ORNL/NSIC-121

REACTOR OPERATING EXPERIENCES

1972–1974

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U.S. Nuclear Regulatory Commission
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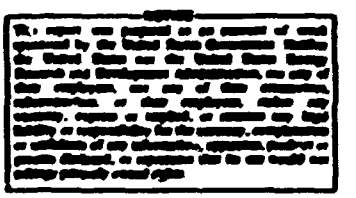

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PREFACE

In August 1966 the Nuclear Safety Information Center published a compilation of selected reportable occurrences experienced at reactor facilities. The report, ORNL-NSIC-17, contained selected operating experiences which had occurred in the United States from 1963 through 1965. This was followed by two other similar reports in October 1969 and May 1972, designated as ORNL-NSIC-64 and ORNL-NSIC-103 respectively. The format employed for each document was basically similar and involved utilization of Reactor Operating Experience (ROE) reports prepared by the former United States Atomic Energy Commission. Each original ROE report was issued by the Commission to help alert the industry to special operating problems by presenting the operating experiences of others. The Nuclear Safety Information Center has enhanced the usefulness of these individual reports by compiling them into single documents with indexes.

This new report, ORNL-NSIC-121, will update the three aforementioned reports. This latest compilation of ROE's covers the period beginning with January 1972 and ending in July 1974. In July 1974 the ROE program was discontinued and a new program was instituted. The last four reports presented in this document are part of the new program.

We wish to acknowledge our appreciation to the Office of Inspection and Enforcement, the Office of Nuclear Reactor Regulation and the Office of Administration for their assistance in identifying and processing of these reports.

Richard A. Hartfield, Chief
Performance Evaluation Branch
Office of Management Information and
Program Control
United States Nuclear Regulatory
Commission

FOREWORD

The Nuclear Safety Information Center is pleased to publish the fourth compilation of unusual operating experiences collected by the U.S. Nuclear Regulatory Commission (formerly a part of the U.S. Atomic Energy Commission). The earlier reports, ORNL-NSIC-17, "Abnormal Reactor Operating Experiences," ORNL-NSIC-64, "Abnormal Reactor Operating Experiences 1966–1968," and ORNL-NSIC-103, "Abnormal Reactor Operating Experiences 1969–1971," are still available from the National Technical Information Service (see page ii for address).

This compilation contains the experiences reported during the period January 1972 through December 1974. The reports have been arranged in numerical order and consequently they are in chronological order. Note that the last four reports are identified in a different manner due to a name change of the reports. An index has been prepared using keywords from the NSIC thesaurus of indexing terms. In addition, a permuted title index was also prepared to assist the reviewer in locating the reports of interest.

R. B. Gallaher and R. L. Scott
Nuclear Safety Information Center

FUEL HANDLING INCIDENTS

Summary

This report describes several INCIDENTS that occurred DURING FUEL HANDLING OPERATIONS. The cause of most of these incidents has been DEFECTIVE FUEL HANDLING MECHANISMS. Although none of the reported incidents resulted in significant radiological consequences, the dropping of a highly irradiated fuel element in a power reactor plant could lead to significant releases of radioactivity to the environment.

Circumstances

Defective Spring in Handling Tool

An irradiated stainless steel-clad fuel assembly came loose from the fuel handling tool as its nosepiece was entering the upper grid guide during core rearrangement at a BWR. The fuel assembly dropped approximately eight feet on the core support plate. Subsequent dry sipping of the fuel assembly showed no indication of cracks or leaks. The core support plate was slightly bent and was replaced with a spare support plate.

The cause of this occurrence was found to be a defective spring in the fuel grapple mechanism.

Inspection of the grapple spring from which the fuel assembly dropped showed that the spring had lost a considerable amount of its spring tension and had taken a permanent set.

A new grapple spring of improved spring material and heat treatment was installed on the fuel handling tool. The spring tension was also increased. This modification reduces the probability of the grapple taking a "set" in such a way as to allow the fuel element handle to come loose when the element is lifted. A check of grapple spring tension and distortion has been included in the periodic routine inspection of refueling tools prior to their use.

Galling of Lead-In Surface

An irradiated fuel element became disengaged from the fuel handling tool and dropped approximately 10 feet into an empty fuel storage position during fuel transfer operation at a PWR. Subsequent visual examination of the fuel element by binoculars and boroscope did not disclose any visible damage. Operating personnel concluded that the fuel element was not damaged because it dropped straight into the storage position and struck the storage pool wooden flooring which absorbed the impact.

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An examination of the fuel handling tool revealed some slight galling of the top edge of the lead-in surface of the fuel handling tool. The galling prevented the tool from properly seating in its mating piece in the fuel element. The galled surface was polished and a microswitch was installed in the tool to prevent upward motion of the tool unless it is properly seated on the fuel element.

No Locks on Latch

Following a series of low power experiments at a research reactor, the reactor tank was emptied of water, and fuel elements were raised individually for visual inspection. Upon raising the handling tool with a fuel element engaged, the operator hit the bottom of the wooden catwalk on the overhead crane with the top of the handling tool. The element came off the handling tool and fell into the reactor tank. Some welds holding the end fitting to the plates of the element sheared, and the leading edge of the end fitting was slightly flattened and driven into the element. No radioactive material was released.

The handling tool latches, which engage the fuel element through holes in the endplates of the element, are held in a retracted position within the tool sleeve by a spring. A long rod extends through the length of the tool sleeve and is fitted at its lower end with a conical knob which forces the two fingers of the latch into the extended, or latched position. The long rod is fitted with a pull trigger at its upper end. Investigation following the dropping of the element showed that the tool could be put into the released condition when it was inadvertently struck, as occurred in this instance.

To prevent a recurrence, the handling tool was modified to lock in the fuel element automatically, and to require a deliberate action by the operator to release the fuel element under all circumstances.

Tool Hits Crane Bus

During fuel transfer operations at a pool reactor, an operator inadvertently contacted the overhead crane power bus with the fuel handling tool. No personnel injury nor equipment damage resulted. Power to the crane bus was turned off in order to complete the task safely. Following this incident, appropriate protective enclosures were installed over the crane bus to prevent a recurrence.

Multiple Design Details

A graphite fuel element of a gas-cooled reactor dropped 13 feet into a parking hole canister when it became disengaged from the grapple of the charge machine hoist during a routine fuel inspection operation. During this operation, the fuel element was grasped with the head oriented 90° from the normal position, in order to provide two views, at right angles, of the element for checking that the element was straight.

ROE 72-1

Investigation following the incident disclosed that design deficiencies and poor adjustment of components contributed to the accident. The hoist and grapple are supported and actuated by independent steel tape systems. Tape adjustment was not optimum to give full jaw closure of the grapple. The jaw mechanism bottomed out on a support plate thus limiting full actuation of the jaw mechanism. There was interference between the jaw locking mechanism and the canister that caused the jaws to open slightly. Differential stretch of the tape systems resulted in an opening motion of the jaws. Rotation of the element 90° reduced the effective gripping area of the grapple by 50%.

Modifications were made to eliminate the design and adjustment problems, and operating procedures were changed to require that elements be picked up with the head in proper orientation for maximum gripping.

Welded Relay Contacts

While an irradiated fuel element was being withdrawn from the core of a water-cooled power reactor, a malfunction of the electrical controls of the fuel handling hoist caused an uncontrolled continuous upward drive. When the fuel element had reached the normal upper limit position, the operator released the "up" button. The hoist continued to raise the element until the operator pressed the "stop" button, de-energizing the hoist motor and controls and stopping the upward motion of the fuel element. The minimum height of water over the irradiated fuel element was estimated at 4 feet, and the maximum radiation level at the location of the operator was 125mR/hr., as measured by the Health Physics Technician present.

Investigation after the incident disclosed that the raise relay contacts were stuck closed. Inspection of the contact points of both raise and lower relays showed excessive pitting. As a result of repetitive jogging of the hoist, the raise relay contacts had finally welded closed.

To prevent recurrence of a similar event, both relays were replaced and arc suppression devices were installed across the relay contacts to increase contact life. Additional limit switches, to interrupt power to the hoist motor, were installed a short distance beyond the normal upper limit of the hoist.

Shorts in Hoist Control Circuit

ROE:67-9 described an incident at a nuclear power station in which a fuel handling grapple hoist experienced an uncontrolled continuous upward drive. The hoist grapple held no load at the time of the incident. The cause was determined to be two electrical grounds in the hoist control circuit which shorted out the raise control contact and resulted in an uncontrolled continuous upward drive. The corrective action consisted of installation of both a mechanical stop on the grapple and an additional electric stop to prevent contacting the mechanical stop during normal operation.

ROE 72-2 January 28, 1972

OVERINFLATION OF SUPPLIED-AIR SUIT

Summary

OVERINFLATION of a SUPPLIED-AIR SUIT worn by a man working in an inerted refueling cell CAUSED THE WEARER TO LOSE HIS BALANCE AND FALL across the reactor vessel head. Had the head of the reactor vessel not been in place, the operator would have tumbled into the vessel containing molten sodium. A CRIMPED VACUUM EXHAUST HOSE caused the overinflation.

See also ROE: 70-8, dated May 26, 1970.

Circumstances

Contact maintenance may be performed in the refueling cell at a liquid-metal-cooled reactor facility. Since the cell has an argon atmosphere, the operator in the cell wears a pressurized plastic suit, to which breathing and cooling air are supplied at controlled temperature and humidity through a flexible hose. Within the suit, the air is supplied to the face mask for breathing, and to the suit extremities for cooling. Exhaust from the face mask passes through a flapper check valve into the suit to mix with the cooling air. Air is exhausted from the suit by a vacuum pump and vacuum control valves through a flexible hose and piping. When suited personnel are working in the cell, standby personnel, equipped for emergency cell entry, are stationed at observation windows outside the cell.

In this instance, a man had been working in the cell approximately one hour when he reported that his suit was inflating. He was observed to lose his balance and fall across the reactor vessel head. The two standby operators outside the cell opened an emergency hatch, assisted the fallen operator out of the cell, and removed the supplied-air suit. The operator appeared to have suffered no injury or ill effect. A number of holes were made in the suit when he fell across the vessel head. By the time the standby operators had reached the fallen man, the suit had partially deflated.

Cause and Corrective Action

Tests showed that an air pressure in excess of 5 inches of water above atmospheric pressure within the suit would cause the suit, with the man inside, to become extended and slightly buoyant in the argon atmosphere, with the result that the man could lose his balance and traction if he were taking a step. The tests showed that when the exhaust hose, attached to the back plate on the suit, was lifted vertically, temporarily deforming the exhaust hose, the suit pressure rose to 15 inches of water in less than five seconds.

ROE 72-2

New hoses are being procured of a reinforced design that should preclude crimping. The use of alternate types of swivel connectors on these hoses will be evaluated. The Site Safety Committee suspended all use of the supplied-air suit until modifications are made, and the suit is given a comprehensive test in which component failures are simulated. The Committee also initiated a study of the basic need for the pressurized suit and is considering alternate means for protecting the operator.

ROE 72-3 February 11, 1972

FAILED BASKET STRAINER

Summary

A FAILURE OF A BASKET TYPE STRAINER IN THE PRIMARY COOLANT SYSTEM occurred at a water-cooled testing reactor BECAUSE OF POOR DESIGN AND CONSTRUCTION. No damage occurred as a result of the failures. In the event of a failure of this type, however, it would be possible for a piece of the broken strainer to lodge against a fuel element in a manner that would significantly reduce the coolant flow through the fuel element.

Description

The strainer assembly, located in a plenum in an 18-inch-diameter pipe section between the reactor heat exchanger and two sections of the reactor inlet pipe, consists of the strainer (number 4 size, 304 stainless steel wire mesh with 1/32-inch diameter wire) welded to a frame, reinforcing bars, and top and bottom plates. The assembly is shaped to fit the contour of the circumference of the strainer plenum. A similar strainer assembly is installed in the reactor outlet pipe.

Circumstances

The reactor was shut down to repair a leak in the vent line attached to the top of the reactor primary water inlet strainer. When the bolted cover plate for the strainer was removed to repair the leaking vent line it was discovered that the wire mesh, the two retaining bars and pieces of the bottom plate had apparently torn loose from the strainer basket and had been washed downstream. The strainer had been installed in the system for approximately four years. This was the first time that the strainer has been inspected. The reactor fuel was removed from the core and placed in the storage pool to permit repairs to the strainer, and the reactor vessel and primary piping were drained to the storage tank.

Inspection for missing pieces included radiographic or visual inspection of all piping between the point of failure of the inlet strainer and the bottom of the reactor vessel below the lower grid plate, disassembly of control and check valves, and examination of the outlet strainer and the reactor vessel. All missing pieces were found and removed, except for a triangular piece of the 1/16-inch-thick bottom plate (approximately 2" × 2" × 2"). The investigators concluded that the missing piece was not between the inlet strainer and the core. It is possible that the piece may have been removed during repairs made to the basket prior to operation of the reactor.

ROE 72-3

Cause

The probable cause of the strainer basket failure was determined to have been poor design and construction, with two main contributing factors:

1. The strainer basket was built of thin materials (1/16-inch plate and 1/32-inch wire). This did not permit adequate weld area to withstand local flow surges, turbulence and pressures occuring within the strainer; and
2. The strainer basket was built to cover almost the entire circumference of the plenum housing thereby considerably reducing the flow area through the strainer and increasing the pressure differential across the wire mesh, although the actual design showed the strainer to be recessed permitting greater flow.

Corrective Action

New strainers for both the inlet and outlet pipes were fabricated of heavier material (3/16-inch plate and 80-mil wire). The new basket is recessed farther from the pipe entrance in the plenum, permitting about 2-1/2 times the flow area and reducing the pressure drop across the wire mesh.

ROE 72-4 February 25, 1972

EMERGENCY POWER FAILURES

Operating Experience Reports, ROE:69-21 and 69-22, both dated October 10, 1969, and ROE:70-15, dated September 29, 1970, described a number of Failures of Emergency Power Sources to respond properly when called upon. Twenty-two MORE INSTANCES OF FAILURE OF EMERGENCY POWER SOURCES to respond properly are reported here. As in the cases covered in the earlier reports, no radiation hazard resulted from any failure.

Emergency diesel generators at reactor facilities failed to start during tests for the following reasons:

1. The governor lube oil supply had been depleted during an earlier shutdown of the diesel generator. The oil supply was restored by manually starting the second working cycle.

Investigation disclosed that when the diesel generator is shut down electrically, the governor attempts to maintain engine speed by applying governor oil pressure to hold open the fuel rack via mechanical linkages. An engine-driven pump supplies lubricating oil to a reservoir in the governor. As the engine coasts down to a halt, the oil supply to the governor is lost. However, the governor remains in the wide-open position until governor oil pressure decays to a point that spring tension returns the governor and the fuel rack to the closed position. At the next attempt to start the engine, it is necessary to crank long enough for the lube oil system to supply sufficient oil to the governor so that the governor actuates the fuel rack, and the engine starts.

A manual shutdown traps the governor oil supply so that it is immediately available during the next attempt to start the engine. It was found that, during a manual shutdown, a pin in the governor linkage could slip out of place if the control lever is released suddenly prior to the engine stopping.

A slightly oversized pin has been installed in the governor linkage. Revised operating instructions that require manual shutdown, and that describe proper manipulation of the governor control lever have been posted at the control panel.

2. The air-driven starting motor did not turn as a result of the failure of a solenoid valve in the air supply system. A buildup of oil and scale had impeded valve seating.

The valve was cleaned and the air reservoir tanks were blown down. It was found that the air supply for the valve plunger was taken from the line upstream of the in-line lubricator for the air motors. The supply line was rerouted downstream of the lubricator.

3. The pinions on the air-driven starting motors did not engage the ring gear of the diesel. The starting motors were found to be running with the pinion gear free wheeling. Both air compressors were running but the air-supply pressure was so low that the starting motors could not rotate the diesel engine.

A piece of weld slag was found in a check valve in the air-supply line that intermittently prevented the check valve from closing. A flow path resulted from the starting air accumulators to the starting motors causing them to rotate prior to engaging the ring gear, and also causing the decrease in air pressure.

4. The air-driven starting motor did not rotate. Dismantling of the air motor disclosed a broken cylinder and damaged vanes. The motor supplier and the diesel-generator manufacturer stated that this was an isolated failure and that such motors start successfully many thousands of times per year in diesel truck service. The failed motor had a prior record of 135 starts at the factory and an additional 135 starts at the reactor facility.

5. The diesel engine failed to start in the first 10-second cranking period. Ten seconds later, it started on the second crank.

The engine-mounted plunger on the hand-operated fuel-oil priming pump was found frozen in place and not fully seated, allowing enough air to be pulled into the fuel system so that the air was not cleared from the fuel system until the second cranking period. A priming pump of improved design has been installed.

6. The diesel engine failed to start on the first crank, but started properly on the second. The cranking procedure for this engine has five 10-second cycles of crank, off, crank, off, crank, and trouble alarm.

On the starting cycle, the engine must crank until the lubricating oil pressure reaches 25 psig, at which pressure a "cut in" pressure switch energizes two solenoids on the hydraulic governor. The governor then permits the fuel-pump rack to withdraw and the engine to start firing. The engine must fire in the remaining time period of the first crank, or wait the 10-seconds/off time.

To reduce the lubricating oil "cut-in" time, the pressure switch was relocated as close as possible to the main oil gallery for the engine by reducing the tubing from three feet of 1/8-inch tubing to four inches of 1/4-inch tubing. The elevation of the switch was also changed from above the pressure tap to below the tap to reduce the possibility of air entrainment. Subsequent corrective action included the installation of an electric-powered immersion heater to maintain higher cooling water and oil temperatures during engine standby periods. These modifications reduced

the "cut-in" time from 4.8 seconds to 2.5 seconds, and in subsequent testing the engine has consistently started in 3.0 seconds or less on the first crank.

7. Failure to start resulted because the controls in the automatic start position of the diesel-control transfer switch were not completely closed. Cleaning and adjusting the switch cured the problem. The control circuitry performed properly on a subsequent test, but the engine failed to start on the first crank and cranking speed was observed to be much slower than had been recorded during preoperational testing. The screen in the air line to a pair of air-driven starting motors was found to be almost completely clogged with rust. Cleaning the screens and blowing down the air lines resulted in successful starts of the diesel engine.

8. The overspeed trip on a diesel-generator unit was found to be in the tripped position during the investigation of an overspeed trip alarm that actuated during the last phase of a normal shutdown after a successful periodic test. The overspeed trip had been actuated by the decrease in lube oil pressure during the shutdown. Corrective action to prevent an alarm and trip during shutdown consisted of installation of a cutout of the low lube-oil-pressure trip during the last phase of normal shutdown of the diesel unit.

9. Pressure to the hydraulic cranking motor of a diesel engine is supplied from a bank of accumulators. Failure of the diesel to start resulted from failure of a 3/4-in.-tubing fitting between the accumulators and the motors. A flexible hose was installed in place of the failed tubing.

