established to insure that all licensed personnel were aware of the new procedures and changes in addition to Technical Specification requirements.

This event is under investigation by the NRC.[1,2]

IMPROPER MOVEMENT OF CONTROL RODS

Unit No. 1 of the Quad Cities Station was in the REFUEL mode for inspection and for control rod drive replacement. Control rod drive CRD F-13 was stuck fully inserted past position 00 and a position indicating box had been installed on CRD F-13 to clear its drift alarm and to obtain a one rod permissive to withdraw CRD L-06 for maintenance. CRD L-06 was then successfully withdrawn, vented and timed. When timing was completed, the control room operator was instructed to leave CRD L-06 fully inserted at position 00. The operator inadvertently left the CRD fully withdrawn at position 48, and informed the shift engineer that CRD L-06 was vented, timed and in the full-in position.

The checklist called for withdrawal of the next rod, CRD K-10. However, with the mode switch in REFUEL, a rod block occurred to prevent movement of CRD K-10. Reasoning that the existing drift alarm on CRD F-13 was the sole cause of the rod block in the REFUEL mode, and also knowing that plant system status was such that unit startup could have commenced, the shift engineer instructed the foreman to have the operator put the mode switch in STARTUP to withdraw CRD K-10. CRD K-10 was withdrawn to position 48 and the mode switch was returned to the REFUEL position.

Twenty-seven hours later, while returning CRD K-10 to service, it was discovered that CRD L-06 was still in the fully withdrawn position. Immediately CRD L-06 and CRD K-10 were inserted and all other rods were verified to be fully inserted.

Even though the rod drift alarm on CRD F-13 contributed to the cause of this occurrence, operating personnel did not follow normal operating procedures when withdrawing the CRD's for maintenance. The position indicator box used on CRD F-13 was contrary to procedures. The control room operator did not adequately scan the full core display to determine that CRD L-06 had been inserted before attempting to withdraw CRD K-10. An additional deviation to the procedures occurred when the operator placed the mode switch in the STARTUP position to withdraw CRD K-10.

During the time that CRD L-06 was in the fully withdrawn position, the eight control rods surrounding CRD L-06 were fully inserted and disarmed electrically as required. Adequate shutdown margin was maintained at all times.

To prevent recurrence, all personnel have been made aware of the significance of their actions and have been directed to follow approved procedures. The operating procedures and the operating checklist have been combined to a checklist that completely covers control rod movement during maintenance. This procedure was also revised to include the use of a computer program to verify CRD position. Also, procedures will be revised to more clearly define the use of substitute position indications for CRD's not involved in CRD maintenance.[3]

REACTOR SCRAM CAUSED BY INADVERTENT RELIEF VALVE LIFTING

With the Brunswick Steam Electric Plant at 20% power and a reactor pressure of 933 psig, the "SAFETY OR DEPRESS VLV LEAKING" annunciator was received. Investigation indicated that one of the safety/relief valve discharge pipe temperatures (valve "G") had elevated to above the alarm point. Other indicators showed the valve had not lifted but was merely leaking steam.

About an hour later, the suppression pool Hi/Lo level alarm sounded and the suppression pool level was observed to be oscillating. This and other indications positively confirmed that one of the safety/relief valves had now lifted. The shift foreman checked the safety/relief valve tail pipe temperature recorder to determine which relief valve had lifted. The highest reading point was still valve "G"; it was just above the alarm point. An attempt was made to reseat this valve by cycling; however, a group I isolation on low steam line pressure (less than 850 psig in the run mode) was received and a subsequent reactor scram resulted. The valve reseated and reactor pressure stabilized at about 400 psig.

Within a few seconds after cycling valve "G", the safety/relief tail pipe temperature printed out valve "K" as being the valve with the highest tail pipe temperature. Apparently, valve "K" had lifted, but the time lag of the multipoint recorder had not permitted this information to be printed when the recorder was checked to determine which safety/relief was lifting.

After reactor cold shutdown, subsequent disassembly of the Target Rock relief valve "K" pilot assemblies revealed the poppet and seat had been cut by steam flow to cause the spurious lift. Three other relief valve pilots were also found to be degraded due to steam cutting.

The valve discs were lapped and each pilot valve was retested satisfactorily. To prevent recurrence, a preventive maintenance program was started to inspect and lap the pilot discs as required.[4]

FAILURE OF AUTOMATIC DEPRESSURIZATION VALVES

During a surveillance test of the reactor vessel main steam relief valves of the Vermont Yankee Nuclear Power Station, the air operator plunger of a Target Rock relief valve did not move when air pressure was applied. The air operators were removed from the three remaining relief valves and the air operators plungers failed to operate on demand on two additional valves.

Investigation revealed the air operators malfunctioned because their silicon-nomex diaphragms had failed. After consultation with the diaphragm manufacturer (Bellofram Corporation, Burlington, Mass.), failure of the bellows was attributed to excessive heating.

Excessive heating of the diaphragms may be attributed to a combination of improper installation of insulation in the vicinity of the diaphragm and the extended two-year operation cycle between refueling operations.

The corrective action included modification of the valves existing insulation to conform with the latest edition of <u>Target Rock Technical Manual</u> and replacement of all air operator diaphragms. Unlike the past two year cycle, the next refueling outage and subsequent refueling outages are anticipated to be scheduled so that operating cycles will nominally be one year in duration. Surveillance testing scheduled for each subsequent refueling outage will include an operability check of the air operator diaphragm followed by diaphragm replacement on all valves and a subsequent retest of new diaphragms independent of the initial test result. This combination of insulation modification, shorter operating cycles, and yearly diaphragm replacement should minimize the potential for a reptitive failure.[5]

LOSS OF DC BUS AND SUBSEQUENT DIESEL FIRE

With Unit No. 2 of the Zion Generating Station at 30% power and increasing to full load, an operator switching error occurred when attempting to take one of the two DC batteries off an equalizing charge. This deenergized one of the 125 VDC control buses and caused a loss of control power to relays for some major equipment and to the main control board annunciators.

The loss of the DC bus correctly resulted in a reactor shutdown. However, because of the loss of DC power capability, only two of the four reactor coolant pumps continued to operate and one of the main feedwater pumps could not be shutdown. The continued operation of the feedwater pump caused a rapid cooldown and pressure reduction in two of the steam generators. This in turn initiated a safety injection signal.

When the main generator field breakers were manually opened from the control board, the Automatic Transfer of the 4kV buses from the unit auxiliary transformer to the system auxiliary transformer did not occur due to the loss of DC control power. As a result, the main generator was motorized by the diesel generator through the 4kV buses.

At the time of the switching error, one of the five diesel generators was undergoing an extended test run. The diesel picked up and attempted to carry the loads on the 4kV buses, however, the loss of generator relaying prevented the shedding of unnecessary loads and resulted in an overload condition and a fire in the generator windings. The generator windings burned to the point where the phases opened; then the main generator and pumps coasted to a stop. The fire was extinguished by actuation of the carbon dioxide system.

There was no hazard to the general public. There were no radioactive releases or personnel injuries.

No safety limits were exceeded during the event and the plant was safely shutdown. The operation and response of all safeguards equipment was as expected except for equipment without DC power. Upon restoration of DC, all equipment started satisfactorily. The requirements for equipment operability as specified in the safety analysis of the FSAR were met at all times throughout the event.

The event was initiated when an equipment operator opened the tie breaker to remove the battery from an equalizing charge prior to paralleling the battery onto the 125 VDC control bus. This deenergized the 125 VDC control power to four of the 4kV buses and caused the immediate loss of generator and transformer metering and relaying. Because of the remote location of the breaker and lack of status lights, the operator was not aware of the consequences of his action. The operator initiated the switching without a check sheet in hand and without the knowledge of the shift engineer. The operator action was contrary to the procedure that requires the battery to be paralleled to the DC bus before the tieline supplying DC power from the bus is opened.

This event has been discussed with operating personnel with the emphasis on the requirement to follow procedures properly and that operations of this nature must be checked off as performed using the appropriate system or general operating procedure.

The procedure for aligning the 4kV buses and the auxiliary and service transformers will be revised so that no more than one 4kV bus will be deenergized on loss of a DC bus. It will also prevent overloading of a diesel generator that is paralleled to the system during a loss of the DC bus.

An automatic throw-over to a backup power supply for the plant computers will be investigated. Although the majority of the alarm inputs into the computer were lost during the incident because of the loss of DC power, the computer was also lost when its power supply opened due to fuses blowing. This loss made the reconstruction of the sequence of events difficult since all information is supplied through the computer.

The main control board annunciators may be revised to annunciate the loss of any DC bus. This type of alarm would enable the operator to quickly identify any DC bus that has been deenergized and immediately take steps to reenergize. All alarms that were to provide this function were rendered inoperable by the loss of the DC bus.

The circuit for main generator tripping is under review for redundant trip capability in the event that normal DC control power is lost.[6]

LEAKS IN SAFETY INJECTION SYSTEMS

Ginna

With the Robert E. Ginna Plant at 100% power, an auxiliary operator found an accumulation of borated water near a valve in the safety injection system piping between the boric acid tanks and the safety injection pumps. Further investigation revealed a leak in a section of 8-inch diameter schedule 10 stainless steel pipe between two valves. The unit was taken to a cold shutdown and leaks were found in two sections of the pipe.

A subsequent liquid penetrant and ultrasonic examination of 73 welds and the piping associated with those welds revealed five other sections of pipe or fittings with indications. All seven of these components of the piping system containing leaks or indications were replaced with schedule 40 piping. The system was hydrostatically tested after repairs.

A preliminary metallurgical analysis and metallographic examination indicated that chloride stress corrosion cracking was the cause of the leaks. This event is being further evaluated by the NRC.[7]

Indian Point-3

During heatup of the reactor coolant system from a cold shutdown condition at Unit 3 of the Indian Point Station, a leak was discovered in a shop weld at the outlet nozzle of the boron injection tank. Unit heatup was immediately terminated and the plant was returned to a cold shutdown condition.

A metallographic examination of the defective weld showed the cause to be corrosion at the outlet nozzle. The weld joint was completely removed and an acceptable repair weld was completed at the leaking joint.

The source of corrosion at the outlet nozzle of the boron injection tank was attributed to removal of the 1/8-inch thick inconel overlay from areas of the carbon steel nozzle during multiple field repairs performed in October 1973.[8]

NUCLEAR CORE POWER DISTRIBUTION ANOMALY

In July 1976, Unit No. 1 of the St. Lucie Nuclear Power Plant was in power ascension testing at 80% power. At that time, the reactor core exhibited an azimuthal power tilt (a measure of deviation from uniform core power distribution) of about 3%; the expected tilt would be no more than 2%. A review of the test data showed that three core characteristics (axial power shape, radial power distribution and gross core reactivity) had begun to show anomalous behavior in June and the magnitude of the anomalies had increased in a slow and uniform manner.

On July 9, 1976, the following measurements of core parameters led to a decision to shut the plant down for testing and inspection: (1) azimuthal power tilt had increased to about 4%, (2) the average axial peak which had been expected to grow to 1.35 had grown to 1.53 and was centered at the core midplane, and (3) the core was about 0.4% more reactive than expected.

Visual inspection of the vessel internals showed some minor debris in the lower plenum; the debris that was removed appeared to have no relationship to the observed anomalous behavior of the core characteristics. However, borescopic examination of fuel bundles revealed extensive blistering and breaches of the lumped burnable poison (LBP) rods. These rods consist of a stack of alumina pellets (with boron carbide particles uniformly dispersed in the alumina) clad with zircaloy tubes and are used to absorb the excess neutrons produced in the fissioning process; they are also used to help shape the power distribution in the core. Burnable poison rods are incorporated in nearly half of the fuel assemblies of the St. Lucie core.

A break of the LBP cladding would allow reactor coolant to diffuse throughout the rod. The boron carbide would then be oxidized and leached out of the LBP rods. Since the process is expected to be both neutron flux and temperature dependent, the rate of removal would be the greatest near the midplane of the core and would account for the increase in core reactivity and axial peaking. Since the poison rod failures and subsequent leaching process may not be azimuthally uniform, the observed flux tilt could also result from this same cause.

Because of the poison pin defects, it was decided to unload the entire reactor core and to replace all burnable poison rods.

A number of LBP rods were removed from the fuel assemblies for examination. Some rods were subjected to detailed metallographic examination. The defects were found to be caused by hydriding of the zirconium cladding from internal moisture. The remaining rods were subjected to accurate reactivity measurements in the Advanced Reactivity Measurement Facility at the National Reactor Test Station in Idaho. The distribution of the boron content in the perforated rods was found to be altered. Some of the boron was gone from the rod and some had been redeposited toward the ends of the rods. The observed boron depletion and redistribution in this sample, taken with the large number of LBP rods known to have defects, fully explain the measured reactivity increase and axial peaking.

All of the LBP rods have been removed from the St. Lucie reactor and replaced with new rods having a reduced moisture content. The modification and reinstallation of the fuel was completed late in 1976.

A preliminary visual examination of eleven fuel assemblies at the Calvert Cliffs Nuclear Power Plant, Unit No. 1, revealed blisters on some of the poison pins. The blisters appear to have been caused by hydriding, and some poison pins appeared to be perforated. Calvert Cliffs-1 is currently in its first refueling outage and visual inspection of these and additional fuel assemblies is continuing.

All other Combustion Engineering plants had been requested by the NRC to increase incore surveillance to assure a similar problem does not exist. In all plants except two, the burnup of the LBP rods had proceeded far enough so that the burnable poison no longer had significant effect on the reactivity and power distribution. The exceptions were Millstone 2 and Calvert Cliffs 2. At Millstone 2, over half of the reactivity effect of the LBP rods has been burned out. A review of this plant's power distribution revealed no anomalous behavior similar to that which occurred at St. Lucie. At Calvert Cliffs 2, which had not yet gone to power, the poison rods were removed, dried to lower moisture specifications and returned to the core.[9-11]

Point of Contact:
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CURRENT EVENTS

POWER REACTORS

UNITED STATES
NUCLEAR
REGULATORY
COMMISSION

THIS COMPILATION OF SELECTED EVENTS IS PREPARED TO DISSEMINATE INFORMATION ON OPERATING EXPERIENCE AT NUCLEAR POWER PLANTS IN A TIMELY MANNER AND AS OF A FIXED DATE. THESE EVENTS ARE SELECTED FROM PUBLIC INFORMATION SOURCES. NRC HAS, OR IS TAKING CONTINUOUS ACTION ON THESE ISSUES AS APPLICABLE, FROM AN INSPECTION AND ENFORCEMENT, LICENSING AND GENERIC REVIEW STANDPOINT.

1 JANUARY - 28 FEBRUARY 1977

(Published Early May 1977)

RECURRENT WATER PRESSURE SURGES

On November 5, 1976, the Beaver Valley Power Station, Unit 1, was operating at approximately 50% power after recovery from a reactor shutdown. The main feed pump suction isolation bypass valve was open and operators were opening the main feed pump suction valve when a rumbling noise lasting from 5 to 10 seconds was heard in the control room. The rumbling was accompanied by a large variation in steam generator water level.

Approximately two minutes later, a second rumbling was heard, louder than the first. At this time, the steam generator level control was operating in the automatic mode and the operator noted large variations (33-60 percent on feed flow and 43-32 percent on level indication) in stability characteristics. Also, operators at the main feed pump suction valve reported a shaking of the feedwater line from the main feed pump to the feed heater.

An operator was sent to the main steam valve room, but steam in the room precluded his entering, so a reactor shutdown was initiated. When reactor power was reduced to approximately 15%, the plant tripped on a low-low steam generator level signal from the "A" generator. No further rumbling was evident during the shutdown.

Investigation revealed the failure of a 3/4-inch drain line connected to the auxiliary feedwater system. Since the 3/4-inch line was welded to the drain header (a condition not considered in the piping design), it resulted in a permanent anchor point and prevented pipe movement. As part of the repair, the 3/4-inch lines were disconnected from the A, B and C auxiliary feedwater lines and replaced with removable spool pieces. Also, the air supply to the "A" feedwater bypass valve had parted. Loss of this line caused the bypass valve to remain closed and subsequently caused the "A" generator to experience the low-low water level trip.

Two hydraulic shock suppressors on the "B" feedwater loop were found inoperable, one was broken at the shaft, the other was locked up.

To ascertain the cause of the feedwater instability, the licensee instrumented the main feedwater and auxiliary feedwater systems. The plant was returned to operation to conduct tests at progressive 5% increments in power level to duplicate the event under controlled conditions to determine the exact cause of the vibrations and take the appropriate corrective action.

In the test, the licensee proposed to induce flow fluctuations by two methods; first by momentarily removing a steam generator water level signal, and second, by momentarily removing a feedwater flow signal.

On December 22 and 23, the instability testing was performed. No pipe motion or flow instability was observed, and thus the cause could not be determined.

On December 27, while operating at 75% power, the plant experienced a feedwater line vibration similar to the first event. The line vibration occurred approximately five minutes after a plant transient and resulted in a reactor trip from a low steam generator level signal coincident with a steam flow/feed flow mismatch signal.

The transient occurred at 600 MWe power when a 200 MWe turbine step load decrease occurred. About six minutes later with the plant now at about 50% reactor power, a 100 MWe spike up and down occurred.

About 6 or 7 minutes later with the plant apparently stabilized after the load excursions, a rumbling noise described as less severe than the November 5 incident, was heard. Shortly thereafter, the reactor trip occurred.

Investigation into the cause of the load variations revealed a broken wire on the No. 2 main turbine governor valve position transmitter. The wire was repaired and the EH (electro-hydraulic) control systems was verified to be functioning properly.

Visual examination of the feedwater lines, snubbers and supports did not reveal abnormalities. However, a 1/4-inch air supply line to the feedwater control valve was broken on the "B" loop bypass valve. Also, a 3/16-inch sensing line to a pressure transducer installed for the instability tests had parted.

The initiating event was the loose wire in the turbine controller; the loose wire also caused the rapid changes in power. However, the feedwater regulating valves were also presumed to be a major contributor to the feedwater flow instabilities. Investigation revealed the valves' trim was not characteristic of a typical feedwater valve. This particular type of valve trim was oversized and capable of quick opening. Very little changes of the valve opening would result in large flow variations; a trim without fine control. It was planned to install hydraulic dampers to smooth the incoming hydraulic signal, and to order a new valve trim with more linear characteristics. A modification was made to the feedwater regulating valves to prohibit them from closing beyond the 5% open position except in the tripped mode to preclude operation of the valve in a known unstable region.

Before these changes could be effected, power operation of the reactor was resumed because the EH controller malfunction which initiated the event had been repaired, thus presumedly eliminating the main source of flow instability.

On January 5, 1977, Beaver Valley experienced its third feedwater line vibration. The reactor was at 75% power when a feedwater heater drain pump tripped; this caused the main feed pumps to trip on low suction pressure, causing a low feed flow. Turbine load reduction was commenced immediately at a rate of 2% per minute. The drain and feed pumps were returned to service, and the plant operated at 54% power for approximately 3 minutes, when a loud rumbling noise was heard, followed by a reactor trip from low steam generator level signal coincident with a feed flow/steam flow mismatch signal. The vibration lasted about 15 seconds.

Some of the damage incurred by the third pressure surge included:

The motor operator on the "B" containment isolation valve was broken off, the four 3/8-inch retaining studs were sheared (a seismic category I component).

Three 1/8-inch lines and one 1/4-inch line had pulled out of the fittings of the bypass regulating valve on the "B" loop. The pressure impulse line from the "B" loop feed control system had also parted. Additional potentiometer wires on the test instrumentation also separated.

Seismic indicators and alarms had actuated; hydraulic fluid from the shock suppressors was found on the floor inside and outside of primary containment.

It is believed the pressure surge was caused by dynamic instability of the feedwater regulating valves; the valves become unstable and opened despite the control signal to the valves.

During this event, data was obtained to calculate forcing functions for several conservative postulated transients in the feedwater piping system both inside and outside of containment. Pipe stresses were calculated based on these forcing functions to identify locations on the feed pipe of the highest stress levels. Based on the results of nondestructive testing of these highest stress areas, it was determined that degradation of the piping had not occurred. From these tests, one can reasonably conclude that the feedwater piping has not been damaged as a result of the three pressure surges.

During a routine review of the piping systems' 2000 support points, twenty-nine were found unacceptable, and restraints at these points have been modified or replaced. Five of the twenty-nine points were identified to be on the main feedwater line. Three of these points involved the replacement of six snubbers while existing supports were modified on the other two points.

Because two snubbers on the "B" feedwater line failed during the November event, it appears likely that the undersized snubbers did contribute to the magnitude of the pipe movement. However, because no snubbers failed or locked up during other events, the undersized supports apparently did not aggravate these events. It should be noted that it is customary to check pipe support points throughout the plant during the startup and power ascension phase of initial operation.

New trims have been installed in the three feedwater regulating valves and the feedwater flow control valves and the feedwater pipes have been extensively instrumented. Preoperational testing consisting of introducing plant transients while the feedwater control system is in the automatic mode will demonstrate the degree of valve stability and the effect of this stability on piping movement.[1-2]

A POSSIBLE HIGH TEMPERATURE PROBLEM WITH H_2/O_2 DRYWELL MONITORS WITH BWRS.

As a result of an engineering study at the Brunswick Steam Electric Plants, either several tubing lines in the containment atmosphere control system to the hydrogen and oxygen (H_2/O_2) analyzers had to be increased in length or higher capacity cooler/dehumidifiers had to be installed to assure individual components of the system operate at acceptable temperatures.

Each H_2/O_2 analyzer has a process temperature limitation of 120 degrees Fahrenheit. To assure operation within these limits, these analyzers are supplied process gas from a cooler/dehumidifier which discharges the process gas at approximately 60 degrees Fahrenheit into the analyzers.

The study found there are temperature limitations on the originally installed cooler/dehumidifiers. Tests determined that if the primary containment gas temperature (from the drywell or suppression chamber) is 150 degrees Fahrenheit or less by the time it reaches the cooler/dehumidifier, the dehumidifier will perform as designed and, in turn, the monitors will operate within their temperature limitations. The reactor building temperature, where the cooler/dehumidifier is located, is at an ambient temperature of up to 130 degrees Fahrenheit.

The maximum sample gas temperature associated with the postulated loss of coolant accident (LOCA) as described in the Final Safety Analysis Report (FSAR) was used as the maximum gas inlet temperature to the cooler/dehumidifier. Using this temperature it was determined that a minimum of 17 feet of instrument tubing was required to reduce the high temperature sample gas to a maximum of 150 degrees Fahrenheit before entry to the cooler/dehumidifiers. For additional conservatism, it was tentatively decided to install at least 40 feet of instrument tubing from the drywell to the cooler/dehumidifier.

After further study and review, it was decided it would be better to install larger capacity coolers instead of additional lengths of tubing and to take no credit for tubing length. New coolers were installed of a capacity such that they can handle the sample gas from the suppression chamber at all times during a LOCA. Drywell sample lines will isolate on a LOCA signal precluding this higher temperature sample gas from the H_2/O_2 analyzer. The isolation valves may be reopened by operator action at a later time when the drywell temperature has been reduced to acceptable level.[3]

REACTOR CORE ISOLATION COOLING TURBINE OVERSPEED TRIPS

Seven Reactor Core Isolation Cooling (RCIC) turbine overspeed trips have occurred in the past year at the Brunswick Steam Electric Plant, Unit No. 2.

These trips occurred when cold, quick-start, reactor vessel injections were initiated from the normal standby lineup without system warmup prior to the initiation. Under these conditions, the RCIC turbine would trip on electronic overspeed before sufficient oil pressure could be developed to throttle the control valve. Upon restart, a sufficient head of control oil would have been accumulated and the turbine would run without tripping. The turbine rated speed is 4500 rpm and the electronic overspeed trip setpoint is at 110%.

From the standby configuration, on system initiation, the turbine begins to roll as the steam supply inlet valve is opened. Oil pressure develops as the turbine speed increases and oil pressure closes the governor valve. A delay in the development of oil pressure would slow the initial closing rate of the governor valve and allow the turbine to overspeed.

To reduce the peak turbine speed and to increase oil pressure flow on system initiation, the Woodward Remote Servo drain (Port D) was rerouted to the EG-R Actuator case drain (Port E) using three-eighths inch tubing. This provided loop seal and continuous prime between the two components. Previously, the Servo drain was routed to the oil equalizer pipe and the EG-R case drain was unused and plugged.

As recommended by General Electric Corporation, the Electronic Overspeed Trip was disconnected from the RCIC trip circuit.

New oil system piping was fabricated to lower the piping as much as possible below the system normal shutdown oil level. Concurrent with installation of the revised piping layout, the EG-R hydraulic actuator supply line was replaced with three-eighths inch tubing. This was an attempt to prevent draining of the oil supply to the EG-R actuator during and extended period of system shutdown. This modification was successful in preventing overspeed trips at 36-hour intervals; however, the turbine tripped on overspeed after a 43-hour interval between cold quick-starts.

After observation of system operation by Terry Turbine and Woodward Governor representatives, and Auxiliary Oil Sump was installed in the oil supply line to the EG-R actuator. This modification resulted in a peak speed of 4500 rpm on a 24-hour and a 45-hour cold quick-start. Later, two cold quick-starts at 42 hours and 96 hours were satisfactory.

STEAM GENERATOR - TUBE DENTING

On S[illegible]r 15, 1976, during normal power operation at Unit 2 of the Surry [illegible]ear Power Plant, a primary to secondary leak of about 80 gpm developed rapidly in a steam generator tube. The tube leakage was quickly detected; the reactor was safely shutdown and offsite releases were within regulatory limits.

Investigation revealed that the leak resulted from an axial crack in the U-bend of the tube near the top; the crack was approximately 4-1/2 inches in length. Removal of the damaged tube showed that the failure was caused by intergranular stress corrosion cracking that initiated from the inside of the tube (the primary coolant side).

The loss of integrity of a steam generator tube results in a breach of the primary to secondary (radioactive to nonradioactive) boundary that keeps the radioactive primary coolant intact in a closed system and sealed off from the environment. When a tube is found to be degraded or leaking, integrity of the steam generator is usually restored by plugging the defective tube at both ends. Plugging eliminates the likelihood of rapid leaks developing from reduced wall thickness tubes or of many degraded tubes failing during an operational transient. To date, approximately 530 tubes in each steam generator have been plugged at Surry-2.

Modern, large pressurized water reactors generally have three or four steam generators, each containing more than 3,000 U-shaped tubes of inconel-600 alloy that are supported at several levels by horizontal steel plates.

Following the conversion from a sodium phosphate secondary water treatment to an all volatile treatment (AVT) a phenomenon known as "tube denting" has occurred at several Westinghouse-supplied plants. Tube denting was first noticed at Surry Units 1 and 2 and Turkey Point Units 3 and 4 in early 1975 when it appeared that eddy current probes properly sized to pass through the inside of the steam generator tubes were encountering restrictions in some tubes at the location of tube support plates.

In May 1976, a dented tube sample and segments of a tube support plate were removed from Surry Unit 2. Inspection of the removed sample revealed the tube support plates were cracked. Laboratory analysis indicated that the annulus between tubes and tube support plates had become filled with a hardened ceramiclike corrosion product (Fe_3O_4) that expanded volumetrically to exert sufficient force to 'dent' the tube and crack the tube support plate ligaments between the tube holes and the water circulation flow holes. This phenomenon of denting was directly attributed to residual phosphates that remained in the annulus when the phosphate treatment was converted to AVT. Known dented tubes have otherwise generally retained their integrity and although there have been very small but detectable leaks at the dent locations, there had been no rapid failures until the failure at Surry 2.

An examination of the failed tube at Surry Unit 2 concluded the tube failed from primary side intergranular stress-assisted attack which was initiated or substantially enhanced by large increases in hoop strain in the U-bends due to inward distortion of the upper tube support plate material into coolant flow slots along the diameter of the plate between the legs of the innermost row of tubes. This tube movement results from the same conditions that have caused 'tube denting.'

In the support plate, along the diameter, between the legs of the innermost row of tubes, there is a row of rectangular flow slots, consisting of six slots, approximately 16-inches long by 2-3/4 inches wide. As a result of the pressures built up in the tube support plate acting on these slots, the slots have been observed to show 'hourglassing' that is, the central portion of the slot walls have moved closer together so that some slots are now narrower in the center than at the ends. Since the slot width had diminished, the tube support plate material supporting the tubes nearest this central portion of these slots has also moved inward, in turn forcing the legs of the U-bend at these locations inward. This inward force on the legs of the U-bends caused a very great increase in the hoop bending strain at the U-bend. This has been shown by an increase in ovalization of the tubes at these locations. It is this increase in hoop bending strain which is believed to have increased the susceptability of the U-bends to intergranular stress-assisted attack in this location, leading to the failure experienced at Surry Unit 2 on September 15, 1976.

Significant steam generator tube denting has also occurred at other reactors - Virginia Electric Power Company's Surry Unit 1, Florida Power and Light Company's Turkey Point Units 3 and 4; Consolidated Edison Company's Indian Point Unit 2; and Southern California Edison's San Onofre Unit 1. All of the steam generators were supplied by Westinghouse, the reactor vendor, and all had switched from phosphate to AVT chemical treatment except San Onofre.

At the request of the NRC, all of these plants have or will perform detailed inspections of their steam generators in the near future. Based on the inspection results, the utilities will complete a repair program if necessary and obtain NRC approval prior to restarting their plants. In addition, should degradation of steam generator tubes continue at a rate commensurate with past experience, unit steam generator replacement or repair programs may be required in the future.[5-7]

Point of Contact:
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U.S. Nuclear Regulatory Commission

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CURRENT EVENTS

POWER REACTORS

UNITED STATES NUCLEAR REGULATORY COMMISSION

THIS COMPILATION OF SELECTED EVENTS IS PREPARED TO DISSEMINATE INFORMATION ON OPERATING EXPERIENCE AT NUCLEAR POWER PLANTS IN A TIMELY MANNER AND AS OF A FIXED DATE. THESE EVENTS ARE SELECTED FROM PUBLIC INFORMATION SOURCES. NRC HAS, OR IS TAKING CONTINUOUS ACTION ON THESE ISSUES AS APPLICABLE, FROM AN INSPECTION AND ENFORCEMENT, LICENSING AND GENERIC REVIEW STANDPOINT.

1 MARCH - 30 APRIL 1977

(PUBLISHED MID-AUGUST 1977)

MALFUNCTION OF ROD WORTH MINIMIZER

On August 3, 1976, Unit No. 1 of the Quad Cities Nuclear Power Station was commencing control rod withdrawals in anticipation of a reactor startup following an outage. The control rod withdrawal sequence was halted after withdrawal of the 50th control rod because the rod worth minimizer (RWM) was still displaying the 6th control rod to be withdrawn in group one and apparently was not following the control rod withdrawals. At this point, the control rod pattern was verified as being correct by both the control room operator and the shift engineer and subsequent rod withdrawals were also verified by a nuclear engineer. Control rod withdrawal was stopped just short of criticality, and all rods were subsequently fully inserted when delays were encountered in the repair of an unrelated system.

On August 4, a computer technician investigated and repaired the rod worth minimizer and declared it operable for an August 5 startup. However, during the maintenance, the wrong control rod withdrawal sequence was loaded into the rod worth minimizer. The control rod sequence which should have been loaded, and the one which was loaded, were identical in sequence through control rod group 6. Groups 7 and 8 on the improper sequence were identical to groups 7 and 8 on the correct sequence, but were in reverse order. Both sequences were substantially different for groups 9 and higher.

After the reactor had reached criticality on August 6, which occurred in rod group 5, control rod withdrawal continued through group 6 with the rod worth minimizer functioning properly. Then, the operator failed to follow the specified sequence and skipped group 7 and went on to withdraw group 8 instead of 7 as proper insequence rod withdrawals. The operator then discovered that a group had been skipped and returned to group 7 to complete the rod withdrawals and thus inadvertently fully complied with the loaded improper sequence. The rod worth minimizer followed the withdrawals. When the operator moved to group 9, the rod worth minimizer properly applied rod blocks. The rod worth minimizer was subsequently bypassed and control rod withdrawal continued with the assistance of an extra control room operator to verify the rod withdrawals.

The RWM is designed to serve as a backup to procedural controls to limit control rod worth during startup and low power operation and the RWM is a passive control as long as the operator follows the proper rod withdrawal sequence. The rod withdrawal pattern is selected to insure a good scattering of rods and to preclude creation of a high worth rod in a given area. If the operator should attempt a rod selection or movement that deviates significantly from the selected program, the RWM either alarms or blocks the action.

The malfunction of the rod worth minimizer was caused by a series of individual component failures. Apparently at some time previous to August 3, a RWM power supply drift caused some of the relay board wires to short. The defective relay boards were not detected and the rod worth minimizer was reinitialized with an error clear message displayed following a correction of the power supply drift. On August 3, a diode in the rod position/error output window display failed. The failed diode should have applied rod insert and withdrawal blocks as part of the fail-safe design of the rod worth minimizer, but the previous relay board wire short prevented this signal from being effected. The control room display panel remained unchanged from the previous error message and the rod blocks were not received because of the shorted relay board. A contributing cause to this occurrence was the control room operator's failure to notice that the rod worth minimizer was not following the selection and movement of the 7th rod in group 1 on August 3, 1976. Had he done so, control rod movement could have been halted until the rod worth minimizer was repaired.

The loading of the rod worth minimizer on August 4, 1976 with the incorrect sequence was attributed to poor communication as well as poor documentation and filing of rod worth minimizer sequences. There was also an apparent inadequacy in the operating procedure for verification that the proper sequence had been loaded into the rod worth minimizer, because only the first five groups of the minimizer's sequence was proofed by the unit operator.

The faulty power supply was replaced and its maintenance schedule has been changed to increase surveillance. The burned out relay board and the bad diode were also replaced. The operating procedure for the rod worth minimizer will be revised to caution that if an error condition cannot be acknowledged and cleared from the control room, it is an indication of a serious type failure requiring the presence of the computer hardware technician. The computer hardware technician, aware of the potential for burned out relay boards, will always check for such failures each time he clears an error condition on the rod worth minimizer before returning it to operation.

Some additional corrective actions taken to improve station performance in this area were:

Computer systems personnel have been requested to modify the rod worth minimizer software to place the rod worth minimizer in a

STALL condition upon receipt of an overload multiple output distribution error. This will provide an independent and redundant rod block signal in the event of an overload error.

The procedure for checking out the rod worth minimizer prior to startup will be changed to require verification of the rod worth minimizer's first ten rod groups to insure the proper sequence is loaded.

A rod worth minimizer log book will be instituted to document all maintenance performed on the rod worth minimizer. Operational information, such as which sequence is presently loaded in each unit's rod worth minimizer, will also be documented.

The computer hardware technician will investigate a wiring change to the rod worth minimizer to supply a special error detection 28 volt D.C. input to the relay buffer from the same power supply that supplies the relay buffer. This change will eliminate a difference in potential in the relay buffer if a power supply fails.[1]

HYDRAULIC TUBING FAILURES

On December 29, 1976, during the startup and power escalation test program at the Salem Generating Station, an hydraulic oil line to No. 12 main steam line isolation valve (MSIV) ruptured while attempting to open the valve. At this time, the reactor was in mode 2 operation at 3.5% power. Oil sprayed on hot piping in the immediate area, and pipe insulation began to smolder, but there was no fire except that caused by fanning action when the insulation was removed. The line failure occurred at a compression type fitting.

During power operation on January 15, 1977, an oil line on No. 12 MSIV ruptured and the valve was declared inoperable. On January 16, a similar failure occurred with No. 11 MSIV. With two MSIVs inoperable, the plant was returned to hot standby condition as required by the Technical Specifications. In both instances, the resultant fluid spray from the parted oil lines wetted an area that included pipe insulation. There was no flame. Both valves remained in the closed position throughout the event.

The three tubing failures were each 3/8-inch O. D. 0.048-inch wall carbon steel hydraulic tubing that was attached to the actuators of the MSIVs. Although these failures are still under engineering evaluation, it appears that the failures may have been from fatigue caused by transverse vibrational bending or wall bending of the tubing that may have been accelerated by the radial restraint of the tubing compression fitting. Minor mechanical damage to the tubing induced by installation of the compression fitting may also have been a contributing factor.

With the concurrence of the valve manufacturer (Atwood and Morrill/Hopkinson), all tubing similar to the failed tubing will be replaced with heavier wall (0.065 inches) 3/8-inch O. D. Type 316 stainless steel tubing. A different type of compression fitting (Swagelok, in place of originally supplied Dealaring) is also being used. The increased mechanical strength of the tubing and the design of the new fittings to avoid mechanical damage should prevent recurrence.[2]

MAINTENANCE ERROR CAUSES FEEDWATER TEMPERATURE TRANSIENT

During normal operation with Unit No. 2 of Dresden Nuclear Power Station at 92% power, an attempt was made to replace a burned-out indicating light bulb for the feed breaker to motor control center. The light bulb glass apparently had loosened from its base. When the operator tried to remove the bulb, the wires twisted together, shorting out the socket, resulting in the trip of a motor control center. Among the systems affected was the motor operated feedwater heater valve, which failed closed resulting in loss of all extraction steam to the feedwater heaters. The decreasing feedwater temperature caused reactor power to increase, which the unit operator effectively countered by insertion of several control rods. However, feedwater temperature decreased 150°F in about 20 minutes before the heaters were returned to service.

The applicable fuel reload license submittal analysis for Unit 2 assumed only a 100°F feedwater temperature reduction (loss of a single heater string) in about a one minute time interval to be the limiting cool water injection transient. The station promptly contacted General Electric to determine whether the critical power ratio (CPR) safety limit had been approached or exceeded during the transient. Based on the prevailing reactor conditions and the much slower feedwater temperature reduction, it was determined that no safety limit had been exceeded. This conclusion was upheld by analysis of the event by the utility's Nuclear Fuel Services department. They determined that a considerable margin had been maintained between minimum CPR and the safety limit.

Following the event, the air ejector off-gas analyses were performed with increased frequency. No significant increase in off-gas activity was noted. A description of the occurrence was sent to General Electric for information.

There were no injuries to or exposure of personnel to radiation as a result of this occurrence, and it was concluded that health and safety of the public were not jeopardized.[3]

MINOR FUEL DEGRADATION

On November 25, 1975, during cycle 4 operation, Unit 3 of the Dresden Nuclear Power Station experienced an increase in off-gas activity. The unit was in the run mode at a power level of 2,355 MWt and 795 MWe, and there had been no power changes in the preceding 32 hours.

The highest stack release occurred on November 26 and the release rate continued to stabilize during the remainder of the week. As station off-gas releases remained well below Technical Specification limits, public health and safety were not adversely affected by this occurrence. The cause of this occurrence could not be established at the time; but limited degradation of fuel cladding was considered probable.

In November, 1976, General Electric Company and Commonwealth Edison personnel visually inspected six fuel assemblies that had been determined to be defective at the end of cycle 4. During the inspection, a major defect was discovered in fuel assembly DD-418. The defect, which was confined to fuel rod A-3, was located immediately above and below the second fuel assembly spacer from the bottom.

Below the spacer, the defect appeared as a longitudinal crack in the cladding approximately six inches long. Above the spacer, the defect consisted of numerous longitudinal splits in the cladding, with an approximately one inch long section completely devoid of cladding. There was no evidence of fuel in this inch-long section.

It was presumed that this single defective fuel rod caused most or all of the off-gas activity increase of November 25-26, 1975. The defect apparently originated below the spacer, with the splitting above the spacer resulting from secondary hydriding of the cladding over a period of time. Through-wall hydride formation was then followed by erosion of the exposed UO_2 pellet(s). Secondary hydriding has been observed before in the BWR fuel rods at Dresden, but never to the extent evidenced by this particular fuel rod.

Because fuel assembly DD-418 was situated in the extreme periphery of the core during cycle 4, operations during that cycle should not have caused the observed primary defect. It appears most probable, therefore, that this defect was related to cycle 3 operations, and in particular to an event of October 31, 1974, in which a change in control rod patterns resulted in fuel rod cladding failures that were determined to be the result of pellet clad interaction. It is believed that the defect either developed during cycle 3, or was initiated during that cycle, and propagated through the cladding wall during cycle 4 operations.

Fuel assembly DD-418 has been permanently removed from the reactor.[4-6]

REACTOR PERIOD LESS THAN FIVE SECONDS AT BWRs

Monticello

During reactor startup at the Monticello Nuclear Generating Plant, the withdrawal of the correct insequence control rod resulted in a reactor period (an increase in neutron flux by a factor of e,(2.71) of less than five seconds. The intermediate range monitor (IRM) was in its most sensitive range and was calibrated to scram the reactor at less than 0.0015% power. The reactor shut down with the trip of this instrument.

The event occurred 10.25 hours after a shutdown from full power operation. The reactor moderator temperature was 480°F and apparently Xenon was near a transient peak. The combined negative reactivity of Xenon and the high moderator temperature at the time of startup required withdrawal of a significantly greater number of rod groups than normally experienced before reaching criticality. The designated rod withdrawal sequence was being followed and it called for withdrawing rods 06-27 and 46-27 from position 00 to position 10. When these rods were individually moved to position 06, the reactor became approximately critical. When rod 46-27 was withdrawn an additional notch from position 06 to 08 the reactor immediately scrammed.

It should be emphasized all applicable pre-startup checks were performed and operating procedures were followed. The rod worth minimizer was operable and was not bypassed. No Technical Specifications were violated and fuel enthalpy criteria was not exceeded.

The designated rod withdrawal sequence being followed was developed using the Haling withdrawal principle. In the next cycle, the generic banked position withdrawal sequence (BPWS) will be used; insequence rod worths using the BPWS are expected to be lower. Until that time (Fall '77) additional analysis to identify high reactivity worth rods will be performed for each rod withdrawal sequence. Steps are in progress to alleviate the potential for recurrence of this type of operational problem.[7]

Dresden 2

During startup operations following a scram at Unit 2 of the Dresden Nuclear Power Station, a short period resulted when control rod drive (CRD) J-2 was withdrawn one notch. The positive reactivity inserted by this notch withdrawal resulted in a transient power increase. The transient was terminated by a scram on the intermediate range neutron flux monitors (IRM) before the operator could reinsert the control rod or adjust instrument ranges. A period of approximately 5 seconds was indicated.

Apparently a combination of conditions including control rod pattern, moderator density (temperature), and local Xenon concentration resulted in an unexpectedly high reactivity worth for the notch. The withdrawal was performed in accordance with General Electric control rod withdrawal sequencing rules for reactor power levels below 20%. The reactor protection systems functioned as designed to terminate the event.

Following the normal scram recovery, startup operations were resumed. Although the notch withdrawal of CRD J-2 was postponed until a later step in the control rod withdrawal sequence, all CRD movements remained in conformance with the General Electric startup CRD withdrawal sequencing rules. Additionally, the nuclear engineers discussed the incident and developed methods of avoiding future potentially undesirable notch pulls under similar conditions.

Because of the similarity of these two events, the NRC issued IE Circular No. 77-07 to alert BWR licensees to review their startup procedures and to assure that their plant operating staff has adequate information for performing a safe reactor startup.[8]

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U.S. Nuclear Regulatory Commission

NOTE: Following the references, a questionnaire has been included to assess the utility of this publication. We would be pleased if the reader would complete the questionnaire.

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Additional comments:

REFERENCES

1. LER 76-26, Docket No. 50-254, August 16, 1976.

2. LERs 76-27 and 77-05, Docket No. 50-272, January 28 and 31, 1977.

3. LER 77-9, Docket No. 50-237, March 21, 1977.

4. LER 75-44, Docket No. 50-249, December 11, 1975.

5. LER 75-44A, Docket No. 50-249, March 31, 1977.

6. LER 74-38, Docket No. 50-249, January 17, 1975.

7. LER 77-04, Docket No. 50-263, March 9, 1977.

8. LER 76-07, Docket No. 50-237, March 10, 1977.

CURRENT EVENTS

POWER REACTORS

UNITED STATES
NUCLEAR
REGULATORY
COMMISSION

THIS COMPILATION OF SELECTED EVENTS IS PREPARED TO DISSEMINATE INFORMATION ON OPERATING EXPERIENCE AT NUCLEAR POWER PLANTS IN A TIMELY MANNER AND AS OF A FIXED DATE. THESE EVENTS ARE SELECTED FROM PUBLIC INFORMATION SOURCES. NRC HAS, OR IS TAKING CONTINUOUS ACTION ON THESE ISSUES AS APPLICABLE, FROM AN INSPECTION AND ENFORCEMENT, LICENSING AND GENERIC REVIEW STANDPOINT

1 MAY - 30 JUNE 1977

(PUBLISHED MID - OCTOBER 1977)

DEGRADATION OF FUEL ROD INTEGRITY

Prior to shutdown for a scheduled refueling outage, the LaCrosse Boiling Water Reactor (LACBWR) operated at reduced power levels to maintain offgas releases within their Technical Specification limits. At the completion of cycle 4, all irradiated fuel (72 fuel assemblies, each containing 100 fuel rods in a 10 x 10 array) were removed from the reactor core for inspection. The visual inspection resulted in the identification of damaged fuel rods in six of the fuel assemblies with an average of 4 to 5 damaged rods in each assembly. Cracks in one or two fuel rods were observed in three of these assemblies but the rods appeared to be integral with no fuel missing. The rod defects in the remaining three assemblies (2-15, 2-39 and 2-43) were major breaches of the fuel integrity (ie. fuel pellets had separated from these assemblies). It was estimated that a total of about 55 inches (length) of fuel pellets which contained approximately 818 grams of uranium had separated from the fuel assemblies. It was estimated that a total of 33.5 inches of fuel rod was missing from assembly 2-15 from a four rod cluster. Approximately 17.4 inches of fuel was missing from two fuel rods in assembly 2-39. Approximately 4.4 inches of a fuel rod was missing from assembly 2-43.

Some of the missing pieces have been accounted for at this point in the outage. The 4.4 inch segment from assembly 2-43 is in the LACBWR fuel storage well. An equivalent of ~ 10.8 inches of fuel rod from assembly 2-39 is in the fuel storage well. Approximately 6 inches of fuel rod from assembly 2-15 is in the reactor core resting in a recoverable location on top of control rod 9. A small piece of cladding (~ 1.5 inches long) was also located on the top of control rod 16. Continuing efforts are being made to locate and recover additional missing fuel and cladding pieces.

The visual inspection also showed fuel rods to be distorted and touching in the high density portion of the core. There were no indications of any departure from nucleate boiling type of failure of the fuel clad.

In addition to the 6 fuel assemblies which exhibited visual damage, 20 fuel assemblies were found to exhibit fission gas release rates above specified limits based on the results of fuel "sipping" examinations which measure fuel assembly radioactive releases to core cooling water.

The licensee has determined that it is not possible to have an inadvertant criticality or flow blockage from the quantity of the fuel that was originally lost from the fuel assemblies.

LACBWR is one of 3 operating reactors and the only boiling water reactor that uses fuel rods with stainless steel cladding. Each fuel rod consists of uranium-dioxide fuel pellets housed in a closed hollow tube of stainless steel about 0.4-inches in diameter and about 8-feet long. The fuel was manufactured by Allis-Chalmers.

The average burnup of the fuel that failed was about 17,-18,000 megawatt days per metric ton. The warranty of the fuel was for a burnup 15,000 megawatt days per metric ton. It is believed that the fuel did not fail prior to expiration of the warranty. This was the highest average exposure of discharged fuel in the history of LACBWR's operation.

Some fuel degradation had been anticipated because of above normal radioactive release rate during power operation. For approximately a five month period prior to the reactor shutdown for the refueling outage, the reactor was operated at reduced power levels to maintain radioactive releases to the environment within the prescribed limits. At shutdown, reactor operation was limited to approximately 60% of rated power.

This event is not the first incidence of fuel rod failures at LACBWR. At the completion of fuel cycle No. 2, there were nine fuel assemblies with visible defects and a total of twenty-three defective assemblies.

Based on preliminary investigations, the observed defects in the cladding of the damaged fuel rods were quite similar to the circumferential cracks observed in fuel cycle No. 2. The circumferential cracks observed at the conclusion of fuel cycle No. 2 were attributed to excessive clad stress from pellet clad interaction. Pellet-clad interaction could be caused by rapid movement of the control rods during control rod repositioning or power level changes leading to excessive clad stress at the pellet-pellet interface. Other factors may also have contributed to the fuel damage.

The licensee believes that the six severely affected fuel assemblies of fuel cycle No. 4 may have been the result of stress corrosion cracking of the stainless steel clad accelerated by relatively high stresses occurring when the control rod was withdrawn after extended periods of insertion. The condition was aggravated when power was escalated rapidly in fuel rods next to rapidly moving control rods during subsequent startups. The damaged rods may have been subjected to flow induced vibration combined with additional reactor shutdowns, startups and power changes. These conditions may have aggravated the circumferential and longitudinal defects to the degree that some rod sections disintegrated resulting in fuel and cladding fragments being transported from the fuel assembly and distributed in the primary system. The actual operating conditions experienced by the grossly failed assemblies will be studied and this history will be used for proposed changes in operation to minimize recurrence of this type of failure.

It was the licensee's conclusion that the rate at which power is escalated during reactor startup must be carefully controlled and limited to minimize the potential for inducing clad failures in fuel rods and/or aggravating the condition in rods which have experienced minor clad defects. The fact that the grossly failed assemblies were located next to control rods which were part of the controlling banks during Cycle 4 has led to the conclusion that it is also vitally important to control the average rate of rod movement.

The consequences of this event were a reduction in electrical generating capacity, increased radiation levels in the reactor coolant and various other areas at the plant, and an extended refueling outage to evaluate the extent of fuel damage and to recover missing pieces of fuel and cladding located within the primary coolant system. There were no personnel exposures to radiation and no radioactive releases to the environs in excess of regulatory limits as a result of this occurrence.

Of the 72 fuel assemblies in the LACBWR core, forty-eight assemblies have been placed in the storage well and twenty-four assemblies were returned to the reactor. The twenty-six defective assemblies will not be used. Most recent plans provide for loading thirty-two core 3 fuel assemblies manufactured by Exxon Corporation and 40 core 2, cycle 4 assemblies.

There have been previous reports from this and other licensees of failed fuel rods, however, this event at LACBWR is unique in the degree and extent of fuel damage experienced. It was estimated that about 1 percent of the fuel rods (about 80 of 7200) were leaking beyond limits of reuse.

The NRC is currently reviewing the information being supplied by the licensee and is considering additional operating restrictions to reduce the probability of future fuel failures.[1-4]

IMPROPER ELECTRICAL CONNECTORS CAUSE FIRE

At the Oyster Creek Nuclear Generating Station, smoke was found to be emanating from a unit substation. The fire was extinguished within 3 minutes and all possible loads were removed from the substation to reduce the amount of heat being generated by the electrical conductors. In transferring the Reactor Protection System to an alternate substation, a reactor shutdown was initiated as a result of the momentary power loss from the switching operation. The plant was in the refueling mode with the reactor core unloaded.

The cause of the fire was attributed to loose connections that were found between the terminal connectors and the aluminum conductors of the cable bus. Investigation revealed that the terminal connectors used were not the type specified for installation. Instead, a connector normally used for copper cable had been used and the different properties of aluminum and copper caused the loose connections to develop. The loose connections were the source of high resistance which produced the intense heat which ignited the insulation.

As a temporary corrective action, a short section was cut from the aluminum conductors and each conductor was restored to its original length by splicing on a section of copper conductor. The conductors were reconnected to the bus extensions using the proper terminal connectors. The aluminum cables are to be replaced with copper cables. In addition, all systems that utilize aluminum cable will be inspected for proper application of terminal connectors and a preventive maintenance program will be started to insure that connection tightness is checked on a routine basis.[5]

OIL DEGRADES POWER REACTOR CABLES

On October 9, 1975, station personnel at the Quad-Cities Nuclear Power Station were cleaning the electro-hydraulic control (EHC) unit which had been dripping fluid on the Unit 2 cable tunnel floor. It was noticed that not only had the EHC fluid been leaking onto the floor but also that it had leaked onto the cables in the surrounding cable pans. Closer inspection of the cables revealed both puffing and plasticization of cables where the EHC fluid had made contact. At the time of discovery, Unit 2 was in the cold shutdown condition.

Cables in the Unit 2 cable tunnel are utilized for both safety and nonsafety-related functions. The EHC fluid leak had not rendered any safety or nonsafety-related system inoperable.

The immediate action was to determine the extent of plasticization of the affected cables. A small section of control cable was hand traced to identify its function and was cut out and analyzed. It was discovered that only the jacketing material had been affected by the EHC fluid.

Various cable manufacturers and the manufacturer of EHC fluid were consulted as to the effects of EHC fluid on various polymers used for electrical cable insulation. Polyvinylchloride (PVC) and neoprene were found to be severely affected by EHC fluid and were not recommended for use in the vicinity of EHC fluid. Other polymers such as polyethylene, teflon, silicone rubber, nylon, and butyl rubber were acceptable for use in an EHC fluid environment.

The next course of action was to determine the function of the cables in the Unit 2 cable tunnel that were affected by the EHC fluid. The types of cable construction were categorized as follows:

1. Control and Power (low voltage): Individual or multiconductor PVC jacketed, mylar wrapped, PVC over butyl rubber insulated conductors.

2. Instrumentation: PVC jacketed, shielded, mylar wrapped, polyethylene insulated conductors.

3. Instrumentation: Single and multiconductor PVC jacketed, polyethylene insulated, mylar wrapped and shielded twisted pairs.

4. Instrumentation: PVC jacketed, polyethylene insulated, coaxial cable.

The control and power cables comprised approximately 80% of all cables in the Unit 2 cable tunnel. Close inspection revealed that the EHC fluid had not permeated through the PVC overall jacket. Since butyl rubber is not affected by EHC fluid, it was recommended that these cables be cleaned and left in place after EHC fluid was removed from the cable pans.

Inspection of the instrumentation cables revealed that some saturation through the overall PVC jacketing had resulted. However, in no case had the EHC fluid permeated through the mylar shielding covering. It was recommended that the plasticized sections of jacketing be removed and a suitable jacketing tape be applied.

The coaxial nuclear instrumentation cables overall jacketing is very thin and consequently suffered from the effects of plasticization. Plasticization had exposed the shielding conductor, such that possible electrical interference could result.

Since there were only 90 coaxial cables affected by the EHC fluid, it was recommended to splice in new coaxial cable sections rather than taping over the shielding. All coaxial cables were identified and labeled before splicing was permitted. The coaxial cables were tested against acceptable electrical properties after being spliced.

The postulated path of EHC fluid migration from the EHC fluid reservoir to the cable tunnel was traced to small cracks in the rough concrete slab of the EHC fluid reservoir. The rough slab serves as the ceiling in the Unit 2 cable tunnel and minor small cracks in the ceiling served as the leak path out of the concrete and onto the cable trays and floor. The upper cable trays did not contain all of the EHC fluid, even though the pans in the cable tunnel were of solid bottom construction. EHC fluid leaked through the cable pan connecting joints and the lower cable pans were also subjected to the EHC fluid. The cables closest to the bottom of the cable pans were most affected by the EHC fluid because these cables were in constant saturation with EHC fluid.

At the present time, all the cables in the affected area of the Unit 2 cable tunnel are being protected from EHC fluid leakage. The leakage has subsided and once it has stopped the ceiling area will be cleaned and a protective sealer will be applied to prevent any possible leakages.

The EHC fluid reservoir foundation will also be sealed with the same protective sealer. The sealer, type 187 HFP, which is a recommended EHC fluid sealant, has been ordered from the Carboline Company.

The licensee's technical staff has been performing a weekly inspection of the Unit 2 cable tunnel to assure that there is no further leakage onto the cables.[6]

BORON DILUTION OF PRIMARY COOLANT WITH SODIUM HYDROXIDE

On February 7, 1977, when Unit No. 3 of the Crystal River Nuclear Power Station was in the Mode 5 (cold shutdown) condition and preparing to enter Mode 4 (hot shutdown) operation, an error in valve alignment permitted sodium hydroxide from the containment building spray system to enter the reactor coolant system. At the time of the event, one train of the decay heat removal (DHR) system was being used to recirculate reactor coolant and the reactor coolant system was being filled from a bleed tank. The filling and recirculation of the reactor coolant system was temporarily discontinued to perform the "Building Spray System Valve Check," a surveillance test that requires cycling of two containment building spray valves. When one of the building spray valves was cycled, sodium hydroxide was drained into the DHR system from the sodium hydroxide tank through a path of three open valves in the decay heat removal system suction line.

The introduction of sodium hydroxide solution to the system was not apparent and recirculation and filling of the reactor coolant system was resumed upon completion of the surveillance test. This introduced sodium hydroxide into the reactor coolant system. An anomaly in the chemical composition of the reactor coolant system became apparent when a boron analysis indicated a concentration of 305 ppmB. The actual boron concentration was approximately 1500 ppm but the alkaline sodium hydroxide solution masked the true boric acid concentration in the titration analysis. Reactor coolant system filling was immediately terminated and source range instrumentation was monitored, which displayed no increase in count rate - a positive indication that no appreciable boron dilution had occurred. After a second boron analysis, it was realized that sodium hydroxide had been introduced into the reactor coolant system.

The cause of the occurrence was procedural inadequacy; there were no precautions in the surveillance procedure to indicate that either of two specific valves in the building spray system (BSV-36 or BSV-37) should not be cycled with the decay heat removal system lined up for reactor coolant recirculation.

It should be noted that there are no Technical Specifications for sodium hydroxide content in the reactor coolant system at temperatures below 250°F. However, the chloride and flouride content of the water in the sodium hydroxide tank were high enough to cause chloride contamination in the range of 1.0 ppm in the reactor coolant system. This level was returned to less than 0.05 ppm by using the makeup and purificaiton demineralizers.

On June 15, 1977, the licensee, Florida Power Corporation, notified the NRC that Babcock and Wilcox (B&W) had evaluated the incident and that the event could be extrapolated as a potential unreviewed safety question. This scenario postulated the single failure of the sodium hydroxide effluent valve. Such a failure during reactor cooldown with the decay heat removal pumps in operation could result in the dilution of boron (the sodium hydroxide tank does not contain boron in solution) in the primary coolant and possibly cause the reactor to become critical with all control rods fully inserted.

Boron is added to the coolant systems of pressurized water reactors in the form of boric acid to aid in the control of the fission process. The purpose of the sodium hydroxide is to control the pH of the fluid inside the reactor containment during a postulated loss-of-coolant accident and to remove iodine from the containment atmosphere to limit offsite release dose. However, if the sodium hydroxide tank effluent valve should fail while the reactor is being cooled in the DHR mode, a path will be made available through which the sodium hydroxide can flow to the primary coolant system. Reactor coolant system boron dilution from this source was not discussed in the Safety Analysis and remedial action was required to prevent such dilution as a result of a single failure.

In the actual event at Unit No. 3 of Crystal River, approximately 600 gallons of sodium hydroxide was discharged into the reactor vessel. Because the dilution was small, the core remained subcritical by a wide margin. It was estimated that this amount of dilution resulted in an increase in reactivity of 0.52% $\Delta k/k$ from an initial subcriticality of -5.07% $\Delta k/k$.

In the hypothetical analysis of an unterminated dilution of the reactor coolant from the sodium hydroxide tank, the Crystal River core would become critical, the time of criticality being determined by the rate of dilution. It was calculated that the maximum possible flow rate from the sodium hydroxide tank could be only 350 GPM due to the 3-inch diameter tank discharge piping. Using this flow rate, the time to criticality would be just over 22 minutes assuming the worst conditions allowed by the technical specifications.

During injection there would be several alarms and indications of dilution of reactor coolant to the operator. However, the loss of 600 gallons, as occurred in the February 7 incident, would not necessarily cause an alarm. A loss of 820 gallons or more would cause a tank level alarm. An addition of approximately 8000 gallons to the RCS would be necessary for criticality. This is not likely to occur as nuclear instrumentation would indicate a change in reactivity before the reactor become critical.

The moderator dilution accident presented in Chapter 14 of the Crystal River-3 FSAR does not consider the possibility of unterminated dilution. However, moderator dilution occurring while operating at power will eventually result in a reactor trip; this action closes the feed block valve and thus eliminates the possibility of continuous dilution and return to criticality.

The Chapter 14 analysis did consider dilution at a cold depressurized core condition as in the refueling mode. In the refueling configuration, the reactor core is heavily borated to assure a large subcritical margin. The dilution event considered at these conditions was limited to the dumping of a full makeup tank volume of demineralized water into the core and demonstrating that core criticality was not a possibility. No continuous dilution or source of dilutant of a volume comparable to the sodium hydroxide tank was considered.

As a result of these two postulated accident conditions, the emptying of the sodium hydroxide tank as dilutant into the reactor vessel was concluded to be an unanalyzed moderator dilution event because only one valve in each sodium hydroxide exit line is available to prevent the full discharge of the sodium hydroxide tank.

Florida Power Corporation is presently evaluating permanent modifications to the sodium hydroxide system. Appropriate revisions to the FSAR will be submitted to the Commission following completion of the evaluation.

1. Prior to aligning the Decay Heat Removal System for operation, the manual isolation valves BSV-97 and BSV-98 that are located in the discharge lines of Sodium Hydroxide Tank will be verified to be closed and the breakers of the motor-operated isolation valves BSV-36 and BSV-37 will be "racked out" with BSV-36 and BSV-37 in the closed position. This provides redundant isolation between the Sodium Hydroxide Tank and the Decay Heat System.

2. The manual isolation valves BSV-97 and BSV-98 will be verified to be in closed position and that the pressure of the Reactor Coolant System is greater than 12 psig (greater than that of the Sodium Hydroxide Tank) before the motor-operated valve cycle testing is performed on BSV-36 and BSV-37. The piping between BSV-97 and BSV-153, and BSV-98 and BSV-152, respectively, will be thoroughly flushed with demineralized water to preclude the introduction of Sodium Hydroxide to the Decay Heat System.

3. The valve cycle testing required by CR#3 Technical Specifications will be performed during a refueling outage.

The possibility of an unterminated moderator dilution may not be unique to the Crystal River Plant. The accident analysis section of the Standard Review Plan does not seem to address sources of possible dilution (other than the chemical and volume control system) such as the sodium hydroxide tank. Other plants have been checked and this type of dilution is possible on at least some of these plants (Rancho Seco and Arkansas Unit 1). Accordingly, the NRC is sending letters to all PWR licensees asking them to investigate the potential for a Boron Dilution Accident.[7-8]

Point of Contact:
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1. LER No. 77-04, Docket No. 50-400, June 2, 1977.

2. Letter, J. P. Madgett, General Manager, Dairyland Power Cooperative to Director of Nuclear Reactor Regulation, Mr. Robert W. Reid, July 8, 1977.

3. Letter, D. J. Skovholt, Assistant Director for Operating Reactors, to Dairyland Power Cooperative, ATTN: Mr. John P. Madgett, June 18, 1973.

4. Advisory Committee on Reactor Safeguards, 208th General Meeting, August 11, 1977.

5. LER No. 77-12, Docket No. 50-219, June 24, 1977.

6. Letter, N. J. Kalivianakis, Commonwealth Edison Co. to J. Keppler, Director, Region III, April 1, 1976. NJK-76-118.

7. LER 77-52, Docket No. 302, June 20, 1977.

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CURRENT EVENTS

POWER REACTORS

UNITED STATES NUCLEAR REGULATORY COMMISSION

THIS COMPILATION OF SELECTED EVENT EVENTS IS PREPARED TO DISSEMINATE INFORMATION ON OPERATING EXPERIENCE AT NUCLEAR POWER PLANTS IN A TIMELY MANNER AND AS OF A FIXED DATE. THESE EVENTS ARE SELECTED FROM PUBLIC INFORMATION SOURCES. NRC HAS, OR IS TAKING CONTINUOUS ACTION ON THESE ISSUES AS APPLICABLE, FROM AN INSPECTION AND ENFORCEMENT, LICENSING AND GENERIC REVIEW STANDPOINT.

1 JULY - 31 AUGUST 1977

(PUBLISHED MID-NOVEMBER 1977)

INSUFFICIENT NET POSITIVE SUCTION HEAD

On August 10, 1977, the NRC was informed by Virginia Electric and Power Company (VEPCO) that Stone and Webster Company, the architect-engineer for North Anna Units Nos. 1 and 2, had discovered a deficiency in the design of the Containment Recirculation Spray (CRS) system pumps for the North Anna facilities. Subsequent discussions with representatives of VEPCO, Duquesne Light Company (DLC) and Stone and Webster (S&W), have indicated that this same design deficiency also exists for the Low Head Safety Injection (LHSI) system pumps. It had been determined that the net positive suction head (NPSH), calculated to be available to the pumps of these systems, is insufficient with respect to the required NPSH specified by the pump manufacturer for the intended pump operation. The deficiency is generic for the following Pressurized Water Reactor (PWR) facilities with a subatmospheric containment design.

State	Utility	Plant Name
Virginia	Virginia Electric & Power Co.	North Anna Unit Nos. 1 & 2
Virginia	Virginia Electric & Power Co.	Surry Unit Nos. 1 & 2
Pennsylvania	Duquesne Light Co.	Beaver Valley Unit No. 1

Both the CRS and LHSI systems are engineered safety features whose functions are to mitigate the consequences of a postulated loss-of-coolant accident (LOCA), a low probability event. The CRS system is designed to remove heat from the containment in order to reduce the containment pressure to below atmospheric pressure within one hour after a postulated LOCA. It consists of four subsystems, each with 50 percent capacity. The pumps take suction from the containment sump, with two pumps located inside and two pumps located outside the containment. The LHSI system is designed to inject cold borated water into the reactor core. The system consists of two 100 percent redundant and independent subsystems. Initially the system is connected to the Refueling Water Storage Tank (RWST), but is switched to the containment sump when the RWST reaches a low-low level.