Emergency diesel generators at reactor facilities failed, after starting successfully, for the following reasons:

1. An emergency diesel had been operating satisfactorily under a test load when the operator noted that the frequency had dropped below 55 cycles/second. As he attempted to increase engine speed, the generator tripped. The engine then tripped on overspeed. Investigation disclosed that the operator may have failed to reset the mechanical overspeed trip before attempting to start the engine.

The cause of the decrease in the engine speed was determined to be a sticking fuel injector. Dirty fuel may have contributed to the sticking injector. Administrative procedures were reviewed to assure that delivered fuel is inspected for conformance to specifications to reduce the possibility of contamination and that filters are inspected regularly.

2. Immediately after an emergency diesel generator was started, high vibration was apparent on the end bearing of the generator. An inspection of the generator indicated that a rotor pole cap, including the attached balancing weights, had been thrown clear of the rotor and had caused damage

to the stator windings. The bolts which had secured the pole caps to the rotor had sheared.

The stator was rewound, and the mounting of the balance weights was changed to the face of the rotor core to reduce the shearing strain on the hold-down bolts.

3. The output voltage of an emergency diesel generator indicated zero immediately after the diesel engine started. Two diodes had failed in the same phase of the exciter for the generator field. No possible cause for failure could be determined as a result of a series of investigations. The failure was attributed to old age or moisture. Operators were reinstructed in the importance of checking for proper generator voltage prior to placing the generator in service.

4. An emergency diesel generator started but did not build up voltage. The governor speed control had been improperly set at less than 800 rpm at the conclusion of the previous surveillance test. The normal shutdown procedure includes the reestablishment of voltage and frequency conditions for automatic operation. The speed at which the start relay in the generator exciter energizes the generator field is 800 rpm.

The procedure for proper voltage and frequency adjustment was subsequently posted at the diesel-generator control switch.

5. A water-cooled diesel generator tripped about seven minutes after loss of offsite power. Although the cause of the trip could not be precisely identified, it was attributed to failure of a coolant boost pump to start when the normal coolant pump failed. The diesel generator is normally operated continuously during reactor operation with coolant flow provided by a pump that is operated from the offsite power. Upon loss of the normal coolant pump, a low-pressure circuit starts the coolant boost pump, powered by the diesel generator bus. It is believed that static pressure in the coolant header prevented the low-pressure circuit from being actuated. The coolant water boost pump control circuit was modified to start the boost pump on loss of offsite power.

6. A diesel started on an initiating signal but tripped because of low coolant pressure and high crankcase pressure. As a result of cool ambient weather conditions, the coolant-temperature control valve had operated to reduce flow, and also had reduced coolant pressure below the low-pressure-coolant trip point.

Corrective action included a lowering of the low-pressure set point for the coolant to 3 psig below the actual pressure at the switch. The crankcase-pressure trip set point was not changed; but the crankcase pressure was reduced by enlarging the flow-restricting orifice to the ventilation eductor for the crankcase.

ROE 72-4

7. A diesel tripped off on a signal from the low lub-oil-pressure switch after about 15 seconds of operation. To eliminate switch actuation resulting from vibration, the switch was relocated on the wall adjacent to the control panels rather than inside the control panels.

The line from the diesel lube-oil system to the pressure switch was approximately 15 feet long and of 1/4-in. diameter. The oil in the line was cold and viscous, and contained some entrapped air. These conditions probably prevented transmission of oil pressure to the pressure switch quickly enough to prevent diesel shutdown after the low oil-pressure shutdown-bypass time delay (15 seconds) dropped out.

The 1/4-in. tubing was replaced with 3/8-in. tubing and a vent was installed to permit the release of any entrapped air.

Gas turbine emergency generators were inoperable for the following reasons:

1. A gas turbine failed to start upon a loss of normal AC power following a turbine trip. A fuse had blown in the power supply to the tach switch which, in turn, prevented the speed switch on the electric generator from completing the start-up sequence. The terminals on the first stage speed-sensing relay had burned because of loose power-supply connections that caused a short circuit and the blown fuse. The fuse and relay were replaced and the power supply terminals connected properly.

2. A gas-turbine generator failed during test because a DC emergency lube-oil pump for the generator failed to reach the required discharge pressure.

The pump speed was found to be about 500 rpm under rated speed. The brush rig position was adjusted to bring up the speed.

The temperature set point for the thermostat that controls the lube-oil reservoir was increased as recommended by the manufacturer. These changes resulted in proper pressures at the generator bearings prior to generator roll-off on a fast start.

The starting time was improved by the installation of improved governor components, and a larger fuel forwarding pump motor.

3. A gas-turbine generator failed because the emergency lube-oil pump failed to reach the required discharge pressure in time to prevent turbine trip. The problem was traced to an excessively low lube-oil sump temperature. The heating capacity of the sump immersion heaters was doubled by adding six more heaters. Two forty-gallon accumulators were installed on the discharge of the lube-oil pumps. The accumulators are kept charged by the continuous operation of the AC lube-oil pump for the electric generator and will function to assure adequate lube-oil pressure during the period

following a loss of normal power until the emergency DC lube-oil pump can furnish the required flow and pressure.

4. The unit, mentioned in 3 above, failed again because the lube-oil pump failed to reach required discharge pressure. When the two accumulators were installed on the discharge side of the lube-oil pump, a vent line that had been connected on top of the pump reservoir was not reinstalled. Air accumulated on the discharge side of the pump, thus requiring a longer time for the pump to attain required discharge pressure.

Reinstallation of the vent line solved the problem. Subsequently, it was determined that one of the accumulators had lost its nitrogen charge. The accumulator was repaired and recharged. The surveillance tests were amplified to include operability of the accumulator and other gas turbine auxiliaries.

5. The excessively slow starting time for a gas turbine was found to be the result of leaks on the seals of the air start motor.

6. While an emergency gas turbine was shut down, the low-level indicator on the lube-oil reservoir alarmed. The oil-pump switch was found in HAND position, rather than AUTO as required by procedure. As a result, the turbine lube-oil pump had continued to run, while the vapor extractor was not running, and oil had been forced out of the system at the air start motor.

ROE 72-5 March 10, 1972

LOSS OF DC POWER SUPPLY RESULTS IN TURBINE DAMAGE AT PWR

Summary

DAMAGE to the MAIN TURBINE occurred at a pressurized water reactor DURING A ROUTINE TEST OF THE TURBINE-OIL SUPPLY WHEN POWER TO THE EMERGENCY OIL PUMP WAS LOST. The battery for the station was supplying power to the emergency oil pump with the battery charger on-line. Because of the larger-than-normal load there was a continuing decrease in battery output causing a reactor trip, a loss of the DC turbine oil pump, and a loss of the normal AC turbine oil pump when the breaker to Motor Control Center-5 tripped. As a consequence, the oil pressure in the bearing decreased as the turbine coasted down. An assessment of the damage indicated that all eight turbine and generator bearings had suffered some damage and that the rotor connecting the two low-pressure turbines was also damaged. In addition, SEAL-WATER FLOW and THERMAL-BARRIER FLOW WERE INTERRUPTED to two reactor-coolant pumps for approximately one minute during the reactor shutdown, RESULTING IN UNEVEN HEATING AND DISTORTION OF THE SHAFT OF ONE OF THE REACTOR COOLANT PUMPS.

Circumstances

While the reactor was operating at 85% of full power (615 MWe), a 50 hp DC emergency oil pump, which is powered by one of two battery banks (battery A), was started for a routine weekly 2-hour test run. The pump was not stopped after two hours as planned. Four hours and twenty-five minutes after the test was begun, the station battery had become so depleted that a reactor trip occurred because of low DC voltage on the trip coils of the reactor trip breakers. The reactor trip initiated a turbine trip, and a generator lockout occurred about one minute later when the circuit breaker and stop valves closed. This generator lockout caused the 4kV busses 3 and 4 to be transferred to the startup transformer; however, because of the low voltage from battery A, the tie breakers to the startup transformer for busses 1 and 2 did not close, and the power to these busses was lost. Emergency diesel generator A started properly but the E-1 emergency bus did not close because of the low DC voltage. The loss of busses 1 and 2 led to the loss of the AC turbine oil pump.

The DC emergency oil pump was already inoperable because of the low voltage in Battery A. As the turbine slowed, the shaft oil pump became ineffective, and the turbine was unable to receive lubrication from either the AC or the DC oil pump. The turbine coasted to a stop in 17 minutes rather than the normal 1-1/4 hours. This resulted in seizure of the turbine rotor in several bearings.

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Discussion

The battery chargers at this facility are rated at 300 amps with a current limiting device set at approximately 375 amps. With the normal load on Battery A being approximately 150 amps and the DC oil pump requiring approximately 365 amps, the approximate load on the DC bus while the DC oil pump was operating was probably in excess of 500 amps. This imposed a minimum discharge rate on the Battery A of 125 to 200 amps. A 200-amp discharge rate would lower battery voltage to 105 V DC in approximately four hours, assuming a fully charged battery initially. A subsequent check of Battery A after the incident showed that it had a voltage of 60 volts and 0 amps current flow.

Shortly before the incident, one momentary alarm was received on the "Battery B Charger Trouble" annunciator. The alarm cleared immediately and no further indication of trouble was noted on Battery B or its charger.

Six minutes before the reactor trip, the plant computer failed. Subsequent investigation revealed the failure was due to low DC voltage (DC power supply for the computer is Battery A). Since there had been numerous computer failures in the past, no significance was placed on this failure at the time. One minute after the computer failure the reactor operator noticed that the reactor-trip-breaker indicator light was out and notified the shift foreman. The bulb was changed with no effect. Several other lights on the reactor turbine generator board were also observed to be out, and a technician was summoned. Instrument busses were checked for failure. Three minutes prior to the reactor trip, a low-flow alarm for thermal-barrier cooling water to the reactor-coolant pumps was received. The air-operated outlet isolation valve had closed because of low DC control voltage and caused the loss of cooling water. Valve-position indication was also lost. Three minutes later, low voltage on the DC trip coils caused a reactor trip, but no battery charger alarms were received.

One charging pump failed because voltage to the E-1 bus was lost. Another charging pump was started immediately to reestablish seal- and charging-water flow. During the seconds that both charging pumps were down, the seal leak-off temperature on reactor coolant pumps A and C (both of which had tripped when busses 1 and 2 were lost) rose sharply to approximately 300°F, and the seal-water flow on the A and C pumps decreased to zero.

The level indicator for the volume control tank indicated zero. The operator switched to the refueling water storage tank to reestablish the volume-control tank level, then switched back to normal lineup after the indicated level in the volume control tank reached 30 inches.

A signal from the safety-injection system was activated as a result of the failure of the instrumentation power supply. The pressurizer level remained above 20%, and pressure above 2000 psi. All safety-injection equipment except that from bus E-1 operated satisfactorily.

Approximately three minutes after the turbine had stopped, the battery-bus tie between Battery A and B was closed manually and Battery-A voltage immediately increased to 125 volts. The breaker between diesel-generator A and the emergency-bus E-1 closed and restored the voltage in E-1. The operator then closed the tie breakers and picked up 4-kV busses 1 and 2 from the startup transformer. He then restored power to the 480 V-bus No. 1 via station-service transformer A. The oil pump for the turning gear started when power to the E-1 bus was restored and the turning gear attempted to roll the turbine. The turbine, however, would not turn and the turning-gear motor began smoking heavily. The turning-gear motor was then manually tripped. An investigation, which was made when attempts to roll the turbine both manually and with an air-driven motor had failed, revealed that oil was pouring from the No. 5 turbine bearing. The oil pump and lift pump for the turning-gear were secured because of the oil leakage from the bearing.

Condenser-vacuum and steam-seals were maintained on the unit, and steam dump to the condenser continued.

Restoration of DC power allowed the outlet isolation valve to open to restore thermal-barrier flow to the reactor-coolant pumps. Approximately five minutes after restoring power to normal, the breaker in Motor Control Center-6 tripped, and the operator was unable to reclose the breaker. The control fuses were replaced and the breaker then closed properly.

Results

An assessment of the damage indicated that all eight turbine and generator bearings had suffered some damage. The most severe damage occurred in bearings 4 and 5, which are between the two low-pressure turbines. These failed to the extent that molten babbit metal flowed through the bearings. As a result, the No. 1 low-pressure turbine rotor dropped enough to allow the rotor to rub the shell. Some steam-seal strips failed and three shroud segments on the No. 6 wheel nearest No. 4 bearing cracked. Surface hardening of the No. 1 rotor had occurred on the oil seal adjacent to the No. 4 bearing, so the rotor was removed to the manufacturer's turbine shop for a complete inspection. The "hard spot" was removed by machining. The bearings were also returned to the manufacturer for repair.

The No. 2 low-pressure rotor was removed from the shell and inspected thoroughly at the plant. Magnaflux readings were taken on all critical areas. No damage was indicated on the No. 2 rotor or shell so that unit was reassembled.

Investigation also revealed that the shaft in pump A had been warped by the excessive temperature in the pump seals and bearings when the simultaneous loss of charging flow and thermal-barrier cooling-water flow occurred. Although seal-leakoff temperatures in both A and C pumps had risen to approximately the same values, C pump was not damaged.

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Corrective Action

The incident was initiated by the decrease in Battery-A voltage to the point where components supplied by bus A in the DC-system A could not function as designed. Several factors, for which corrective actions have been initiated, contributed to this loss of DC power. Corrective actions include the following:

a. Operating procedures and operator training have been reviewed, to ensure that a longer-than-planned operation of the DC emergency oil pump does not occur.

b. A low voltage alarm has been installed on the battery bus to warn the control operator of low DC-bus voltage. In addition, the battery-charger annunciator alarm, which formerly remained on only while the alarming condition existed, will now continue after the alarm condition clears and until the annunciator is manually reset.

c. Additional batteries have now been added to furnish control power to the diesel generator when the main batter voltage is lost. This supplements battery voltage to ensure proper operation of the emergency busses in the event that a diesel-supply breaker fails to close.

ROE 72-6 March 24, 1972

FIRES

Introduction

This operating experiences report describes SEVEN FIRES that have occurred at reactor facilities. Although none of these fires directly affected the nuclear portions of the plants and the personnel reacted promptly and correctly, knowledge of the causes of and events surrounding these fires can be of potential value to personnel at other plants. Other fires have been described in the following previous ROEs: 63-1, 63-2, 67-11, 69-4, and 70-6.

Circumstances

Low Flow Through Air Dryer

While a power reactor was shutdown a loud blowing sound became clearly audible in the reactor control room, followed at once by several alarms. Investigation disclosed that the instrument air header had separated at the discharge of the after-filter of the air dryer. The after-filter had overheated, and loosened a silver-soldered copper-to-copper joint.

The cause of the incident was determined to be a low flow of air through the air-dryer unit. The sequential timer on the air dryer had been set for a cycle of three hours of heating followed by one hour of cooling. The heater thermostat was set at 650°F. These settings were based on an anticipated 100–200 standard cubic feet per minute (scfm) of air flow. The actual air flow through the unit was only about 20 scfm. This lower flow did not deposit enough moisture on the desiccant to absorb the heat input from the heating element of the dryer with the controls set for the design value of 100–200 scfm. the resultant high temperature led to the ignition of the filter paper of the after-filter. The intense heat had then melted the solder of the silver-soldered joint.

To compensate for the low air-flow through the dryer, the manufacturer recommended that the controls be reset for a cycle of two hours of heating and two hours of cooling, and that the heater thermostat setting be reduced from 650°F to 350°F. The damaged filter was replaced and the filter medium was changed to a material capable of withstanding 350°F.

Charcoal Filter

When the Standby Gas Treatment System at a boiling-water reactor was started, sparks were noticed going past an inspection port that was downstream of the charcoal filter bank. The unit was shut down immediately, and the fire in the charcoal filters was extinguished with a CO_2 extinguisher.

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The fire had been caused by the overheating of the electrical strip heaters of the charcoal blanket. A short circuit across one of the heaters, caused by a deterioration of the plastic tape on the lead wires, had initiated the overheating.

To preclude recurrence of the overheating, the lead wires to the strip heaters were taped with asbestos tape. Also, the heater circuits were modified to include temperature switches that sense the surface temperature of the heaters and interrupt a control signal to the power-control unit if the heater temperature exceeds 400°F. The damaged charcoal filters were replaced, and the filter unit was tested.

Further review and evaluation of the system revealed that the charcoal blanket could be heated sufficiently by ensuring that the room temperature did not fall below the dew point while the reactor was shutdown. To maintain the temperature of the charcoal filters above the dew point temperature in the room, two 12 kW heaters were installed. The thermostatically-controlled heaters are powered from the emergency bus. Also, a temperature sensor was installed downstream of the charcoal filters to annunciate in the reactor control room if the room temperature should exceed a preset value.

Oil Leaks

a. Smoke was detected during an entry into the containment for an inspection during full power operation at a pressurized-water reactor (PWR) facility. The vicinity of a main coolant pump was identified as the source of the smoke. Power was reduced and the reactor coolant loop from which the smoke was emanating was isolated for purposes of investigation.

   The fire had resulted from oil leaking from a thermocouple junction box on the upper thrust bearing of the main coolant-pump motor. The oil soaked into the insulation on the suction piping from the pump and vaporized on the hot pipe.

   The outer layer of the four-inch-thick insulation of wire-wrapped fiberglass mat was charred as a result of the burning and smoldering. The oil was reported to have a flash point of 395°F and an ignition temperature of 700–750°F. The oil leak was repaired, the damaged insulation and residual oil were removed, and the pipe was reinsulated and sealed with aluminum cloth.

b. Coastdown tests of the reactor-coolant pumps were in progress during preoperational testing at a PWR facility. An observer, stationed at the pump for the test, noticed smoke coming from the insulation that covers the volute of the reactor coolant pump and immediately called for assistance to fight the fire. Several minutes after the fire was extinguished, a reflash

occurred and was immediately extinguished. To prevent a recurrence of flashing, a cooldown of the primary system was initiated. As cooling progressed, pieces of the oil-soaked insulation were removed and any resulting fires were extinguished.

A rupture in the high-pressure oil line from the oil-lift pump to the upper thrust shoe on the motor of the reactor-coolant pump allowed the oil to seep onto the hot volute (547°F) where it flashed. The rupture in the oil line occurred because a female swivel fitting was omitted during construction, and the oil line could not turn when a twisting force was applied.

The fitting was replaced by one of an improved design and splash pans were installed to prevent oil spillage from reaching hot piping areas. The oil specifications were rechecked to ensure that they had the following characteristics: flash point, 455°F; fire point, 490°F; ignition, 682°F.

NaK Spill

A spill of between one and two pints of sodium-potassium (NaK) eutectic from an argon-purification bubbler occurred in the refueling cell of a liquid-metal-cooled reactor. Carbon dioxide was injected into the cell to convert the NaK to carbonate, but when the cell air purge began, a NaK fire was observed in the cell. The air-purge valves were immediately secured. Argon was discharged into the area of the fire and additional CO_2 was introduced into the cell. Again, while the cell was subsequently being purged with air, a NaK fire broke out and was extinguished by a purge of argon over the NaK.

An investigation disclosed that, when the CO_2 was introduced into the cell, there was insufficient moisture for conversion of the NaK to carbonate.

The NaK was postulated to have entered the argon-circulation system because of errors in valving. Consequently, operating procedures to prevent these valving errors were instituted. Additionally, the purification system was redesigned to include a cyclone separator in the discharge line so that any NaK carryover is prevented, and a catch tank was included in the suction line to prevent backflow. The NaK-cleanup procedure was revised to ensure that a sufficient amount of moisture is introduced into the cell prior to the addition of CO_2 so that the NaK could be converted to the carbonate form.

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Sodium Leak

A mild, explosive energy release and a sodium fire occurred when sodium leaked from a piping system in the cold trap room of the fuel-handling building of a sodium-cooled reactor. A sodium-water reaction in the annulus of the double walled pipe in the cold trap caused the rupture of the outer pipe. The cold trap room was immediately isolated from the ventilation system and purged with argon. The heating of the sodium-system piping was shut off to freeze the sodium. The incident was confined to the cold-trap room and did not involve the sodium from the reactor primary-cooling system.

The sodium piping and equipment comprising the cold trap system are enclosed in a carbon-steel structure, and the resulting annuli are inerted with nitrogen.

Post-incident investigation and analysis indicated that a combination of two separate failures associated with the cold-trap system caused the sodium-water incident. The source of water was a small leak in the water-nitrogen heat exchanger in the nitrogen-cooling system, although there was some evidence that the water could have accumulated beneath the cold trap. In addition, the inlet to the electromagnetic sodium pump contained a small crack which provided a path for leakage of sodium into the secondary containment region where the water accumulated. It is hypothesized that hydrogen and sodium hydroxide or sodium oxide were formed as reaction products. The heat of reaction raised the temperature, weakening the steel-lined structure and raising the internal pressure. Both of these phenomena contributed to the subsequent failure of this containment barrier. It is further postulated that hydrogen may have reacted with the available air in the room, producing a pressure pulse which caused the observed damage to the secondary containment, and which permitted the sodium retained by the barrier to enter the cold trap room where it oxidized slowly. The sodium-air reaction was terminated by a buildup of a protective layer of oxide on the sodium surface and by oxygen depletion which occurred as a result of isolating the cold-trap room and introducing argon through a temporary connection to an available header.

The pertinent operating procedure states, "If cold trapping is being done at the time (of a leak detector alarm), the operator will secure the system by shutting down the EM pump, nitrogen blower, all heaters external to the transfer tank room and close all valves." The facility had a history of ten leak-detector alarms since the system was put into operation four years previously. Seven of these alarms had proven false, resulting from either thermal movement of the piping or contaminants at the electrode gap, and three false alarms had occurred within the preceding six months. Based on this past experience, the operators immediately notified the Technical Engineer rather than shut down the system when a leak-detector alarm was received in the control room. A visual inspection of the cold-trap room was made by the Technical Engineer, the Maintenance

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Engineer and the operator. No unusual conditions were noted, and the group returned to the operating room to review conditions. A second leak-detector alarm was received, followed immediately by the sound of the explosion from sodium-water reaction.

As a result of the review and evaluation of the incident, design changes were made to the electromagnetic pump, the nitrogen-water heat exchanger, and the cold-trap system and its instrumentation, to minimize the probability of occurrence of a sodium-water reaction. In addition, the management of the facility re-emphasized the requirement that operating procedures be followed, and that the existence of abnormal conditions and suspected unreliable equipment should be reported promptly to the Plant Superintendent for his evaluation and action.

ROE 72-7 April 21, 1972

TURBINE LOCKOUT AT A BOILING WATER REACTOR

Summary

A TURBINE LOCKOUT occurred at a boiling water reactor (BWR) SUBSEQUENT TO A LOAD-REJECTION TEST from approximately 15% of full-power. The result of the turbine lockout was a LOSS OF AUXILIARY POWER and AUTOMATIC SHUTDOWN OF THE REACTOR. After restoration of auxiliary power, the recirculation pumps could be neither restarted nor isolated in time to prevent the failure of the seals on the pumps. This failure of the pump seals allowed the release of primary coolant into the primary containment volume (drywell) and increased the drywell pressure approximately 1 psi until the drywell was vented to the atmosphere through the Standby Gas Treatment System.

Circumstances

Preparations for a scheduled load-rejection test included both procedures for anticipated plant response under the test conditions, and precautionary procedures for which operators were stationed at key locations so that they could restore the auxiliary power for the plant in the event it should be lost.

With the reactor at rated temperature and pressure and at a power of 235 MWt, a load rejection was initiated. Fifty seconds later a turbine lockout occurred. The output breakers from the Motor-Generator (MG) set supplying the Reactor Protection System (RPS) were tripped automatically by their under-frequency relays. This resulted in the automatic shutdown of the reactor and the isolation of the primary containment system. Since the feedwater, control-rod drive (CRD), and recirculation pumps had tripped prior to reactor shutdown, the reactor-core isolation-cooling system provided makeup water to the core until these pumps were restarted. The feedwater and CRD pumps were restarted within 6 minutes; however, difficulty was encountered when attempts were made to restart the recirculation pumps because permissive interlocks apparently failed to operate properly. Attempts to protect the seals of the recirculation pumps by isolating the pumps were unsuccessful also, and within 15 minutes after the scram the drywell pressure had risen about 0.6 psi. Observations confirmed that the seals had failed on one of the recirculation pumps.

Because the temperature of the water in the pressure-suppression chamber (torus) had begun rising slowly, one of the residual-heat-removal (RHR) pumps and one of the residual-heat-removal service-water (RHRSW) pumps were started to cool the torus water. However, the control valve for the service-water outlet of the RHR heat exchanger failed to open. When a third attempt to open the control valve failed, the operator switched the valve controller to the manual mode and opened the valve. The valve operated properly when the controller was returned to the automatic mode.

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The feedwater pump was removed from service when the water level in the reactor vessel had risen to 50 inches above the reference level. Since water was still being added by the CRD pumps, the charging-water supply was shut off to decrease the addition rate. The reactor-core isolation-cooling system, operating in the TEST mode, was extracting the steam through the cleanup system.

Further attempts to isolate the recirculation pumps were still unsuccessful. At this time it was determined that, in addition to the RHR control-valve failure, the isolation valves for the drywell-sampling system would not open.

When drywell pressure reached 15.4 psia, the drywell was vented through the 18-inch line of the Standby Gas Treatment System (SBGTS) for about 1 minute. The drywell pressure rapidly decreased to 14.1 psia with the stack-gas activity being limited to about 15 μCi/sec. About 75 minutes after the turbine lockout occurred, the suction valve on one of the recirculation pumps closed while an operator was contacting his attempts to close the valve from the control room. Subsequent investigation of the problems with the pump led to the hypothesis that the inner seal on the pump had failed.

Preparations were begun to re-establish condenser vacuum. The outboard main-steam-line isolation valves (MSIVs) were opened, but attempts to pressurize the system between the inboard MSIVs and the turbine-stop valves by means of the main steam-line drain valve proved futile because the outboard isolation valve for the inner drain line would not open. The isolation valves were opened by manually opening the contactors at the motor control centers. Meanwhile, the suction valve on the other recirculation pump was closed manually by closing the contactors on the valve motor.

Condenser vacuum was established and depressurization of the reactor was begun about 98 minutes after the turbine lockout. Three hours and fifteen minutes after the turbine lockout, all reactor trips had been cleared.

Causes and Corrective Action

Turbine Lockout

The most probable cause of the turbine trip was postulated to be a high-water-level trip from a moisture-separator tank. However, the occurrence of the level trip could not be verified because the high-level indications from the moisture-separator drain tank were not connected to the data-logging computer, although an alarm was attached to this indicator. The indicator is now connected to the computer so that a sequential, chronological computer printout of events can be obtained for any high-level condition for the moisture-separator tank.

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The drain valves and controls for the four moisture-separator drain tanks were checked. One drain valve did not function properly, so it was repaired.

Recirculation Pumps

One recirculation pump failed to restart after the RPS MG set was returned to service because a valve-position limit switch which provides a permissive-interlock function in the pump-starting circuit did not operate properly. The second recirculation pump, after starting, tripped again because of an incorrect setting on a time-delay relay in the pump-starting circuit and because of a shift in calibration of a differential-pressure transmitter which provides a permissive signal to the autostart sequencing logic. The differential-pressure transmitters for both pumps were calibrated and the autostart sequencing logic for both pumps was checked for proper time-delay settings. All valve interlocks in the recirculation system were checked and adjusted where necessary to assure proper operation of the relays. The seal cooling system for the recirculation pumps was totally redesigned. The new design provided for using the same cooling-water system that was used for the control-rod-drive seals.

Failure of the Recirculation-Pump Suction Valves to Close and the Main-Steamline Drain Valves to Open

Torque limit switches that were improperly set were the cause of the malfunctioning of the suction valves in the recirculation system and of the drain valves in the main steam line. The torque-switch settings were checked and properly reset where required. All the valves were then tested under cold conditions to verify proper operation. A program for continual surveillance of the torque-switch settings and the operation of their related valves was then developed.

Drywell-Sampling Isolation Valves

When the reactor shut down from the turbine trip, the sampling-system valves could not be opened from the control room. An investigation of the problem revealed that the instrument air supply to the valves was provided by the header for the CRD scram system, and that the header was depressurized by the backup scram-solenoid valves subsequent to reactor shutdown. The air supply to the sampling-system valves was changed so that the air supply comes directly from the header for the reactor building air-supply system.

Possible Effects of Drywell Moisture on Nuclear Instrumentation

During preparations for returning the plant to the line, resistance measurements were taken on all cables for the local-power-range monitors. Nine detectors produced above-normal signals and all nine detector cables

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indicated low resistances. The cable connectors were cleaned and the resistance values returned to normal. All nuclear instrumentation was functioning normally before the plant was returned to service.

BDE 72-8 May 5, 1972

STRUCTURAL DAMAGE TO CONTAINMENT TORUS BAFFLES

Summary

During a scheduled maintenance shutdown at a boiling water reactor (BWR), STRUCTURAL DAMAGE OF BAFFLES in the pressure suppression chamber (torus) of the containment was noted during internal inspection of the torus. On the basis of an engineering analysis, it was concluded that the damage RESULTED FROM THE DYNAMIC LOADING PRODUCED BY THE DISCHARGE OF THE PRIMARY-SYSTEM SAFETY/RELIEF VALVES into the water in the torus. The baffles were removed, and the discharge point for the relief valves was moved into the deepest part of the torus water.

Circumstances

The torus of the BWR containment was provided with 72 baffle sections for the purpose of preventing a short-term overpressure in the event of blowdown of the primary system within the containment. This overpressure had been observed in 1/4-scale tests of the containment design, but later evidence obtained from full-scale tests showed that the baffles were unnecessary.

The baffle sections consisted of two I-beams that were supported by brackets on each side of the torus wall. Channels were welded along each I-beam with the wide surface of the channels positioned vertically and the channel webs welded to each other. The baffles were connected to the brackets by four 7/16-inch bolts at each end and were mounted just below the normal water level in the torus. Prior to the scheduled plant shutdown, an air-actuated torus-to-drywell vacuum breaker valve had not responded to test signals.

Upon entering the containment torus, personnel found that 11 of the 72 baffle sections were dislodged from the support brackets at one or both torus walls, and that 114 bolts were out of place. The damaged baffles were located in the area where the relief-valve discharge lines and the discharge line from the high-pressure-coolant-injection-system turbine entered the torus. The air-supply line to the actuator for the inoperable vacuum breaker valve was broken off inside the torus near its penetration of the torus wall. The line breakage apparently was caused by a baffle striking the vacuum-breaker air-supply line. Damage was also noted to 6 of the 8 low-point drain lines on the drywell vent-distribution header.

Angle-iron supports from the lower torus-wall area provide the bracing for the catwalk to the vacuum breakers in the torus. Four of these supports were sheared off and four more were badly bent, although they were still in place. The wall surface of the torus was scratched by the movement of the ends of the baffles, but no significant damage was done to the metal walls.

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All the u-bolts that had been used to anchor the 10-inch relief-valve discharge lines to the torus wall were stretched and the brackets were bent.

Conclusions

Based on an engineering analysis of the type and extent of physical damage, it was concluded that the damage resulted from the discharge of compressed air which immediately follows the discharge of water when the primary system safety/relief valves open into the torus. Although the water that is in the discharge pipe is rapidly ejected from the piping when the valves open, calculations showed that the forces produced by the water would be short lived and that the baffles were designed to withstand greater resultant forces.

Air, that is distributed in the relief-valve piping under normal conditions, is compressed by the steam flow when the relief valve is actuated. As the compressed air is suddenly injected into the suppression pool, the displaced water exerts forces which could be capable of displacing the baffles, especially baffles that are close to the discharge point. The steady-state steam flow, which follows the initial transient from the water-air slug, exerts insignificant forces on the baffles.

Remedial Actions

Since the torus baffles had been shown to be unnecessary and have been omitted from later-design BWRs, the reactor manufacturer recommended that the baffles be removed.

In the original design the relief-valve discharge line released steam straight down near the inner torus wall, 4 feet below the normal torus water level. The design was modified to extend the discharge line into the deepest region of the torus water so that steam is ejected about 9 feet under the water from a ram's-head tee that directs the steam flow away from the walls of the torus. Also, in the modified design, new supports were provided to anchor the discharge lines within the torus.

ROE 72-9 May 19, 1972

EQUIPMENT MALFUNCTIONS IN A STANDBY GAS TREATMENT SYSTEM

Summary

During testing of the STANDBY GAS TREATMENT SYSTEM at a boiling water reactor (BWR) facility a series of DIFFICULTIES was EXPERIENCED involving electrical heaters, dampers, and damper controllers. The three separate occurrences were detected during the pre-fuel-loading testing periods when secondary containment was not required.

Circumstances

Each of the two Standby Gas Treatment System (SGTS) was originally provided with a 20 kW air heater. To reduce the pressure drop in the system, and thereby increase the gas flow rate, the 20 kW heater in each train was replaced by three heaters of 12 kW each, raising the total heat rating from 20 to 36 kW per train. Since the power-control circuitry for each filter-train heater had been designed and sized for 20 kW, recalibration of the current-limiting circuitry was necessary when the 36 kW of heating capacity was installed. During the recalibration, a fuse to one of the SGTS heater circuits was blown. The cause of the blown fuse was traced to a short in one of the 12 kW heaters. The heater was disconnected, the blown fuse was replaced and recalibration continued. About ten minutes later, when the control panel door was opened for calibration of the current-limiting circuit to the two operational heaters in the filter, smoke was observed in the panel. A short in the air-heater power-control circuitry, in combination with a momentary overload produced as part of the recommended calibration procedures, resulted in a high current flow which damaged one of the silicon-controlled rectifiers, a current-limiting transformer, and other components in the power-control circuitry.

The damaged components were replaced or repaired and put back into service. Procedures were changed to calibrate from a lower power level up to the maximum set point of 20 kW which is the limiting value for which the circuitry is rated. In addition, the heater capacity was physically limited by disconnecting sufficient heater elements to reduce the capacity from 36 kW to 20 kW.

Following the event described above, the SGTS train B was put into service to verify its operability. A flow of 4000 cfm is the design value for maintaining a partial vacuum of 0.25 psi in the secondary containment during emergency conditions, but only 2800 cfm was flowing through train B.

One of the turbine building exhaust fans was exhausting into stack-dilution fan A. When the low flow in filter train B was observed, the flow was switched to filter train A. Low flow was also observed in filter train A. Stack-dilution flow was switched from dilution fan A to fan B. Flow through filter train A then increased to 3900 cfm. When flow was

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transferred back to train B, it decreased to 3300 cfm. Investigation revealed that a back-draft damper on stack dilution fan B had failed to close properly when operation was transferred from filter train B to train A. The dilution fan B back-draft damper was manually closed and, with the stack dilution fan A operating, flow in filter train A increased to 4000 cfm. When flow was switched to filter train B, however, flow was only 3300 cfm. The stack dilution fan B back-draft damper was found to be binding in the duct work as a result of end play of the damper shaft. After this was corrected, dilution fan A damper was modified in the same manner to prevent a possible similar malfunction.

When turbine exhaust fan B was started, the flow from filter train A decreased from 4000 cfm to 3850. Investigation revealed a design error in the logic circuitry for the plenum-exhaust dampers. The error in wiring caused filter train A to be associated only with plenum-exhaust damper A, and filter train B only with plenum-exhaust damper B. Since exhaust damper A did not open when filter train B was placed in service, additional dilution air was supplied by turbine-building exhaust fan A and the flow through train B was reduced. A wiring change was made to open the proper plenum exhaust damper, independent of which SGTS train was operating. The difficulty was corrected and both trains were successfully cycled several times.

Further testing was performed of train A of the SGTS. The first operability test was satisfactory, and a 4000 cfm flow was achieved through the train. However, when the system was restarted the flow was only 3950 cfm with the discharge damper adjusted to approximately 80% open. When the operator attempted to adjust the discharge damper, the controller failed to respond to the signal. The controller was then placed in the manual mode, but the discharge damper could not be adjusted as the controller output was fixed at a constant value.

Investigation of the malfunction revealed that there was a damaged field-effect transistor in the controller. A new transistor was installed in the inoperable controller, and a capacitor was installed on the output side of the transistor in each filter train. These capacitors were connected directly to ground to protect the transistors suppressing feedback noise spikes.

Testing of both trains continued and the controllers in the system operated properly.

ROE 72-10 June 2, 1972

RECENT PROBLEMS ENCOUNTERED DURING RESEARCH REACTOR OPERATION

Summary

This report provides brief descriptions of some representative problems that have occurred during operation of RESEARCH REACTORS. The problems involve MECHANICAL OR COMPONENT FAILURES that may be of general interest to reactor operators.

Failure of a Safety Rod to Insert Fully as a Result of Temperature Sensitive Alignment Problem

When an Agronaut-type research reactor operating at 100 kW was tripped by a spurious scram signal, the reactor shut down normally, but one of the safety rods failed to insert fully. A spare safety rod was inserted in place of the sluggish rod and tests of the sluggish rod were conducted later.