For each of these systems to satisfy its intended safety function, the pumps in each system must be capable of providing the design flow rate under all postulated post-LOCA conditions of containment pressure and sump water temperature. Thus, conditions leading to inadequate NPSH for the CRS and LHSI pumps for extended periods of time could affect the capability of these systems to perform their intended safety function.

The design deficiency was determined to exist when a reanalysis of the containment pressure transient response -- which included the associated time dependent NPSH available to the pumps in both the CRS and LHSI systems -- was performed by Stone and Webster for VEPCO. This reanalysis used more refined and conservative considerations of the overall thermodynamic model for the containment pressure response, i.e., assumptions that minimize the calculated containment pressure and maximize the containment sump water temperature; thus, these assumptions minimize the calculated NPSH for conservatism in the analysis. Application of these assumptions in the reanalysis resulted in the new calculated result that the available NPSH for these pumps would temporarily be less than the minimum required NPSH specified by the pump manufacturer. This reanalysis also corrected an error in the earlier calculations in the reference elevation for the LHSI pumps.

Based on additional tests performed at North Anna, information from the pump manufacturer, low probability of the event and operating restrictions that will satisfy the intended safety function of the CRS, Surry Units 1 and 2 and Beaver Valley Unit 1 were permitted to continue operating for an interim period.

In the additional tests performed at North Anna, the CRS pump minimum NPSH required to assure satisfactory pump operation without cavitation was measured to be 10.2 feet for the design flow rate of 3300 gpm used in the containment depressurization analysis. This is in contrast to the 15.0 feet specified by the pump manufacturer. The tests also demonstrated the ability of the pumps to operate in the cavitating mode, though at a reduced flow rate, for at least 30 minutes without sustaining serious damage.

The following changes were subsequently imposed on the operation of the CRS system in the Surry CRS system.

1. Flow limiting orifices were installed in the discharge lines of the two CRS system pumps located outside containment. These orifices would reduce the design flow from 3300 gpm to 2000 gpm and would reduce the required NPSH to 6.4 feet compared with a calculated available NPSH of 7.3 feet. Consequently, the associated flow

reduction assures continued pump operation without cavitation. With this reduced flow rate of 2000 gpm for the outside CRS pumps, and assuming the most limiting single failure (i.e., the loss of a diesel generator and hence one train of inside and outside CRS pumps), the remaining two CRS pumps would be capable of delivering a total recirculation flow of at least 5000 gpm, which is adequate to ensure containment integrity.

2. The CRS system pumps located inside containment would be required to operate in a cavitating mode only for a limited time (from 700 seconds to 2100 seconds after a postulated LOCA) and at a reduced flow rate of 3000 gpm. At all other times, the calculated available NPSH to these pumps would be greater than the NPSH required to preclude cavitation for a flow rate of 3300 gpm.

3. In addition, limits on certain operating parameters (service water temperature, containment temperature, and containment air partial maximum pressure) were implemented to ensure adequate NPSH.

With respect to the LHSI system, a potential for pump cavitation was found to exist for a short period of time during the recirculation mode if the flow rate exceeds 3500 gpm (adequate for long term core cooling requirements). In order to assure that this flow rate will not be exceeded, VEPCO has proposed an interim solution of throttling the valves in the pump discharge line while monitoring the flow rate in the control room.

Actions have also been taken at Beaver Valley to ensure that the original planned design margins are restored. In addition, cold quench spray water will be divereted from the spray header system to the inlet of the outside CRS pumps at Beaver Valley. With respect to the North Anna Units, these design deficiencies will be corrected prior to the issuance of operating licenses for these plants.

Both VEPCO, operator of the Surry and North Anna Units, and DLC, operator of Beaver Valley, are committed to submitting plans and schedules for implementing a final resolution of this problem within 90 days from August 24, 1977.[1,2]

CONTROL ROOM ATMOSPHERE DEGRADED

At approximately 1:15 a.m. on August 5, 1977, a chemical spill occurred in an area below the control room of Dresden Units 2 and 3. Both of these units were operating; Unit 1 was shutdown. Some fuming from the chemicals resulted, and when these fumes entered the control room, a Generating Station Emergency Plan (GSEP) "on-site alert" was initiated. Two control room operators donned Scott Air Pack breathing apparatus as a safety precaution, although this was not needed during the entire period. The Dresden Units were not taken off the line, no personnel injuries occurred and the health and safety of the public was not affected.

The spill occurred when a plant operator was simultaneously filling the make-up demineralizer acid and caustic day tanks. His attention was diverted by other activities in the area, resulting in the overflow of both tanks. The chemical mixing produced a high concentration of chemical vapors that prevented the operator from reaching the controls to stop the flow of chemicals into the tanks. The fan in the demineralized make-up room was not operating, and the fumes seeped through the ceiling into the Shift Engineers locker room, the lunch room and ultimately into the Control Room Ventilation System. The vent fans for the control room were turned off to minimize the inflow of fumes. In the meantime the flow of chemicals into the tanks had been stopped by control switches at a remote location from the tanks. The control room atmosphere had been degraded for approximately 45 minutes.

After the area was cleaned up, the control room ventilation was returned to normal recirculation, and within approximately 5 minutes, the control room atmosphere was adequately purified. The GSEP on-site alert was terminated at approximately 3:00 p.m.

The following were contributing factors that caused the event:

1. No automatic shutoff of caustic and acid flow to the day tanks on high level;

2. No immediately available emergency cutoff switches for the pumps -- it took approximately 15-20 minutes to get to the remote breakers.

3. No means of taking the control room heating, air conditioning and ventilation system off 90% recirculation flow and placing it on 100% outside air ventilation mode.

Extensive helium injection testing was performed to investigate the flow path of the fumes. The two major causes for the infiltration of the fumes into the Shift Engineer's locker room and ultimately the Control Room ventilation system were:

1. inadequately sealed holes between the make-up demineralizer room and the Shift Engineer's locker room, and

2. an out of service vent fan whose purpose is to exhaust the make-up demineralizer area and the Shift Engineer's locker room.

The following immediate short term corrective actions to prevent recurrence of this event were proposed:

1. The procedure for transfer of acid or caustic to the day tanks will be changed so that the operator shall be required to be present during the filling operation and in addition the tanks shall not be filled simultaneously.

2. The exhaust fan for the make-up demineralizer room and Shift Engineer's locker room is to be repaired.

3. All penetrations in the make-up demineralizer room ceiling and walls will be sealed and the seams in the control room and computer room heating, ventilation and air conditioning ducts that go through the demineralizer room will be taped.

Long term corrective measures will include:

1. Installing a switch in the control room that will permit operation of the control room ventilation system in either the recirculation mode or outside air supply mode. A procedure will be written so that operating personnel will have adequate instructions as to when the operating mode of the system should be changed.

2. A modification will be made to move the demineralizer day tanks and to place high level trips on all day tanks.[3]

SPEED CONTROLLER MALFUNCTION

On March 16, 1977, during a routine surveillance test of the High Pressure Coolant Injection (HPCI) system at the Cooper Nuclear Station, it was found that the speed of the HPCI turbine could not be reduced below 4000 rpm. The system met operational requirements for flow and was therefore not declared inoperable.

The HPCI system is one of the three Emergency Core Cooling Systems (ECCS) that provide cooling water to the core over a wide spectrum of line breaks. When the HPCI was declared inoperable to perform the necessary repairs to the speed controller, the Automatic Depressurization, Core Spray and Low Pressure Coolant Injection systems were operable and the occurrence had no potential adverse consequences on the safe operation of the plant or to the public health and safety.

It was found that the speed control capability was limited because the governor valve nozzle block lift rods were deformed. There are two such rods and each was bent just below the upper connecting clevis. The bend in the rods prevented complete closure of the governor valve and in turn would not allow the turbine speed to decrease below 4000 rpm. The cause of the bent lift rods has been attributed to binding of the rods at the steam chest bushings, with the binding caused by rust collection on the rods. (This binding causes a bending load on the lift rods because of the linkage design.) A suggested maintenance technique to reduce the possibility of this type of occurrence is to exercise the valves on a more frequent basis with the hydraulic oil system. This should prevent the buildup of deposits on the lift rods of the speed controller of the Terry turbine until a linkage modification can be made to the lift rods.[4]

FIRE PREVENTION

On May 13, 1977, work was being performed by Carolina Power and Light Company personnel in a laydown area of the Brunswick Unit 1 turbine building when a mechanic welding on the interior surface of a basket strainer from a main steam stop valve noticed a blue flame burning just above the surfce of the fire blanket on which the strainer was set. The mechanic extinguished the fire with a portable extinguisher and, although the control room was notified of the fire, the fire brigade was not assemblied because the flame was immediately extinguished.

Investigation revealed that the fire resulted when a sheet of plastic placed under the fire blanket to catch filings was heated during the course of the work. When the blanket was heated, the plastic beneath it began to evolve ignitable vapors which, on passing through the relatively porous material of the blanket began to burn upon reaching the air above the fire blanket.

The work was being performed under a valid permit in accordance with FP-5, Welding and Burning Control. Although all procedures were carefully followed by the personnel involved, and combustible material that chould not be removed was covered by fire blankets, consideration was not given to the fact that elevated temperatures might occur in some areas and thus present a hazard.[5]

Point of Contact:
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2. Letter, DLC to Reid, August 20, 1977 (Docket No. 50-334).

3. LER 77-31, Docket No. 50-237, August 18, 1977.

4. LER 77-17, Docket No. 50-298, April 14, 1977.

5. LER 77-18, Docket No. 50-325, May 26, 1977.

CURRENT EVENTS

POWER REACTORS

UNITED STATES NUCLEAR REGULATORY COMMISSION

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1 SEPTEMBER - 31 OCTOBER 1977

(PUBLISHED DECEMBER 1977)

OPERATOR ERROR

On January 11, 1977 while the Fort Calhoun Station Unit 1 was operating, water from the Refueling Water Storage Tank was pumped into the containment through the containment spray header due to an operator error.

During the performance of a quarterly test of the safety injection and containment spray pumps, the operator noticed an increase in the containment sump level approximately ten minutes after the low pressure safety injection pump had been started. Approximately 3300 gallons of water had been pumped to the containment. About one minute later the ventilation isolation actuation signal was received. At this time the operator realized he had failed to follow the surveillance procedures and had left the discharge valve of the low head safety injection pump open. He immediately secured the pump.

The Reactor Coolant System was checked for leakage and containment entry was made approximately one hour later. Inspection revealed that a discharge from the containment spray nozzles had occurred. A few minutes later power reduction was started. A second containment entry was made about an hour later, after containment air samples confirmed that a full face mask would provide adequate respiratory protection for the levels of radioactivity in the building. A detailed inspection revealed no serious deficiencies and no electrical grounds; the power reduction was terminated at a power level of 83%.

Although the operator had not followed the procedure and the discharge valve was open, the containment spray header isolation valve (HCV-345) and the low pressure safety injection to containment spray header cross-connect valve (HCV-335) should have prevented the event. The electric/pneumatic converter on HCV-345 had failed and both red and green position indication lights were on, indicating the valve was partially open. Prior to the event the auxiliary Building Equipment Operator had taken local control of the valve in an attempt to completely close the valve. After about 1/2 inch of stem travel, the operator removed the valve pin and the valve went back to its previous position as demanded by the valve positioner. The third valve (HCV-335) in the incident had a leakage problem that had been previously identified but no corrective action had been taken.

The pneumatic relay on valve HCV-345 was replaced and valve HCV-335 repaired. Valve HCV-344 and HCV-345 are now required to be placed in the test mode prior to operating the low pressure safety injection pump or contain spray pump for testing. This mode along with verification of an annunciator will ensure that both of these valves are in the fully closed position prior to pump operation.[1]

VALVE MALFUNCTIONS

1. Primary System Depressurization

On September 24, 1977, Davis Besse Nuclear Power Station Unit No. 1 experienced a depressurization when a pressurizer power relief valve failed in the open position. The Reactor Coolant System (RCS) pressure was reduced from 2255 psig to 875 psig in approximately twenty-one (21) minutes. At the beginning of this event, steam was being bypassed to the condenser and the reactor thermal power was at 263 MW, or 9.5%. Electricity was not being generated. The following systems malfunctioned during the transient:

a. Steam and Feedwater Rupture Control System (SFRCS).

b. Pressurizer Pilot Actuated Relief Valve.

c. No. 2 Steam Generator Auxiliary Feed Pump Turbine Governor.

The event was initiated at 2134 hours, when a spurious "half-trip" occurred in the SFRCS, resulting in closure of the No. 2 Feedwater Startup Valve and loss of flow to No. 2 Steam Generator. Approximately one minute later, low level in the No. 2 Steam Generator caused a full SFRCS trip, closing the Main Steam Isolation Valves (MSIV). The loss of heat sink for the reactor caused the RCS temperature, pressure, and pressurizer level to rise.

The RCS pressure increased to the pilot actuated relief valve setpoint (2255 psig) and the valve cycled open and closed nine times in rapid succession, failing to close on the tenth opening. Meanwhile, the reactor operator observed the pressurizer level increase and manually tripped the reactor about one minute after MSIV closure (two minutes into the transient). At this point the RCS pressure was approximately 2000 psig and decreasing while the pressurizer level had reached its maximum initial rise of about 310 inches. The RCS pressure continued to decrease due to the open relief valve and upon reaching 1620 psig approximately three minutes into the transient, actuated Safety Features including high pressure (water) injection and containment isolation.

Approximately five minutes into the transient the rupture disc on the pressurizer quench tank, which was receiving the RCS blowdown, burst. Bursting of the rupture disc was aggravated by the actuation of containment isolation, which had isolated the quench tank cooling system, resulting in expedited pressurization of the quench tank.

The RCS continued to blow down through the open pressurizer power relief valve and the quench tank rupture disc opening until primary coolant saturation pressure was reached, about six minutes into the transient. The formation of steam in the RCS caused an insurge of water into the pressurizer. This insurge and the high pressure water injection then restored pressurizer level to about 310 inches after nine minutes into the transient.

Approximately thirteen minutes into the transient, the secondary side of the No. 2 Steam Generator went dry. About fourteen minutes into the transient, the operators noticed the low level condition and found that the auxiliary feed pump was operating at reduced speed. Manual control of the auxiliary feed pump was started and water level restored to the No. 2 Steam Generator.

At approximately 21 minutes into the transient, the operators discovered that the pressurizer power relief valve was stuck open. Blowdown via this valve was stopped by closing the block valve, thus terminating the reactor vessel depressurization. The RCS pressure recovered to normal and cooldown of the system followed.
The reason for the spurious "half-trip" of the SFRCS has not yet been determined. An extensive investigation revealed several loose connections at terminal boards, but nothing conclusive.

Investigation into the failure of the pressurizer pilot actuated relief valve revealed that a "close" relay was missing from the control circuit. This missing relay would normally provide a "seal-in" circuit which would hold the valve open until the pressure dropped to 2205 psig. Without the relay the power relief valve cycled open and closed each time the pressure of the RCS went above or below 2255 psig. The rapid cycling of the valve caused a failure of the pilot valve stem, and this failure caused the power relief valve to remain open.

It was determined that the auxiliary feed pump did not go to full speed because of "binding" in the turbine governor.

The transient was analyzed by the NSSS vendor and determined to be within the design parameters analyzed for a rapid depressurization.

With exception of the above noted malfunctions, the plant functioned as designed and there was no threat to the health and safety of the general public.[2-3]

2. Feedwater Isolation Valves

On two occasions in July, at the Trojan nuclear plant, a hydraulic feedwater isolation valve failed to close upon receipt of a close signal. All other equipment required to operate, functioned normally.

The first failure, July 6, 1977, had been attributed to an improperly assembled solenoid in the hydraulic actuator. Investigation of the second failure indicated that both events were due to a lack of sufficient hydraulic pressure.

Failure of the valve to close was caused by the pressure regulator leaking and failing to close down to regulate the pressure. This caused the hydraulic system on the valve to be drained down to a point that the valve would not operate. Inspection of the regulator revealed that a locking screw on the regulator adjusting knob was loose and would allow the knob to vibrate to any position. With the regulator improperly set it would not close down to regulate pressure and would allow the hydraulic fluid to drain before the hydraulic operator could function. A similar problem was discovered on two other valves, although the maladjustment was not sufficient to prevent these valves from operating. All of the regulators were reset and the adjusting knobs were locked in place so that they could not vibrate loose. The isolation valves were tested satisfactorily following these adjustments.[4]

3. Off-Gas System Valves

At the Oyster Creek nuclear generating station on August 27, 1977, the reactor building ventilation system isolated and the standby gas treatment system (SGTS) automatically initiated.

Investigation revealed that at approximately 1850 hours a station employee performing housekeeping duties in the main control room accidently caused the augmented off gas (AOG) mode switch to move from "isolate and bypass" to the "isolate" position. This resulted in the off gas valve and the off gas drain valve going closed, and since the AOG was not in service the gas flow was stopped. The isolation of the reactor building ventilation system and initiation of the SGTS occurred at 1905. The two off gas valves were opened four minutes later and the SGTS was secured. The reactor building ventilation system was returned to normal at 2000 hours.

The off gas drain valve did not seat properly and was not leak tight. This condition allowed the gaseous radioactivity within the isolated off gas system piping to travel up through the stack sump in the stack base and fill the air space in the ventilation tunnel. When the radiation level in the reactor building ventilation duct reached a level of 17 mr/hr the monitors located next to this duct initiated the SGTS.

The safety concern associated with this event is the possibility of a submergence dose a person would have received from the radioactive gaseous atmosphere if they were in the tunnel area. The atmosphere in the tunnel area is processed through the radwaste ventilation system, which contains both roughing and absolute filters, prior to exhausting through to the stack which is monitored. The maximum radiation level sensed in the tunnel was 26 mr/hr.

No personnel exposures or releases to the environment resulted from this event. The licensee is investigating the feasibility of installing an alarm to alert operations personnel to the closure of the off gas valve when the AOG is out-of-service.[5]

SMALL PIPE BREAK ANALYSIS

On June 9, 1977, an orderly shutdown of the Yankee Nuclear Power Station (Yankee Rowe), a pressurized water reactor, was initiated by the licensee because of an error discovered in the Emergency Core Cooling System (ECCS) performance analysis.

Yankee Atomic Electric Company (YAEC), the licensee, notified the Nuclear Regulatory Commission (NRC) that an error had been discovered in a particular small break loss of coolant accident (LOCA) analysis, which permitted reactor operation with Core XII in a manner less conservative than assumed in the original analysis.

While performing a review of the analyzed small break accidents for the Core XIII reload, the YAEC Safety Analysis Group determined on June 7, 1977 that an incorrect fluid flow resistance calculation was made in the safety injection line break analysis. The fluid flow characteristics study had taken credit for the 2-1/4 inch safety injection line thermal sleeve to retard spillage from the accumulator -- a tank which supplies borated water to the reactor core in the event of a reactor coolant system pipe break. The flow resistance of the sleeve should not have been included in the flow calculation, as a new worst case pipe break was identified in a 4-inch diameter line section.

The recomputed decreased flow resistance allowed increased accumulator flow to be calculated for the break, and decreased the ECCS supply pressure to less than had been assumed, thus decreasing the core reflood capability of the ECCS. This corrected flow resistance assumption was used for the accident analysis of the present core, Core XII, which was operating at 79% of rated power in a coastdown program prior to the June 9, 1977 shutdown. Operation of the reactor with Core XII commenced in December 1975.

Upon discovering the error, the licensee reduced power level to 300 megawatts thermal (50% rated power), which was believed to conservatively accommodate the analysis error. During subsequent analysis, however, the licensee was unable to assure himself that the 10 CFR 50.46 limits on peak fuel cladding temperature could be maintained for the postulated small break. Therefore, the facility was shutdown pending resolution of this matter and to proceed with the Core XIII refueling outage which had been previously scheduled to commence on July 2, 1977.

The licensee subsequently performed an approximate best estimate analysis of the postulated worst case small pipe break, which included assumptions based on actual facility equipment availability during Core XII operation. The results of this analysis indicated that the calculated peak fuel cladding temperature was well below 10 CFR 50.46 limits. The more conservative 10 CFR 50 Appendix K reanalysis of Core XII operation, however, indicated that 10 CFR 50.46 limits might have been exceeded in the event that the safety injection pipe break had actually occurred.

Prior to returning the plant to operation after refueling of Core XIII the licensee: 1) performed flow measurements tests to determine the actual flow resistance through the safety injection piping; 2) changed the flow resistance in the safety injection lines, by an ECCS modification; and 3) analyzed appropriate pipe break accidents in accordance with 10 CFR 50 Appendix K criteria. The changes and results of tests and analysis were submitted to the NRC and were approved prior to restart of the plant after the refueling.[6-7]

DIESEL GENERATOR TRIP

During a loss-of-power test on August 26, 1977, the E-4 diesel of the Peach Bottom Atomic Power Station Unit 2 started properly as a result of the undervoltage condition, but tripped immediately. This trip was caused by the overspeed mechanism. The circuitry was reset, an adjustment was made to the mechanical governor to limit the diesel speed during a start and the unit was started successfully. Because the exact cause of the trip was not firmly established, surveillance testing of the diesel was increased from once a week to once per shift.

During one of these tests, on August 27, 1977, the diesel tripped again. Another adjustment was made to the mechanical governor, the load capability was checked and several successful starts were performed. Once per shift surveillance was continued.

On August 29, 1977, the diesel again tripped on overspeed and was declared inoperable. The diesel was then operated in excess of synchronous speed in order to determine the exact speed at which the overspeed mechanism would function. This test determined that the diesel would trip at 940 rpm instead of the desired setpoint of 990 rpm. The trip mechanism was adjusted to 985 rpm by a manufacturer's representative and diesel was started twice, successfully.

Investigation into the cause of the change in the trip setting determined that during the diesel maintenance in June 1977 a camshaft was replaced. In order to replace this camshaft the overspeed mechanism had been removed. When the overspeed mechanism was replaced, some necessary shims were not installed. Although this was the only diesel requiring this maintenance during the annual check, the other diesels were operated up to a speed of 945 rpm to verify proper operation. None of these diesels tripped on overspeed.

Analysis of this event revealed that a deficiency exists in the maintenance procedure associated with the diesel yearly inspection and the post-maintenance testing procedure. These procedures will be revised to correct the deficiencies.[8]

ELECTRICAL FAULT

On July 13, 1977 while the personnel at James A. Fitzpatrick nuclear power plant were conducting refueling operations a short in a cable caused 600 volts AC to be introduced into a 115 volt circuit. The 600 volt AC supply for the refueling bridge and the 115 volt AC circuit for refueling interlocks are both located in the same cable. Flexing of the cable with bridge motion over the core caused the cable to short internally. The introduction of the 600 volts into the 115 volt circuit caused nineteen relays in the rod manual control system to burn out. All of the refueling operations were halted until the interlocks were repaired. The rod worth minimizer and rod sequence control systems were also checked for damage.

A modification is being prepared that will remove the 115 volt AC interlock circuit from the cable carrying the 600 volt AC supply. This will prevent recurrence.[9]

PIPE CRACK

The Brunswick Steam Electric Plant Unit 2 was in hot shutdown and preparations were underway to startup the unit when the Shift Foreman noticed a small leak of the recirculation loop suction piping. This discovery was made during the closeout inspection of the drywell.

Investigation revealed the leak was from a crack in the socket weld on a three-quarter inch test connection 90° elbow that was nonisolable, and the plant was placed in the cold shutdown condition. The cracked pipe was cut out of the system and the connection was capped. Similar connections on both Units 1 and 2 were dye-penetrant checked with no other indications of cracks.

Further investigation revealed that the crack was contained in the weld metal and intergranular stress corrosion in the heat affected zone of the base metal was ruled out. A dye-penetrant inspection of the internal and external diameters of this section of pipe revealed no other cracks. The inspection of the internal diameter of the socket weld joints showed that a proper gap was present between the socket and the pipe end.

Based on a stress analysis and the observed condition of permanent deformation of the failed area, along with the location of the crack, it is concluded that the initial crack was caused by stress concentration in the weld fillet area. It is believed that this deformation was the result of workmen (during construction) using the pipe as a step. This use of the pipe for this purpose plus vibrational stress resulted in the failure.

A visual inspection of similar piping on the other loop of Unit 2 and both loops of Unit 1 revealed no deformation as was observed on the failed pipe. It was also noted that the location of the three remaining pipes is such that they are not likely to be used as a step or support because of physical interferences. These three pipes will be supported to protect them from experiencing excessive external loading and vibration, or will be removed and capped.[10-11]

Point of Contact:
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2. LER 77-16, Docket No. 50-346, October 7, 1977.
3. Supplement to LER 77-16, Docket No. 50-346, November 14, 1977.
4. LER 77-23, Docket No. 50-344, July 29, 1977.
5. LER 77-21, Docket No. 50-219, September 23, 1977.
6. LER 77-30, Docket No. 50-29, August 3, 1977.
7. Summary of June 17 Meeting, NRC-YAEC, June 22, 1977.
8. LER 77-37A, Docket No. 50-277, September 9, 1977.
9. LER 77-43, Docket No. 50-333, August 11, 1977.
10. LER 77-7, Docket No. 50-324, February 28, 1977.
11. Supplement to LER 77-7, Docket No. 50-324, September 30, 1977.

CURRENT EVENTS

POWER REACTORS

UNITED STATES NUCLEAR REGULATORY COMMISSION

THIS COMPILATION OF SELECTED EVENTS IS PREPARED TO DISSEMINATE INFORMATION ON OPERATING EXPERIENCE AT NUCLEAR POWER PLANTS IN A TIMELY MANNER AND AS OF A FIXED DATE. THESE EVENTS ARE SELECTED FROM PUBLIC INFORMATION SOURCES. NRC HAS, OR IS TAKING CONTINUOUS ACTION ON THESE ISSUES AS APPLICABLE, FROM AN INSPECTION AND ENFORCEMENT, LICENSING AND GENERIC REVIEW STANDPOINT.

1 NOVEMBER – 30 DECEMBER 1977

(PUBLISHED FEBRUARY 1978)

DIESEL GENERATOR MALFUNCTIONS

1. At Peach Bottom Unit 3 on June 13, 1977, three of four diesel generators were inoperable for a period no greater than six hours. Unit 2 was shutdown for refueling, and Unit 3 was at full power with diesel generator E-1 out of service for its annual maintenance outage.

   At about 8:00 a.m., the control room operator noticed trouble alarms on E-3 and E-4 diesels and assigned their investigation, as well as a high drywell temperature problem investigation and a blocking test, to the plant-operator. No task priority was given, and the operator did not reach the diesel building until approximately 10:30 a.m. He noted that both diesel air receivers were depressurized and that the associated compressors had tripped on thermal overloads. The operator then reset the overloads, returned the compressors to service, and established 70 psig in the starting air receiver tanks prior to informing the control room operator of his findings and corrective actions.

   No shutdowns or power reductions were initiated, but another operator was shortly sent to check the pressurization status. He found the receiver tanks were at 170 psig, with the air compressors again tripped on thermal overloads. The operator reset the overload devices and returned the compressors to operating status.

   A few hours later, the valves which interconnect the diesel starting air systems were checked. The E-3-E-4 sectionalizing valve, which was found partially open, was then closed to isolate the starting air systems of the E-3 and E-4 diesels. During the entire period, both of the normal off-site electrical supplies were in-service.

   To date, investigation of the occurrence has revealed two areas of deficiency. One is that of valving, in that valving from previous maintenance on a diesel air compressor had not been returned to normal.

The exact nature of this failure is currently unknown, but the air receiver tanks were equipped with check valves which failed to maintain the air pressure in the tanks.

The other area of deficiency relates to operator performance. The length of time prior to responding to the initial alarm was too long, and priority should have been given to the diesel alarm over the other tasks assigned to the plant operator. In addition, the operator should have immediately informed shift supervision and tried to locate the cause of the air compressor trips. Both initial response and followup action were, therefore, inadequate.

Corrective actions taken on the valving problem has been to lock the starting air header sectionalizing valves closed, thus preventing a single failure from affecting more than one diesel air starting system, and to replace the leaking air receiver tank check valves. In addition, shift personnel have been forcefully reminded of the need for immediate response to diesel generator malfunction alarms, and the alarm cards have been changed to reflect this requirement.

The investigation of this occurrence is continuing in the area relating to valving and safety blocking of the diesel generator starting air systems, the conduct of shift operators, and the assignment of priority tasks. Further corrective action indicated by the investigation will be promptly taken.[1]

2. During a loss-of-power test, August 26, 1977, at Peach Bottom Unit 2 the E-1 diesel failed to start on the loss of voltage signal. During these tests another failure was also experienced which involved the E-4 diesel generator. This event was reported in the Current Events for 1 September - 31 October, 1977 that was published in December 1977. It should be noted that diesel generators E-2 and E-3 were confirmed to be operable at the time of the loss of power tests. An immediate investigation determined that the diesel circuitry was in the tripped condition due to a jacket coolant high temperature condition which occurred on August 23. The diesel circuit was reset and the diesel started and accepted load within 15 minutes of initiation of the loss of power test. An investigation revealed the following sequence of events.

   The weekly surveillance of the diesel was successfully performed on August 23, but approximately 20 minutes after the diesel generator was shutdown a diesel trouble annunciator was actuated in the control room. The operator dispatched to investigate the condition noted the high temperature alarm on the jacket cooling, and verified the fact that the jacket cooling temperature was higher than normal. The operator also noted that the jacket coolant circulating pump, which operates the coolant while the diesel is shutdown, had tripped on thermal overload. He reset the thermal overloads, started the pump and monitored the system temperature. When the temperature returned to the normal standby value, the operator attempted to reset the high temperature annuciator by means of the reset button on the alarm panel, but was unsuccessful. He therefore assumed that the sensing element associated with this alarm had malfunctioned and reported to the control room that, since the jacket cooling system was returning to normal he would remain on station to watch it cooldown. The control room operator informed the shift supervisor of the suspected defective sensing element and indicated that he would initiate a maintenance request form to have the sensing element checked. (Due to an oversight he failed to carry out this assignment.) The control operator believed at this point that the diesel generator was operable when, in fact, it was inoperable because the shutdown relay had not been reset. There was, however, no control room indication of this condition.

The diesel generators were being inspected on a daily basis, but the man who performed the inspections on August 23, 24 and 25 had been told that the sensing element for the jacket coolant was defective, that the alarm condition was present, that a maintenance request form would be submitted and that the diesel was operable. The second operator who performed the routine inspections, therefore, took no action to report or correct the condition since he believed that all steps had already been taken.

Following the failure of the E-1 diesel to start, additional investigations revealed that the temperature sensors on the jacket cooling system would trip at 194°F on two sensors and 185°F on the third. The sensors were recalibrated to trip at the desired setpoint of 205°F.

The sizing of the thermal overload devices associated with the pump was checked and it was learned that the setpoints were marginal. The Electrical Engineering Department directed that the overload devices on all four diesel generator jacket coolant circulating pumps be increased.

The confusion associated with the original problem on August 23, 1977 was caused by the operator's belief that the annunciator was a direct result of a high temperature switch malfunction rather than an auxiliary relay operation. The diesel circuitry is such that a high temperature switch operates an auxiliary relay which actuates the alarm and provides an input to a two of three logic circuit that shuts down the diesel. This confusion was further complicated by the fact that this auxiliary relay was not connected to the "Diesel Generator Not Reset" alarm in the control room even though plant personnel believed that this particular alarm did exist. This belief was based on a misinterpretation of details on a secondary and control print which, while it showed that actual condition of the wiring, could be construed as having the alarm in service. On September 1, 1977 the connections were made that put the alarm in service on each of the diesel generators.

In addition to the letter issued to shift personnel concerning this event, training sessions were scheduled for all personnel to discuss the diesel circuitry and operating requirements associated with the diesel generators. To increase attentiveness to the annuciators associated with the diesel generator inoperable condition, a yellow background will be provided. 2/

INOPERABLE SGTS

On two separate occasions during October, Standby Gas Treatment System (SGTS) No. 1 at the Oyster Creek Nuclear Generating Station failed to operate as required during surveillance testing. The plant was operating at 634 MWe at the time, and SGTS No. 3 was operational.

During the surveillance test on October 11, indications in the control room appeared to show that the discharge valve to the exhaust fan opened slowly and was later reported as not opening at all. Investigation of the discharge valve showed that the flow sensing probe downstream of this valve was pulled out of its normal position. After the flow sensing probe was returned to its proper position, the SGTS was retested and was found to operate properly. At this time it was believed that the discharge valve had opened but, since the flow sensor was inoperable, reclosed on a low flow signal. Tests performed on the system the following week showed it operable.

On October 25, the discharge valve failed to open on the first SGTS initiation signal. A second signal caused the valve to open and the system operated as required. Investigation revealed that the flow control plunger on the pilot solenoid valve to the discharge valve was deteriorated to the extent that proper seating did not always occur. The initial cycling of the plunger resulted in its not properly seating on the exhaust port which kept the discharge valve from opening. The second signal cycled the plunger and satisfactorily sealed the port.

It is now believed that, in addition to the flow sensing probe problem seen on October 11, the pilot solenoid malfunction also occurred but, due to the irregular nature of the problem, it was not immediately evident.

A more detailed inspection of the flow control plunger revealed that the rubber surface of the plunger, which mates with the port to form a leak tight seal, had deteriorated with repeated use of the discharge valve. A new plunger was installed in this valve, and similar valves in both SGTS No. 1 and SGTS No. 2 were inspected and plungers replaced as required to insure integrity of both systems.

The apparent cause of the displaced flow sensor is attributed to the construction of some scaffolding near the duct. During this work the tubing connected to the probe was snagged, pulling the sensor from its normal position. Corrective actions taken were to replace the flow sensor in its normal position and to peen the collar penetrating the duct to prevent it from being pulled out. 3/

BORON INJECTION TANK THERMOWELL FAILURE

On October 26, 1977 while in hot shutdown the H. B. Robinson Unit 2 received a safety injection (SI) signal which started the SI pumps. The pumps pressurized the Boron Injection Tank (BIT) and this increased pressure ruptured a thermowell coupling on the BIT.

The plant was in hot shutdown to repair a packing leak in a valve in the residual heat removal system. Boration of the system was taking place in preparation for the reduction to cold shutdown condition. The Reactor Coolant System temperature was 465°F with a pressure of 2210 psig when the steam header to steam line differential pressure exceeded 100 psi (due to a biasing in the steam header pressure monitoring circuit which prevents this signal from going below 585 psig) on 2 of the 3 comparison monitors, and the safety injection signal was initiated. Prior to this the safety injection block permissive signal had not been received at the Reactor Turbine Generator Board (RTGB).

The SI pump discharge pressure increased the pressure in the BIT and a one inch hole was opened in the injection path when a thermowell ruptured. The flow path was maintained even though in a degraded condition. When the BIT low level alarm was received at the RTGB the BIT was isolated. During the blow down, an estimated 148 gallons of solution containing approximately 1.014 μCi of activity was released. This drainage was collected in the plant sediment ponds and will be released at controlled rates to the adjacent Black Creek. The release is much less than the maximum permissible concentrations and is no threat to the health and safety of the public.

Metallurgical analysis revealed that the couplings on the BIT containing the thermowells were sensitized and therefore more subject to fracture. Investigation confirmed that the couplings were welded to the tank and were heat treated simultaneously with the tank during the tank fabrication process. The tank cladding was constructed of a lower carbon content steel, and should not have been sensitized to the same degree as the couplings. An additional factor contributing to the failure was the improper fitup of the coupling. The metallurgical examination of the coupling socket weld indicated that the male socket fitting was firmly seated at the base of the socket, while a proper socket weld would have provided some clearance at the socket mating surface. The improper fitup caused additional stress which, with the sensitization and operating pressure, resulted in coupling failure.

The investigation of the tank revealed that the stainless cladding was blistered in several locations with higher concentrations of blistering in the upper and lower hemispherical sections of the tank. At the blistered locations there was some evidence of corrosion products indicating the possibility of discontinuities in the cladding and localized attack of the carbon steel tank.

Although the thermowells could have been repaired, it was evident that the stainless steel cladding was degraded to such an extent that reasonably fast repair was not possible. It was therefore decided to replace the tank, and a new solid stainless steel tank, not subject to the sensitized properties of the old tank, has been purchased. 4/

PROCEDURE PROBLEMS

1. Sodium Hydroxide Concentration

In August, Westinghouse Electric Company notified Carolina Power and Light Company (CPL) that an error existed in the procedure used at H. B. Robinson to determine the sodium hydroxide (NaOH) concentration in the Safety Injection Spray Additive Tanks.

The error was found in the section of the procedure containing the formula for calculating the percent by weight of NaOH in aqueous solution. The instruction stated the quantity of sample taken for titration in terms of volume; instead, the quantity of sample should be in sample mass. Use of sample volume instead of mass in the calculation creates a non-conservative error of 30-35%.

Upon receipt of notification of the error, plant procedures were revised to include the corrected calculation. Analysis of the Safety Injection Spray Additive Tanks, using the revised procedures, showed that the concentration was within the Technical Specification limit.

It was concluded that the Technical Specifications have never been exceeded, since the Spray Additive Tanks were filled in 1970 and no additions or dilutions have occurred since that time._5/

2. Positive Moderator Temperature Coefficient

On August 10, while testing at about 5% power, the moderator temperature coefficient (MTC) for Joseph M. Farley Unit No. 1 reactor was determined to be more positive than the Technical Specification limit for the conditions of: the rods fully withdrawn, beginning of cycle life, and hot zero thermal power. The Technical Specifications allow the reactor to be tested to determine the MTC limits while at or below 5% power. By August 15, sufficient test data was available from the physics tests to determine the control rod withdrawal limits that would keep the MTC to within the required technical specification limit. Based on this data, a temporary change was made to the startup procedures. The change added a figure defining the withdrawal limits for control rod Bank D, which would ensure a negative MTC during operation.

Subsequently, on three occasions in October and November, the reactor was taken critical with a positive MTC, thus violating a Technical Specification limiting condition of operation. The startups were made using a copy of the revised procedure that did not contain the calculated rod withdrawal limit curves needed to preclude a positive MTC. The erroneous procedure was used by the operator to go from Hot Standby to Minimum Load Conditions. Also the withdrawal limit requirements were not noted on the Estimated Critical Calculation form used by the operator for reactor startup.

On November 11, it was determined that the facility had been started up, as noted above, with a positive MTC. This was determined by the plant Quality Assurance (QA) Engineer, after the reactor reached a power level of approximately 48% and had a negative temperature coefficient. The QA Engineer was conducting an investigation of a previous Licensee Event Report when he discovered the MTC had, at that time, become negative after operating for approximately 15 hours with a positive MTC. Subsequent review of the startup records revealed that the reactor had been brought critical with a positive MTC on October 26 and again on October 27. The reactor had been critical with positive MTC's for approximately 2.5 hours and 5.6 hours, respectively, following those startups.

Although the plant was operated outside of the Technical Specification limits and the operating staff was not aware of this fact, the positive MTC was eliminated within the 25-hour period allowed by the Technical Specifications. The health and safety of the public was not affected and there was no adverse effect on plant operations.

Corrective actions were:

1. A requirement was added to the Calculation of Estimated Critical Condition form to assure that a negative MTC exists when the estimated cricital boron concentration and rod height have been determined.

2. The operator's copy of the procedure has been updated to incorporate the rod withdrawal limits. Also a laminated copy of

the rod withdrawal limit curves has been posted on the main control board.

3. Reactor engineers have been instructed to make a more timely review of the reactor start up data.

4. The event has been reviewed by all cognizant operations personnel to assure that they are aware of the requirement to verify that a negative MTC exists prior to startup. This will also be stressed as part of the requalification program. 6/

3. Surveillance Procedures Deficient

On November 17, operations personnel at the Davis-Besse Station discovered auxiliary feedwater valves AF 599 and AF 608 closed. Closing these valves rendered the Steam and Feedwater Rupture Control System (SFRCS), Steam Generator to Feedwater Differential Pressure Switch inputs inoperable. There was no danger to the health and safety of the public or to station personnel, and the SFRCS would have actuated from a diverse steam generator low level input if a loss of feedwater had occurred.

Investigation revealed that there was a deficiency in the procedure for monthly testing of the SFRCS. This error was in two sections of the procedure which failed to reset the valve logic for the auxiliary feedwater valves. The test had been performed on November 14, 1977.

The procedure for testing the SFRCS has been revised to remove the deficiency. 7/

4. Surveillance Procedure Changes

At a Station Review Board Meeting (Davis-Besse Station) on November 1, 1977 it was learned that a surveillance requirement on one of the four high pressure injection lines had not been performed.

The Emergency Core Cooling System surveillance tests require that the four High Pressure Injection (HPI) lines be vented at least once each 30 days. Valve HP-72 had not been vented since August 1, 1977. There was no danger to the health and safety of the public or to station personnel since only one of the four lines was not vented. Also, once the HPI lines are filled, they remain filled with the pressure supplied from the Borated Water Storage Tank.

Investigation revealed that valve HP-72 had been removed from the surveillance procedure by a change request on August 31, 1977. Personnel had incorrectly requested removal of the valve from the procedure because the valve was difficult to service.

Valve HP-72 was opened on November 1, 1977 to vent the HPI line. The modification to the procedure was voided and a facility change request was written for an improvement in the accessibility of vent valve HP-72. The requirements needed to make deletions from surveillance tests will be reviewed with all operations personnel. 8/

5. RWST Water Volume

At about 9:00 p.m., on September 13, 1977, the quantity of borated water in the Turkey Point Unit 4 refueling water storage tank (RWST) fell to approximately 3% below the limiting conditions for operation minimum value (320,000 gal.) allowed by Technical Specification 3.4.1.a.1.

The decrease occurred during the routine performance of a monthly periodic test which requires stroking the valves individually. As the operator inadvertently opened two valves in series in a line from the B containment recirculation sump, a flow path was briefly established from the RWST to the containment sump. The water was then pumped to the waste holdup tank for normal processing.

Immediate corrective actions were closing of the motor operated valves and initiation of a unit shutdown in accordance with administrative procedures. Makeup was established to the refueling water storage tank and the tank was confirmed to be within specification at 9:50 pm. The shutdown was terminated, and the unit was returned to full power. No release of radioactive material occurred.

During an accident, injection of RWST water is terminated before the tank is completely emptied; hence, all piping remains filled with water before recirculation is begun. In this case, the small amount of water drained from the RWST was transferred to the containment floor and would have only resulted in the recirculation phase starting slightly earlier.

The decrease in the RWST water volume was caused by operator error. This resulted from the operator's attempt to perform simultaneously (in the most cost effective manner) the Technical Specifications requirement on pump and valve surveillance tests (valve cycling) and the Inservice Inspection and Testing Program valve exercising (timing) tests. This created an operational and procedural situation in which there was increased margin for personnel error; the error directly causing the occurrence being the operator's failure to close one of two valves in series prior to opening the second valve.

In order to minimize the possibility of recurrence, all licensed operators on shift have been trained in the circumstances of this occurrence. In addition, during the time when periodic valve surveillance and valve exercising tests are performed in conjunction, an additional person will be assigned to assist the operator performing the tests. 9/

SURVEY RESULTS

We have reviewed the responses to the questionnaire included in the March-April issue of Current Events, and wish to thank the respondents.

Two-hundred fifty questionnaires were returned, showing that 80% of the readers found the publication useful for some specific purpose, 16% did not use the publication for any specific purpose but found it interesting to read, and the remaining 4% either did not find the publication useful or did not answer the question.

Answers to questions concerning presentation, understanding, and credibility of the material showed that 231 readers thought the events reported were properly clarified or explained, 214 thought Current Events provided a good spectrum of information, and 7 believed the publication to be biased.

As to frequency of publication, the majority of readers (108) preferred monthly, with 70 readers choosing bi-monthly, 66 quarterly, 3 semi-annually, and 3 not at all. We have no plans to increase the frequency at this time.

Many readers had additional comments pro and con, the most frequent being the publication of events should be more timely. This situation should be improved in the next few months. Attempts will also be made to include both BWR and PWR items in each issue. In general, we appreciate all constructive comments received, and hope to produce an improved publication in the months ahead.

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REFERENCES

1. LER 77-26; Docket No. 50-278; June 30, 1977.
2. LER 77-37B; Docket No. 50-277; September 9, 1977.
3. LER 77-25; Docket No. 50-219; November 10, 1977.
4. LER 77-25; Docket No. 50-261; November 8, 1977.
5. LER 77-20; Docket No. 50-261; September 9, 1977.
6. LER 77-42; Docket No. 50-348; November 12, 1977.
7. LER 77-19; Docket No. 50-346; November 12, 1977.
8. LER 77-92 Docket No. 50-346; November 29, 1977.
9. LER 77-9; Docket No. 50-251; September 27, 1977.

OFFICE OF OPERATIONS EVALUATION
U. S. ATOMIC ENERGY COMMISSION

OPERATING EXPERIENCE

INFORMATION ON REGULATORY OPERATIONS BULLETINS AND REPLIES

January 15, 1975

CRACKS IN PIPES AT BWR FACILITIES

Regulatory Operations Bulletin 74-10 was issued on September 18, 1974, after discovery of cracks in two pipes at the Dresden Nuclear Power Station Unit 2. These were through-wall cracks in two four-inch diameter bypass lines connected to the 28-inch "A" and "B" recirculation headers, as shown in Figure 1. (Figure 1 is drawn with only one loop for purposes of simplicity. The locations of the cracks on both loops are illustrated on this single loop. The "A" bypass loop and "B" bypass loop are identical in terms of pipe sizes, pipe length and location of valves.)

As shown in Figure 1, each bypass loop is connected at both ends to the 28-inch recirculation header. The purpose of the bypass loop is to supply reactor coolant water to warm the 28-inch header before the recirculation pump is started. Prior to discovery of these cracks, Dresden 2 was operated with the discharge valve open while the bypass valve was closed, thus preventing water flow through the bypass loop. This mode of operation has been changed since these cracks were found. The new mode of operation requires that the bypass valve remain open during reactor operation at some BWR facilities.

The cracks were found after the reactor was shut down to investigate a 5 gal/min. unidentified leak in the drywell that was detected by the drywell sump monitoring system on September 13, 1974. Prior to that time, the unidentified leak rate was 1.0 to 1.5 gal/min during the period of September 1-5 and 2.9 gal/min during the period of September 7-10. The first crack was discovered in the heat-affected zone of the weld that ties the four-inch "B" bypass loop to a weldolet connection on the 28-inch recirculation header, (see Figure 2). The crack was approximately three inches long and extended circumferentially on the outside diameter of the pipe from the 8 o'clock position to the 11 o'clock position (see upper right of Figure 1). Ultrasonic examinations of the cracked area revealed that the inside surface was also cracked from the 6 o'clock position to the 12 o'clock position. Based on these findings, the Commonwealth Edison Company ultrasonically examined the 10 welds in each of the four-inch bypass loops and discovered a second crack in the bypass loop of the "A" recirculation header. This crack was 5/8-inch long on the outside of the four-inch pipe and 1 1/2-inches on the inside surface. The defect in the "B" bypass loop was isolable. However, the cracks in the "A" bypass loop were not isolable and special procedures had to be developed to repair this line.

Three options considered for repairing the crack in the "A" bypass loop included:

a. Unloading the core and lowering the water level to below the level of the "A" loop. This was impractical because there was insufficient on-site storage space for the 727 fuel elements.

b. Plugging the jet pumps associated with loop "A" so that the recirculation line could be drained without lowering the vessel water to the 2/3 core height level. This option was not attractive because of the time required to remove the vessel head.

c. Plugging the four-inch loop by the use of a freeze plug in a manner that would allow the crack to be repaired without completely draining the loop.

Commonwealth Edison selected the third option. However, before this procedure was used, the AEC required Commonwealth Edison to construct mock-ups that would reproduce the full dynamic conditions that existed in the original loop so that repairs could be conducted safely. In addition, maintenance personnel for all three shifts were trained in special emergency procedures through the use of mock-ups to prepare for any contingency that might develop in the event the freeze seal failed during the initial cut or final welding. The entire repair effort required four days from the time the freeze plug had been established until the pipe was repaired; no special problems were experienced during this period.

During repair of the "B" bypass loop, a 1-inch segment of the pipe was removed for replacement. Samples of the pipe (schedule 80, type 304 stainless steel) were sent to the General Electric Company and to Argonne National Laboratory for metallurgical examinations.

During the time that Commonwealth Edison was checking the drywell area for leaks, another leak was discovered in a one-inch diameter Type 304 stainless steel instrumentation line. This line is welded to a half-coupling which, in turn, is welded to the 28-inch reactor coolant recirculation line. As a result of this third crack, 58 similar lines were examined, including all vents, drains, and instrumentation lines connected to the reactor coolant system. Dye penetrant examinations were conducted on each weld, and the supports and restraints for each line also were examined. The investigation revealed one additional circumferential crack in a 3/4-inch Type 304 stainless steel vent line located at a welded joint between the line and a 45-degree elbow fitting. The pipe failures were determined to have been caused by excessive vibration of small "field run" piping. As a corrective measure additional supports or restraints were installed.

Shortly after these cracks were discovered at Dresden in September 1974, officials at Quad-Cities Station, Unit 2 were notified of the problem. At the time this information was received, the Quad-Cities 2 plant had been shut down for maintenance, so the 22 welds in both bypass loops were immediately inspected. Only one was found to be defective. The defect was a subsurface crack about three-inches long located at the top of "B" bypass loop, approximately 1/4-inch away from the pipe to weldolet weld on the upstream side of the discharge valve at the point where the bypass loop joined the recirculation header (see Figure 3).

A third reactor, Millstone Nuclear Power Station Unit 1, experienced cracks in one of its bypass loops. Investigation of the four-inch "A" bypass loop revealed a leak from a circumferential crack about 2 1/2-inches in length parallel to the weld joint on the downstream side of the bypass valve (see Figure 3). Although the crack was located in a non-isolable area of the bypass loop line it was unnecessary to develop special procedures to repair the line as in the case of Dreaden 2 since the fuel was out of the core at the time. Repairs were made by lowering the reactor water level. Millstone's repair involved the replacement of both four-inch bypass loops.

As a result of the cracks at these three BWR's the AEC issued RO Bulletin 74-10, to 15 BWR licensees with facility piping systems similar in design to that of Dresden 2. These licensees were requested to examine their bypass piping for cracks and to report their findings to the AEC within 60 days. With the exception of the three BWR's noted above, no other facility discovered any cracks in their bypass piping. In addition to the 15 BWR's, the Bulletin was sent for information to owners of six older BWR's with piping configurations different from that of the Dresden 2 reactor. Four of these six plants notified the AEC of their plans to examine their piping systems; no problems have been found to date at two of these older reactors. The two facilities that notified the AEC that they did not plan to examine their piping did so on the basis that they either had no recirculation piping or that their piping was recently examined, see Table 1. All 21 facilities that received RO Bulletin 74-10 are listed in Table 1.

At the time this report was being written, the Commission was notified by Commonwealth Edison on December 13, 1974, that additional circumferential cracks were found at Dresden 2 in the heat affected zone of a weld which joins the "B" bypass line to the weldolet fitting on the 28-inch recirculation header. Leakage from the pipe was noted during grinding operations of the pipe wall surface in preparation for ultrasonic examination of the bypass piping which was part of the inservice inspection program. Subsequent ultrasonic examinations revealed that there were two cracks on the inside surface of the 4-inch pipe. One crack was 1-1/2" long and extending from the 7 to 8:30 o'clock position. The other crack was about 4" long and extended from the 2 o'clock position to the 8:30 o'clock position. These cracks were undetected during similar ultrasonic examinations last September. During the time that these cracks were discovered the reactor was shut down from refueling. Both defects were located in a non-isolable area of the bypass loop. As a result of this second series of cracks at Dresden 2 all boiling water reactor facilities having jet-pumps were requested (through Regulatory Operations Bulletin 74-10A issued on December 17, 1974), to reevaluate records of previous ultrasonic examinations and other examinations conducted in accordance to Regulatory Bulletin 74-10 or as part of the baseline inservice inspection. In addition they were also requested to examine (either ultrasonically or by other techniques) the bypass piping lines around the recirculation pump discharge valves as soon as possible.

As a result of these last series of cracks at Dresden 2, the Commonwealth Edison Company has informed the AEC that they plan to replace the bypass loops for their Dresden 2 and Quad Cities 2 facilities immediately. Both of these plants are presently shut down for refueling. The Dresden 3 facility and the Quad Cities 1 facility will have their bypass loops replaced in the spring of 1975 and fall of 1975, respectively. During this period of operation with the old bypass loops, special surveillance requirements will be instituted to assure that any leak which may develop will be immediately detected.

The AEC has been notified that similar problems were experienced at two Japanese facilities similar in design to Dresden-2. These two reactors had components manufactured in the United States. Although few details are available at this time it is reported that at one facility, Fukushima 1, the bypass loop was replaced.

Based on metallurgical tests conducted by Argonne National Laboratory and the General Electric Company, it appears that in each case the cracks were caused by stress-assisted corrosion originating on the inside surface of the pipe. At the present time, the origin of the stress has not been determined although it is under investigation. It is expected that more definitive information related to the cause of this problem will become known early in 1975.

Even though the stress mechanism is not understood at this time it is known that the cracks were located in a low stress area where propagation of the cracks progressed slowly. If similar cracks develop in bypass pipes at other BWR facilities in the future, the resultant water leaks should be detected by the drywell monitoring system before any castastrophic pipe break occurs. In the unlikely event of a gross failure of a four-inch bypass loop, the resultant break would be well within the capability of the ECCS system.

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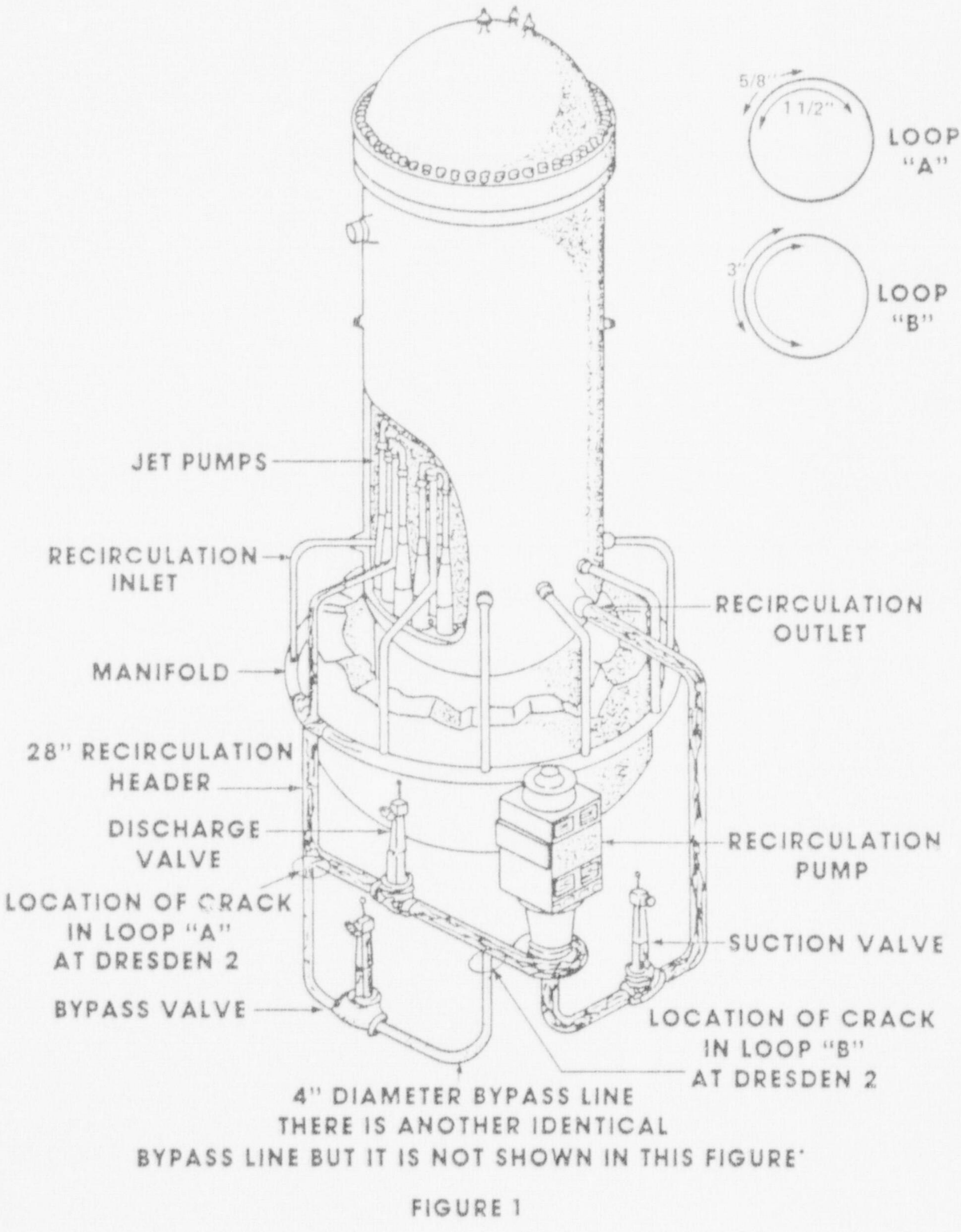
5/8"
1 1/2"
LOOP "A"
3"
LOOP "B"
JET PUMPS
RECIRCULATION INLET
RECIRCULATION OUTLET
MANIFOLD
28" RECIRCULATION HEADER
DISCHARGE VALVE
RECIRCULATION PUMP
LOCATION OF CRACK IN LOOP "A" AT DRESDEN 2
SUCTION VALVE
BYPASS VALVE
LOCATION OF CRACK IN LOOP "B" AT DRESDEN 2
4" DIAMETER BYPASS LINE
THERE IS ANOTHER IDENTICAL
BYPASS LINE BUT IT IS NOT SHOWN IN THIS FIGURE

FIGURE 1

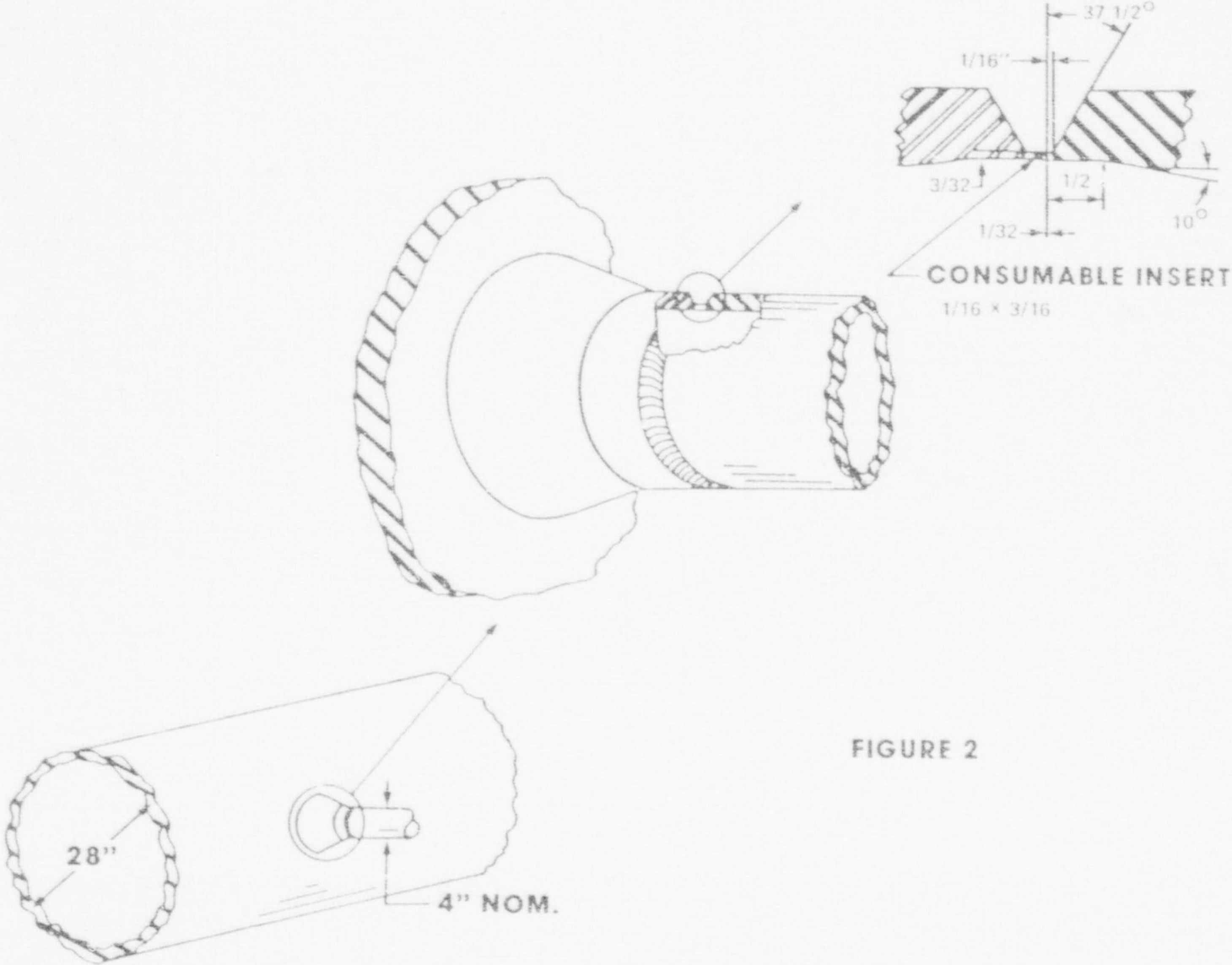

FIGURE 2

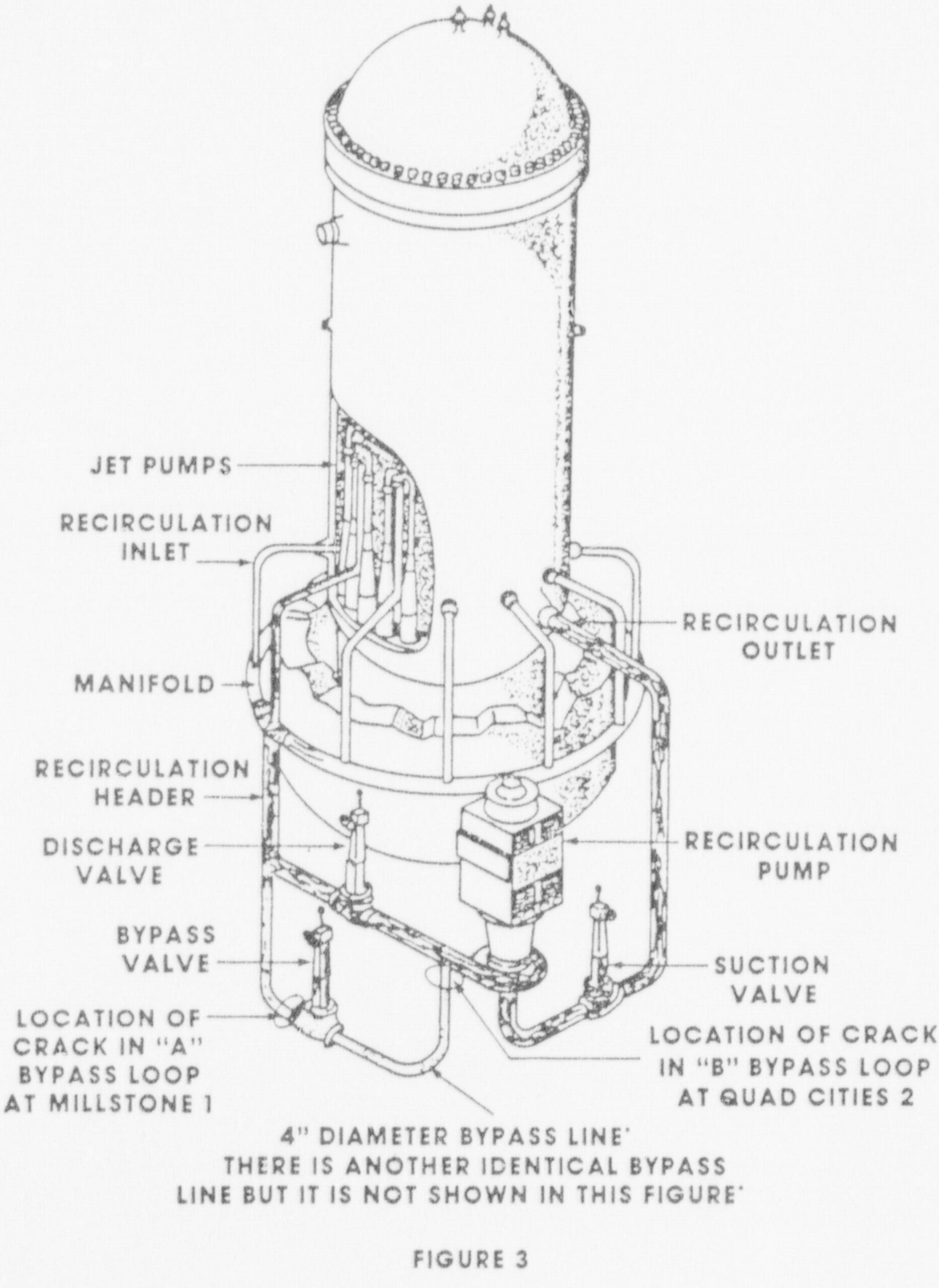
JET PUMPS
RECIRCULATION INLET
MANIFOLD
RECIRCULATION HEADER
DISCHARGE VALVE
BYPASS VALVE
LOCATION OF CRACK IN "A" BYPASS LOOP AT MILLSTONE 1
RECIRCULATION OUTLET
RECIRCULATION PUMP
SUCTION VALVE
LOCATION OF CRACK IN "B" BYPASS LOOP AT QUAD CITIES 2
4" DIAMETER BYPASS LINE'
THERE IS ANOTHER IDENTICAL BYPASS LINE BUT IT IS NOT SHOWN IN THIS FIGURE'

FIGURE 3

TABLE 1

FACILITY (Jet Pump Plants)	INSPECTION FINDINGS
Browns Ferry-1	No cracks identified.
Browns Ferry-2	No cracks identified in 4-inch bypass piping; cracks identified and repaired in smaller (2-inch) socket welded piping.
Cooper Station	No cracks identified.
Dresden-2	Cracks identified in two bypass lines. Repairs complete and operation resumed.
Dresden-3	No cracks identified.
Duane Arnold	No cracks identified.
Hatch-1	Inspected in December 1973 - No reinspection planned. In early phase of startup operation.
Millstone-1	Cracks identified in one bypass line - Replacement of bypass piping complete.
Monticello	No cracks identified.
Peach Bottom-2	No cracks identified.
Peach Bottom-3	No cracks identified.
Pilgrim-1	No cracks identified.
Quad-Cities-1	No cracks identified.
Quad-Cities-2	No cracks identified.
Vermont Yankee	One small ultransonic idication found. Determined not to be a crack.