When the reactor-coolant temperature was low, the rod performed satisfactorily, but when the temperature approached 120°F (the operating temperature for 100 kW power level), the rod motion was sluggish. As a result of these observations, the entire rod drive assembly was removed, including the rod drive shaft (approx. 8 ft long) which extends through the biological shield. A pinned coupling between the drive shaft and the rod assembly had prevented removal of the shaft in routine maintenance. By bore-sighting along the bearings supporting the long drive shaft, a misalignment was noted. As the operating temperature increased, this misalignment accentuated bowing in the shaft, causing the pinned coupling to bind as the shaft rotated.

The control-rod maintenance procedures were modified to include a visual alignment of each rod drive shaft. The pinned coupling was replaced by one which allows expansion of the drive shaft with temperature increases and which permits remote disassembly. In addition, rod-drop checks at operating temperature are now performed subsequent to any maintenance on the drive shaft.

Broken Bolts in Primary-System Check-Valve Flange Result from Improper Materials and Installation

After a tank-type research reactor was refueled, a leak of about 80 gph was discovered in the pressurized primary-cooling system It was suspected that the reactor-vessel head had not been properly secured after the refueling. Additional efforts were made to tighten the vessel head without overstressing the studs but these efforts did not stop the leakage. The reactor was shut down and defueled and the primary system was depressurized. A leak was found in the 12-in. primary-system check valve.

Inspection of the check valve showed that seven of the sixteen valve cover bolts had fractured completely resulting in a slight warpage of the cover plate. Further investigation showed that the bolts had been fabricated of aluminum instead of the specified type 18-8 stainless steel.

The manufacturer of the valve was consulted, the valve cover was remachined, and new stainless steel bolts were installed.

Pinhole Leaks in Gasoline Tanks for Emergency Power Supply as Result of Corrosion

During the completion of startup checklists at a tank-type research reactor the emergency generator would not start. A gasoline sample, taken from the reservoir above the generator, contained water. The system was flushed and the generator was started twice to verify operability.

Subsequently a temporary gravity-feed gasoline tank was installed to supply the emergency generator so the main gasoline tank which was fabricated from carbon steel and covered with asphaltum could be removed from the ground and inspected. This inspection showed that several small pinhole leaks had developed from corrosion and had allowed water to seep into the underground gasoline tank. Although the water apparently entered the tank primarily through the leak paths, it could also enter and condense in the normal course of breathing of the tank.

A stainless steel tank was installed in concrete footings that were poured into the same location as the old tank. Provisions were also made for periodic sampling and draining of water condensate from the bottom of the tank to assure reliability of the emergency generator.

Failure of Glass Dewar Flask Sample Container Results from Discharge of Ionization Induced Static Charge*

As a liquid-nitrogen Dewar flask, which contained an experiment sample, was being remotely refilled at a swimming-pool-type research reactor, a series of three minor explosions destroyed the flask and its container, scattering small glass splinters about the area immediately adjacent to the experiment loading tube. Physical damage was limited to the experiment can, the disposable glass Dewar flask, and the experiment sample. No personnel were exposed to irradiation.

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*Material for this section was furnished by an AEC field office.

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It was postulated that an ionization-induced static charge had built up on the flask while it was being irradiated. The static charge then discharged via the glass tip of the sealing tube at the bottom of the flask, and caused the glass tip to shatter. The exact mechanism that triggered the subsequent explosions is unknown but oxygen contamination of the liquid nitrogen is suspect, since oxygen exclusion is believed to be the only successful method of preventing such explosions. The potential for fracture of the Dewar flask as a result of static charge had not been considered in the design of the equipment.

ROE 72-11 June 16, 1972

COMPLETE LOSS OF OFF-SITE POWER

Summary

A COMPLETE LOSS OF OFF-SITE POWER at a nuclear power generating facility resulted in a REACTOR SCRAM, AUTOMATIC DEPRESSURIZATION of the reactor, and subsequent INITIATION of the LOW PRESSURE CORE FLOODING, and CORE SPRAY systems. No damage to the facility resulted from the occurrence and no measurable radioactivity was released to the site or the environs.

Circumstances

A boiling water reactor was operating normally at full load conditions of 210 MWt, 65 MWe, 1140 psig, 560°F. The 2.4 kV auxiliary equipment bus was being supplied from the reactor generator house transformer and the plant start-up transformer bank was available for automatic transfer. One of two 54 MWe fossil-fueled generating units, at the same site, was operating normally at 20 MWe.

The oil circuit breaker (OCB No. 132) for the nuclear-plant generator opened on a generator-backup overcurrent-relay action that was initiated by a fault at an off-site substation (the breaker numbers given refer to those shown in Fig. 1). The substation operator had opened OCB No. 12 in order to de-energize a section of line for maintenance. The position lights at the control switch indicated that the OCB was open, when in fact it did not open because of a physical blockage in the OCB trip mechanism which had been left there following previous scheduled maintenance. When the substation operator subsequently opened an air disconnect switch on the same hot 60 kV line, flashovers, both to ground and between phases, occurred causing generator-backup overcurrent-relay action. In addition to tripping OCB 132, this relay action also tripped the house transformer breaker, the generator field breaker, the turbine control valves and the turbine stop valves. Power was lost to the 2.4 kV auxiliary equipment bus and the automatic transfer of the 2.4 kV auxiliary equipment bus to the start-up bank occurred. The OCB for the fossil-fueled generator opened on generator-backup overcurrent-relay action, but the unit remained in service supplying its own auxiliaries. These operations de-energized the 60 kV bus and OCB Nos. 62, 42, 22 and 12 on the plant 60 kV line opened on loss of power. As a result, all of the normal a-c power at the nuclear unit was lost. The emergency propane engine generator started automatically upon loss of normal power to the 480-volt load center.

The loss of normal power resulted in an isolation scram, loss of feed-water flow, loss of drywell cooling, and loss of all indication of reactor vessel water level and pressure in the reactor control room. As a result of the transient, the reactor pressure increased to the set point for automatic initiation of the emergency condenser (1200 psig). However, the condensate return valve on the emergency condenser did not operate,

and the reactor pressure increased to the set point of the safety valve having the lowest pressure setting, and the safety valve lifted. Shrinkage of reactor water level from void collapse, because of the scram and primary system isolation, combined with loss of coolant due to blowdown through the safety valve, resulted in a low water level scram signal. This signal, combined with the loss of feed-water flow and an increase in drywell pressure to two psig (which resulted from the loss of drywell cooling fans and of the closed cooling water system) started the 60-second automatic-control timer that actuates the reactor pressure vessel auto-depressurization vent system. Steam escaped from a rupture in the bellows expansion joint on the safety-valve discharge line leading to the suppression pool. This also contributed to the increase in drywell pressure. After the preset time delay elapsed, the reactor auto-depressurization vent valves opened, allowing steam to dump to the suppression chamber pool through the safety valve discharge lines.

The Senior Nuclear Engineer, who is also a licensed Senior Reactor Operator, was present in the control room, and he assumed command of the situation as the senior management representative. The drywell pressure was confirmed to be approximately two psig and the Engineer concluded that no actual pipe break existed. The control operator was directed to close the reactor depressurization vent valves manually. The valves were closed about five minutes after they had opened. Another operator checked the reactor pressure by reading gauges connected to the emergency condenser condensate return line; the pressure was 170 psig.

About 14 minutes after the power failure, the fire pumps started automatically, indicating the initiation of operation of the low-pressure core-flooding system. A minute later, operation of the core-spray system was automatically initiated. Operation of both low-pressure core-flooding systems was initiated automatically by the simultaneous occurrence of low reactor-water level, high drywell pressure, and loss of power to the safety system, concurrent with a reactor pressure of 150 psig or lower. These systems were left in service about four minutes, until normal electric power was restored; the power had been lost for a total of about eighteen minutes. At this time, one of the reactor feedwater pumps was restarted; the vessel was filled with condensate to a level above the flange and the core flooding systems were deactivated. Once normal power was restored, reactor vessel instrumentation was also restored, and it was observed that the reactor pressure was approximately 160 psig.

Investigation and analyses, following this incident, based upon the observed change in suppression pool level and upon chemical analyses of reactor water samples, indicated that no more than 3500 gallons of reactor water were blown into the suppression pool via the depressurization vent valves and the opened safety valve. Chemical analysis of the reactor water indicated that about 500 gallons of suppression pool water were injected into the vessel via the core spray system. It was not possible to determine how much water from the fire-fighting system was injected into

the vessel via the low-pressure core-flooding system because reactor pressure was approximately the same as the fire-pump shutoff head.

A program of sampling and analysis of the reactor water for chromate ions, chloride ions, pH, conductivity and radioactivity was begun shortly after power was restored and conditions were stabilized. Reactor water was cleaned up by routing it through a condensate demineralizer and then through the reactor cleanup demineralizer back to the reactor vessel.

Discussion

Loss of 60 kV Bus

When the substation operator opened the air disconnect switch, and the 60 kV line flashed over to ground and between phases, the fault should have been cleared immediately by the opening of the OCB by directional ground relay action. The relay operated satisfactorily; however, OCB No. 12 did not open because of the physical block which had inadvertently been left in the trip mechanism following scheduled maintenance the previous month.

With substation OCB No. 12 inoperative, the next line of protection became OCB Nos. 12, 22, 42 and 62 at the power plant. These OCBs are provided with zoned, impedance-type, directional distance relays. The distance relays sensed the fault to be in a zone such that there was a time delay before the relays operated to open the plant OCBs. The purpose of the time delay is to allow circuit breakers closer to the fault, which, in this case, was the faulty OCB at the substation, to operate first. The settings of the time delays proved to be too long to prevent operation of the generator-backup overcurrent-relay from the fossil-fueled plant, and it operated to separate the generator from the 60 kV bus.

To prevent similar occurrences, improved maintenance procedures were put into effect at the substation, including revised check-off sheets to help assure that all circuit breakers are completely operable before being returned to service after maintenance. In addition, the time delay settings on the distance relays at the power plant have been reduced.

Tripping of Reactor Generator

The main generator breaker (OCB No. 132) for the nuclear unit opened by generator-backup overcurrent-relay action as a result of the fault on the 60 kV bus. This should have removed the fault current from the generator. To protect the generator and main transformer from faults on the plant side of the OCB a twenty-cycle time-delay relay is used. However, the unit tripped out after a delay of only two cycles. Investigation showed that the time-delay relay had not operated because of a failed silicon-controlled rectifier. The relay was replaced and the testing frequency for protective relays increased from every 2.5 years to every refueling cycle.

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When the nuclear unit tripped, automatic transfer to the start-up transformer was not accomplished because of the loss of the main 60 kV bus. Personnel at the fossil unit then proceeded to attempt to restore power to the nuclear unit. This took longer than normal -- the outage lasted 18 minutes -- because the appropriate OCB would not operate from its remote manual switch and an operator had to be dispatched to operate the controls in the switchyard. It was later discovered that wiring to the remote manual switch had inadvertently been left disconnected following maintenance work several months prior to this incident. The OCB was still capable of being tripped by automatic operation of fault protection relays.

Emergency Condenser Condensate Return Valve

During the subsequent investigation of the failure of the condensate-return valve on the emergency condenser to open, the valve and the operator were disassembled. The valve wedge gate was found to be stuck in its guide. The parts were separated by jacking the gate out of the body. The absence of physical damage to the valve that would explain its failure to operate indicated that a high closing-torque-switch setting probably caused the valve gate to jam occasionally in the valve guide. The torque-switch setting was reduced, valve operation was satisfactorily tested, and the frequency of testing of valve operation was increased.

An indicator light was installed in the valve-operator thermal-overload relay circuit to alert operating personnel when the relay drops out so that they will be aware that the emergency condenser system is not operable.

Auto Depressurization

The reactor-vessel automatic depressurization system is equipped with a 60-second timer to provide time for personnel to evaluate plant conditions. If conditions indicate that a loss-of-coolant accident has not occurred, automatic operation of the valves can be precluded by switching the controls to the manual position. During the power outage, the timer had completed its delay function and the valves had opened before the controls were checked by control room personnel. The decision to intervene in the depressurization was made by a senior member of operating management, who happened to be in the control room at the time of the occurrence, after it was concluded that no actual pipe break existed. Shift operating personnel on duty at the time of the incident later stated that they would have permitted the system to operate by itself since it is an engineered safety feature designed to protect against a loss-of-coolant accident.

Senior management of the facility subsequently determined that the operators would have been correct to permit the system to blow down: but that by virtue of his knowledge of the plant the Senior Nuclear Engineer who had assumed command was able to conclude correctly that no pipe break

existed because of the lack of an increase in drywell pressure. Procedures have since been written to furnish guidance to operators for the combined set of circumstances that occurred in this incident.

Instrumentation

The loss of power deactivated the instrumentation in the control room that was necessary for the operator to assess whether a loss-of-coolant incident had occurred. The only useful instruments available to the operator in the control room were the pneumatic indicators that sensed drywell and suppression-chamber pressures. Some recording instrumentation was not operating during the eighteen minutes of normal power loss. During the incident, operations personnel could not place full confidence in the information supplied by instrumentation since they were uncertain as to which instruments were on emergency power.

As a result of a review of control room instrumentation, emergency power was provided for the following instrumentation:

Three independent means of measuring and recording reactor level;
Reactor pressure recorder;
Reactor power range recorder; and
Suppression-chamber and drywell temperature recorder.

An alarm was installed to alert the Control Operator of the activation of the 60-second time delay relay for the reactor vent valves.

Fuel

Analyses of primary coolant after the incident showed that the concentration of radioactivity was such that fuel integrity had not been lost as a result of the automatic depressurization of the system. The incident released a significant amount of crud from the fuel cladding during the transient.

Reactor Safety Valves

When the drywell head was removed, the condition of the stainless steel bellows in the safety valve exhaust line confirmed that one safety valve had lifted. The bellows were found to have ruptured in two places. The ruptures were attributed to the sudden release of high-pressure (1230 psig) steam into the exhaust line. The discharge end of the exhaust line is submerged under approximately two feet of water in the suppression chamber.

The rupture in the bellows permitted the introduction of steam directly into the drywell. The steam, combined with the loss of drywell cooling, resulted in the drywell pressure of two psig which is one of the three required conditions which must be satisfied before the timer on the automatic depressurization system starts to run.

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Drywell Cooling

The cooling fans in the drywell tripped on loss of normal power. The fans were on emergency power but would have had to be manually restarted. The fans were not restarted during the power outage. Operation of the fans would have removed some heat from the drywell, but the pumps supplying water to the drywell coolers were fed only by normal power, and therefore were inoperative during the power outage. Operation of the fans and pumps has been changed so that they will automatically restart after transfer to the emergency power supply.

Emergency Operating Procedures

The plant Emergency Operating Procedures provided detailed instructions on the operation of engineered safety features and provided guidance for evaluating a possible loss-of-coolant incident. The procedures did not provide guidance to the operator in the event of a possible loss-of-coolant incident concurrent with a loss-of-power incident. The procedures did not contain guidance on the permissive conditions required for initiating, overriding or terminating action of the primary-system automatic depressurization system. Additions and modifications to the plant Emergency Operating Procedures have been made relative to these types of situations.

Low Pressure Core Flooding System

As the pressure in the reactor vessel decreased to approximately 150 psig, the emergency diesel fire pump started and the isolation valves on the shutdown cooling line and the flow-control valve on the low-pressure flooding system opened to supply water from the fire loop system to the reactor vessel.

Calculations showed that the dynamic head of the fire pump plus the static head of the low-pressure flooding system approximately equaled the reactor pressure. Therefore, there was some doubt that the low-pressure core-flooding system had injected water into the reactor vessel during the period that it operated. The reactor feed pump was started and the core flooding system deactivated when the power was restored.

A small thermal relief valve in the shutdown cooling supply line lifted at a pressure of 130 psig. This resulted in a measurable increase in air activity in the refueling building.

The pressure relief valve was replaced with a new valve of the proper rating. A method of exhausting the relief valve to a closed system is under consideration.

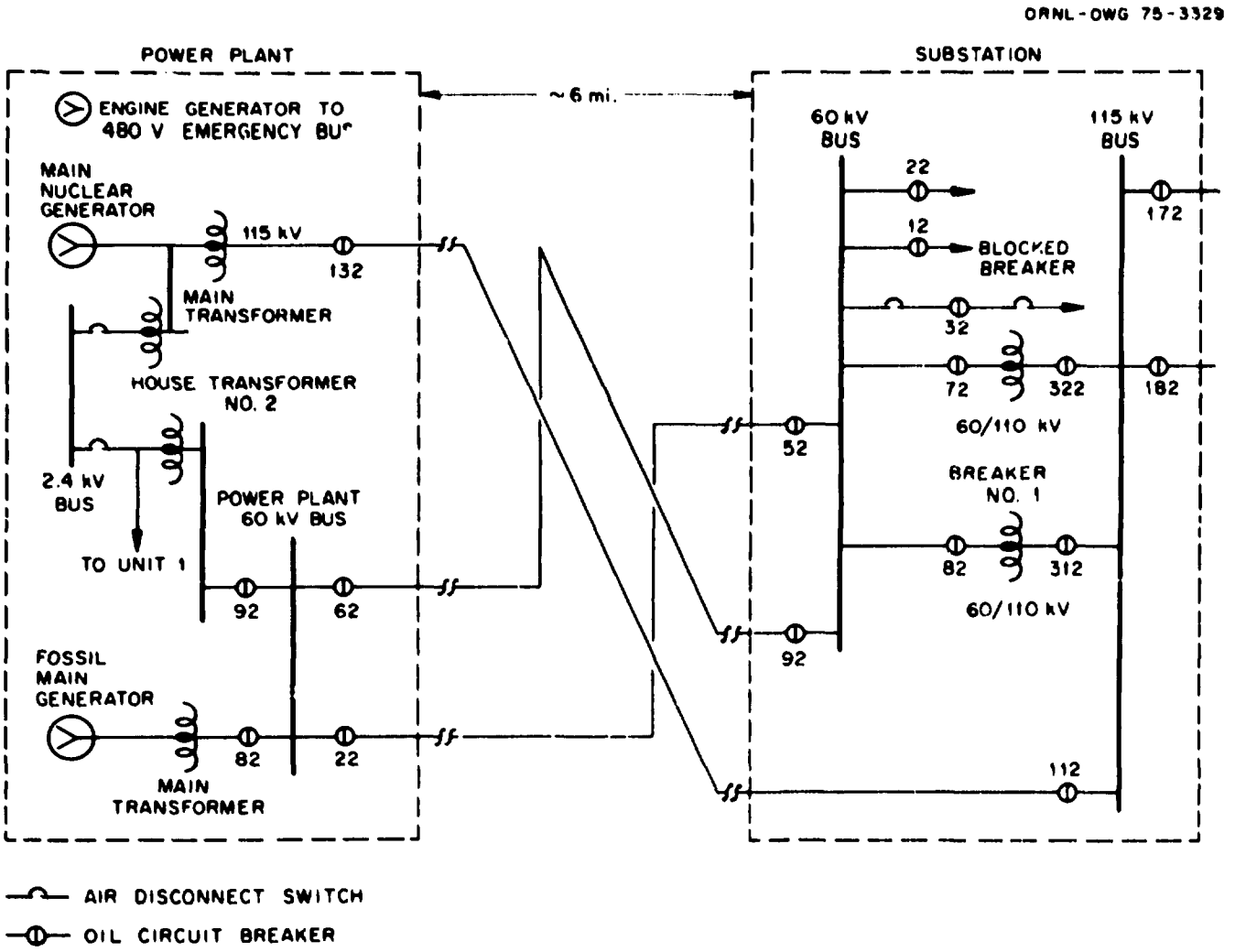

Fig. 1. Simplified Transmission Diagram

ROE 72-12 June 30, 1972

TURBINE PROBLEMS AT BWRs

Summary

Recurring problems with turbines and associated equipment result in significant outages at nuclear power plants, in spite of the fact that turbine technology is not a recent development. In the case of boiling-water reactors (BWRs), personnel are exposed to radiation when recurring or extensive maintenance and repair are required. Two of the more complex PROBLEMS that have occurred recently WITH TURBINE COMPONENTS at BWRs are discussed in this report.

Circumstances

Failures of Turbine-Blade Attachment Pins

At a nuclear power plant, inspection during a refueling outage confirmed that many of the pins that attach the last-stage buckets to the turbine shaft were cracked.

The turbine at this plant is a six-flow, reheat type with 38-inch last-stage buckets having two tie-wires but no shroud band. The bucket shanks fit into dovetail grooves in a five-finger pattern and the buckets are attached by passing pins through the shaft and catching each of the fingers. This attachment technique creates ten shear plans in each pin. Three pins are between adjacent buckets around the circumference of the shaft. Figure 1 shows the general arrangement of the bucket-wheel assembly. Ultra-sonic testing during routine surveillance of the 2646 pins in the rotor assembly revealed that 92 of the pins had failed. When the failed pins were removed, it was observed that some were broken in more than one place. Some of the pins were broken along the shear planes and some were broken between shear planes.

The failure was attributed to stress-corrosion cracking caused by chloride and sulfur contamination in the cutting oil that was used in reaming the holes for the pins. All 2646 pins were replaced with pins that were made of a chromium-molybdenum vanadium steel. Plans were also made for sampling the new pins with the same nondestructive testing techniques after one year or less of operation.

Early detection of the failed components during a maintenance shutdown possibly precluded more serious consequences.

Failure of Level-Controller on Turbine Reheater

At another BWR, the reactor was at 160 MWt (97% of full power) when a loud noise was heard and steam was observed to be filling the turbine room. The reactor was shut down immediately, the turbine was tripped, and the turbine was isolated from the primary system. A controlled entry

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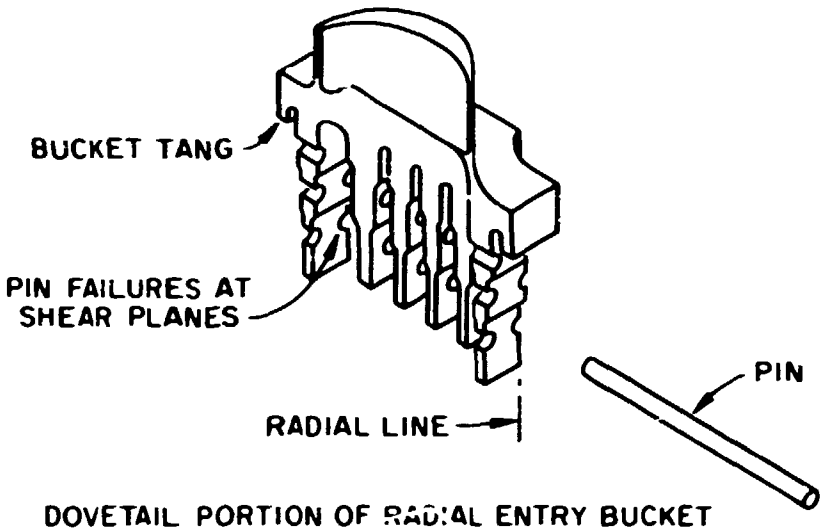
into the turbine building was necessitated by the higher-than-normal radioactivity levels that were present in the building. A ruptured float case on the level controller for the turbine-steam reheater proved to be the source of steam that was filling the turbine building.

The level controller (Fig. 2) was a factory-fabricated unit that consisted of a level float encased in 4-inch Schedule-80 pipe. A 2.75-inch O.D. branch connection, welded to the vertical case, contained the torque arm that transmitted the fluid-level signal to an air-controller unit. This air-controller unit, in turn, modulated the level-control valve.

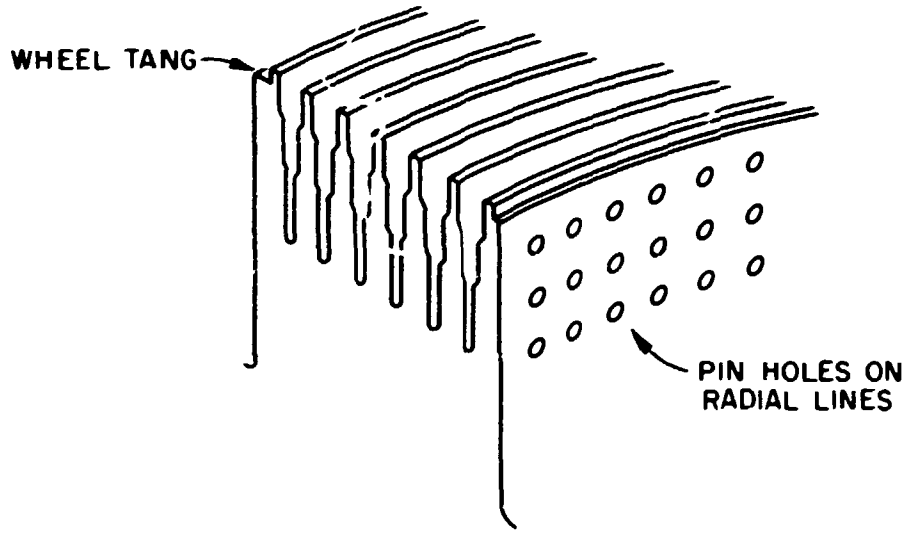
The pipe rupture appeared to start on one side of the weld at the branch connection and propagate in both directions around about 60% of the 4-inch pipe. An oval piece of metal that was about 10 inches high and 8 inches wide was blown out of the 4-inch pipe. A visual examination of the failed section showed that the failure was caused by an insufficient weld penetration at the branch connection, poor weld-surface preparation at the joint, and inadequate reinforcement metal at the weld to ensure adequate strength at the operating-temperature and -pressure conditions.

All instrument units for level control were examined, but no other defective units were found. The failed unit was replaced by a new unit which conformed to the intent and requirements of the latest applicable codes before the plant was returned to service. The failed level controller on the turbine-steam reheater resulted in at least 5 days of plant outage and radiation exposure to plant personnel, although the failure posed no hazard to off-site areas or personnel.

ORNL-DWG 75-3330



DOVETAIL PORTION OF RADIAL ENTRY BUCKET
—FINGER PIN TYPE—NESTED



PARTIAL SECTION OF WHEEL DOVETAIL FOR RADIAL ENTRY BUCKET
—FINGER PIN TYPE—NESTED

Fig. 1. General Arrangement of Bucket Wheel Assembly

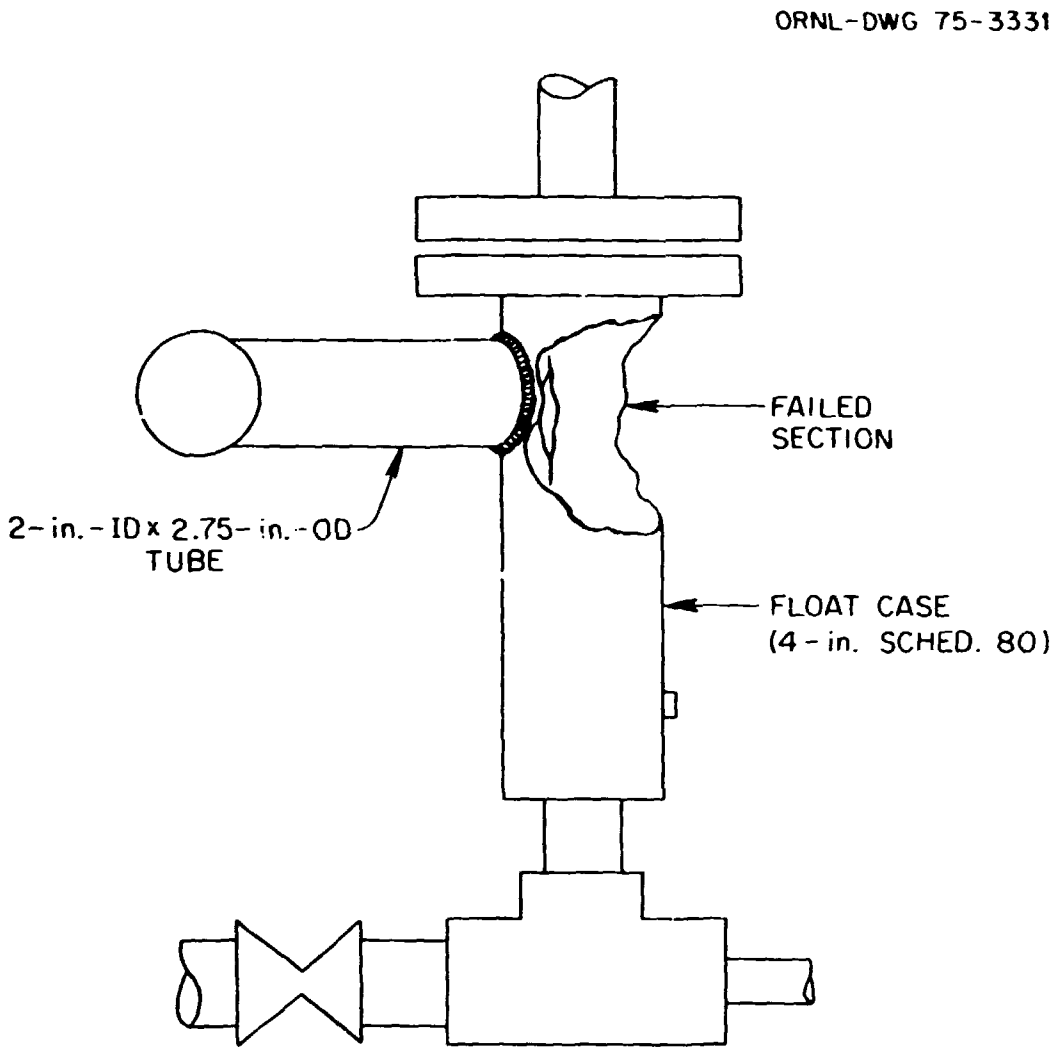


Fig. 2. Reheater Level Controller

ROE 72-13 July 28, 1972

PRESSURE TRANSIENT IN PRIMARY SYSTEM OF A BWR

Summary

A MALFUNCTION of a TURBINE-CONTROL SYSTEM at a boiling water reactor (BWR) caused a PRESSURE TRANSIENT in the cooling system which resulted in a high neutron-flux trip of the reactor. Simultaneously with the scram a RELIEF VALVE MALFUNCTIONED, lifting prematurely, causing a SHARP DECREASE IN PRIMARY-SYSTEM TEMPERATURE AND PRESSURE.

Although the pressure transient that occurred was not as severe as the design-basis transient, an engineering analysis was performed to evaluate the postulated effects on the primary cooling system of 120 repetitions of a similar transient. Results of these analyses indicated that one such transient would not have a significant effect on the integrity of the primary system.

All engineered safety features performed as intended and the plant was brought to a safe shutdown condition.

Circumstances

When an unexplained instability occurred in the turbine control system, the reactor operator began reducing the power level, according to procedures, by flow reduction using the recirculation pumps. Approximately one minute later, the instability in the turbine control system caused an increase in primary system pressure to 1040 psig. This pressure increase, in turn, caused a high-high neutron-flux trip of the reactor from the average power-range monitors (APRM). The turbine was manually tripped within a few seconds after the automatic reactor trip. The turbine bypass valves opened in accordance with design and the control valves closed.

Normally, the bypass valves open for only a very short time and then close to maintain reactor pressure. However, this time one of the bypass valves remained completely open, and this resulted in a continuing decrease in primary system pressure. Noting this continuing decrease in pressure, the operator closed the main steamline isolation valves in an effort to prevent a further decrease in pressure. When the depressurization continued, the operator became aware that the relief valve had remained open since the reactor scram.

About 18 minutes after the reactor scram, the reactor pressure had decreased to 263 psig, and the relief valve then reseated. After the operator had confirmed that the pressure was increasing, he initiated a controlled cooldown of the reactor vessel via the isolation condenser. During the 18 minutes that the malfunctioning relief valve stayed open, the pressure dropped from 1035 to 263 psig, and the temperature dropped from 525 to

390°F. After the valve reseated, the pressure in the reactor vessel increased to 360 psig before a normal cooldown was begun. During the cooldown the faulty relief valve lifted twice again. After the incident, a total of 75,000 gallons of water was removed from the torus. It was estimated that 30,000 gallons had been added as a result of the initial relief-valve actuation and the remaining 45,000 gallons were added as a result of the two subsequent relief-valve actuations.

Causes and Remedial Actions

The transient resulted from two independent failures. One failure was within the turbine-control system; the second involved the relief valve.

Turbine Control System

Immediately after the incident, an investigation showed that the dashpot on a pilot valve in the turbine control system had vibrated loose. The dashpot is connected to a torque tube which is required to maintain control-system stability. The loss of this dashpot is postulated to have precipitated the instability of the turbine control system.

Subsequent investigations revealed additional problems in the turbine-control system. The weights on the turbine governor were loose, the horizontal rod from the pilot valve to the reactor-coolant-flow limit switch was bent and a pillow-block bearing for the torque tube on the output of the bypass relay had vibrated loose. These occurrences were considered to be effects of the instability, not the cause.

The in-depth examination of the turbine-control system resulted in the following corrective actions: The dashpot was pinned to prevent its vibrating loose again; the linkage clevis and studs on the bypass valve were replaced with heavier units; new orifice plates were installed on the hydraulic servo-motors in the individual control valves to increase the damping of the control valves; the turbine-governor weights were retightened and locked; "stop blocks" were installed in the pillow-block bearing on the bypass-valve relay to provide additional support for the bearing; the control-valve and control-speed relays were checked for excessive wear or friction by hysteresis methods; all rod-end bearing connections on the control linkages in the front standard were checked, and where clearances were greater than desired, the linkages were replaced; a preloading piston was installed to stabilize the bypass-relay pilot valve; some floating levers with undesirable deflections were replaced with stronger levers; a linear variable differential transformer (LVDT) and a rotary potentiometer were installed on the torque tube of the pressure regulator to assist in monitoring turbine-control behavior; and maintenance and inspection checks were performed on all parts of the turbine control system.

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Relief Valve

The relief-valve failure that occurred at the time of the scram was caused by the relaxation of a pressure-adjustment set spring. This spring relaxation allowed the valve to lift at 1040 psig instead of the normal set-point value of 1095 psig. The other two relief valves had experienced a similar reduction of pressure-relief set-point valve, but the set point had not decreased as much as that of the valve that lifted.

After the plant was brought to a cold shutdown condition, the valve that malfunctioned was disassembled and inspected. The main disc was eroded by steam in some places, and the pilot-valve seat and disc were badly eroded. The erosion of the pilot valve had prevented the valve from reseating properly.

Further investigation into the problem of both the spring relaxation and the scoring of the pilot-valve seat revealed that the valves had not been designed to function in the environment to which they had been exposed. With regard to the set-pressure adjustment spring, the alloy used in the manufacture of the original spring was adequate for temperatures up to 500°F. However, the valves had been insulated, and the insulation raised the temperature in the pilot-valve section to near the 546°F temperature of the steam.

Subsequent tests of relaxation rate as a function of time were conducted with the relief-valve spring material. At 500°F the spring material exhibited a one-percent relaxation in about 72 hours. After 72 hours the relaxation continued at a reduced rate. A one-percent relaxation of the spring material corresponded to a 28-psig decrease in set-point lift pressure. The spring material also was tested 550°F and at 600°F. At 550°F the spring-material relaxation was three percent and at 600°F the relaxation was about five percent. An examination of the temper colors on the relief valve indicated that the spring material had been exposed to temperatures of about 550°F.

The erosion on the disc of the pilot-valve was a result of the lowered pressure-relief set-point of the valve. When the operating pressure came within 97 percent of the pilot-valve setpoints, the valves simmered. This leakage eroded the valve seat. Although it was not enough to equalize forces on the second stage piston and cause the relief valve to lift, it did prevent the valve from reseating properly.

As a result of the malfunction of one of the relief valves, all three were thoroughly inspected. The main disc seat on the malfunctioning valve was reground, and the disc and spring on the pilot-valve were replaced. The secondary pilot-valve seats and discs on all the valves were redressed and lapped. The springs were changed on all valves, the set-point was properly reset, and the insulation was removed from the upper valve bodies.

ROE 72-13

During the ensuing plant startup, all valves were functionally tested and checked for capacity. Procedures were also developed for future periodic testing of the valves.

Effects of the Depressurization on the Reactor Vessel

During the pressure transient, the change in the reactor water temperature was 140°F in 18 minutes. This change was less severe than the design-basis transient of 171°F in 10 minutes. From an analysis of the transient and its effect on stress levels and fatigue life, it was determined the effects of the single transient were negligible.

ROE 72-14 August 11, 1972

FEEDWATER TRANSIENT AT A BWR

Summary

A TRANSIENT INCREASE in the REACTOR VESSEL WATER LEVEL occurred in a boiling water reactor (BWR) when the feedwater pumps were tripped by a low suction-pressure signal as a result of a trip of one of the condensate-booster pumps. An abnormally HIGH WATER LEVEL in the reactor vessel, following the scram, CAUSED WATER TO ENTER THE MAIN STEAM LINES. The water that entered the main steam lines CAUSED A SAFETY VALVE TO OPEN for about 1.5 minutes, RESULTING IN THE PRESSURIZATION OF THE DRYWELL.

The cables on one local power-range monitor (LPRM), one solenoid operator for an electromatic relief valve, and some piping insulation were damaged by the occurrence. All safety systems functioned as they were designed to do.

Circumstances

With the power plant operating at 792 MWe, one of the three operating condensate-booster pumps tripped and the remaining two condensate-booster pumps could not supply the required amount of water at the full-load level. A resulting low pressure condition then occurred at the suction to the two operating feedwater pumps, and these two pumps tripped, automatically causing a standby feedwater pump to start. Fourteen seconds after the condensate-booster pump had tripped, the reactor tripped automatically because of the low water-level condition that had resulted from the decrease in feedwater flow. The water level continued to decrease until it reached a low point of about 108 inches above the top of the core.