TABLE 1

FACILITY (Non-Jet Pump Plants)	INSPECTION FINDINGS
Big Rock Point	No cracks identified.
Dresden-1	No cracks identified.
Humboldt Bay	Has no recirculation piping.
LaCrosse	No inspection planned because bypass lines were examined and repaired less then two years ago.
Nine Mile Point	Plan to inspect at a later date.
Oyster Creek	No cracks identified.

OFFICE OF OPERATIONS EVALUATION
U. S. ATOMIC ENERGY COMMISSION

OPERATING EXPERIENCE

INFORMATION ON REGULATORY OPERATIONS BULLETINS AND REPLIES

February 6, 1975

UNDERRATED COILS IN RELAYS

Regulatory Operations Bulletin 74-12 issued on October 25, 1974, identified a problem with 11 Westinghouse relays (type SG293-B255A20) supplied by ITE for use in 4kV and 12kV switchgear equipment. During preoperational testing at Portland General Electric's Trojan Nuclear Plant, it was discovered that these relays contained coils that were rated for 48 volts dc (Vdc) rather than 125Vdc. The resistance of the 48 Vdc coils is 725 ohms while the resistance of the 125 Vdc coils is 4650 ohms. The 48V relays were labelled incorrectly as 125 Vdc relays by Westinghouse.

Five of the 11 underrated relays were used in control circuits of engineered safety feature (ESF) circuits. The others were used for undervoltage tripping and voltage monitoring in control circuits of equipment not associated with ESF.

The incorrectly labelled relays could either fail open or short to ground when subjected to 125 Vdc. Either mode of failure would have caused the affected relay to drop out and retain its normally open contacts in the deenergized position. Two of the five relays in the ESF circuits were voltage-monitor types used in diesel-generator protection relay circuits. If these relay coils had failed in an open mode they would have initiated an alarm in the control room, and disabled the diesel generator protection circuits. This relay failure mode would not have affected the capability to start the emergency diesel generator automatically. However, a shorted relay would have blown the circuit fuse and prevented automatic startup of the diesel generator.

A third underrated voltage-monitor relay was used in one of the protection circuits associated with a 4 Kv bus which indirectly initiates startup of diesel generator "A." Open mode failure of this coil would not have affected the protection circuit. A shorted coil would have blown the circuit fuse and prevented diesel generator "A" from starting automatically. Either mode of failure would have resulted in a control room alarm.

The remaining two affected relays in the ESF circuits are designed to prevent automatic closure of diesel generator feed breakers to the 4Kv bus for one second following a main generator trip. During this short period of time, load shedding occurs followed by a sequential transfer of certain ESF systems to the emergency bus which is fed by the emergency diesel generator. Even with the underrated coils, the short duration of overvoltage applied to these coils is not likely to have caused relay failures in either open or short failure modes.

Regulatory Operations Bulletin 74-12 was issued to approximately 100 licensees. These licensees were requested to examine their Westinghouse type SG relays in class 1E equipment to determine whether or not any of these relays had underrated coils. Eighteen licensees replied that they had type SG relays installed in Class 1E equipment and in other equipment, but none found any evidence of relays containing underrated coils.

John J. Rizzo
Office of Operations Evaluation
U. S. Nuclear Regulatory Commission

UNITED STATES NUCLEAR REGULATORY COMMISSION	OPERATING EXPERIENCE INFORMATION ON INSPECTION AND ENFORCEMENT BULLETINS AND REPLIES

April 8, 1975

RELIEF VALVE DISCHARGE TO SUPPRESSION POOL

On November 14, 1974, the NRC issued Bulletin 74-14 to all BWR operators to alert them to a potential problem that could be caused by extended discharge from one or more steam relief valves into the suppression pool. This problem was highlighted to all BWR operators because of past difficulties experienced at two GE-designed BWRs located in Europe and similar recent blowdowns at two U. S. facilities.

The first incident occurred in Germany while a relief valve was being tested with the reactor at 60% power. When the valve was given a signal to close it did not respond, and attempts were made to close the valve for about 30 minutes while the reactor remained at power. During this period the suppression pool temperature continued to rise due to the discharge of steam from the open relief valve. When the suppression pool temperature exceeded 160° F, excessive vibrations occurred which increased until the suppression pool metal liner separated from the reinforcing beams that had been bolted to the inside of the liner. The relief valve discharge pipe at this facility is directed downward into the pressure suppression pool; this design is different from that used in BWRs operating in the United States.

The second incident occurred in Switzerland while relief valves were being tested with the reactor at 40% power. While one relief valve was being operated for five minutes, a second adjoining valve was opened by the operator. Within two minutes, suppression pool vibration was heard; approximately one minute later the test was terminated by closing both valves. The vibrations caused displacement of the catwalk sections and failure of an instrument line in the suppression pool.

The vibrations at both foreign reactors were associated with the condensation process of the steam discharge jet into the suppression pool water when the pool temperature is at or about 160° F. The high temperature condensation creates destructive impulses produced by the rapid collapse and formation of steam bubbles in the hot suppression pool water.

In the United States, there have been two events at BWRs involving stuck relief valves which raised suppression pool temperatures to at least 120° F. Neither resulted in vibration or damage to the pool because temperatures remained within a range of 120-145° F, which is about 15° F below what appears to be the critical temperature.

One of these incidents occurred at the Peach Bottom Atomic Power Station, Unit 2, while the reactor was operating at 100% power. A relief valve spuriously opened and remained open for 20 minutes, causing reactor depressurization. At that time the plant was shut down. Reactor temperature decreased 55° F during the first ten minutes following the shutdown and 102° F within two hours. Torus water temperature increased to approximately 120° F, as measured by one of two thermocouples in the torus. The torus water temperature was later reduced, using torus cooling water, to less than 100° F in about two and one-half hours. Inasmuch as there were only two thermocouples in the torus it is possible that local water temperatures in excess of 120° F existed but were not detected.

A similar problem was experienced at the Cooper Nuclear Station when the reactor was operating at approximately 43% power. While testing the main steam relief valves, one of the valves failed to close. After the suppression pool temperature limit of 120° F was exceeded, the reactor was immediately shut down. Following depressurization, the suppression pool temperature reached a maximum value of 145° F, but started to decrease following closure of the relief valve. If automatic depressurization had been required with the suppression pool temperature at 145° F, it might have resulted in destructive vibrations.

NRC requested BWR licensees to review operating procedures applicable to this problem to determine if those procedures should be modified in any of the following ways:

1. Limiting bulk suppression pool temperatures during normal operation and during controllable transients;

2. Requiring reactor trips if the bulk suppression pool temperature exceeded that established as a limit of controllable transients, or if one or more relief valves fails to reseat properly;

3. Taking prompt steps in case of inadvertent relief valve actuation or failure to reseat, to minimize the duration of steam discharge to the suppression pool; in case of relief valve discharge, promptly initiating suppression pool circulation to dissipate local peaking of water temperatures; and

4. Conducting visual internal and external inspection of the suppression pool structure for evidence of damage in instances where one or more relief valve(s) failed to reseat properly or discharged to the suppression pool for an extended period of time.

Licensees also were requested to assure that procedural changes made to minimize the effects of steam discharge to the suppression pool did not have any adverse effects in other areas.

All licensees who received Bulletin 74-14 were required to inform NRC within 20 days concerning the changes which they planned to make with respect to their operating procedures including the date when these changes would be completed.

In addition to Bulletin 74-14, licensees received information from GE about interim operating procedures and pool temperature limits to assist them with relating this problem to their own operation. Specifically GE recommended a limit of 110° F for the torus temperature, followed by a scram.

The licensees' replies to NRC considered the recommendations made by GE. However, based on review of the 32 responses from BWR licensees, there was considerable variation in the procedures to limit and control temperatures in suppression pools. Accordingly, NRC will be discussing with General Electric and licensees, proposals designed to assure that the final suppression pool temperature limits will not result in unacceptable structural effects as a result of steam quenching vibration which could occur in the event of a malfunction of steam relief valves.

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U. S. Nuclear Regulatory Commission

UNITED STATES NUCLEAR REGULATORY COMMISSION

OPERATING EXPERIENCE
INFORMATION ON INSPECTION AND ENFORCEMENT BULLETINS AND REPLIES

May 13, 1975

IMPROPER MACHINING OF PISTONS IN EMERGENCY DIESEL GENERATORS

Inspection and Enforcement Bulletin 74-16 issued on December 13, 1974, identified a deficiency involving the machining of pistons in diesels used to operate emergency generators at nuclear power plants. The most significant problem occurred at the Northeast Nuclear Energy Company's Millstone 2 facility and involved a Fairbanks Morse (a Division of Colt Industries) emergency diesel generator, type H7B. The deficiency was discovered while the licensee was performing a semiannual field inspection of these units. At that time it was found that the four capscrews which retained the piston insert against the piston had broken away from the piston and were located in the engine's upper crankcase. An investigation of the problem revealed that the cause of the failures was improper machining of the underside of the piston crown which left an elevated, ring-shaped surface inside the piston. This elevated surface prevented the piston and piston insert from mating properly. As a result, the piston crown tended to flex as it was forced down on the insert during the compression stroke. This produced alternating stresses in the capscrews, causing them to fail. Two other pistons in this engine were found with the same machining error. However, the capscrews associated with these pistons had not failed.

Another licensee, the Baltimore Gas and Electric Company, also reported finding deficiencies in their emergency diesel engines which serve Units No. 1 and No. 2 at the Calvert Cliffs facility. One diesel associated with the No. 2 Unit had two improperly machined piston crowns and four defective locking strips used to retain the capscrews. Another diesel serving Unit No. 1 had a defective locking strip.

Fairbanks Morse indicated that the most probable cause of the locking strip failures was improper torque sequencing of the capscrews during installation. Sketches of the piston, piston inserts, locking strips and capscrews are depicted in Figures 1 and 2.

Inspection & Enforcement Bulletin 74-16 was issued to all power reactor facilities with Operating Licenses and Construction Permits. These licensees were requested to:

a. Notify NRC if the diesel engine, type H7B was used at their facilities.

b. Specify schedules concerning the inspection of all type H7B engines.

c. Report results of the examinations and description of any required repairs.

A total of 105 licensees were contacted and of this total number, approximately 13 had Type H7B diesels. Only the two licensees mentioned above appeared to have found defective pistons and locking strips.

Colt Industries indicated that based on their engineering analysis any of the engines having the defects described above would manifest obvious engine problems within the first 100 hours of operation. However, to assure that all type H7B diesels were free of these deficiencies, Colt Industries initiated a program for examination and corrective action on those diesels that had a potential for this problem. As a result all problems involving the incorrectly machined pistons and defective locking strips have now been corrected.

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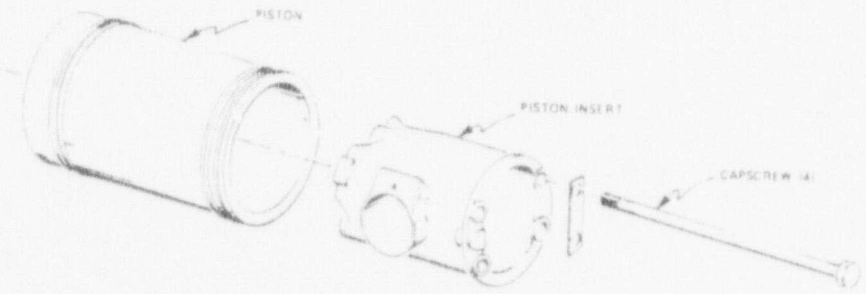

FIGURE 1

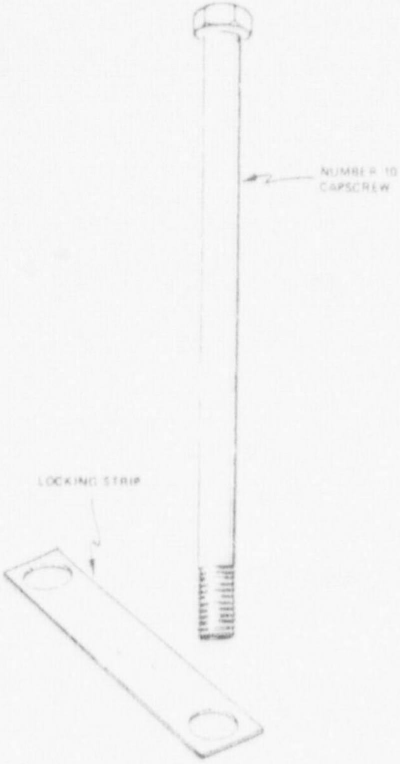

FIGURE 2

UNITED STATES NUCLEAR REGULATORY COMMISSION	OPERATING EXPERIENCE INFORMATION ON INSPECTION AND ENFORCEMENT BULLETINS AND REPLIES

June 17, 1975

MALFUNCTION OF AIR SOLENOID PILOT VALVES

Inspection and Enforcement Bulletin 74-03 issued on March 17, 1975, identified similar problems at the Point Beach Nuclear Plant Unit No. 1 and the Kewaunee Nuclear Power Plant Unit No. 1 involving air solenoid pilot valves which malfunctioned. At both facilities the defective pilot valves prevented closure of one of two isolation valves in the sample lines associated with steam generators. The health and safety of the public was not affected by these events because each of the sample flow lines had a backup (redundant) valve which closed upon receiving its appropriate isolation signal.

The air solenoid pilot valves at these plants were manufactured by the Automatic Switch Company (ASCO) and are designed to be three-way acting valves containing only four moving parts: a core, a lever and two poppet-type valve discs. An exploded view of the valves is depicted in Figure 1. The valves are designed to fail in an open position upon loss of electric power to the solenoids. The air solenoid pilot valves in question are the Series 8300-C and 8302-C units.

The defective valve from the Point Beach facility was inspected by the Automatic Switch Company and found to contain a lower disc spring capable of exerting a greater force than the valve specifications require. In addition the gap between the lower surface of the lever arm and the lower disc was less than the minimum specification limit of 0.008 inch. It was the opinion of the Automatic Switch Company that the gap descrepancy was the apparent cause of the malfunction of the valve.

The Point Beach licensee reported to NRC that there were 79 of these valves at the Point Beach Units No. 1 and No. 2. Based on a comprehensive testing program conducted by the licensee which involved testing each valve, it was found that at Unit No. 1, 26 air solenoid pilot valves had the wrong size lower springs with 21 of these also having gaps that were out of specifications. At Unit No. 2 there were 26 solenoid valves with incorrect lower springs, of which 24 had gaps other than allowed by specifications. All springs were found to exert a force approximately one pound greater than the specifications required. Point Beach personnel replaced all of the overrated lower disc springs with the correct size springs. In addition, all gaps were reset according to specifications by filing the lever arms.

It should be emphasized that although 66% of the air solenoid pilot valves had springs and gaps out of specifications, only one valve malfunctioned at the Point Beach facility. Nevertheless the licensee decided to change the lower springs in 52 valves to assure maximum reliability of these air solenoid pilot valves over a long period of time.

At the time this report was in preparation Kewaunee informed NRC that they had approximately 70 of the ASCO type valves identified above, in safety related systems. Four of the suspected solenoid valves were removed and sent to ASCO for analysis. Based on the results of this analysis, Kewaunee will modify or replace any or all of the 70 valves in their safety related equipment.

The gap adjustment is an example of an important parameter which contributes to optimum operation of valves. This gap is between the disc stem and lever (see Figure 1 and 2) and allows the top spring to perform two functions when the solenoid is de-energized. The first function is to separate the face of the core from the solenoid base. Only a small amount of travel is required for this function. The gap allows the top spring to move the core away from the solenoid base before the upper spring begins to compress the weaker lower spring. It appears that when these valves are energized over a long period of time the core and solenoid base become magnetically saturated.

Without a sufficient gap between the lower disc stem and lever, the top spring has marginal ability to break the force of the residual magnetism and subsequently compress the lower spring, see Figure 1. It was the opinion of the Point Beach staff that most of the valves operated even with gaps out of specifications because the residual magnetism was low enough so it could be overcome by the force of the top spring.

Inspection and Enforcement Bulletin 74-03 was issued to approximately 110 operating reactor licensees and facilities under construction. All were requested to initiate the following corrective action:

1. Determine whether Series 8300-C and 8302-C ASCO valves were used or planned for use.

2. Notify in writing (30 days for operating reactors and 60 days for facilities under construction) the Regional Offices of these findings.

3. If solenoid valves of the type described in 1 were used or planned for use in safety related systems, a description of corrective actions was requested which would demonstrate how the occurrence described above could be prevented. In addition, the approximate date when this corrective action would be completed was also requested.

A review by NRC, of all replies received from licensees and permit holders indicated that 45% had ASCO valves of the model and type described above. The remaining 55% had either direct current ASCO valves which were not affected by this problem or valves manufactured by other vendors.

Those licensees and permit holders having the valves in question indicated that they would check the gaps and lower springs and perform any necessary modifications. It is expected that all licensees and permit holders will complete their checks and modifications by the fall of 1976. Information concerning appropriate measures to be taken by those affected, to assure continued high reliability of these valves was obtained from the Automatic Switch Company. ASCO offered appropriate instructions related to this problem and also suggested that valves 8300-C and 8302-C containing resilient seats (O-rings in the valve seats) be serviced every three years or converted to metal to metal type seating if the valves were in safety related systems.

It should be noted that the type of failures described above involving ASCO valves, series 8300-C and 8302-C, were reported at only two facilities, Point Beach and Kewaunee. No other operating reactor or facility under construction appeared to experience similar malfunctions with these ASCO valves.

Point of Contact:

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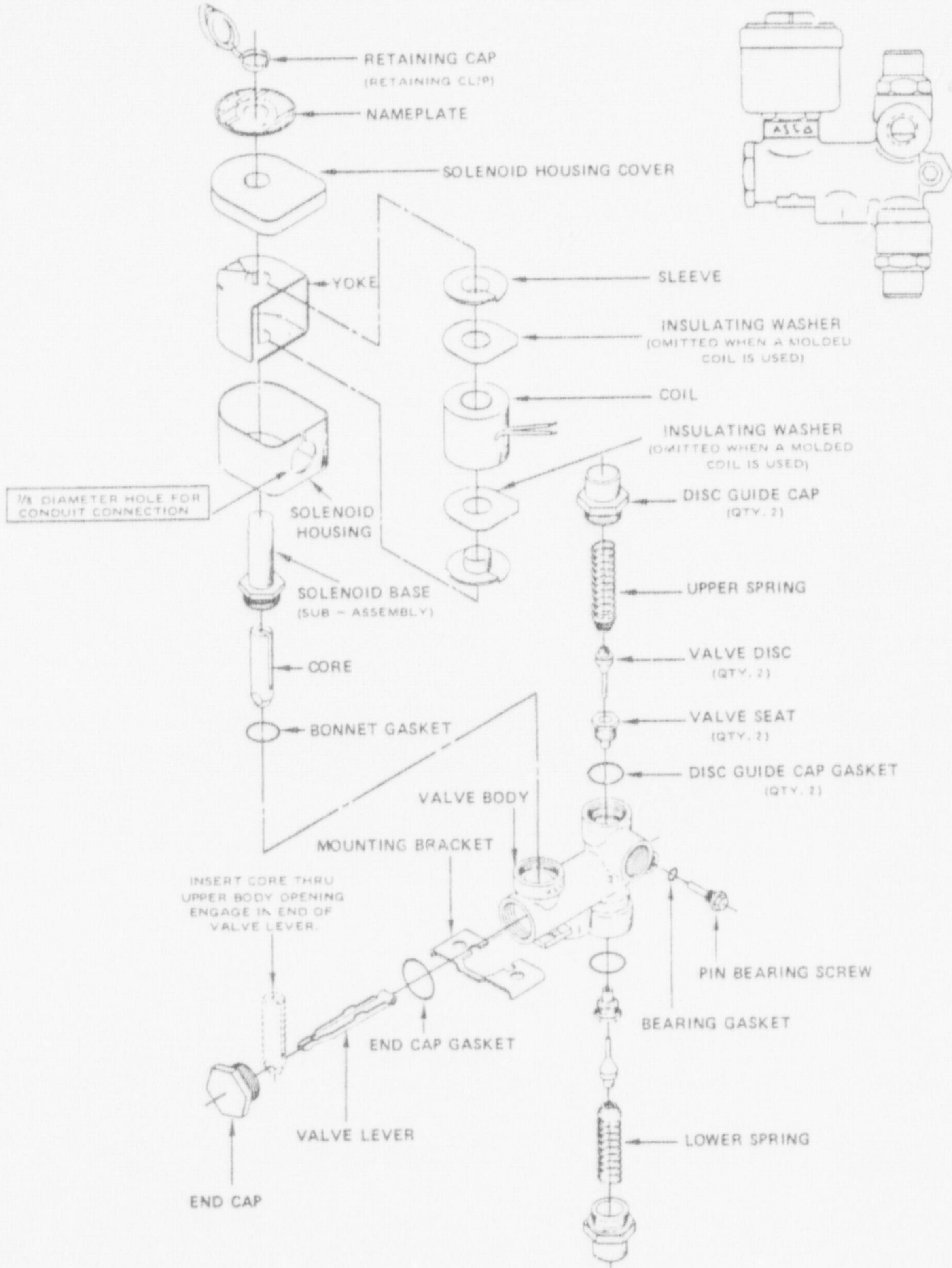
RETAINING CAP
(RETAINING CLIP)
NAMEPLATE
SOLENOID HOUSING COVER
YOKE
SLEEVE
INSULATING WASHER
(OMITTED WHEN A MOLDED COIL IS USED)
COIL
INSULATING WASHER
(OMITTED WHEN A MOLDED COIL IS USED)
7/8 DIAMETER HOLE FOR CONDUIT CONNECTION
SOLENOID HOUSING
DISC GUIDE CAP
(QTY. 2)
UPPER SPRING
SOLENOID BASE
(SUB – ASSEMBLY)
CORE
VALVE DISC
(QTY. 2)
VALVE SEAT
(QTY. 2)
BONNET GASKET
DISC GUIDE CAP GASKET
(QTY. 2)
VALVE BODY
MOUNTING BRACKET
INSERT CORE THRU UPPER BODY OPENING ENGAGE IN END OF VALVE LEVER.
PIN BEARING SCREW
BEARING GASKET
END CAP GASKET
VALVE LEVER
LOWER SPRING
END CAP

FIGURE 1

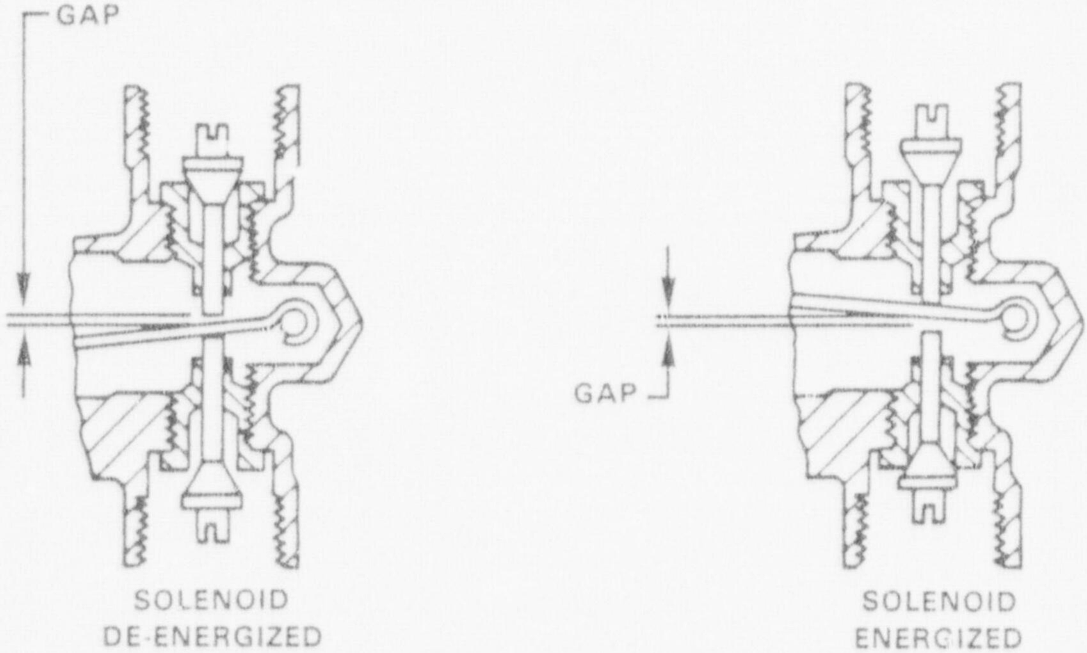

FIGURE 2

UNITED STATES NUCLEAR REGULATORY COMMISSION

OPERATING EXPERIENCE
BULLETIN INFORMATION REPORT

DEFECTIVE CONTROL SWITCHES

On May 30, 1975, the U.S. Nuclear Regulatory Commission (NRC) issued Bulletin No. 75-06 which discussed a problem involving defective Westinghouse Type OT-2 electrical switches located on the main control board of the TVA Sequoyah Nuclear Power Plant. The problem was originally called to NRC's attention by the Westinghouse Electric Corporation. The Type OT-2 switch is a spring-return-to-neutral design, and is manually operated by rotating the handle clockwise or counterclockwise. An internal spring force returns the switch to its central neutral position. At the Sequoyah plant, some of the switches were binding and not returning to their neutral positions because of internal friction caused by switch components that were out of tolerance.

The section of the main control board which contained the defective switches was fabricated and assembled by Westinghouse Nuclear Instrumentation and Control Division in Baltimore; the Type OT-2 switches were manufactured by Westinghouse Control Products Division in Beaver, Pennsylvania. To assure that the appropriate licensees were aware of the problem, Westinghouse sent a letter to utilities with operating pressurized water reactors and to site managers at plants under construction advising them on methods of testing the switches, and also recommending the testing of circuits connected to the switches.

Subsequent to the Westinghouse letter, NRC issued Bulletin 75-06 to 83 owners of nuclear power plants requesting NRC be informed whether similar switches were installed or planned for use at their facilities. If they had these switches, they were requested to describe whatever corrective actions they had planned, to prevent the occurrence of a similar malfunction as described above.

Forty-nine of the eighty-three utilities reported that they did not have Type OT-2 switches. Thirty-four utilities reported that they had located approximately 1700 Type OT-2 switches at their facilities. Thirty-one utilities were able to test their switches in accordance with instructions provided by Westinghouse. This resulted in the detection of approximately twenty-one defective switches. The remaining three utilities postponed their tests until a later date. Two of these utilities own facilities that are in the preoperational testing phase. They plan to conduct their tests before fuel loading. The third utility is conducting all required tests of Type OT-2 switches and plans to issue a final report to the Commission in a few weeks. Facility representatives from all three nuclear stations have stated that any defective switches found will be replaced.

Most of the switches are used to control valves in the following areas; refueling water chemical systems, recirculation spray systems, component cooling water systems, bearing cooling water systems, condensers, low head safety injection systems, boron injection systems, residual heat removal systems, steam generators, accumulators, reactor containment systems, control room emergency supply systems, core deluge systems, loop safety injection systems and pressurizer relief tanks. Type OT-2 switches are also found in refueling handling equipment control system.

A review of this problem by Westinghouse revealed that it was caused by excessive tolerance stack-up of certain internal switch components. These components were manufactured approxir tely five years ago in limited production runs. The molds producing these components have been replaced with molds having tighter tolerance specifications thus correcting the original manufacturing defects. It should be noted that a number of licensees reported having Type OT-2 switches at their facilities which have been operating for approximately eight years without any problems verifying that the switch malfunctions discussed above were probably not caused by degradation of switch components but by manufacturing defects.

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U. S. Nuclear Regulatory Commission

UNITED STATES NUCLEAR REGULATORY COMMISSION	**OPERATING EXPERIENCE** BULLETIN INFORMATION REPORT

PIPE CRACKS IN 4-INCH AND 10-INCH LINES AT BWR FACILITIES
(As of March, 1976)

April 12, 1976

INTRODUCTION

In September 1974, cracks were discovered in 4-inch diameter bypass lines at Dresden Unit 2, Quad-Cities Unit 2 and Millstone Unit 1. A short time later, additional cracks were discovered in the bypass lines at Dresden Unit 2, Quad-Cities Unit 2 and, eventually, at other boiling water reactors (BWR's). On January 28, 1975, the Nuclear Regulatory Commission (NRC) was informed by the Commonwealth Edison Company of Chicago that throughwall cracks were found in two 10-inch core spray injection lines. All the cracks were found in Type 304, austenitic stainless steel pipe. A discussion of these pipe crack occurrences (with appropriate diagrams) and their safety implications, are presented.

Discussion

Cracks were experienced in 4-inch bypass lines and 10-inch core spray pipes. The bypass lines are designed to provide a means of preheating a 28-inch idle recirculation loop before it is placed back in operation. (See Figure 1.) The flow from this 4-inch line reduces thermal shock on the components in the idle loop. In addition, these bypass lines are used to equalize pressure on both sides of the discharge valve to assure proper seating and closure of this valve.

The core spray lines are used to supply emergency core cooling water to the reactor vessel should a loss-of-coolant accident occur. Figure 2 depicts how one core spray pipe system is connected to the reactor vessel. Most BWR's have redundant core spray systems. All BWR's have other core cooling systems so that failure of one core spray system does not impair core cooling capability.

The first problem involving two bypass lines was discovered at the Dresden Unit 2 facility when water leaks were detected by the plant leak rate surveillance system. Subsequent ultrasonic testing of 10 welds showed some throughwall cracks. These cracks were located in the heat-affected zone of the welds which joined the bypass lines to pipe fittings connected to the 28-inch diameter recirculation pipes. (See Figure 3.) In the diagram, "A" and "B" before the "cracking incident numbers" refer to loops A and B, respectively.

On September 16, Commonwealth Edison ultrasonically examined 22 welds in the bypass lines of the Quad-Cities Unit 2 facility. One crack was discovered which had partially penetrated through the bypass line from the inner surface. The crack was located in the heat-affected zone of a weld joining the bypass line to the 28-inch main recirculation pipe. (See Figure 4.)

Based on these findings and recommendations by the General Electric Company, the Northeast Energy Company examined both bypass lines in their Millstone Point Nuclear Unit 1 facility. Inspection of the 11 circumferential welds in these bypass lines revealed water seeping from a crack on one of the welds (again in the heat-affected zone area) which joined one of the bypass lines to the motor-operated bypass valve. Two other cracks, which were not leaking, were found by ultrasonic examination. (See Figure 5.)

The existence of some cracks at these three BWR facilities prompted the issuance of Bulletin 74-10 on September 18, 1974 to all BWR's that were licensed at that time. This included 15 BWR's with piping configurations similar to Dresden 2, and six other facilities with different piping designs. The 21 facilities receiving this Bulletin are listed in Table 1. The Bulletin requested each licensee to examine, by ultrasonic or other suitable volumetric nondestructive examination technique, all accessible welds in the 4-inch bypass piping, for evidence of cracks. It was further requested that this information be sent to the (former) AEC within a certain specified time. Based on replies received from all 21 licensees, no additional cracks were found.