At this point, the continuing feedwater addition from the standby feedwater pump began to override the reactor vessel pressure. When the water level began to increase, the reactor operator manually reduced the set point on the master feedwater controller to zero, and then transferred the feedwater controller to manual operation in an attempt to provide manual control of feedwater addition.

Although it was not detected by the operator, manual control of feedwater flow was not possible because the feedwater control valve was inoperable. This condition occurred when the initial, sudden demand to close the valve created a localized effect of low air pressure at the valve positioner causing the feedwater control valve to be locked out. Thus, subsequent attempts to control feedwater flow in the manual mode were ineffective.

As the level of the rising water approached its normal operating height above the core, the operator started closing the motor-operated isolation valve in the feedwater line ahead of the feedwater control

valve. However, the valve stalled after the feedwater flow was reduced to about 20% of full flow because of the high differential pressure across the gate of the valve.

Because of the continuing cold feedwater addition, the reactor pressure decreased. At about 65 seconds after the trip of the condensate-booster pump, the main steamline isolation valves closed because of a low reactor pressure signal. Reactor pressure continued to decrease because of the addition of the cold feedwater and reached a low point of 795 psig. At this point, the feedwater addition and decay heat caused the pressure to begin increasing.

Meanwhile, the reactor water level had continued to increase. Eighty-one seconds after the condensate-booster pump trip, the low-reactor-water-level trip automatically reset. When the water level rose to about one and one half feet above normal, the turbine stop valves tripped as they were designed to do.

The continued feedwater addition caused the pressure in the reactor vessel to continue to increase so the operator manually valved the isolation condenser into the system. However, by this time the water level in the reactor vessel was above the supply nozzle to the isolation condenser so that operation of the isolation condenser had little effect on the reactor vessel pressure. The reactor-vessel water level continued to increase until it began to fill the main steam lines.

As the water level in the reactor vessel increased, the pressure in the vessel increased to 1020 psig. When the pressure reached this level, one of the safety valves lifted and the reactor-vessel pressure decreased rapidly. However, when the safety valve lifted, primary-system water was released to the drywell and flashed to steam, pressurizing the containment vessel. As the drywell pressure rose to two psig, the containment high-pressure trip was actuated, automatically starting both diesel generators, the core spray pumps, and the low-pressure coolant-injection (LPCI) pumps. Although an actuation signal also was received by the high-pressure coolant-injection (HPCI) system, it did not inject water because of the reactor-high-water-level trip of the HPCI turbine that was in effect. The containment high-pressure trip also tripped the reactor recirculation pumps and isolated the containment building.

The safety valve was open for about 1.5 minutes. During this time the drywell pressure rose to a peak value of 20 psig. About 30 seconds after this peak pressure was reached, cooling of the pressure suppression chamber (torus) was initiated by circulating the water in the torus through the heat exchangers in the containment cooling system. The spray system in the torus was not used during the cooling and depressurization of the torus.

About 13 minutes after the initial pump trip, the operator tripped the only feedwater pump that had been operating and the reactor pressure dropped from a peak of 1025 to 980 psig before fission-product-decay heat

caused it to start increasing again. About 9.5 minutes after this, one of the high-pressure sensors tripped at 1044 psig. The reactor vessel pressure then decreased temporarily because of a loss of water when an unsuccessful attempt was made to place the cleanup demineralizer in service.

The drywell pressure had decreased to 13.5 psig within 22 minutes after the initial pump trip because of the operation of the pressure-suppression cooling system. Three hours and 47 minutes after the pump trip the containment pressure had been reduced to about 4.5 psig. About eight hours later the drywell pressure had decreased to 1.75 psig, the high-pressure trip for the containment had been reset, all emergency core-cooling systems had been returned to the standby condition, and the drywell coolers had been restarted manually.

A jumper had been installed about four hours after the original pump trip so that the reactor water-sample isolation valves could be opened and a water sample could be collected prior to a deliberate reduction of the reactor coolant level. The sample was collected, the jumper was removed and isolation of the system was reestablished. Analysis of the sample indicated normal activity, and a reduction of the reactor coolant level via the reactor cleanup system was initiated about six hours after the initial pump trip. About one hour later, the water level in the reactor vessel had been reduced to a point below the main steam lines. The water level in the reactor vessel had reached a maximum of 145 inches above normal because of the continued input from the control-rod-drive (CRD) system.

The use of the cleanup system for a controlled cooldown of the primary system continued until about 33 hours after the original pump trip. At this time the normal shutdown cooling system was placed into operation.

Samples of the drywell atmosphere were first taken about 13 hours after the initial pump trip. These samples indicated a radioactivity level in the containment that was slightly above normal. Twenty hours after the first sample was taken, the drywell atmosphere was sampled again. The radioactivity levels had been reduced sufficiently to permit deinerting of the drywell. Six hours later, personnel entered the drywell to inspect it.

The inspection revealed that: rupture discs on the discharge line for four of the eight safety valves were ruptured and that the rupture disc in the safety valve that had relieved was blown completely out; the steam jet from the relieving safety valve had discharged against the solenoid operator on one of the electromatic relief valves; some thermal insulation for some piping was damaged; the top coat of paint on a 3 × 3 squate-foot area was removed from the containment wall by the steam jet; sections of ventilation duct around the steam jet were displaced; and practically all local power-range monitor cables were damaged.

ROE 72-14

Conclusions

The effects of the transients on the pressure vessel and containment system were insignificant. However, efforts to establish an exact mechanism by which the safety valve opened were unsuccessful because of the existence of several unknown conditions. Regardless of the exact mechanism of safety-valve lift, the cause of the lifting of the safety valve was determined to be the flooding of the steam lines at elevated reactor pressures.

The feedwater-control system did not function properly during the incident. When the sudden demand for closure of the feedwater-control valve was received at the valve positioner, the rapid movement of this valve created a localized low air-pressure condition at the positioner and rendered the control valve inoperable. Also, previous experience had demonstrated the inability of the control system to control the water level automatically below the high-water-level trip point when the main steam line is isolated during oscillations in reactor coolant level such as occurred in this instance. Therefore, it was necessary that the operator take action.

With two significant exceptions, the responses of the operator were in accordance with operating procedures. The operator did not reset the lockout of the feedwater-regulating valve, but reduced the control potentiometer to zero and transferred it from automatic to manual mode. His second error was in not tripping the feedwater pump when the reactor-vessel water level reached five feet above normal height. A third, but less significant, violation of procedures occurred when the torus spray was not manually initiated when drywell pressure reached 2 psig.

Corrective Actions

After the damage in the containment system was assessed, repairs and corrective maintenance were begun. All the defective LPRM cables and the damaged piping insulation were replaced. The safety valve that had relieved was replaced with one that had been previously tested, and the ram's-horn exhaust was rotated to direct the safety-valve discharge opening away from the solenoid operator of the nearby electromatic relief valve. The torque setting of the feedwater-regulating isolation valve was increased, the damaged paint on the drywell was repaired, and a 10 ft^3 accumulator and larger air-supply piping were installed on the feedwater control valve to reduce the probability of inadvertent lockout. Additionally, detailed checks of all systems were performed prior to restarting the reactor.

Operating procedures for handling oscillations of reactor coolant level were revised and emphasized.

ROE 72-15 September 8, 1972

FAILURE OF SAFETY-VALVE HEADER AT A PWR

Summary

Two FAILURES of HEADERS on STEAM LINES have occurred in as many years at PWR nuclear-power plants during preoperational, hot-functional testing before fuel had been loaded into the core.

The first such failure was discussed in ROE 71-12; the second failure is discussed in this ROE. As a result of the second steam-line failure, sixteen persons received treatment or observation for injuries from the steam and flying debris. Of the sixteen persons, only two were injured seriously enough to be hospitalized overnight. The DAMAGE to the plant resulting from this steam-header failure was LIMITED to ONE of the STEAM-LINE LOOPS and the surrounding areas.

Circumstances

Pre-incident Plant Description

The main steam line for each of the three steam generators in the subject PWR runs in an east-west direction from the containment building to the turbine island. Each steam line has four safety relief valves, two each on the north and south segments of the main-steam-line branch headers. Figure 1 shows the physical arrangement of the steam line and the relief valves, and Figure 2 shows the original header design. The original header assembly was fabricated of 12-inch Schedule-60 SA-106 Grade-B seamless pipe. It had a 12-inch Schedule-60 pipe cap, a 6-inch-on-12-inch weldolet and a 6-inch ASA 1500-lb small-tongue welding neck flange. The header assemblies were field welded to the 26-inch-O.D. main steam line through a 12-inch-on-26-inch weldolet. The safety valves were bolted to the top of the 6-inch flanges and they discharged into 10-inch Schedule-40 stacks. A 1-inch-thick support saddle assembly was welded to the 0.56-inch-thick header pipe at 2 points that were 24-inches apart. The saddle slid on a Lubrite plate embedded in concrete. All of the steam-line safety valves had been set by the valve manufacturer about two weeks before the header failure. Each of the three loops had four safety valves, set at 1085, 1100, 1115, and 1130 psig, respectively. After the valves had been set by the manufacturer, it was necessary to gag the 1100-psig valves on each line because they were weeping excessively.

Pre-incident Conditions

Early on the morning of the incident the hot-functional tests were nearing completion and preparations were under way for rolling the turbine. The header failed about 15 minutes prior to the shift change, so that only personnel from the midnight crew and some of the day-shift crew who had

come early were present. Equilibrium conditions of 547°F and 2235 psig had been established in the primary cooling system for at least eight hours prior to the header failure. Three primary pumps were in service, one charging pump was operating, and letdown flow through the mixed-bed demineralizer was 60 gpm. The pressurizer pressure and level controls were on automatic. Boration of the primary system was the only test procedure in progress and this operation had been established almost two hours prior to the incident.

The secondary-system pressure had been established at 990 psig for over eight hours. The main steam-line isolation bypass valves were closed, the main feedwater and feedwater-bypass valves were closed, and the steam-generator feed pumps were off. Thus, the secondary system was operating under static-load conditions, only.

The Incident and Operator Actions

The initial indication of the incident to the operators in the reactor control room was a loud noise that sounded like escaping steam. The operators then observed a rapid decrease in pressurizer level and pressure, a rapid decrease in the temperatures of the hot and cold legs of the loop and in the average loop temperature, a rapid decrease in steam-generator level, closure of the letdown valve, and a trip of the pressurizer heater. From the reactor control room console the operators immediately stopped the three primary pumps, started a second charging pump, closed the feedwater valve to the steam generator, closed the atmospheric steam-dump valves on the other two loops, and initiated makeup of primary water to restore the level in the volume-control tank. The pressurizer level was restored to normal within fifteen minutes and then one of the charging pumps was stopped and a 45-gpm letdown was established. When conditions had stabilized, the coolant pump in the failed loop was restarted and an orderly cooldown was initiated.

Damage from Incident

Overall Plant. When the steam blowing had subsided, it was observed that three of the four safety valves had blown off the header on one steam loop and that the north segment of the header was split open. Figure 3 indicates failure modes for the header, and Figures 4–6 show failure modes for each safety-valve connection.

The escaping steam also had blown away the test station for the main-steam-line isolation valves and the access platform for the safety valves. The handwheel on the manual isolation valve for steam dump to the atmosphere was missing. Also, the motor operator on the steam supply to the auxiliary feedwater pumps, sections of the penetration-cooling ducts for the main steam and blowdown lines, handrails, stair treads, light standards, lagging and insulation material, and two steam-line pressure transmitters had been blown away.

Steam-Loop Components. The three safety valves that were ejected from the header had fallen within a short distance of each other. One valve landed on the steam-generator blowdown piping and the motor-operated valves in the piping.

A manufacturer's representative inspected the safety relief valves from the failed header and decided that they should be returned to the factory for testing. All the valves from the failed header, including the one that was not ejected, were returned to the factory with two valves from an unfailed header that were to serve as references.

Analyses of Steam Header and Safety Valves. After the incident, all six of the valves were tested at the manufacturer's plant using nitrogen, but only four were tested with steam. The two that were not tested with steam because of apparent physical damage were two of the three that had been ejected from the failed steam header. One of the damaged valves was disassembled to ascertain the extent of damage. The nut assembly at the top of the tension spring was broken and the valve shaft was bent.

Since the header appeared to be properly fabricated and no preexisting defects were present, the cause of failure was attributed to an overstressing of the header. Some aspects of the failure indicated a sudden application of the overstress, and apparently residual stress played no role in the failure. Also, investigations confirmed that the failure of each valve attachment began at the point which is opposite the valve discharge stack, and that this point would sustain the highest stress under a bending moment produced by a valve reaction force.

Remedial Action. The steam-line headers for all 3 loops have been redesigned completely, and have been replaced by heavier 14×14×8 Schedule-160 forged T's. The valve side of the 6×8 expander flanges has a tongue-in-groove construction, and the discharge pipes are supported so that no bending moment can be transmitted to the main-steam-line piping. The safety relief valves have been rearranged on the headers so that the lower lift pressure valves are nearest to the main steam line.

Conclusion

It was concluded that the probable cause of failure was the actuation of the safety relief valve that was set at 1085 psig. The dynamic loading resulting from the actuation of this valve, combined with the condensate in the line, exerted a bending moment and torsional stress on the header at the location of the valve attachment. Since the architect-engineer had not taken these overstressing forces into account in the original design, the valve attachment was not fabricated to withstand this dynamic loading and the valve tore loose from the header at a point opposite the valve discharge stack. The two other valves failed when they lifted as a result of the forces that were set up in the steam header by the water and steam escaping

from the failed 1085-psig valve. The valve that had been gagged previously did not tear loose from the header.

The header design had been analyzed only for static loads; the analysis did not consider the conditions associated with actuation of the safety relief valves. In contrast, the designs for the replacement headers in all three main steam lines have included analysis of transients as well as the static and operating loads.

Effects on Other PWRs

As a result of the occurrence at this PWR, all owners of PWRs that were either operating, or very close to being operational, were notified immediately to check their plants and designs. Necessary modifications disclosed by these reviews are under way.