During a refueling outage at a later period, Commonwealth Edison discovered another leak in the Dresden 2 piping. The leak originated from cracks in the connection between the bypass line and the recirculation loop. This was confirmed by ultrasonic tests which verified that the cracks started inside the pipe and penetrated through the outside wall of the pipe, (See Figure 3). The new series of cracks at Dresden 2 prompted the AEC to issue Bulletin 74-10A on December 17 to seventeen BWR facilities with jet pumps requesting the seventeen licensees to perform the following tasks and then inform the AEC of the results:

1. Reevaluate the results of ultrasonic and other examinations conducted previously, or as part of the baseline inservice inspection for those facilities not examined under the requests specified in the earlier bulletin.

2. Reexamine (by ultrasonic or other suitable volumetric inspection technique) all accessible welds in the bypass piping lines around the recirculation pump discharge valves.

On December 23, Commonwealth Edison informed the AEC that additional cracks had been found in the bypass piping of the Quad-Cities 2 facility. The location of these latest cracks at Dresden 2 and Quad-Cities 2 were in areas examined earlier in September as a result of Bulletin 74-10. (See Figure 4). At that time there were no reportable indications noted, based on applicable codes.

Replies to Bulletin 74-10A indicated that cracks also existed in bypass lines for the Quad-Cities Unit 1 facility (See Figure 6), the Philadelphia

Electric Company's Peach Bottom Unit 3 facility, and the Northern States Power Company's Monticello facility. The cracks in the last three units did not penetrate through the bypass piping wall and, therefore, caused no water leakage.

In summary, eight cracks were found in bypass lines of six boiling water reactor plants from September 1974 through January 1975; 15 of 21 plants did not experience any pipe cracking. The corrective measures taken included the replacing of entire or partial sections of bypass lines. The detection of those cracks prompted the NRC to issue Bulletin, 74-10B, on January 24, 1975, which directed licensees to continue close surveillance of their reactor coolant systems and specifically, their bypass lines.

There have been three recent crack occurrences involving 4-inch bypass lines, since the last Bulletin was issued. These cracks were reported for the Georgia Power Company's Hatch Unit 1 (12-26-75), the Quad-Cities Unit 1 (1-22-76), and Boston Edison Company's Pilgrim Unit 1 (3-15-76). All of these were similar to the cracks found previously in the piping of other boiling water reactors.

On January 28, 1975, during an inservice inspection of the Dresden Unit 2 piping system, Commonwealth Edison discovered leaks on the outside surface of each of the core spray pipes. Ultrasonic examination revealed two hairline longitudinal cracks and a pinhole leak in one pipe. The longitudinal cracks were approximately 1/8 inch long. The approximate locations of these cracks are depicted in Figures 7 and 8. In an effort to understand the problem further and assess the extent of the pipe cracking problem, NRC issued Bulletin 75-01 on January 30, 1975 and supplemental Bulletin 75-01A on February 7, 1975. These Bulletins were sent to 23 BWR facility licensees and requested that inservice inspections be conducted of specific systems within 20 days of the date of issuance. Specifically, these Bulletins requested that certain circumferential welds in the core spray loop be examined, and that a system functional test or hydrostatic test be conducted on the core spray system piping beyond the second isolation valve. In addition, licensees were requested to examine representative samples of the pressure retaining welds in austenitic piping that was part of the reactor coolant pressure boundary, and some circumferential welds in piping greater than 2 inches in diameter for certain systems.

The inspection was conducted at all the facilities noted in Table 1, as well as Fitzpatrick and Brunswick 2.

During January 1975, the AEC formed the Pipe Cracking Study Group (PCSG). This group reviewed and evaluated the pipe occurrences discussed above from the point of view of metallurgy, coolant water chemistry, mode of plant operation, and pipe configurations and supports. The PCSG was particularly interested in the safety aspects of pipe cracks, that is, whether cracks could lead to major pipe failures and a loss-of-coolant accident.

In reviewing the general history of cracks in pipes made of various materials it was found that rapidly propagating brittle cracking has not occurred in austenitic Type 304 stainless steel piping. In fact, no previous crack in austenitic piping in a nuclear system has ever resulted in any serious consequence. Small leaks in pipes usually can be identified by leak detection instrumentation or visual inspection. This is important since a major break in austenitic stainless steel piping is highly unlikely without some prior leakage. A corollary conclusion is that, for austenitic Type 304 stainless steel piping, growth of cracks proceeds slowly, and water leakage should be detected before any major pipe failure occurs.

The NRC reviewed the safety consequences resulting from the unlikely event of a break of one bypass line, a core spray line or even the more severe accident resulting in the simultaneous rupture of two core spray lines. Even in the latter incident, the core would be flooded by the low pressure system through the recirculation lines thus assuring that the fuel rods would remain intact. This would prevent the release of any significant amount of radioactivity to the environment.

Based on an extensive study of the data associated with the pipe cracks experienced with 4-inch bypass lines and core spray lines at BWR's, the Pipe Cracking Study Group and its consultants made a number of important observations which are presented, in part, below:

1. AISI Types 304 and 316 austenitic stainless steels experience intergranular stress corrosion cracking when exposed to oxygenated water in regions where stresses equal or exceed the yield strength of the material, coincident with sensitization of the material adjacent to welds.

2. Flaws or cracks in stainless steel pipes grow relatively slowly because of the ductile nature of the material, and sudden severence of the pipes is not expected to occur. Leaking should develop in the cracked area well before the ductile pipe loses its structural integrity. When leakage develops, it can be detected by the leakage monitoring system located inside containment, at which time the plant is shut down for repair of the affected pipe.

3. Cracking occurred near the weld joints where residual stresses are estimated to be at or above the yield strength of the material.

4. Time required for initiation and propagation of intergranular stress corrosion cracks is dependent on the level of dissolved oxygen in the water, degree of sensitization of the steel, and the level of stress.

5. The oxygen level in the coolant, at rated normal operating conditions is estimated by the Nuclear Steam Supply System manufacturer to be approximately 0.2 ppm. This level of oxygen is sufficiently high for stress corrosion to occur when combined with sensitization due to welding and yield strength level stresses.

6. In stagnant lines, where there is no water flowing during operation of the plant, dissolved oxygen in the water may remain at a high level. The pipe material may be exposed to high levels of oxygen and, if so, the time required for stress corrosion cracking to occur will be shorter.

7. The larger diameter pipes within the reactor coolant pressure boundary have relatively thicker walls than the 4-inch and 10-inch pipes that have experienced cracking. The thicker wall pipes provide a more effective heat sink during welding operation, therefore the sensitization of the base metal adjacent to the weld should occur to a much lesser degree and the levels of residual stress may be lower than in smaller diameter pipes. On this basis the larger pipes should be less susceptible to intergranular stress corrosion cracking then the pipes that have experienced cracking.

The PCSG completed its study in October 1975 with a number of recommendations that will assist in the identification of stress corrosion cracking in austenitic stainless steel piping of BWR operating plants. They also presented long-term recommendations that if followed should eventually reduce the probability of pipe cracking to a low level in operating plants and future plants. These recommendations have been reviewed by the NRC and the Advisory Committee on Reactor Safeguards. A final decision regarding their implementation will be made by NRC in the near future.

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REFERENCES

1. AEC Regulatory Operations Bulletin No. 74-10 dated September 18, 1974.

2. AEC Regulatory Operations Bullentin No. 74-10A dated December 17, 1974.

3. NRC Inspection and Enforcement Bulletin No. 74-10B dated January 24, 1975.

4. NRC Inspection and Enforcement Bulletin No. 75-01 dated January 30, 1975.

5. NRC Inspection and Enforcement Bulletin No. 75-01A dated February 7, 1975.

6. Technical Report: Investigation and Evaluation of Cracking in Austenitic Stainless Steel Piping of Boiling Water Reactor Plants, NUREG 75/067.

7. General Electric report entitled, Investigation of Cause of Cracking in Austenitic Stainless Steel Piping, NEDO-2100-1.

8. Nuclear Regulatory Commission Action Requiring Safety Inspections Which Resulted in Shutdowns of Certain Nuclear Power Plants, (Joint Hearing before Joint Committee on Atomic Energy), February 5, 1975.

TABLE 1

FACILITIES THAT WERE REQUIRED TO TAKE

ACTION IN ACCORDANCE WITH

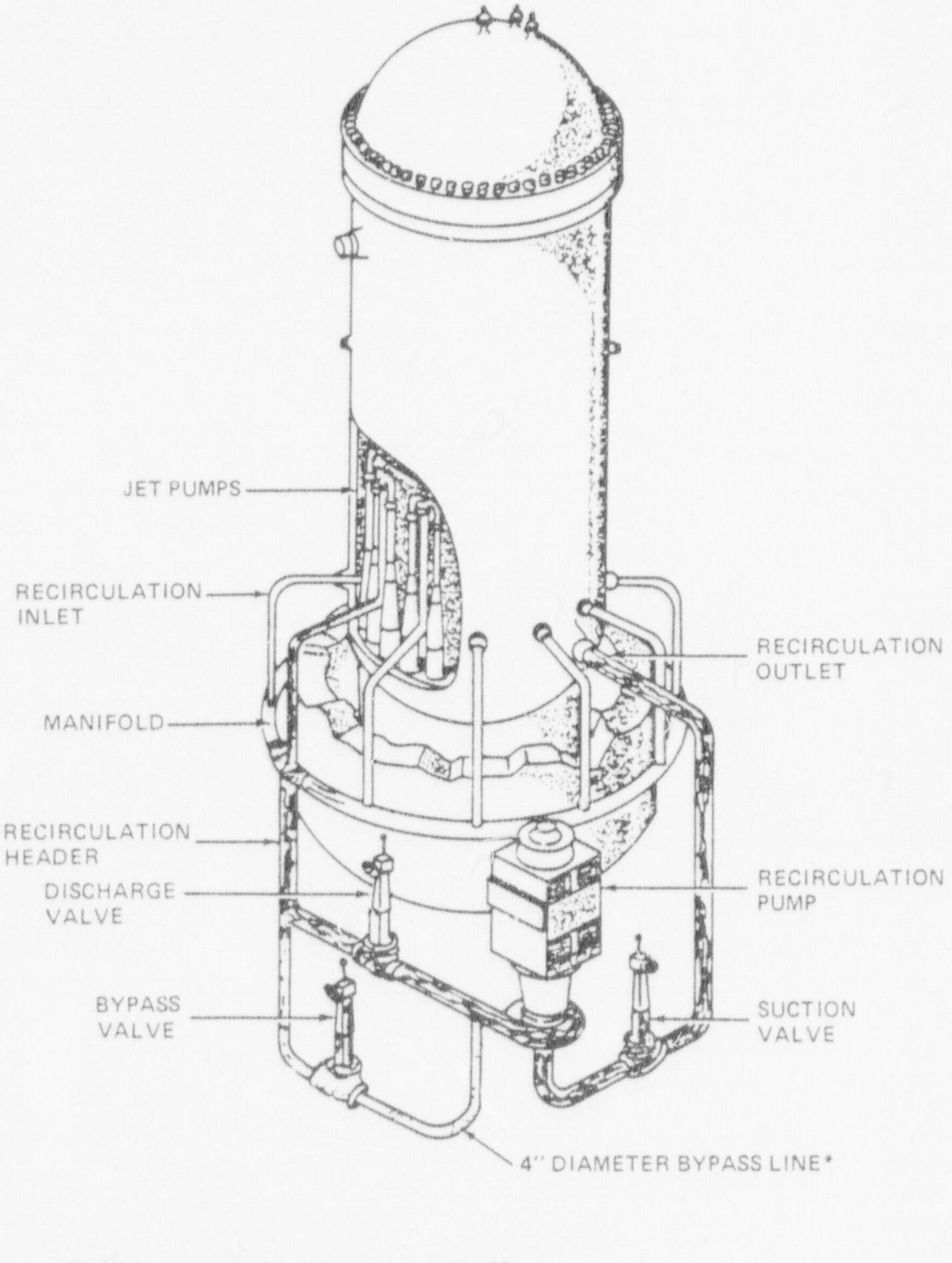
BULLETIN 74-10

Jet Pump Plants

Browns Ferry-1	Cooper Station	Dresden-3	Hatch-1	Monticello	Peach Bottom-3
Browns Ferry-2	Dresden-2	Duane Arnold	Millstone-1	Peach Bottom-2	Pilgrim-1
		Quad-Cities-1			
		Quad-Cities-2			
		Vermont Yankee			

Non Jet Pump Plants Without Bypass Lines

Big Rock Point	Humboldt Bay	Nine Mile Point
Dresden-1	LaCrosse	Oyster Creek



*THERE IS ANOTHER IDENTICAL BYPASS LINE BUT IT IS NOT SHOWN IN THIS FIGURE

Figure 1

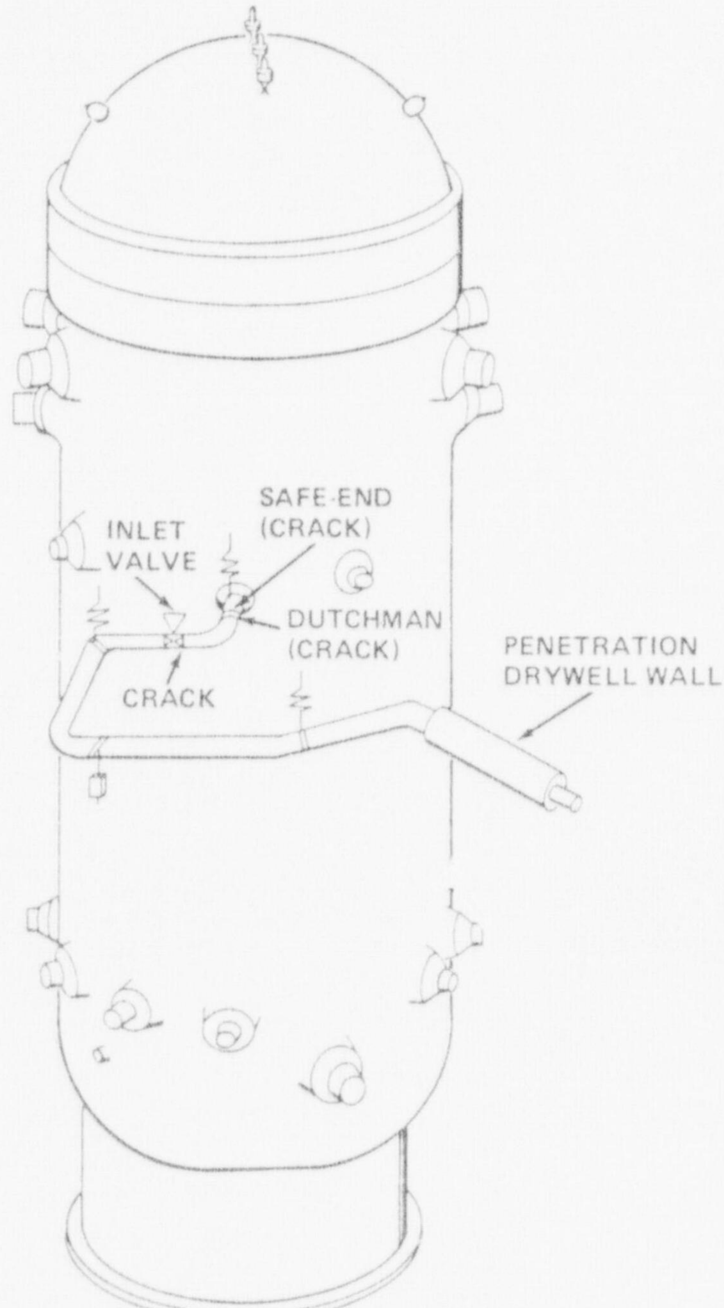
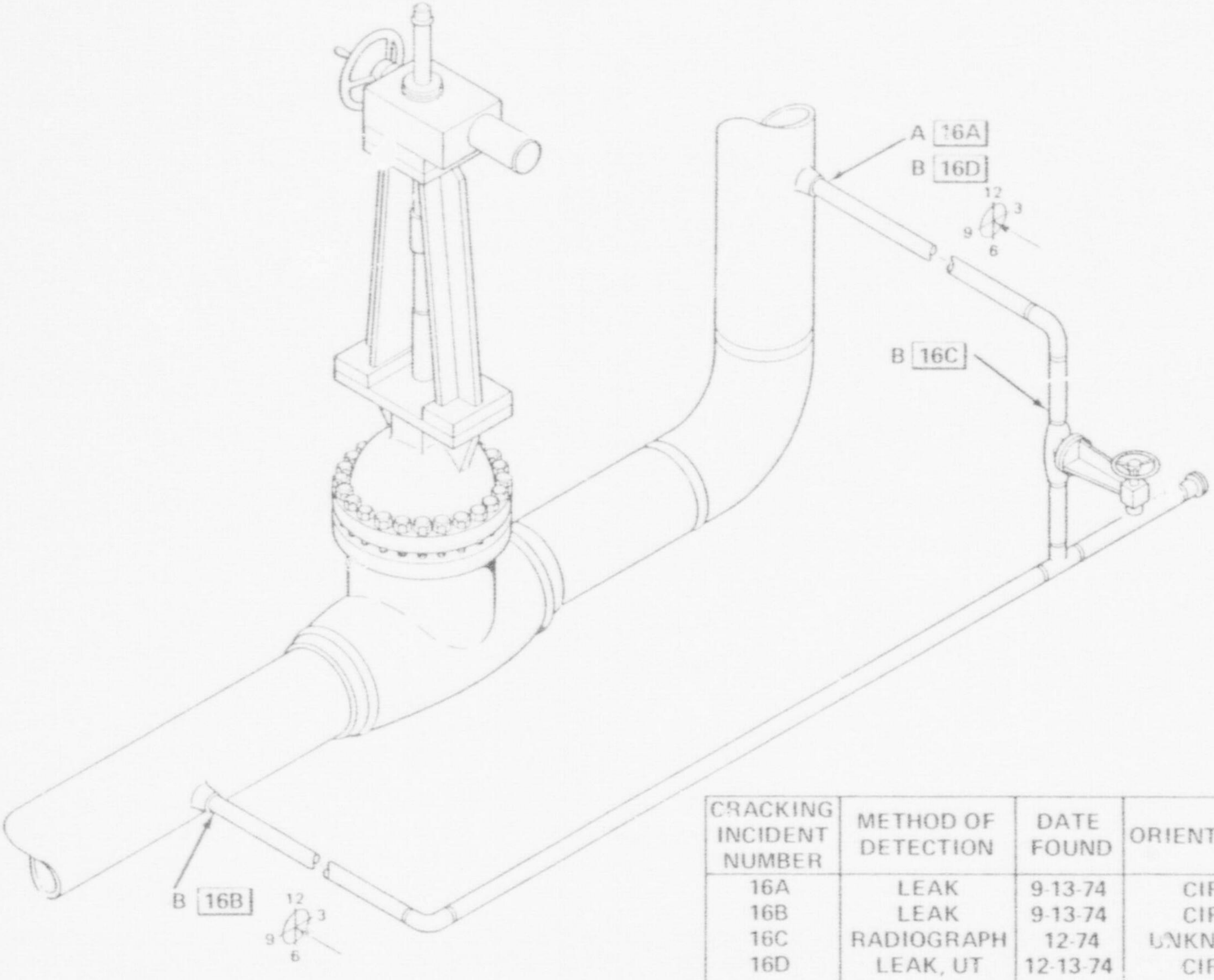
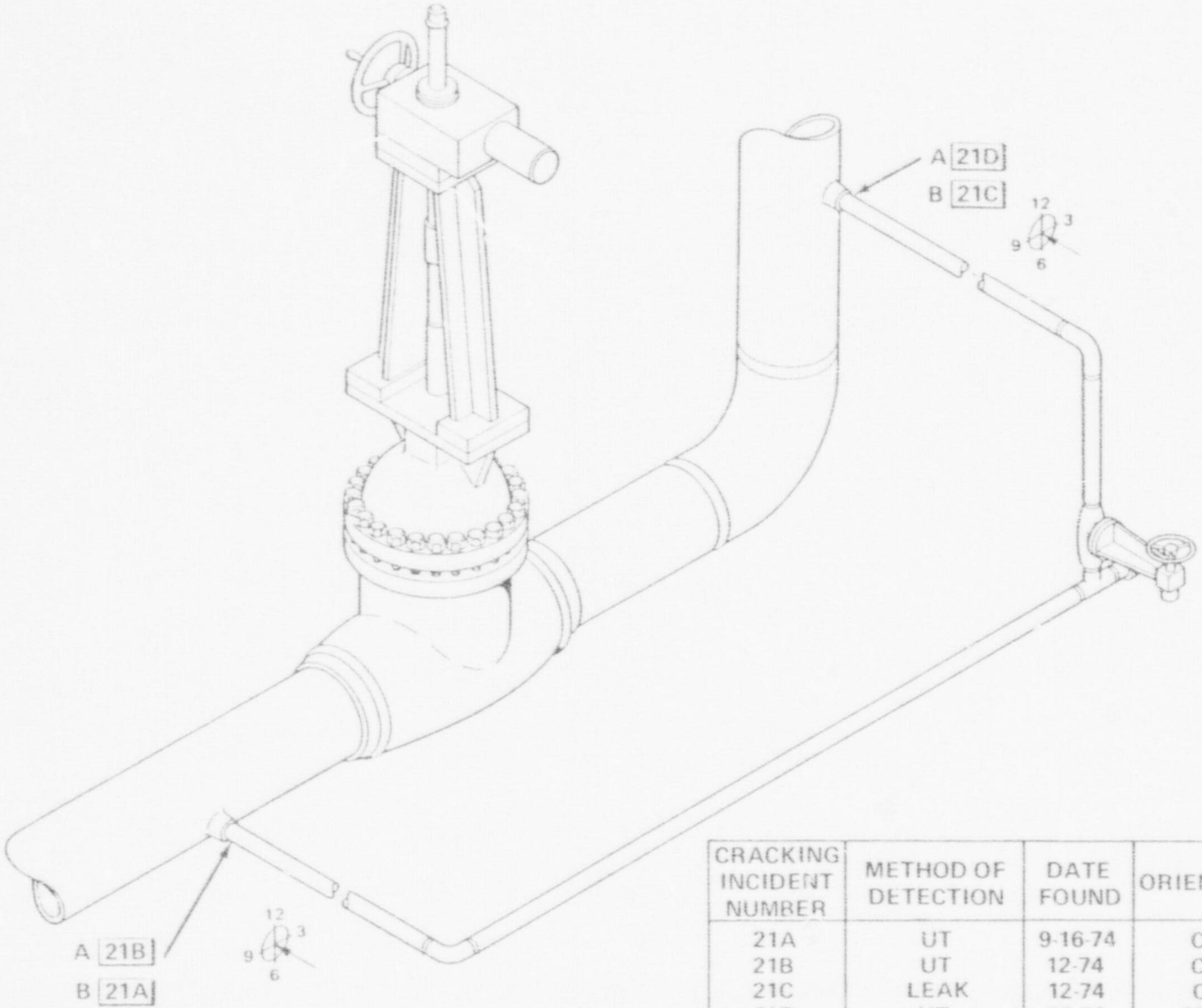


Figure 2. Dresden 2 Core Spray South



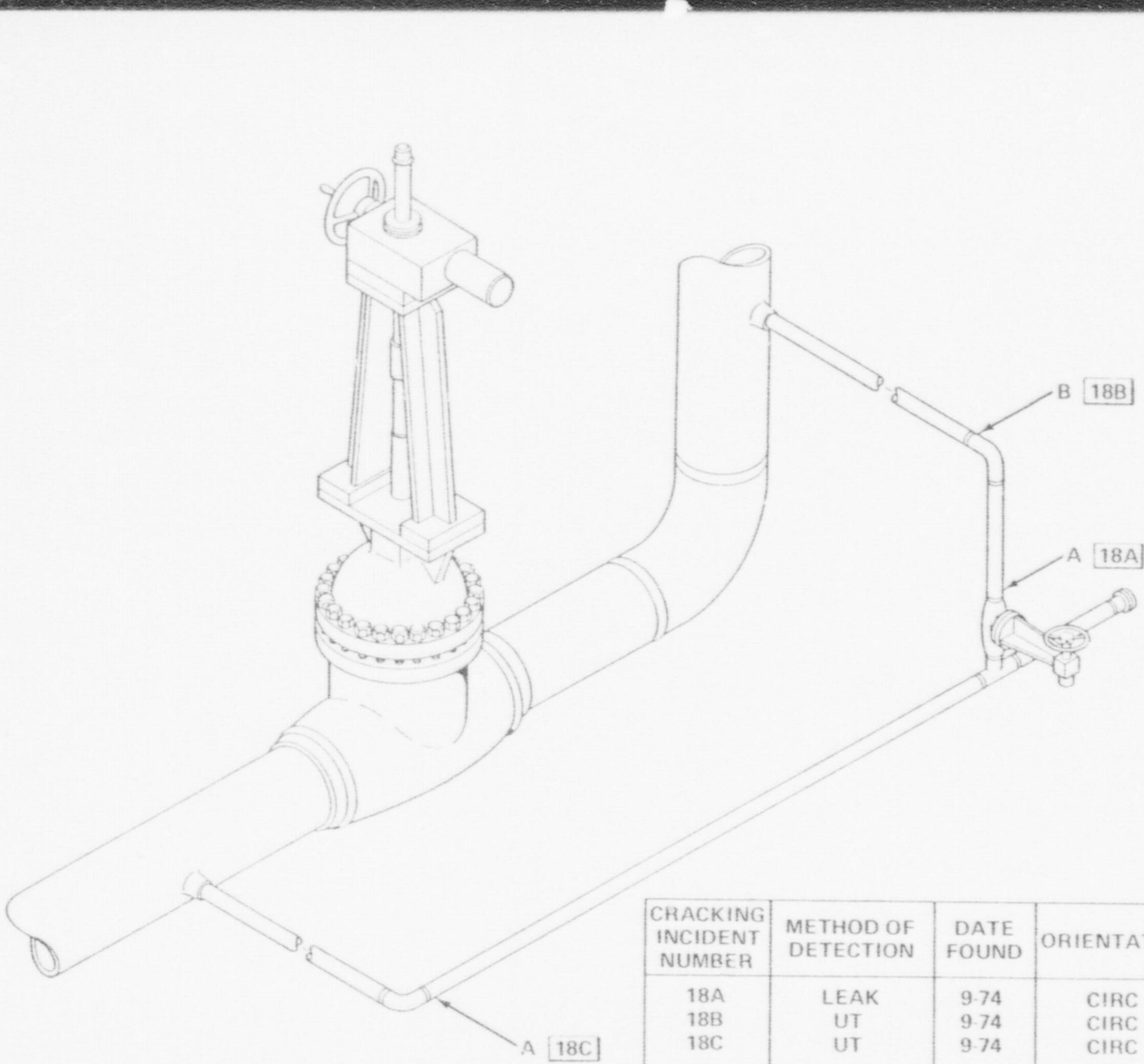
CRACKING INCIDENT NUMBER	METHOD OF DETECTION	DATE FOUND	ORIENTATION	AZIMUTHAL LOCATION
16A	LEAK	9-13-74	CIRC	3:00
16B	LEAK	9-13-74	CIRC	12:00
16C	RADIOGRAPH	12-74	UNKNOWN	UNKNOWN
16D	LEAK, UT	12-13-74	CIRC	3:00–5:00 6:00–10:00

Figure 3. Crack Locations – Dresden 2 Recirculation Bypass Lines – Loops A and B



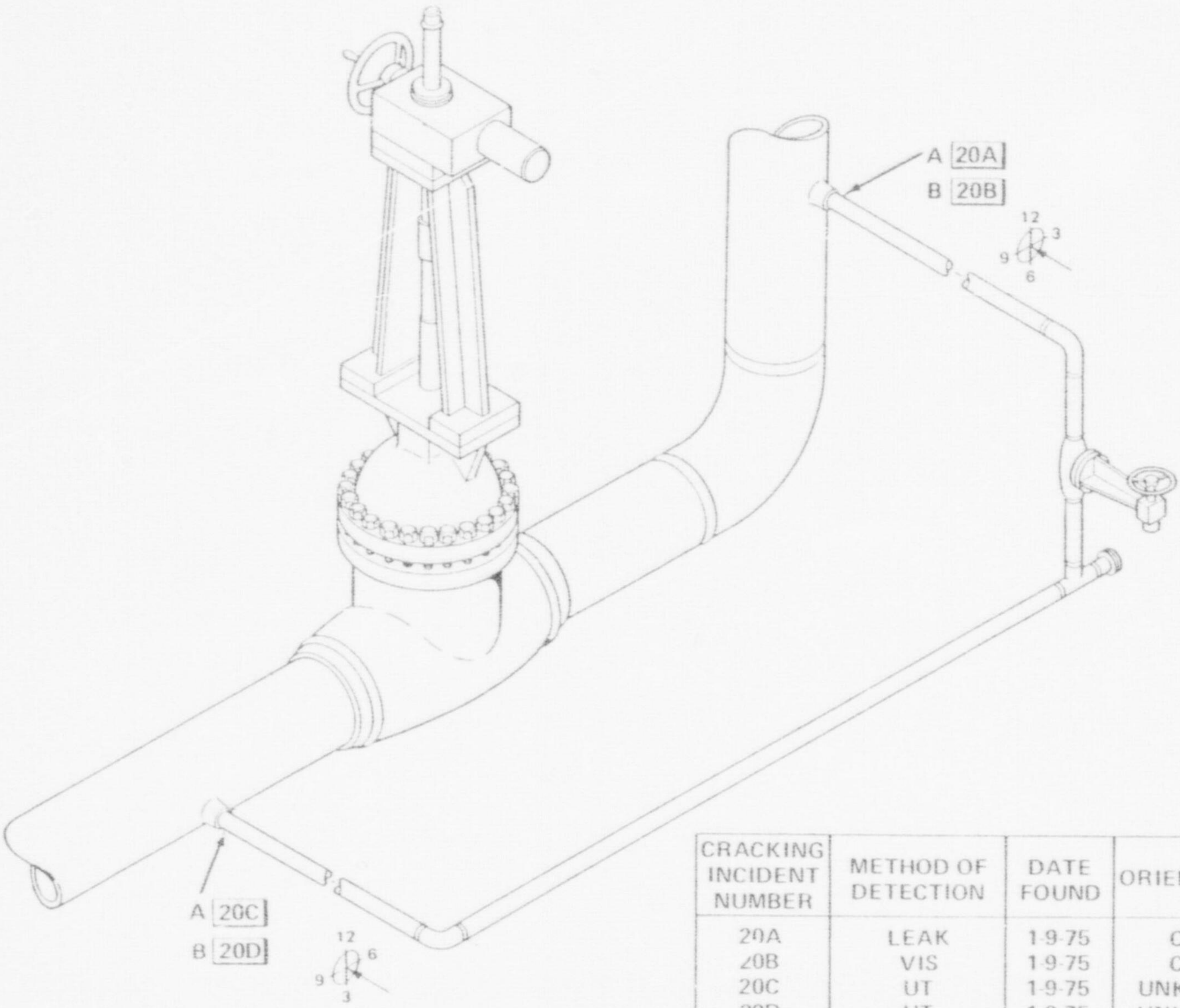
CRACKING INCIDENT NUMBER	METHOD OF DETECTION	DATE FOUND	ORIENTATION	AZIMUTHAL LOCATION
21A	UT	9-16-74	CIRC	3:00
21B	UT	12-74	CIRC	UNKNOWN
21C	LEAK	12-74	CIRC	10:30
21D	UT	12-74	MIXED	1:30

Figure 4. Crack Locations – Quad Cities 2 Recirculation Bypass Lines – Loops A and B



CRACKING INCIDENT NUMBER	METHOD OF DETECTION	DATE FOUND	ORIENTATION	AZIMUTHAL LOCATION
18A	LEAK	9-74	CIRC	UNKNOWN
18B	UT	9-74	CIRC	UNKNOWN
18C	UT	9-74	CIRC	UNKNOWN

Figure 5. Crack Locations – Millstone Pt 1 Recirculation Bypass Lines – Loops A and B



CRACKING INCIDENT NUMBER	METHOD OF DETECTION	DATE FOUND	ORIENTATION	AZIMUTHAL LOCATION
20A	LEAK	1-9-75	CIRC	1:00
20B	VIS	1-9-75	CIRC	1:00–2:30
20C	UT	1-9-75	UNKNOWN	UNKNOWN
20D	UT	1-9-75	UNKNOWN	UNKNOWN

Figure 6. Crack Locations – Quad Cities 1 Recirculation Bypass Lines – Loops A and B

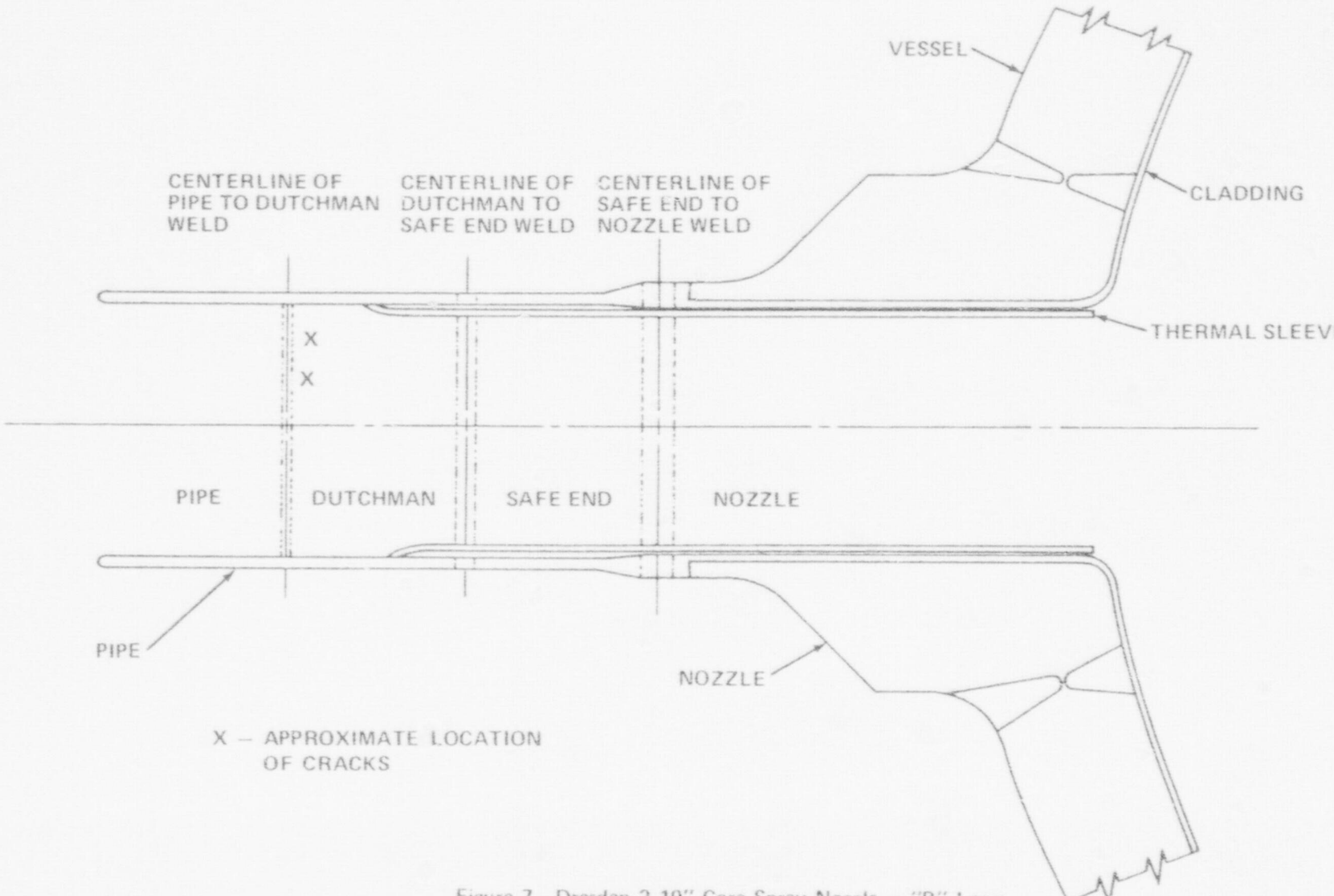


Figure 7. Dresden 2 10" Core Spray Nozzle – "B" Loop

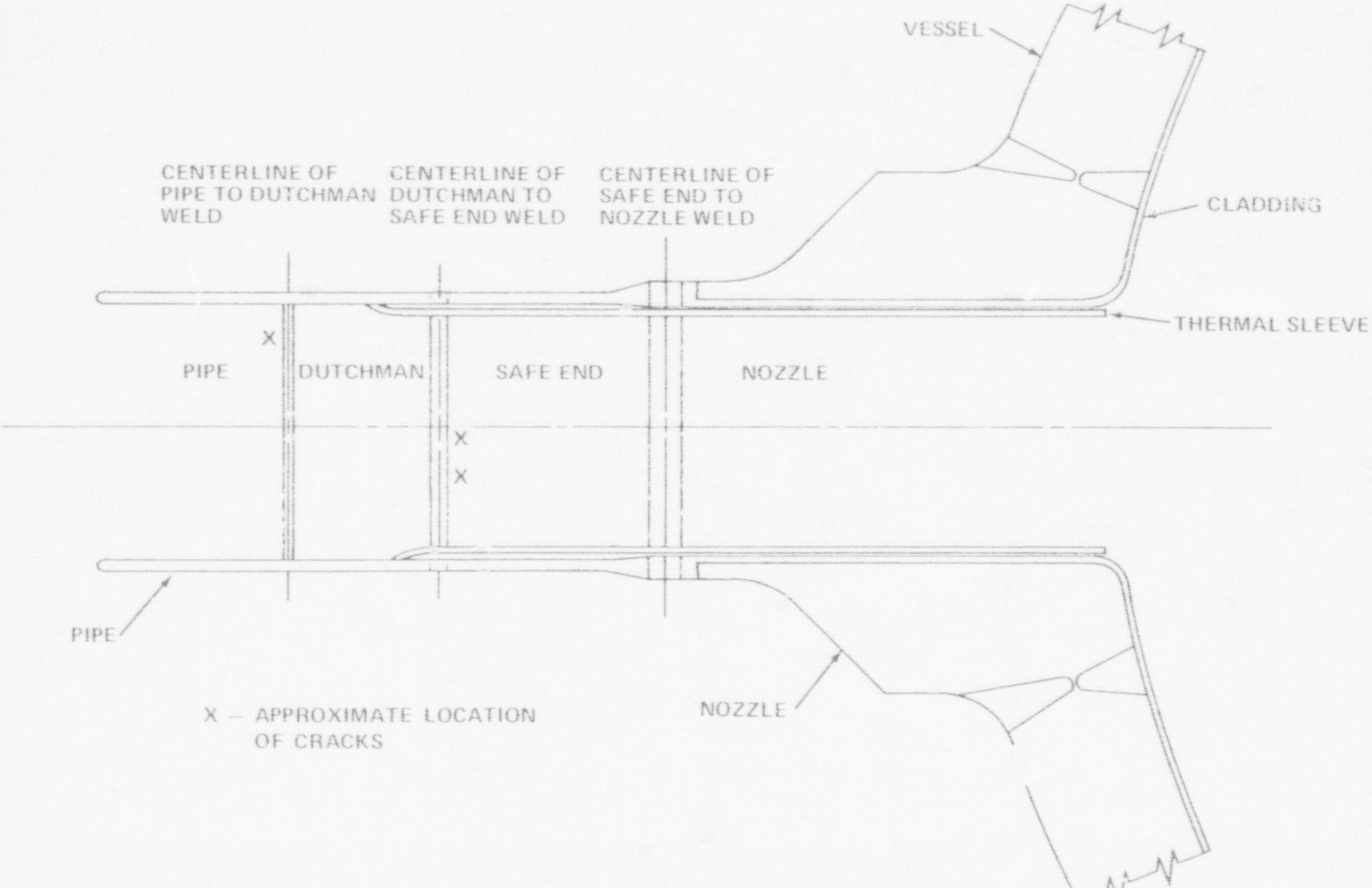


Figure 8. Dresden 2 10" Core Spray Nozzle – "A" Loop

UNITED STATES NUCLEAR REGULATORY COMMISSION

OPERATING EXPERIENCE
BULLETIN INFORMATION REPORT

May 7, 1976

RADIOACTIVE WASTE PACKAGE HEPA FILTER INCIDENT

Inspection and Enforcement Bulletin 75-07 issued on November 26, 1975, identified an event involving a HEPA filter that occurred at the Nuclear Engineering Company's burial grounds at Beatty, Nevada.

On June 26, 1975, upon opening a Super Tiger* shipping container the crew noticed a small quantity of smoke inside the unit. This particular waste shipment contained an inventory of thirty - fifty-five gallon drums in addition to 14 HEPA filters. The latter were individually packed in DOT Specification 12B fiberboard cartons. While the Super Tiger container was being unloaded the workmen discovered that one of the fiberboard cartons was hot to the touch even through workgloves. The surface of the carton appeared scorched. In addition, the nylon sealing tape had melted, fusing the scorched carton to an adjacent carton. Radiation smears revealed only minimal contamination on the affected carton but no contamination on any other carton in the Super Tiger container. The fiberboard carton was immediately buried without opening it after an identification tag was removed to permit the contents in the carton to be identified by the responsible licensee, the Kerr-McGee Nuclear corporation's Cimarron Oklahoma Plant.

Based on the information obtained from this licensee it appears the filter was used in a glovebox system of a scrap recovery area where scrap material containing plutonium had been processed. Nitric acid was used in the recovery operation to dissolve the scrap oxide. It is likely that some dilute nitric acid had collected in the HEPA filter during use. The heat generated outside the fiberboard carton was the result of an exothermic reaction, most likely between the nitric acid and some other material. It was determined that this licensee had wrapped the filter in a 4 mil polythelene (PE) bag and

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*The Super Tiger Shipping Container is designed to provide impact and thermal protection to its contents in accordance with 10 CFR 71. The overall dimensions of the standard size container are eight feet by eight feet by twenty feet. The container is constructed of 3/16" steel. Each container is packed (or unpacked) through the back which is otherwise kept bolted, and sealed with a silicone rubber gasket. A pressure fitting connection is included for leak testing.

then boxed it in the original cardboard shipping box. This box was further wrapped in another PE bag before being placed in the fiberboard carton.

Subsequent tests conducted at the Cimarron Plant on similar HEPA filters did not reveal any significant reactions between nitric acid and the filter media, separators, or sealants. Therefore, it is believed that the reaction which occurred involved the nitric acid and the original cardboard shipping carton or the nitric acid and some cleaning rags (cellulose material) which may have been inadvertently left in the package containing the HEPA filter.

In order to inform appropriate licensees of this problem, the Nuclear Regulatory Commission issued Inspection and Enforcement Bulletin 75-07 to 57 facilities, including reprocessing plants, fuel cycle plants and major laboratory licensees known to be processing radioactive material and possibly using HEPA filters in their gloveboxes and ventilation systems. These licensees were requested to review their operations and determine if adequate precautions were being taken regarding the handling, packing, and storage of HEPA filters exposed to nitric acid fumes in light of the HEPA incident. All licensees were requested to reply to NRC within 30 days.

Based on NRC's review of these licensee replies, approximately 45 facilities were not involved with any operations emitting corrosive gases or oxidizers, such as nitric acid fumes, into their ventilation systems. However, 12 licensees use or plan to use oxidizers such as nitric acid as part of their operations. NRC reviewed their procedures and found that four of the twelve licensees have satisfactory procedures which should preclude exothermic reactions during shipment of their HEPA filters. The remaining eight licensees volunteered to make changes to their procedures and operations in light of the HEPA filter incident. These changes include installation of scrubbers and/or storage of their used HEPA filters in hot waste rooms up to two months after making non-destructive examinations. This will assure that exothermic reactions will occur onsite in safe areas prior to shipment. In addition, these licensees plan to indoctrinate their employees on the safe packaging and shipping of HEPA filters to prevent a recurrence of the type of event discussed above.

In summary, it appears the 12 licensees using HEPA filters in acid environments presently have or will soon have satisfactory procedures for controlling the use of cellulose materials during packaging of their HEPA filters for shipment. Changes to existing procedures will be checked by NRC inspectors during future inspections. We believe these steps are adequate to prevent a recurrence of the type of event experienced at the Nuclear Engineering Company's burial grounds.

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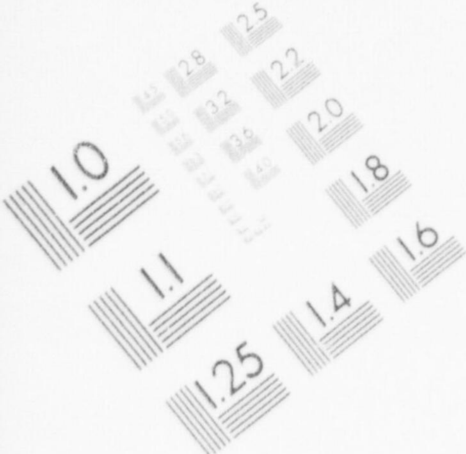


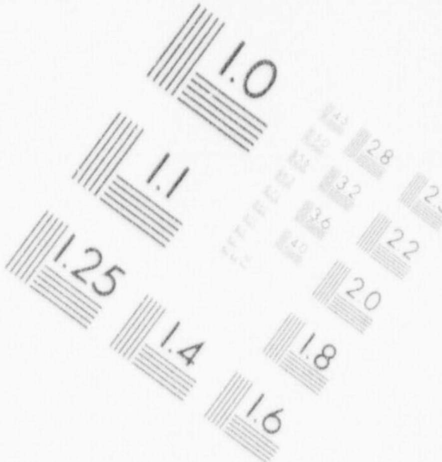
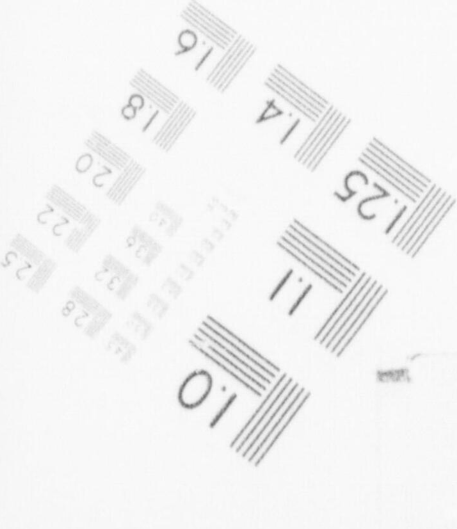
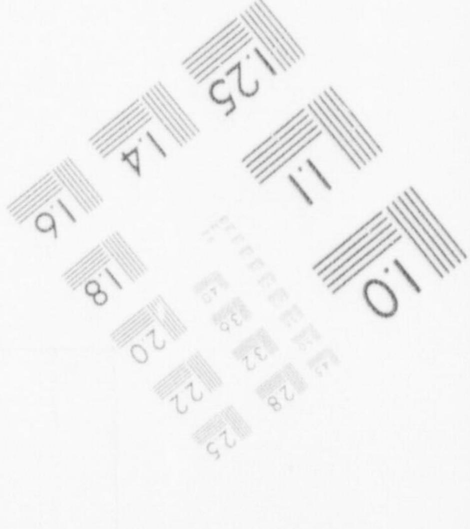


IMAGE EVALUATION
TEST TARGET (MT-3)

6″

MICROCOPY RESOLUTION TEST CHART





UNITED STATES NUCLEAR REGULATORY COMMISSION

OPERATING EXPERIENCE
BULLETIN INFORMATION REPORT

DEFECTIVE RADIOGRAPHIC DEVICES

June 21, 1976

Inspection & Enforcement Bulletin 75-02, identified a problem with a radiographic exposure device. The unit involved was a Radionics Model #P192-35 manufactured by Radionics Incorporated and contained 29 curies of Iridium-192. The defective unit was found at the Ryan Airport at Baton Rouge, Louisiana by personnel associated with Delta Airlines after an abnormally high radiation level was discovered coming from a shipping container. Within a few hours after this problem was detected, personnel from the Louisiana Division of Radiation Control and the Nuclear Regulatory Commission arrived to conduct an investigation.

A visual examination revealed that the unit had been shipped in a 20-gallon drum by the Pittsburgh Testing Laboratory. In order to ship this device in the designated container, it was necessary to rotate the unit 90° in the drum. This placed the lockbox at the top of the container and outlet port at the bottom. A radiation survey of the container and the radiographic device was immediately conducted by investigating personnel. The radiation level on the outside of the steel drum was as high as 200 mR/hr on the surface in one area. The radiation levels measured around the device itself are depicted on the enclosed Figure. A small area, about the size of a quarter, at the base of the unit had a radiation level of 300 mR/hr.

To assist the investigators in understanding the problem further, the device was taken to Gamma Industries and examined in a hot cell. There, the steel container was cut in half by the use of a torch. No casting defect was noted in the lead shielding. The source tube was also examined but no defect was found in this tube. A dummy source pigtail was constructed measuring 10-1/2 inches in length which was the same dimension as the original. The dummy pigtail was inserted into the tube and the precise position of the source noted after the pigtail was in the locked position.

As seen in the attached Figure the source came to rest in a position in the tube where there was minimum shielding in the vertical direction. It appeared from this experiment that the pigtail was too short, although 10-1/2 inches was the length required by the specifications. Based on the findings of this examination it was concluded that too many shims were installed between the steel shell and the lockbox. This would have caused the source to miss the top of the tube by one inch even with the correct length pigtail, see enclosed Figure. In this position the radiation could stream down the vertical portion of the source tube and out through the base at the bottom of the unit.

As a result of the handling procedures employed while the unit was in transit, the defective device did not affect the health and safety of the public, airline passengers, flight crews or freight handlers. It should be noted that 10 CFR 20.105 limits whole body exposures in unrestricted areas to 0.5 rem/year. To have received this radiation dose, an individual would have had to stand three feet in front of the container for more than half a day.

Inspection and Enforcement Bulletin 75-02 was issued to licensees known to have similar model radiographic devices based on NRC records. Attached to each Bulletin was a blank Summary Report Form which each licensee was requested to complete. Completion of the form required each licensee to conduct a radiation survey for hot spots producing radiation levels in excess of 50 mR/hr, six inches from the shielded surface or base. The survey procedures included the following steps:

1. While the device rested on its base, a survey was performed using a calibrated survey meter on all surfaces (other than the base) at a distance of six inches from the surface. These surveys were to be performed while moving the pigtail back and forth but with the end of the pigtail locked in position.

2. The device was then turned on one side and the bottom surface was surveyed at a distance of six inches.

3. The measured maximum readings at six inches were converted to values which would result if the devices were loaded to their rated capacities, allowing an excess of 20% for Ir-192, and 10% for Co-60. For example if the original device was loaded with 100 curies of Iridium-192 but had decayed to 25 curies and one reading was 15 mR/hr six inches from the surface, then the capacity would be 120 curies allowing 20% excess for Iridium-192. Hence, the maximum reading with the original device loaded with 100 curies of Iridium-192 would have been;

$$15 \text{ mR/hr} \times \frac{120 \text{ curies}}{25 \text{ curies}} = 72 \text{ mR/hr}$$

Licensees were informed that any direct or converted reading which was greater than 50 mR/hr at 6 inches from the surface of the radiographic device indicated a defective unit.

A survey of the Summary Report Forms revealed that several of the devices when loaded to the rated capacity would have had radiation levels in excess of 10 CFR 34.21 limits. The licensees having these defective devices took immediate and appropriate action to eliminate any hazard to the health and safety of the public. On June 8, 1976 an Order was issued by NRC to fourteen licensees which had the original authorizations to possess Radionics devices. Prior to issuance of the Order it was found through the survey that ten of these licensees did not possess such devices, or possessed them but did not use them. The remaining four licensees indicated through the survey that they were actively using their Radionics devices. The Order to the ten licensees modified their licenses and revoked authority for any further use of their Radionics units. The remaining four licensees were required by the Order to reduce the quantity of radioactive material in their devices to assure that radiation levels would remain within the limits specified in 10 CFR 34.21.

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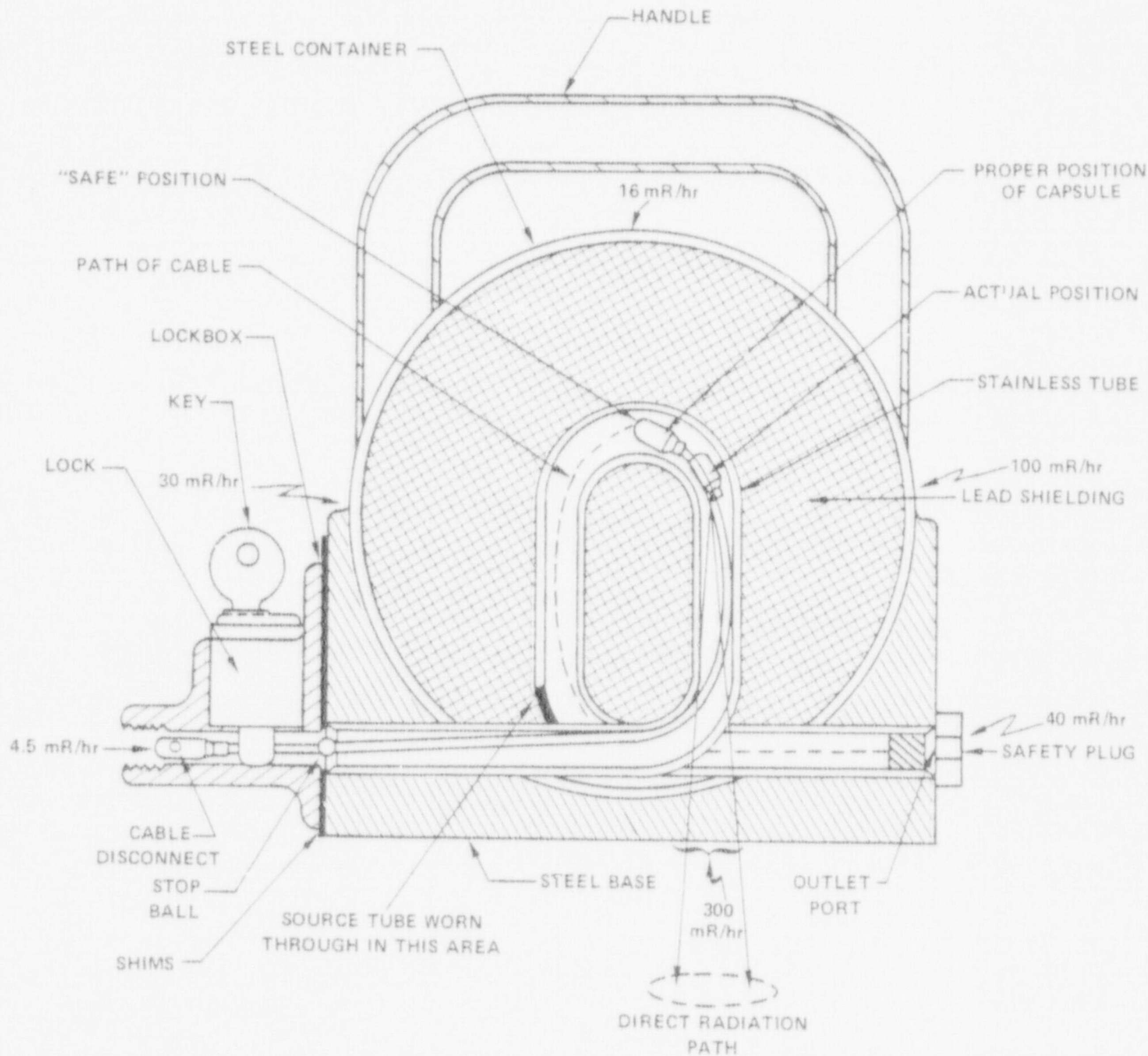
RADIONICS RADIOGRAPHIC DEVICE



FIGURE

UNITED STATES NUCLEAR REGULATORY COMMISSION

OPERATING EXPERIENCE
BULLETIN INFORMATION REPORT

ISOLATION CONDENSER LEAK

November 12, 1976

Introduction

On February 12, 1976, a tube failure occurred in the isolation condenser of the Millstone Point 1 Boiling Water Reactor Facility. This resulted in a minor release of a radioactive steam and water mixture from the isolation condenser vent to the ground outside the reactor building. The health and safety of the public was in no danger as a result of this event. Nevertheless NRC considered the event sufficiently important to issue Bulletin 76-01. This report discusses the circumstances involved in the aforementioned event and the corrective action taken by NRC.

Discussion

The isolation condenser tube leak occurred after (though it was not caused by) an electrical problem was experienced with the Main Transformer. This electrical problem was sensed by the protective circuitry which initiated a generator trip and a reactor trip from 100% power. Based on NRC's review of available data it appears that reactor pressure never reached the trip point required to initiate operation of the isolation condenser. The pressure surge which did occur, was a normal pressure transient resulting from closure of the Main Steam Isolation Valves. This pressure transient was apparently sufficient to cause failure of an isolation condenser tube which had experienced some corrosion from a previous incident (discussed later in this report).

A sketch of the isolation condenser system is presented in Figure 1. A review of the function and operation of the isolation condenser will enhance the reader's general understanding of this problem.

The isolation condenser at Millstone and at other BWR's provides a heat sink for the reactor if an incident isolates the reactor from the main condenser. The isolation condenser which is located in an elevated area in the reactor building depends on natural convection to maintain circulation. The tubing in the Millstone isolation condenser has a design pressure of 1250 psig at a temperature of 575°F. The pressure on the shell side is maintained at 30 psig. The tubing was made of Type 304 stainless steel and the shell side, of carbon-steel alloy. Valves A, B, & C are normally open during reactor operation hence the tube bundles in the isolation condenser are continuously subjected to reactor pressure.

The isolation condenser is placed in operation by opening valve D, the condensate return valve to the reactor system. This occurs either from a high pressure signal, or the valve may be manually opened by an operator. When the isolation condenser is operating, steam in the tubes will condense and return to the reactor vessel through line No. 1, see Figure 1. Water on the shell side of the condenser will boil and exhaust to the atmosphere through the vent, line No. 2. Radiation monitors located in the shell side of the isolation condenser were designed to read out in the control room and sound alarms in the event of high radiation levels caused by one or more tube failures. After the February 12, event this radiation monitoring system was modified so that in addition to sounding an alarm, valves A, B and C will be automatically closed, isolating the condenser from the reactor.

If additional makeup water is required it can be obtained from the station firemain storage tanks or the condensate storage tank.

Following a reactor scram from 100% power the radiation level in the isolation condenser began its upward climb. The alarm setpoint was not reached until one hour and 16 minutes after the scram. Immediately after the scram, steam puffs were observed coming from the isolation condenser vent. Simultaneously, rumbling sounds were heard coming from the isolation condenser, suggesting operation of the condenser even though valve D was closed. After the alarm setpoint was reached valves A, B, C, and D were manually closed isolating the condenser from the reactor. Shortly thereafter the flow of the steam and water mixture from vent No. 2 stopped. Approximately 2 hours after the initial tube failure the Millstone staff instituted their emergency plan involving site traffic control, offsite and onsite radiological surveys and decontamination, where necessary. A contaminated area was found extending approximately 300 to 350 feet from the reactor building. However, no contamination was found outside the fenced area known as the exclusion area. As part of the decontamination program 16 cubic yards of top soil were removed and disposed in an authorized burial site. NRC inspectors found that decontamination efforts conducted by the licensee were sufficiently adequate to assure there was no hazard either to workers onsite or to the general public. In terms of personnel involvement, seven individuals associated with the Millstone facility who could have been contaminated by the radioactive steam and water effluent were given whole body counts. Four of the individuals showed no measurable activity while three showed activity of less than 2% of the maximum permissible body burden.

As indicated above, there is a reasonable possibility that the normal pressure surge resulting from closure of the MSIV's may have contributed to failure of a tube in the isolation condenser which was probably degraded as a result of salt water intrusion on September 1, 1972. This salt water intrusion into the reactor coolant system was caused by tube failures in the main condenser.

The mechanism of stress corrosion cracking which appeared to be the basic cause of the isolation condenser tube failure was based on an analysis of the failed tube obtained 24 hours after the event occurred. The actual hole in the tube was approximately one inch wide by two inches long. Examination of the tube revealed the following information:

1. Cracks originated on the inside surface of the tube and were transgranular in nature. They also appeared to have the branching characteristics of stress-corrosion cracking.

2. Many secondary cracks existed penetrating up to 90 percent of the wall thickness in different sections of the tube.

3. No indication has been found of cracks originating on the outer side of the tube.

4. The cracks appeared to have been present in the tube for some time and were not produced during the February 12th incident.

5. The cracks contained significant amounts of calcium, sulfur and aluminum. Since none of these chemical elements are found in reactor primary water their presence suggested intrusion of seawater into the isolation condenser at some point in time.

As a result of further examination and tests such as non-destructive examination and high pressure leak tests of other condenser tubes, it was found that 130 tubes out of a total of 242 in the isolation condenser were not acceptable. Accordingly the licensee, Northeast Nuclear Energy Company has decided to replace all the tubes in the isolation condenser with 0.065" wall thickness Inconel 600 tubes. A photograph of the upper half and lower half of the isolation condenser is shown in Figure 2.

On March 9, 1976, NRC issued Bulletin Number 76-01 to all licensees of BWR power reactor facilities and requested those licensees with isolation condensers, which included only nine facilities, to take the following specific action:

1. Assure that the integrity of the isolation condenser tubes is maintained during operation. This assurance will be obtained by the implementation of tube leak detection procedures such as control of temperature, volume and isotopic content of the shell side water.

2. Assure that the margin of isolation condenser tube integrity is maintained. This assurance could be obtained by periodic nondestructive examinations of the tubes. In the event that nondestructive examinations of the tubes is impractical, hydrostatic testing, in accordance with the 1974 ASME Section XI requirements, is considered an acceptable alternate.

3. Review procedures to assure prompt detection and operator response to an isolation condenser tube leak.

Licenses were requested to reply to the above requirements within 30 days.

The nine facilities which have isolation condensers include Big Rock Point, Dresden 1, 2 & 3, Humboldt Bay, LaCrosse, Millstone, Nine Mile Point and Oyster Creek. A review of the information received from these facilities revealed that seven had isolation condensers with tube material of stainless steel while two facilities had tubes made of copper-nickel. Other than the isolation condenser problem experienced at Millstone only Big Rock Point has experienced tube leaks. This facility has stainless steel tubes in its isolation condenser.

Use of the isolation condenser varies with each facility. For example, in 1975 condenser usage varied from once per year to six times per year with an average of twice per year for the nine facilities. This usage frequency includes testing of the condenser.

Further NRC reviews of licensee replies disclosed that existing procedures pertaining to isolation condensers will be updated to include additional monitoring efforts. This involves (1) monitoring of shell side water level and temperature, (2) analysis of shell side water periodically for pH, nitrate concentration and conductivity, and (3) analysis of shell side water for gross beta-gamma activity.

In addition, every BWR facility with an isolation condenser had some form of radiation monitor on the shell side which will sound an alarm in the control room in the event of a tube leak.

With regard to periodic testing of isolation condensers, the existing technical specifications require operability and capacity tests for all nine facilities. Only two facilities are required to hydrostatically test their isolation condensers (one annually the other in conjection with primary system testing). All licensees will be required to conduct at least one hydrostatic test of their isolation condensers to satisfy the requirements of Bulletin 76-01. In the near future NRC will be reviewing existing technical specifications to determine if any updating is in order regarding this matters. Presently each of the nine facilities is required to check automatic operation of its isolation condenser in addition to cycling the outlet valves associated with the isolation condenser. In addition four of the nine facilities conduct special tests once every five years to verify the heat removal capacity of their isolation condensers.