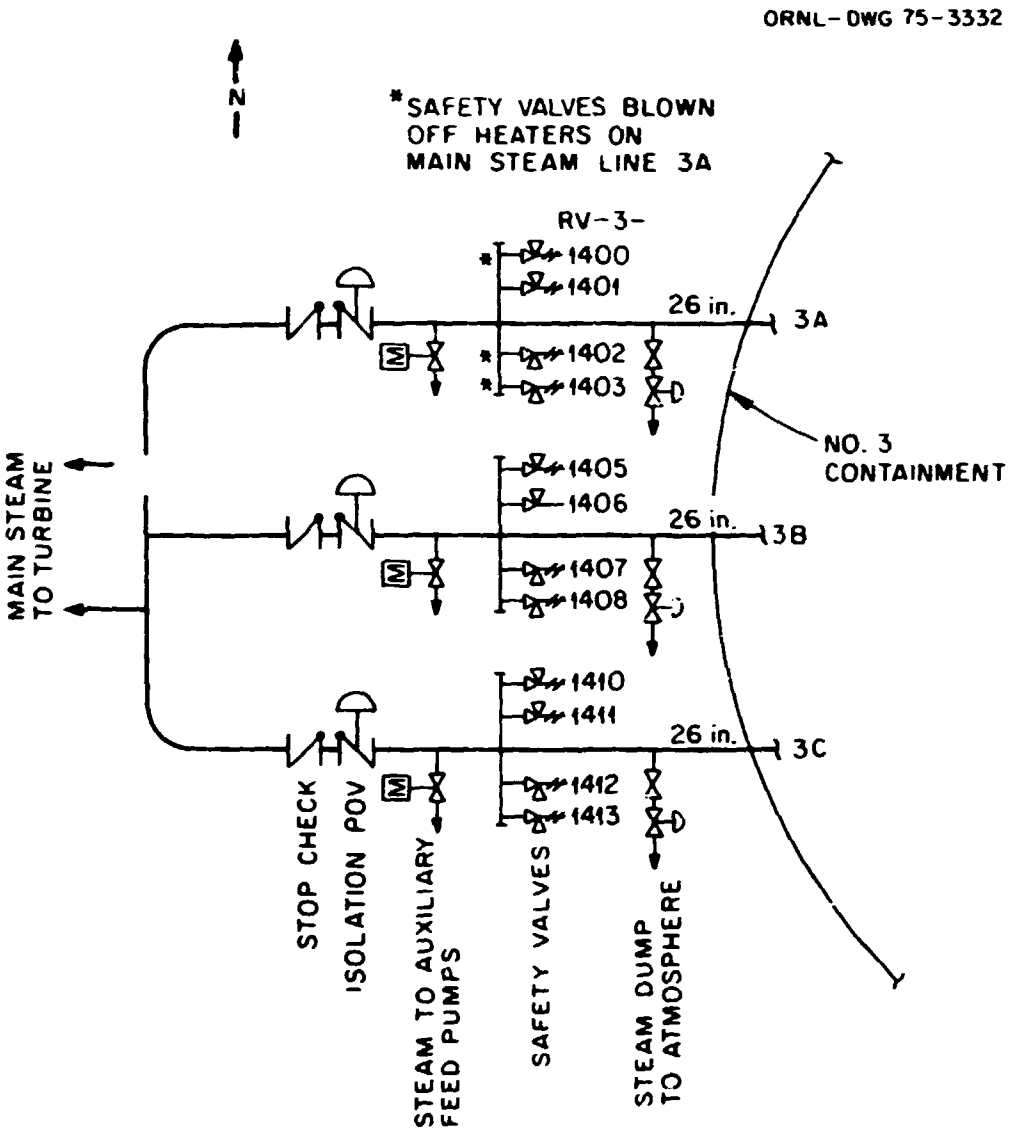


Fig. 1. General Arrangement Main Steam Piping and Safety Valves

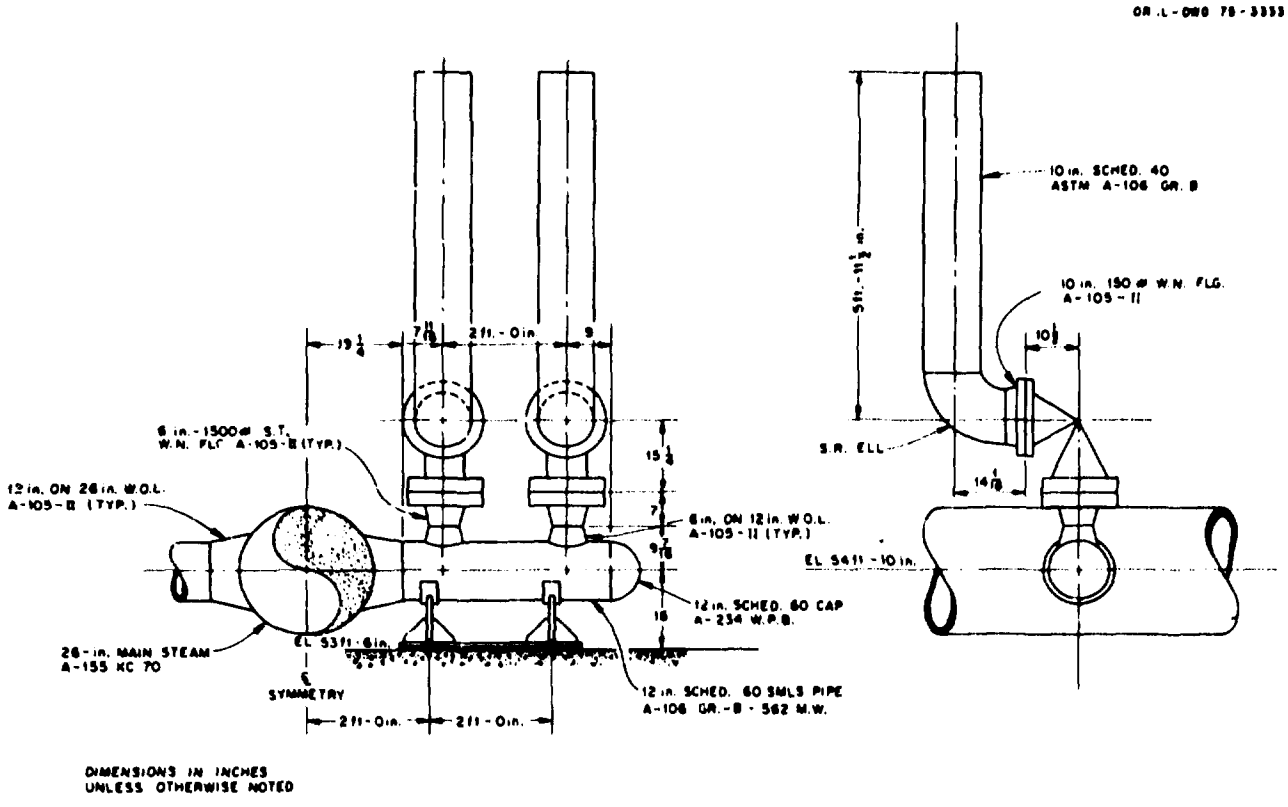
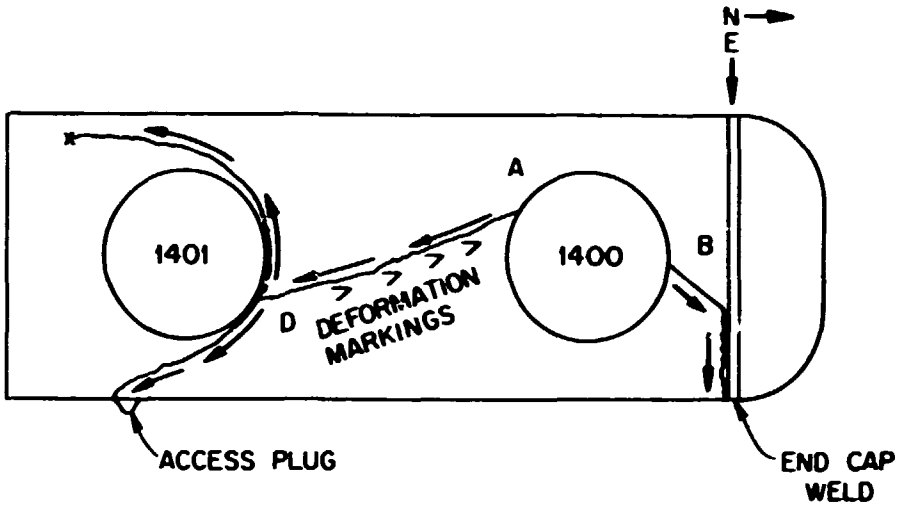
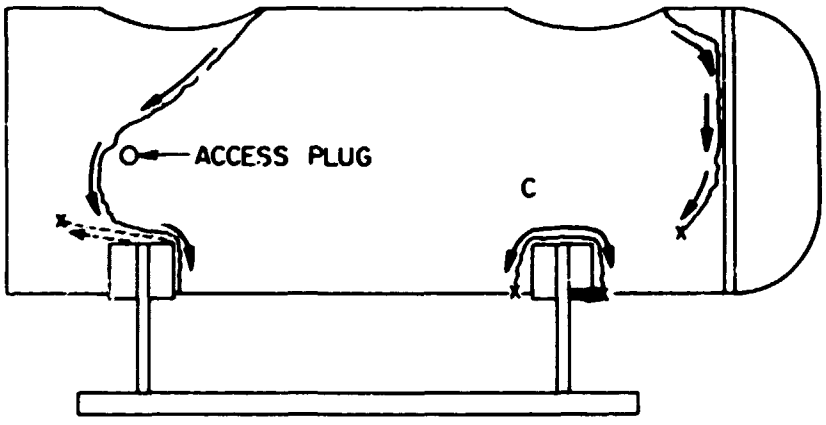


Fig. 2. Main Steam Piping Unit No. 3 — Steam Gen. "A"
Original Design

ORNL-DWG 75-3334



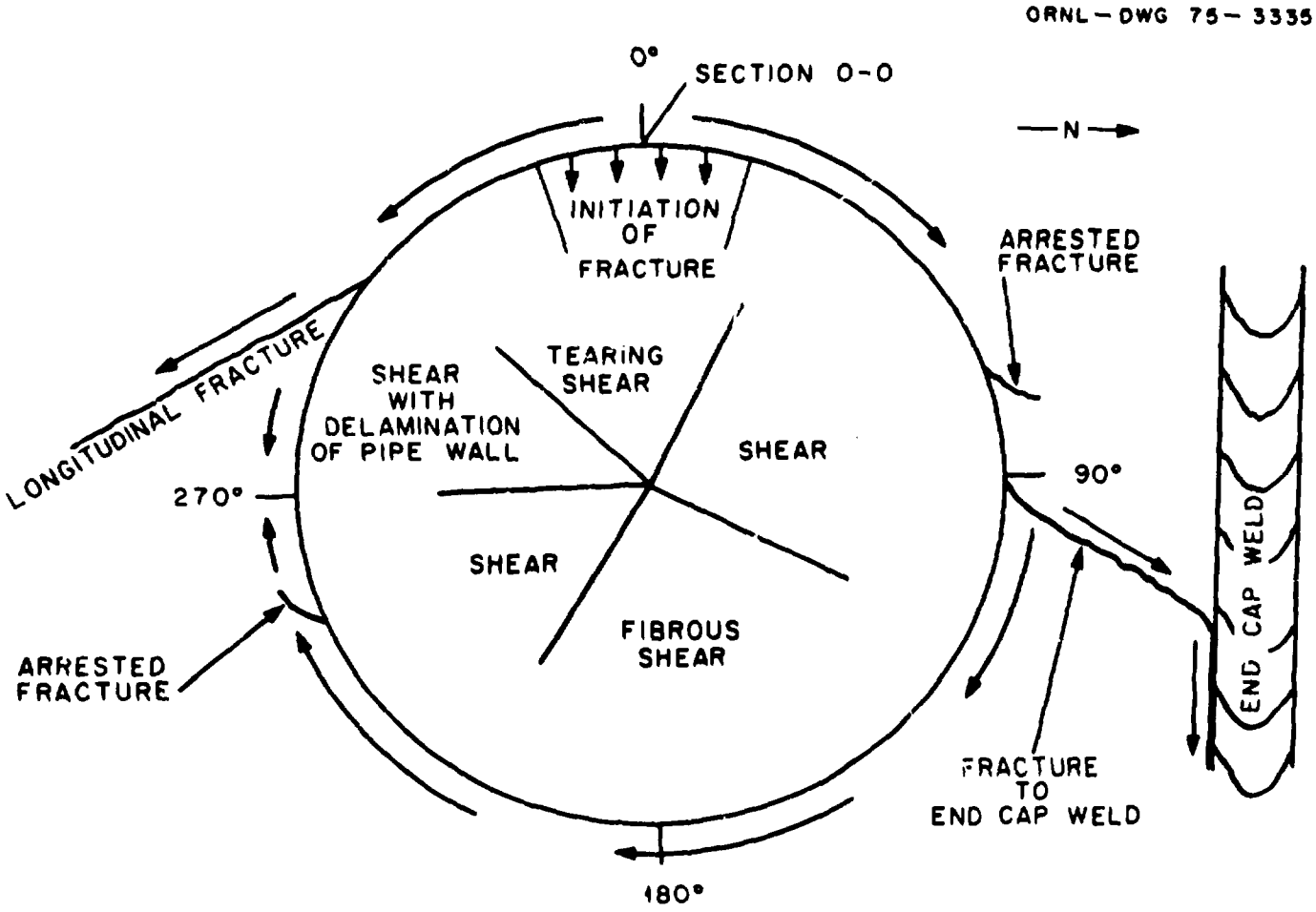
TOP VIEW



SIDE VIEW LOOKING WEST

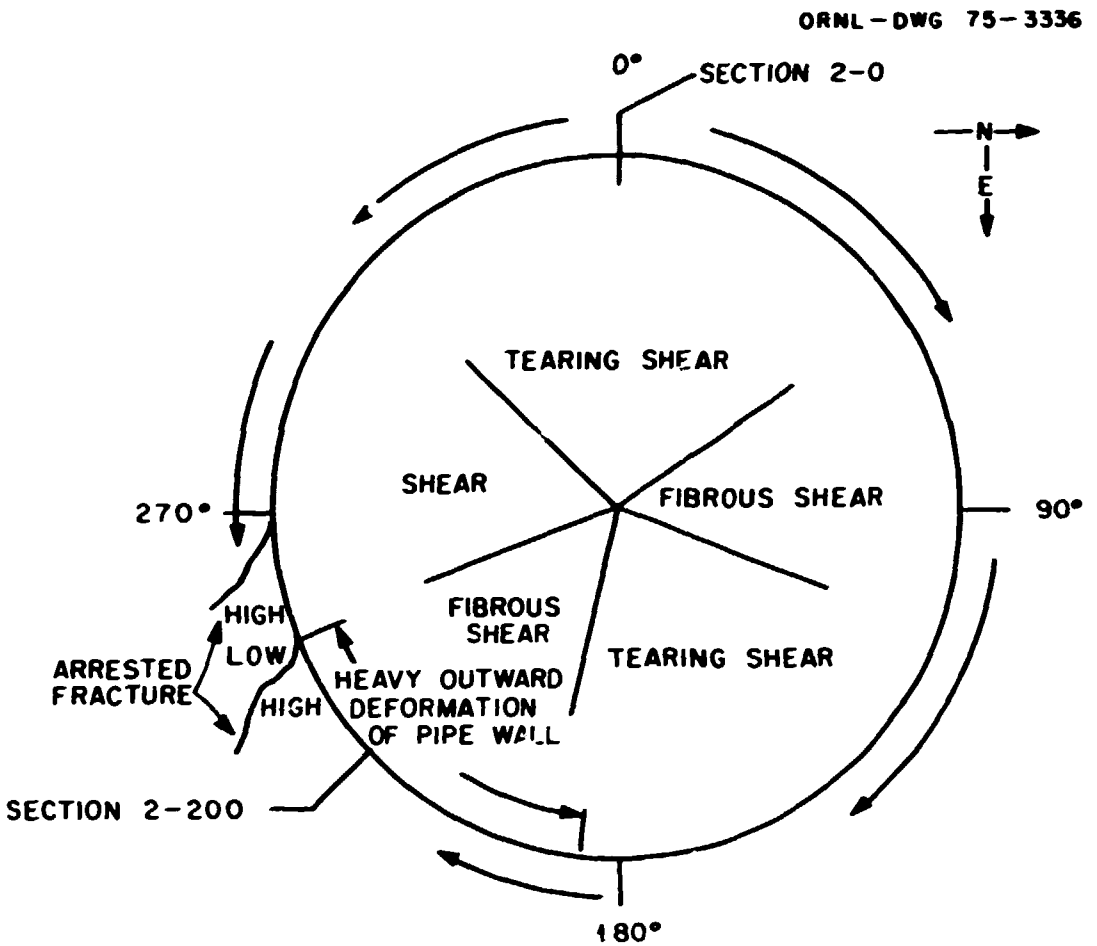
Arrows indicate direction of fracture propagation "x's" indicate fracture termination points.

Fig. 3. North Header Pipe Fracture



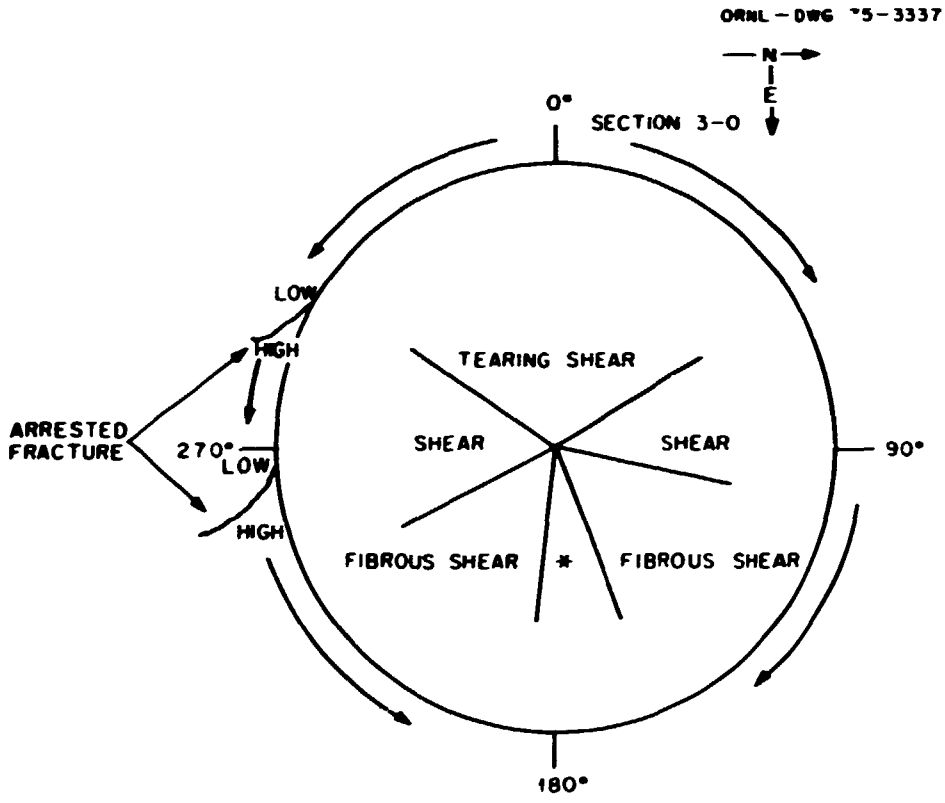
Arrows indicate direction of fracture propagation.

Fig. 4. 1400 Connection Fracture



Arrows indicate direction of fracture propagation.

Fig. 5. 1402 Connection Fracture



* FRACTURE SURFACE IN THIS REGION WAS FIBROUS ON ID HALF AND SHEARED ON OD HALF OF FRACTURE.

Arrows indicate direction of fracture propagation.

Fig. 6. 1403 Connection Fracture

ROE 72-16 September 29, 1972

PROCEDURAL PROBLEMS AT RESEARCH REACTORS

Summary

The reactor operating experiences reported herein are illustrative of OPERATIONAL PROBLEMS RELATED to the DEVELOPMENT and USE of WRITTEN PROCEDURES. Each of the events reported occurred at research reactors or critical facilities.

Circumstances

Research Reactor is Operated with Experiment Apparatus Partially In-Core*

A lithium-filled heat-pipe experiment apparatus that was to be irradiated in a pulsed research reactor consisted of an upper evaporator section containing a graphite element, in which ^{235}U fuel was embedded, and a 30-inch-long condenser section, containing the lithium coolant for the heat pipe. The apparatus was to be irradiated with the fueled section in the core and the condenser section in the reactor coolant plenum below the core.

When the experiment had received the specified fluence, the research reactor was shut down so the experiment could be removed. However, difficulties were encountered in sliding the experiment through the seal in the reactor vessel head so operations personnel clamped and sealed the apparatus in a partially withdrawn position. In this position, the fueled part of the experiment was well out of the core and only the condenser section was still in the core. The reactor was then restarted. During the increase in power level, the reactor was automatically shut down by the period circuit. A routine check was made by the reactor supervisor and reactor operator. No problems were noted, so the reactor was restarted. At the same thermal power level where the previous shutdown had occurred, another automatic shutdown was initiated by the period circuit. This time extensive checks were made, but there still was no indication of problems. The decision was made to start up the reactor very cautiously and go to a lower power level than that at which the two previous trips had occurred. As the power level approached the previous shutdown point, the period trip was bypassed, and the reactor behavior was watched closely in an effort to obtain sufficient information to diagnose the problem. When the power level reached the point where the two previous trips had occurred, power spikes were observed on all power-level instrumentation at

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* Material for this Section of the ROE was contributed by an AEC Field Office.

about 40-second intervals. The fluctuations stopped when the power level was reduced. At this point, operations personnel shut the reactor down for the night and consulted the reactor steering committee the next morning.

The steering committee noted that a chugging phenomenon had been observed in laboratory experiments with lithium-filled heat pumps. On the basis of this information, it was theorized that the lithium could be a possible source of periodic reactivity addition that was causing the power spikes because the experiment had been clamped in a position which left the lithium-filled condenser section in the core. A possible mechanism by which the reactivity could have been added periodically was by means of the lithium becoming superheated and being forced up through the heat pipe.

Subsequent investigations verified this hypothesis. The observed power spikes were determined to be caused by the periodic reactivity insertion of 12 ± 1 cents. The total reactivity worth of the 3 grams of lithium in the condenser had been measured previously and determined to be 15.3 ± 0.6 cents, lending credence to the hypothesis.

When the operations crew again attempted to remove the experimental apparatus from the core, they found that it could not be removed because two hanger tubes had been tack welded together. This change in the experiment design had not been recorded on either the operations log or the design drawings, and had not been approved. Also, a weld on one of the tubes was too large to pass through the seal.

Two irregularities in personnel action caused this event. First, undocumented and unapproved changes were made during the fabrication and installation of the experiment assembly. As a result of these changes the complete withdrawal of the assembly was not possible. The second contribution to the incident was that the shift supervisor approved reactor operation with the experiment assembly partially withdrawn. To reduce the probability of future incidents of this type, the reactor steering committee was assigned the tasks of specifying in-depth quality control procedures for each in-core experiment and for assigning the responsibility for execution of these procedures to a member of the operating group. Additional guidance was also provided to the shift supervisors as to when higher approvals for reactor operation are required.