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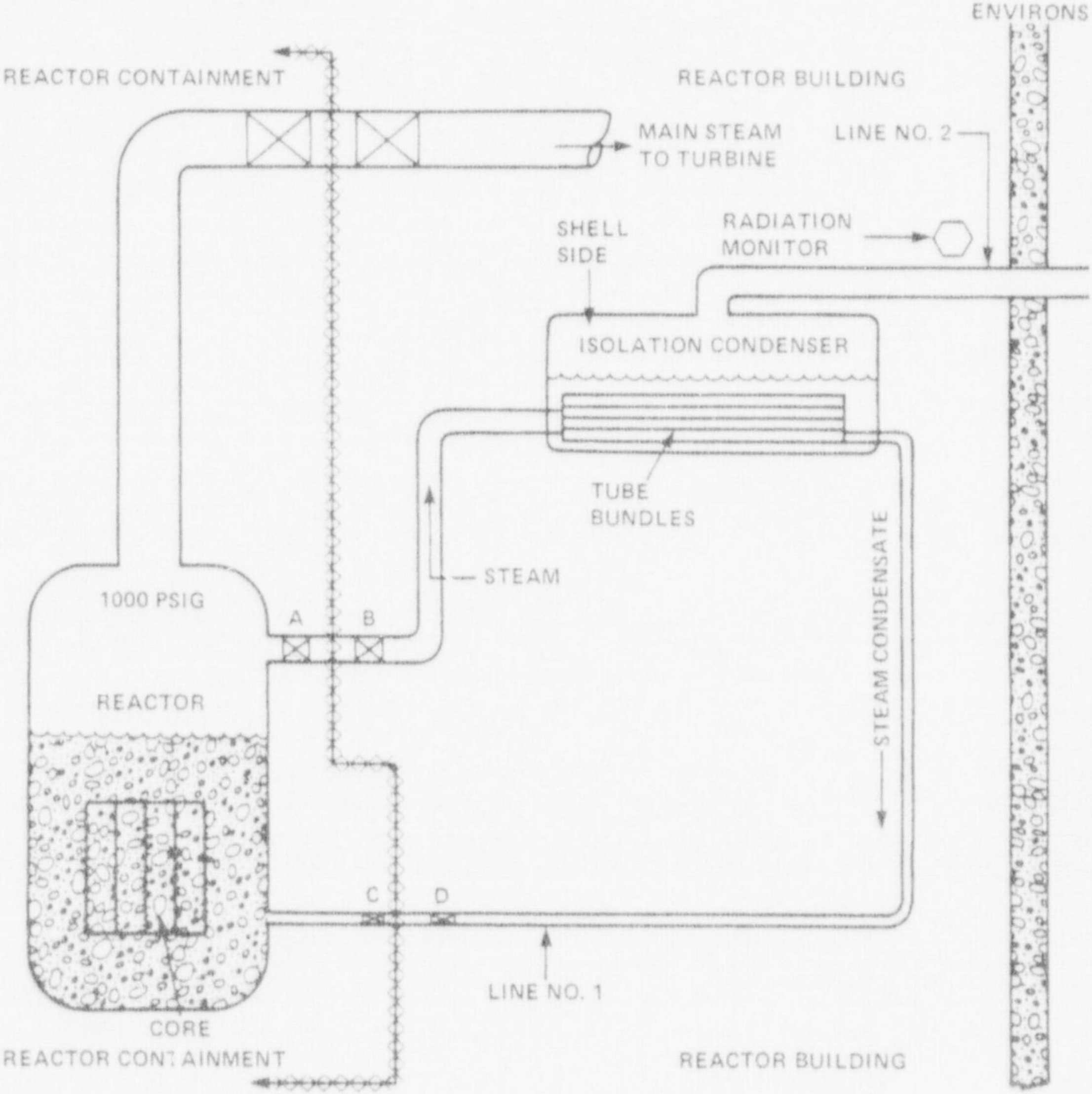
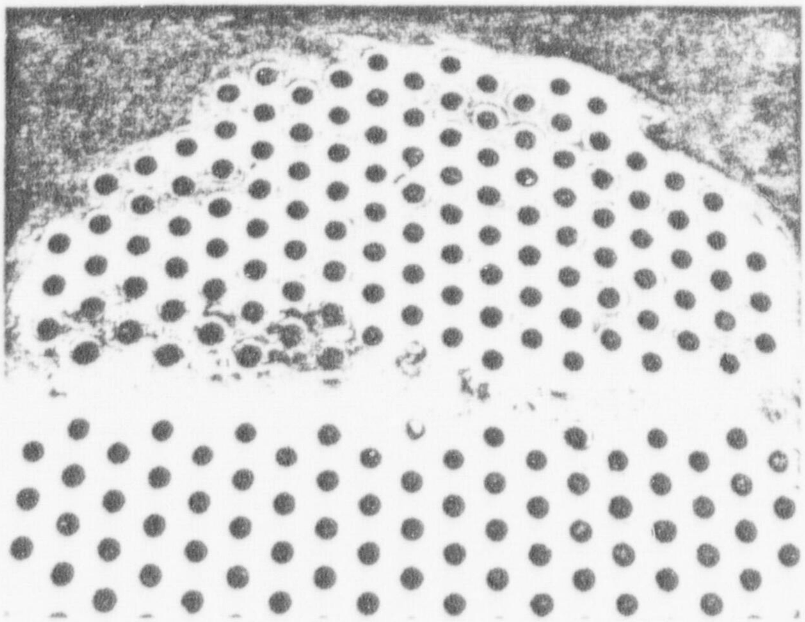
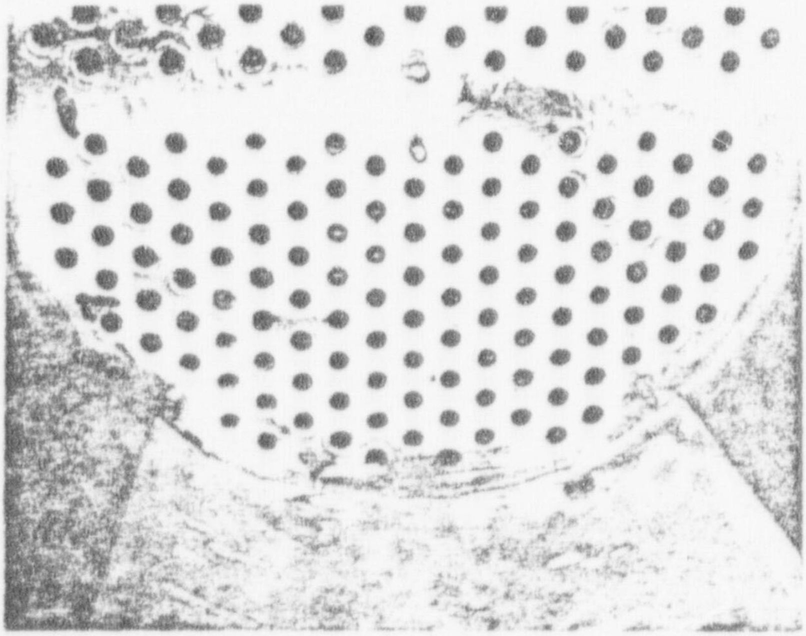

ENVIRONS
REACTOR CONTAINMENT
REACTOR BUILDING
MAIN STEAM
TO TURBINE
LINE NO. 2
SHELL
SIDE
RADIATION
MONITOR
ISOLATION CONDENSER
TUBE
BUNDLES
STEAM
STEAM CONDENSATE
1000 PSIG
A
B
REACTOR
C
D
LINE NO. 1
CORE
REACTOR CONTAINMENT
REACTOR BUILDING

FIGURE 1



UPPER HALF OF ISOLATION CONDENSER



LOWER HALF OF ISOLATION CONDENSER

FIGURE 2

UNITED STATES NUCLEAR REGULATORY COMMISSION

OPERATING EXPERIENCE
BULLETIN INFORMATION REPORT

CRACKS IN COLD WORKED PIPING AT BWR's

I&E Bulletin 76-04 was issued on March 30, 1976, after three different leaks were experienced with the reactor Cleanup System at Nine Mile Point. These leaks were discovered on November 28, 1975, March 19 and March 22, 1976. Each leak occurred at a different pipe bend and was the result of through-wall cracks in the base material.

The piping in each one of the three events was six inch schedule 80, ASTM A-376, Type 304 stainless steel. A section of piping was removed after the first event (November 28, 1975) and sent to a hot lab for metallographic examination. This pipe section connected the high pressure supply from the reactor, outside the drywell to the regenerative heat exchanger.

According to available records, fabrication techniques used to form this pipe included the formation of a 45° cold bend on a 30" radius. This pipe was not solution annealed as is normally the practice after cold bending. A photograph of the outside section of the pipe is shown in Figure 1. The cracks seem to be longitudinal on the outside surface of the 45° bend. Figure 2 is a photograph of the inside surface of the pipe which appeared to be deformed during cold bending operations.

Figures 3 and 4 are photographs of the outside and inside surfaces respectively after the application of a dye penetrant. Since the cracks are more severe on the inside surface, it appears likely that they were initiated on this surface.

The main crack was approximately 3" long on the outside and 6" long on the inside surface. The numbers in Figure 4 represent the various sections which were individually subjected to metallurgical examination. Figures 5 and 6 illustrate the formation of transgranular cracks in the heavily cold worked surface. This propagation changed to an intergranular mode below the cold worked surface. This specimen was obtained from Section 1 of the sample shown in Figure 4. In Figure 7 significant carbide precipitation at the grain boundaries is clearly visible for the Number 1 sample.

Figure 8 (a photograph of Section 2 specimen noted in Figure 4) reveals another crack in the cold worked surface which appears to be transgranular although it has started to propagate in an intergranular mode.

Based on laboratory tests, the structure and hardness of all five specimens, obtained from the pipe sections illustrated in Figure 4, were similar.

I&E Bulletin 76-04 was issued to all BWR and PWR facilities with operating licenses and to all BWR and PWR facilities under construction. Only BWR licensees with operating licenses were required to take immediate action by NRC, because this type of stress corrosion has only occurred at BWR's due to the high oxygen content in the reactor coolant. This action involved:

1. Development of the following information for those systems located within, or connected to, the reactor coolant pressure boundary if these systems were exposed to reactor coolant system pressure during operation;

   a. A specific listing of installed austenitic stainless steel piping or fittings made from piping, greater than two inches nominal size, which may have been cold worked without solution annealing, following forming.

   b. A description of the program and procedures including inspection criteria and schedules, for the nondestructive volumetric examination of the items identified in (a) above.

2. BWR licensees were requested to report to the NRC Regional Office within 24 hours, any adverse findings obtained during nondestructive examination of pipes and fittings.

3. BWR licensees were also requested to submit a report of the performance, results, and evaluation of any nondestructive evaluation conducted on cold worked stainless steel piping or fittings within 60 days following completion of the examination.

Holders of BWR construction permits were informed that this issue would be reviewed by NRC construction inspectors during future inspections and so they were not required to reply in writing to the Nuclear Regulatory Commission.

NRC reviewed replies from 24 operating BWR licensees. Only two facilities (other than Nine Mile Point) appeared to have cold worked stainless steel piping that was not solution annealed. These facilities were Humboldt Bay and LaCrosse. In the case of Nine Mile Point, a total of five-6" pipe bends and two-2" cold worked pipe bends were replaced after additional defects were found by UT examination. Humboldt Bay discovered defects in a 3" cold worked stainless steel pipe. This pipe has been replaced. LaCrosse identified 24 sections of piping which had been cold worked but not solution annealed. Ten of these pipes were subjected to nondestructive examination; no defects were found. The remaining 14 sections of piping will be examined during the next refueling outage.

Of the 24 plants that transmitted replies to NRC, six stated they had incomplete records making it impractical for the reactor owner to determine whether existing cold worked piping had been solution annealed. In each of these cases the licensees committed themselves to an extensive nondestructive examination program during the next refueling outage. The intent of each of these programs will be to identify any and all pipe defects requiring futher attention.

In summary, NRC has reviewed the problem involving nonsolution annealed cold worked piping at each of the 24 operating BWR's which had a potential for this problem. NRC considers the majority of these replies to be adequate and, therefore, believes that the issue of cracks in cold worked piping at operating BWR plants is not a significant generic issue.

Point of Contact:
John J. Rizzo
Operating Data Branch
Office of Management Information
and Program Control
U.S. Nuclear Regulatory Commission

Figure 1.

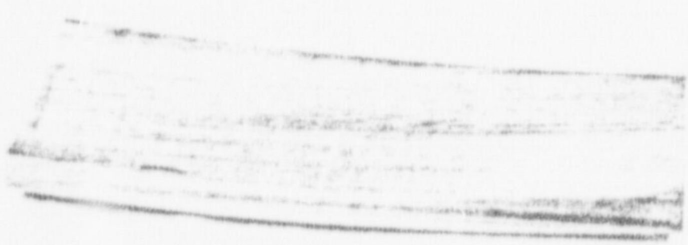


Figure 2.

Figure 3.

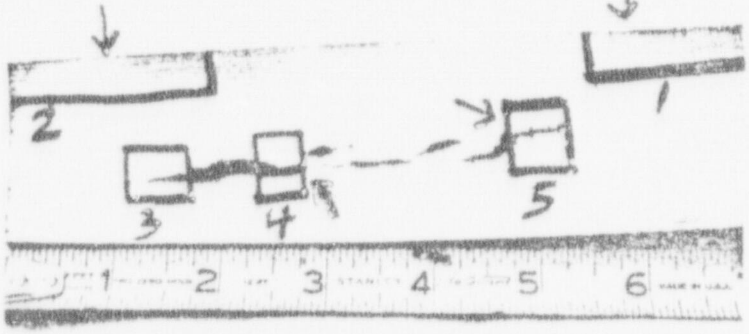


Figure 4

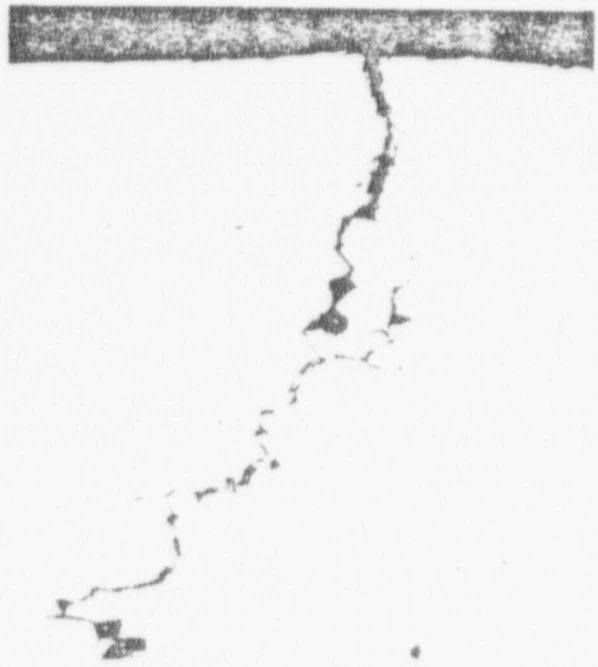


Figure 5. Magnification 100x

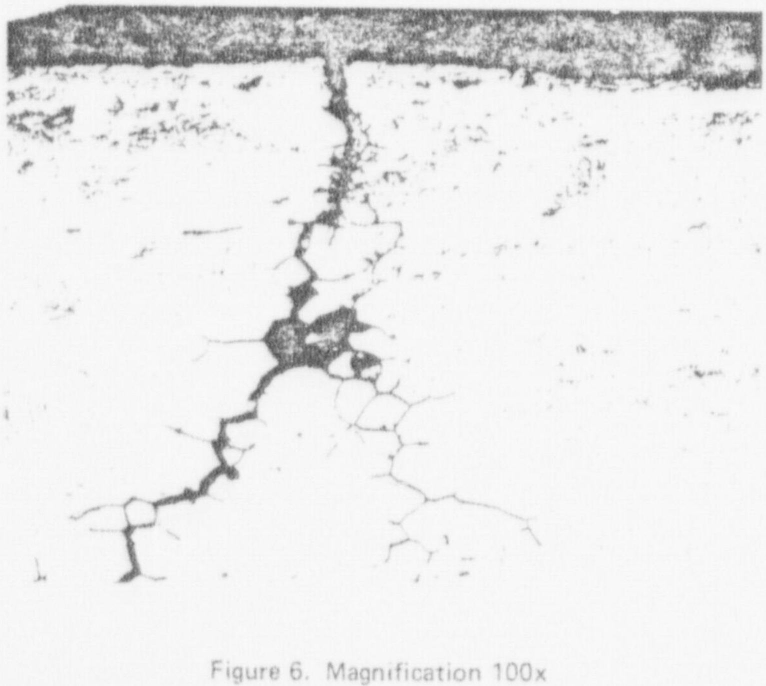


Figure 6. Magnification 100x

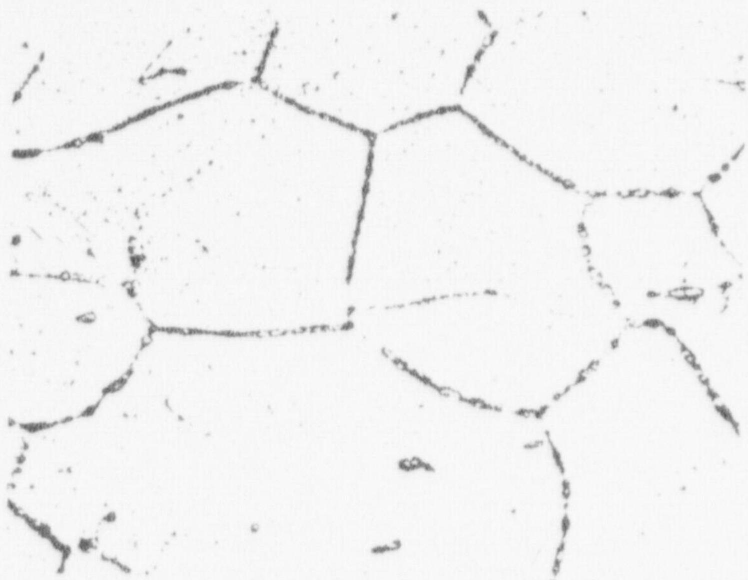


Figure 7. Magnification 500x

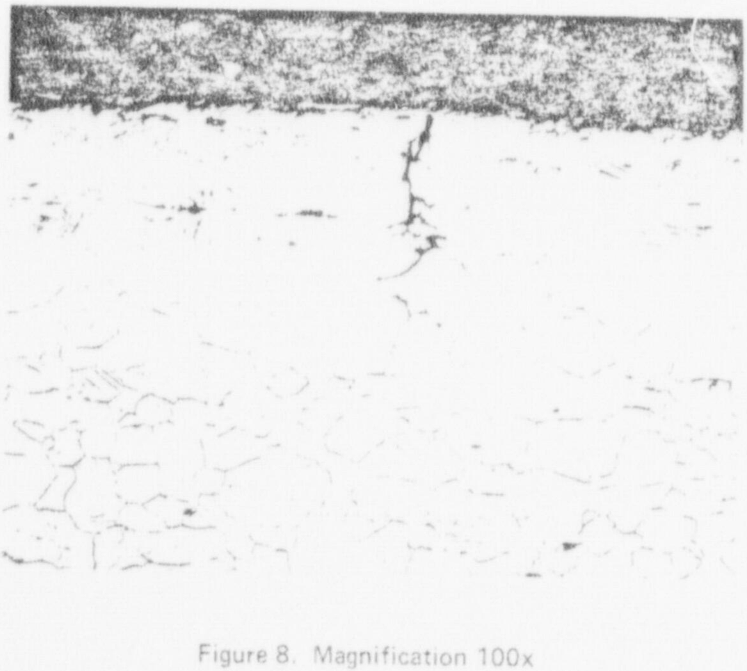


Figure 8. Magnification 100x

UNITED STATES NUCLEAR REGULATORY COMMISSION

OPERATING EXPERIENCE
BULLETIN INFORMATION REPORT

RECENT PROBLEMS WITH GENERAL ELECTRIC HFA AND STD RELAYS

March 22, 1977

SUMMARY

This report discusses some recent problems involving General Electric HFA and STD relays. The NRC issued two separate bulletins on this subject in 1976 to licensed power reactor facilities and those with construction permits. The cause of the problems with these relays have been identified and corrective measures taken to NRC's satisfaction.

HFA RELAYS

A number of problems have been experienced with General Electric relays over the past few years. The most recent failure occurred at the Turkey Point 4 Nuclear Power Plant in May 1975. The latter involved a defective Type HFA-DC relay which prevented the stripping of various breakers from the 4B-4600 volt bus. This precluded the 4B diesel generator breaker from closing since complete load stripping of a 4160 volt bus is a required permissive to close the diesel generator breaker.

During a review of the problem the licensee found that failure of the HFA relay in question could not be duplicated. The relay was removed and sent to General Electric for further examination. GE's investigation revealed that the HFA relay failure mode was similar to other relays (HGA, HKA and HMA relays) which had malfunctioned over the past few years. Specifically, this involved the heat stabilizing compound used in the nylon spools of each relay coil. The spools released halogen ions over a period of time and in the presence of moisture, the halogen ions formed hydrochloric acid. This acid caused electrolytic corrosion of the copper wire which eventually resulted in a relay coil open circuit failure.

Nylon was used in the manufacture of spool material in the late 1950's since it was an improvement over paper base materials previously used in spools. In the late 1960's a substance called LEXAN became available whose chemical, electrical and mechanical properties were significantly better than nylon for use as spool material. There are no known corrosion problems associated with LEXAN. Although LEXAN had become the dominant material in the manufacture of spools for relays it appears that nylon spools were in extensive use in relays at nuclear plants. There was also an inventory of relays containing nylon spools which could have been used as replacements for those relays which deteriorated.

In the spring of 1976 the Nuclear Regulatory Commission became concerned about this problem and on March 12, issued I&E Bulletin 76-02 to approximately 110 power reactor facilities with licenses and construction permits. This involved all operating licensed power reactors and most reactors under construction. The subject bulletin requested each facility to determine whether relay coils with nylon spools existed in their electrical systems. If such coils were found, the facilities were requested to inform the Commission of the nature of the corrective action planned with regard to these coils. Replies were requested within 30 days.

NRC reviewed these replies to determine the generic nature of the problem in addition to correlating the experiences of BWR and PWR facilities. It was found that approximately 24% of all facilities (both operating and under construction) did not have any relays containing coils made of nylon spools while 52% of all facilities had nylon spools in both safety and non-safety related equipment. A significant number of licensees reported finding over 100 nylon spools in safety systems at each of their facilities. It should be noted that no facility in this 52 percentile bracket reported finding relays with nylon spools which had malfunctioned or showed signs of deterioration. Nevertheless all facility representatives finding DC relays with nylon coils operating in an uncontrolled environment (such as high humidity and temperature), informed the NRC of their plans to replace these relays. A few licensees reported finding HGA, HFA, HKA, and HMA relays operating in low humidity and low temperature environments. They suggested to the Commission that replacement of these relays with LEXAN type spool relays appeared to be unnecessary at this time. The Commission accepted this position with the understanding that the relays in question would be closely monitored to detect any future spool deterioration. Some licensees responding to Bulletin 76-02 (approximately 9%) stated that their relays contained LEXAN spools.

The remainder of the replies (approximately 15%) were received from facilities under construction planning to install HFA, HGA, HKA or HMA relays. Each of these facility representatives assured NRC that their vendors would be requested to use only LEXAN spool relays in their installations.

STD TRANSFORMER DIFFERENTIAL RELAYS

In addition to the HFA relay problem this report also discusses recent experiences with GE Type STD Transformer Differential Relays. A problem involving this relay occurred at the Joseph M. Farley Nuclear Plant which was under preoperational testing. During the testing phase of a 600 volt Motor Control Center (MCC) at this plant, a false operation of the STD transformer differential relay was observed. This caused loss of power to the essential MCC. An investigation revealed that the cause was radio frequency interference from an activated transceiver. Further testing disclosed that any of the 5 watt transceivers available at the plant site, having frequencies ranging from 150 MHZ to 470 MHZ, could cause false operation of this STD relay. These transceivers were used by personnel at the facility to coordinate test activities during plant preoperational testing.

This event was significant because each 600 volt load center contained one 4160/600 volt transformer with a 600 volt bus on the secondary side.

When Type STD differential relays are energized, the breakers trip, isolating the transformer. This removes power to all loads on the 600 volt bus. Since many of the 600 volt load centers are associated with safety system loads, maximum reliability of STD relays is paramount.

Other facilities experienced similar problems with STD relays. For some of these events, General Electric found that the STD Sense Amplifier cards had failed shorted. This was traced to two zener diodes whose cases had been physically touching, short circuiting one diode and overloading the circuit. GE concluded that this shorted condition made the circuit associated with the STD relay, radio frequency sensitive.

As a result of these malfunctions GE issued Service Advice Bulletin (SAB) 1.50.1 dated November 17, 1975 to their service engineers alerting them of the problem. On March 15, 1976, the Nuclear Regulatory Commission issued IE Bulletin 76-03 to approximately 110 power reactor facilities with licenses and construction permits. As in the case of Bulletin 76-02, each facility representative was requested to determine if STD relays were installed at their facility. If STD relays were found, the facility representative was requested to describe to the Commission the corrective action that would be taken to prevent any occurrence similar to the one experienced at the Farley Nuclear Plant.

Replies to this bulletin fell into three general categories: (1) approximately 81% of the facility representatives stated that STD relays were not used in their equipment, (2) approximately 8% of all facility representatives (mainly at operating reactors) reported finding STD relays used with their electrical systems, and (3) the remaining replies (approximately 11%) included those reactors under construction, planning to use STD relays.

Facility representatives in categories 2 and 3 assured the Commission they would contact General Electric to obtain instructions regarding the appropriate modifications required to correct the deficiencies with STD relays. The nature of the modifications include redesigned circuit boards with components arranged to prevent short circuiting. GE believes these modifications will prevent the type of occurrence experienced at the Farley Nuclear Power Plant.

The Office of Inspection and Enforcement has reviewed the fixes and modifications described above and has found them to be adequate measures to correct the problems described in Bulletins 76-02 and 76-03.

Point of Contact:
John J. Rizzo
Office of Management Information
and Program Control
U. S. Nuclear Regulatory Commission

UNITED STATES NUCLEAR REGULATORY COMMISSION

OPERATING EXPERIENCE
BULLETIN INFORMATION REPORT

THIS REPORT CONTAINS THE DIAGRAM WHICH WAS MISSING FROM AN IDENTICAL DOCUMENT RECENTLY ISSUED

PROBLEM WITH CRANE HOIST CIRCUIT MODIFICATIONS

MAY 16, 1977

This Bulletin Close-Out report discusses a malfunction involving a slow speed crane hoist control system which on two occasions resulted in overtravel of the crane load. This problem was experienced with the Dresden Units 2 and 3 reactor building crane. Prior to its modification, the main hoist control system consisted of two electrical mechanical brakes in series. When the hoist motor was energized, the DC solenoids were also energized releasing the loaded brake shoes. When the solenoids were deenergized a spring force engaged the brakes and held the cable drum stationary.

The original hoist control system utilized a single Size 2 DC contactor (two contacts in series) in the solenoid circuit. A simplified diagram, showing the two electro-mechanical brakes and the two contactors of the original circuitry, is depicted in the upper half of the attached figure. In order to provide additional hoist redundancy and slow speed hoist capability in accordance with Regulatory Guide 1.104, Commonwealth Edison made various modifications to the Dresden Units 2 and 3 and Quad Cities Units 1 and 2 crane hoist systems. These included a slow speed hoist with a capability of 4 inches per minute and some changes to the associated circuitry. Part of this circuit modification involved the installation of a circuit in parallel with the original DC contactor which utilized four AC rated Size 1 single contacts in a series-parallel array to distribute the current carrying and interrupting load. This part of the circuitry is shown in the lower half of the figure.

On May 11, 1976 the modified system including the low speed crane was being used to reinstall the vessel head on the Dresden Unit 2 vessel. At one point in the operation the crane operator attempted to halt the downward motion of the vessel head. Instead of stopping, the vessel head continued to drop another 15 inches before the load was finally stopped. An additional 15 inch drop was experienced just before the head was seated on the reactor vessel flange. Both events occurred as the head was being guided down over the reactor vessel studs with protectors installed on four studs for use as guides. There was no major abrasive or forcible contact experienced between the vessel head and the vessel flange or studs and hence no damage to the reactor components occurred.

Shortly after these two events occurred, Commonwealth Edison conducted a detailed investigation of the problem. They found that on some occasions, when power to the crane motor drive was terminated, sporadic arcing occurred across the contacts of the modified series-parallel array (see lower half of figure). It was during this arcing that the crane brake failed to operate because current flow through the brake solenoid was not interrupted. The licensee concluded that the AC rated Size 1 single contacts associated with the modification simply did not provide sufficient DC interrupt capacity and therefore could not always promptly stop current flow to the brake solenoid when power to the motor drive was terminated.

NRC Regulatory Guide 1.104 issued on February 1976 encouraged licensees to review various safety aspects associated with their cranes. One of the areas discussed was related to low crane velocity (approximately 5 fpm) as an operational safety limit. No circuit modifications were recommended or suggested in the guide. Since Commonwealth Edison made their modifications after receiving the Guide and in as much as the Guide received wide distribution there was concern that the event described above could have had generic implications. Accordingly the NRC issued Bulletin No. 76-07 and Circular 76-07 on July 27, 1976. The Bulletin was issued to all Operating Reactor Licensees and the Circular to most Construction Permit Holders. The Bulletin and Circular requested the following information:

(1) A description of the modifications to the hoist control sytem made or planned in the future.

(2) A description of the steps to be taken to assure that crane hoist brake power contactors were adequate for the service to be performed.

A reply was requested within 20 days for the Bulletin and 90 days for the Circular. As a result of the aforementioned Bulletin and Circular, the NRC received approximately 122 replies from Licensees and Permit Holders. A review of these replies revealed that circuit modifications, which could have produced similar incidents as described above, were found at two operating facilities although neither of these facilities had experienced any problems. The remaining responses from the Licensees and Construction Permit Holders fell into the following four categories:

(1) 48% had crane control circuits that were different than that described in the Bulletin and Circular. In addition no modifications were planned to the existing controls at these plants.

(2) 8% either planned to make modifications to their crane control circuitry in the future or had completed some type of modification to their circuitry.

(3) 19% had specifications for their crane designs which were under review at the time the Bulletin and Circular was issued. Each reply in this category stated that information from the Bulletin or Circular would be factored into the final design.

(4) 25% of the replies stated that cranes are presently being installed or being designed but in each case no modifications were planned insofar as the crane circuitry was concerned.

In summary a review and evaluation of all replies revealed there was no generic problem inasmuch as the circuit modification depicted in the lower half of the figure was limited to only a few facilities. Nevertheless the experience gained from the Dresden Unit 2 event stressed the importance of a functional testing program following modification to the crane, as stipulated in Occupational Safety and Health Administration regulations No. 29-CFR 1926.179.

Point of Contact:
John J. Rizzo
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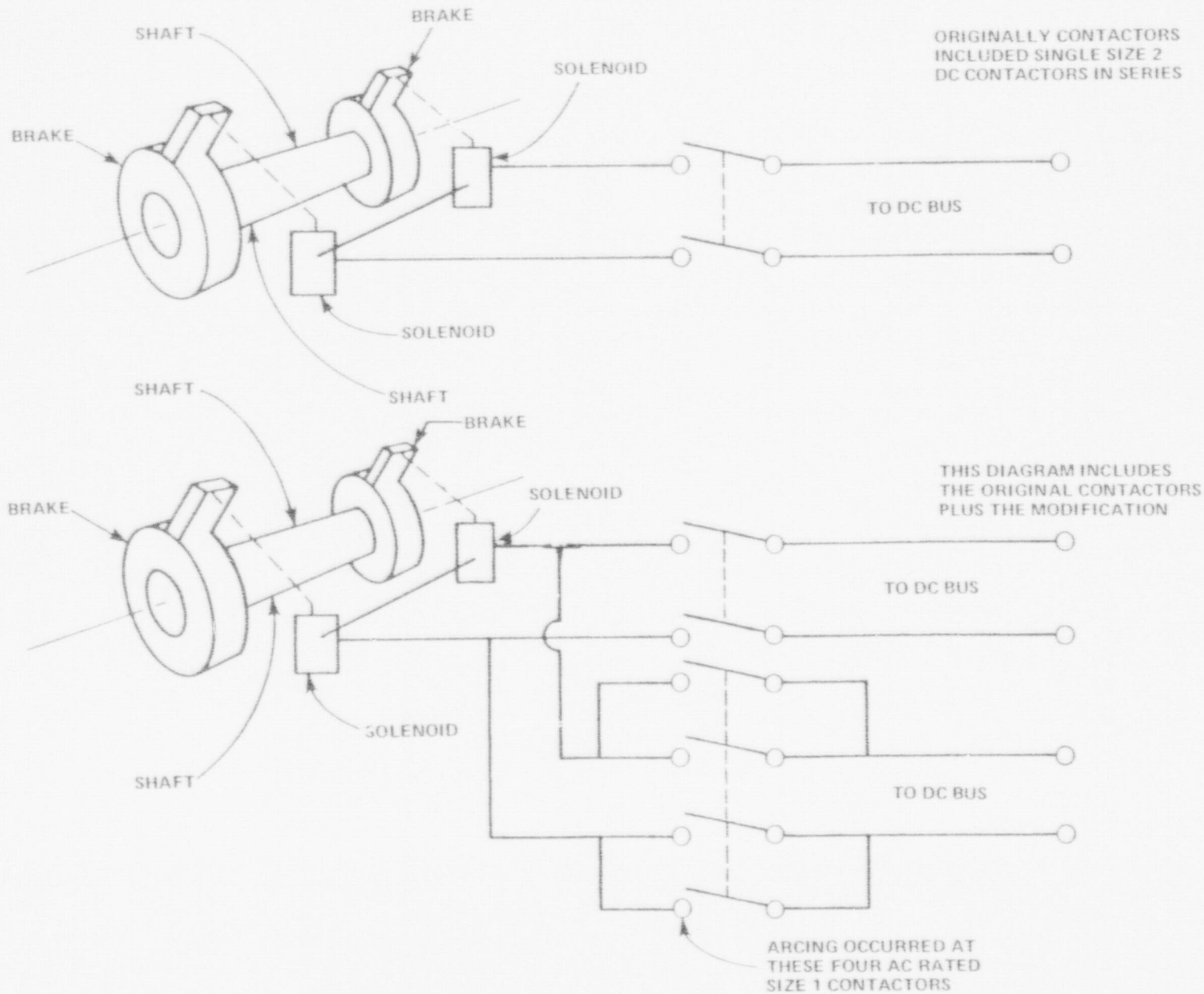
Information and Program Control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