Operation of Subcritical Assembly with a Mispositioned Source*

At a subcritical assembly that is used for quality control purposes, functional testing of the protection systems is achieved prior to startup by moving the neutron source near each of two ion chambers that are located at opposite ends of the lattice.

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*Material for this Section of the ROE was contributed by an AEC Field Office.

ROE 72-16

Prior to the incident discussed below, the source position had been determined from a source rod which protruded from the core and which was in clear view of the assembly operator. However, just before the incident, a shield had been installed to reduce the radiation exposure to operations personnel. While the shield accomplished its intended purpose, it also blocked the assembly operator's view of the source-position indicator. Consequently, the operator had to have assistance during startup.

During this particular startup of the assembly, the operator had an instrument mechanic move the source for pre-startup verification of instrument response. Following the movement of the source, it was not repositioned to its operating location, since the instrument mechanic had not been instructed to do so. In addition, since he was not a certified operator, he had no knowledge of the need to reposition the source. After instrument-response verification, the operator proceeded to start the subcritical assembly. Upon insertion of a standard fuel element that was used for calibration, the operator noted the abnormally low instrument readings and recognized that the source was mispositioned. In violation of procedures, he then moved the neutron source to the correct position without shutting down the assembly. The movement of the neutron source caused an increase of one-percent reactivity in the assembly because of the removal from the lattice of the cadmium follower on the source rod.

While the effects of the source-rod removal would not have exceeded the previously evaluated design-basis accident for the critical assembly, the incident demonstrated the need for fully considering all aspects of equipment changes. Because of the inadequate design of the radiation shield, the efficiency, and possibly the safety of, operation of the assembly was impaired.

To prevent a repetition of the accident, an interlock was installed to prevent either startup or operation of the assembly with a mispositioned source rod; procedures were revised to require two certified operators during pre-startup checks; and strick adherence to operating procedures was emphasized to operations personnel.

Communications Problems Between Reactor Supervisors of Different Shifts

At a university research and training reactor, the spent-fuel storage tank, located inside the reactor containment building, was scheduled for repainting. To provide adequate ventilation for the repainting operation, a temporary vent line was installed that extended from the fuel-storage room through the reactor-building wall via the neutron-beam window to the outside. The dished aluminum flange that sealed the neutron-beam window was removed to allow the temporary vent-line installation. The removal of the flange was duly noted in the log book.

The painting of the spent-fuel storage pool was completed the same day that it was begun, and the neutron-beam window was closed by replacing

six of the twenty-four bolts on the flange at equidistant positions and tightening them. An additional item was added to the operations work schedule, instructing the crew to replace the remaining bolts the following day. However, the additional item was overlooked the next morning, and the reactor building was closed for the weekend.

On the following Monday the reactor was operated at its authorized power rating. The Monday night shift supervisor noted that the additional work item had not been signed off. He then inspected the neutron-beam window, and replaced the remaining bolts.

Since the six bolts that were installed had been placed equidistantly and the seal was provided by a soft rubber gasket, an adequate seal was ensured. Also, the seal design is such that an overpressure in the containment would improve the seal.

Nontheless, the occurrence revealed a lack of communication between shifts. Consequently, it was restated and emphasized the importance of reactor supervisors checking operations schedules and reactor log books before beginning any activities that involve the movement of control rods or fuel within the core.

ROE 72-17 December 1, 1972

XENON OSCILLATIONS IN A LARGE POWER REACTOR

Summary

The possibility of the occurrence of XENON OSCILLATIONS IN THE CORES of LARGE POWER REACTORS has been known for some time. A relatively simple method for control of oscillations in the axial power distribution for a pressurized water reactor has proved effective.

Circumstances

Normal Plant Operating Conditions

A 700 MW(e) pressurized-water reactor (PWR) had been base loaded for several months, during which time the most significant deviations from the 100% power level occurred during scheduled load reductions for tests of turbine stop valve and governor performance. These weekly tests required that the load be reduced to 70% of full power for varying lengths of time, depending on valve performance during the tests. The time required at reduced power levels varied from approximately one hour to more than twelve hours.

Power was reduced for the tests by inserting one of the control rod banks to the 100-step withdrawn position. The increase in negative reactivity resulting from the buildup of xenon was then compensated by withdrawal of control rods in the other control rod banks and by boron dilution, to maintain power at the 70% level.

When the plant was returned to full power following the weekly tests, the axial power offset of the core was normally positive, but continued operation resulted in a substantial variation in the offset during the first xenon cycle, as illustrated in the first twelve-hour period of the lower curve of Figure 1.

Scheme for Controlling Oscillations

In this PWR, an axial stability index for the core has been measured to be +0.008, indicating an unstable condition. With this value for the axial stability index, the difference between positive and negative limits of successive oscillations would increase by about 23% for each oscillatory cycle; further divergence would be curtailed by a turbine runback when the overpower and overtemperature setbacks were exceeded.

Although part-length control rods are available in this reactor for control of axial xenon oscillations, they have not been utilized because a simpler method has proved effective. The control scheme that was used is known as a first-overtone control method. It utilized the same control rod bank for control of the oscillations as was used to reduce power

for the valve tests described above. In this control method, the control rod bank was inserted in a carefully timed manner, several hours after return to full power, to counter simultaneously the axial xenon and iodine oscillations, with a return to normal control rod configuration when oscillations have died out. Figure 1 shows axial offset measurements using the first-overtone control method.

This control method was used for control of increasingly divergent xenon-iodine instabilities as the core approached the end of life.

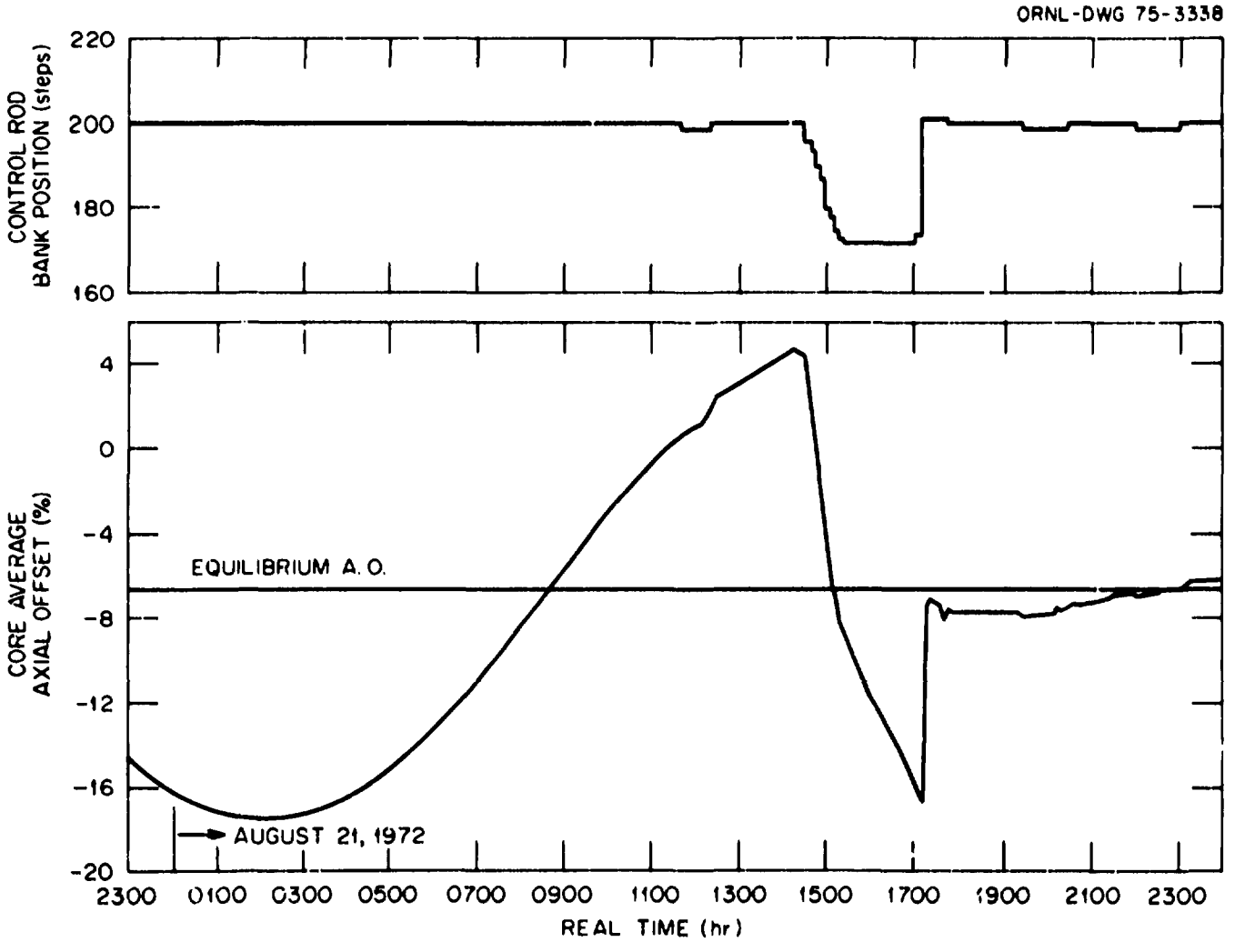

Fig. 1. Xenon Oscillation Control Test at Full Power

ROE 72-18 December 15, 1972

PWR CONTROL ROD DRIVE PROBLEMS

Summary

The events described in this report illustrate different MALFUNCTIONS that have occurred AT PRESSURIZED WATER REACTORS INVOLVING CONTROL RODS OR CONTROL ROD DRIVES. All malfunctions were detected during testing periods; none compromised safety of the plant. In one instance, DEPOSITS OF EPOXY-LIKE MATERIAL ON THE FACES OF CLUTCHES in control rod drive mechanisms (CRDMs) CAUSED FAILURES OF SINGLE CONTROL RODS TO DROP ON SIGNAL. In a second case, CRDMs were DAMAGED when they were dropped with the hydraulic DASHPOTS either EMPTY or only partially filled BECAUSE OF INADEQUATE VENTING THROUGH HOUSING SEALS. Third, INTERMITTENT RESPONSE TO WITHDRAW AND INSERT SIGNALS on one control rod was TRACED TO A DRAGGING MOTOR BRAKE on the CRDM. Finally, LOOSE DOWEL PINS used to position the stationary brake discs were found to be the CAUSE of MISPOSITIONED CONTROL RODS.

Circumstances

Failure of Control Rods to Drop on Test Signal

During drop tests of individual control rods being conducted as part of the low power physics testing at a pressurized water reactor (PWR), a test switch on the power supply for one of the control rod drive mechanisms (CRDMs) was opened in accordance with test procedures, but the control rod failed to drop as expected. The circuit was checked and determined to be functional, so a slight force was applied to the lower half of the CRDM clutch. This freed the rod and it dropped. The CRDM was exercised ten times and, when no problems were experienced, the low power physics testing was resumed.

Later during these tests, the rod drop test switch for another CRDM was opened and this rod also failed to drop immediately, although it did drop within a few seconds.

The tests of drop times for single rods were completed, and the reactor was secured to remove the two malfunctioning CRDMs for observation. An examination of the clutch surfaces in the two CRDMs affected showed a slight deposit of an epoxy-like material combined with some additional foreign material. These deposits apparently had hampered the free movement of the spring-loaded movable clutch face in the CRDM.

It was concluded that an excessive amount of epoxy had been used when new springs and pins were installed on the magnetic clutches. Some of the epoxy had flowed into the spring holes in each of the two lower clutch faces and, in some cases, into the spline area of the lower jaw of the clutches. All the CRDMs were cleaned and tested prior to reuse.

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Control Rod Drive Mechanism Damaged When Control Rods Were Drop-Tested With No Water in Dash Pots

After an extended outage at a PWR, drop tests of control rods were conducted prior to reactor startup. During these tests, anomalous behavior of one of the control rod drives led operations personnel to suspect that the energy absorber had shifted its location. When the control rod drive was removed from the vessel head for inspection, pressurized air was observed to escape from the drive housing, indicating that the CRDM had not vented through the housing seal as was the design intent.

To investigate further the functioning of the CRDMs, the primary-system pressure was raised to 200 psig and the rods were tested again. During these tests one control rod could not be withdrawn. The drive mechanism for this rod was removed and inspected and the shaft from the clutch output was found to be broken. In addition to the broken shaft on this CRDM, what appeared to be mechanical problems were encountered with two other CRDMs. As a consequence of these four problems, all four CRDMs were replaced.

Because of the problems that had occurred with these four CRDMs and suspected problems with six more, it was decided that further detailed investigations of all CRDM packages were in order. The CRDMs were operated and observed closely; the clutch units were removed and inspected at the plant and then returned to the manufacturer for complete disassembly and detailed inspection. All parts of the CRDMs that had sustained any damage were repaired or replaced and displacement measurements were made on all energy-absorber units. In addition, the reactor vessel head was removed and all control blades were visually inspected for damage.

Analyses of the events surrounding the damaged CRDMs indicated the possibility that the CRDM motor could not drive the rod into the energy absorber with the force necessary to cause shaft breakage. Based on these analyses, the tests performed by the manufacturer were designed to simulate the effects of a rod drop from the fully withdrawn position when the hydraulic dash pots were dry. The tests showed a pronounced recoil of the vertical motion assembly and a deformation of the coupler. Results of metallographic examinations of the failed clutch output shaft revealed that the shaft failure was caused by an impact loading in the same direction in which the recoil loading was applied. Other deformations in the input and output shafts were caused by a similar loading. Metallographic analyses of damaged gears in the drive train confirmed that the gears also had been subjected to impact loading.

The cause of the damage to the CRDMs was determined to be inadequate venting through the housing seals prior to trip testing. This caused the rods to be tripped with the hydraulic dash pots either dry or only partially filled with water. The hydraulic dash pots were then ineffective as energy absorbers and allowed the CRDMs to impact the hardstops with sufficient force (15,000–17,000 lbs) to displace the mechanical energy absorber units. These mechanical energy absorber units had been installed to preserve the

integrity of the vertical motion assembly and were not intended to prevent damage to the assembly.

The corrective or remedial actions that were taken by the licensee as a result of these incidents included the replacement of all twisted or broken output clutch shafts, replacement of all twisted clutch input shafts, replacement of the two CRDMs that had gear damage, replacement of pinion gears that showed a significant spalling of the malcolmizing coat on load-bearing surfaces, replacement of two bevel gears that had been slightly warped, replacement of all couplers that showed signs of damage, replacement or repair of the four energy absorber units that were displaced, and inspection of load-bearing surfaces on the upper end fitting of the control rod blades for structural integrity and reworking as necessary for proper coupling operation. In addition, calculations were made to determine the pressure that is required in the dash pot to provide normal deceleration of the drives and plant operation and testing procedures were revised to preclude tripping of the drives with the dash-pot pressure below the calculated value.

Intermittent Malfunctioning of Control Rod Drive Mechanisms

During preparations for testing of feedwater pumps at a PWR, a four-inch deviation alarm was received from the bank of control rods that was being used to control the reactor. An investigation revealed that one control rod was about four inches below the rest of the rods in the group.

The controls for the low rod were switched from automatic to manual, but the rod response to withdraw and insert signals still was intermittent. The wiring and circuits were inspected and tested, and these appeared to be satisfactory. Consequently, the problem was thought to be a malfunction of the motor brake on the CRDM. Before the reactor was shut down to remove the malfunctioning CRDM, the rest of the CRDMs were checked to assure that they functioned properly.

The motor for the malfunctioning CRDM was replaced, and the motor that had been removed was disassembled and inspected. Aside from what appeared to be excessive wear on the brake, no other abnormalities were noted, so the CRDM was shipped to the manufacturer for further inspections. The inspections by the manufacturer confirmed that the brake had been "dragging", and that the dragging would have been sufficient to cause intermittent malfunctioning because the motor develops very low torque when it is running.

Although the incident revealed an inadequate design of the CRDM that caused operating problems, it did not compromise the safety of the reactor because the CRDM could still be tripped. Because the clutch separates the CRDM from the motor, the deenergizing of the clutch as a result of a motor malfunction only serves to separate the motor from the CRDM.

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Misposition of Control Rods

Three instances of misposition of the same control rod occurred at a PWR when the power level was between 20 and 30 percent of rated power. When the 50 percent power level was achieved, two additional mispositions occurred.

The first incident occurred during testing of the plant. The regulating rod group was being withdrawn in the automatic mode when a four-inch deviation alarm on one bank of control rods was received in the reactor control room. During the ensuing investigation to verify the alarm, an eight-inch deviation alarm was received. When both alarms were confirmed, the reactor operator proceeded, as directed by procedures, to attempt to withdraw the affected control rod with the control system in the manual mode. When these efforts were unsuccessful, the fuses in the CRDM motor packages were changed and another unsuccessful attempt was made to withdraw the control rod. The control rod was then inserted about an inch and successfully withdrawn to its proper place. During further testing and operation, the control rods functioned normally.

The second and third incidents happened within a period of two days. During the second occurrence the four-inch deviation alarm did not actuate but, when the control rod lagged the bank by eight inches, both the four-inch and eight-inch deviation alarms sounded. Normal corrective action, which is to move the affected control rod until it is aligned with the rest of the bank, was initiated. Additional observations and investigations revealed that sticking relay contacts were contributing to the erratic behavior of the alarms.

The third event also occurred during withdrawal of the affected control rod. At this time, the affected control rod lagged the bank by 10.2 inches because neither the four- nor the eight-inch deviation alarms actuated at the proper times. An immediate investigation revealed that the deviation alarms could not respond rapidly enough to prevent a deviation greater than eight inches when the control rods were being withdrawn continuously. To compensate for this condition, the deviation alarms were reset to trip for three-inch and six-inch deviations, and the reactor operators were instructed to move the rods in four-inch increments to check for possible relay problems as the rods were being withdrawn.

The two incidents that occurred during later testing at the 50 percent power level involved the same control rod. During the first of these two incidents, the rod failed to withdraw with the bank and, once again, initiated the eight-inch deviation alarm. The rod was successfully repositioned with the control system in the automatic mode.

Later, during a test of plant response to a ramp decrease in load, the same control rod continued to insert into the core after the insert signal was removed, because of brake slippage. The rod drifted 8.9

inches farther into the core than the rest of the bank and had to be repositioned manually.

Because of these continuing problems, a detailed investigation of the control rod drive system was initiated. Inspection, cleaning, and dimensional checks of the brake assemblies were performed. All control-relay auxiliary contacts were replaced by slightly modified assemblies, according to the manufacturer's suggestion, because intermittent problems had been experienced in other applications. During the inspection of the brake assemblies, about 60% of the dowel pins, which position the stationary brake discs, were found to be loose. These loose dowel pins, which were galling the moving brake faces, were the cause of the continuing CRDM problems. Since the loosened pins had been held in their yokes by interference fits, all the pins were replaced with pins that were slightly oversized.

ROE 72-19 December 15, 1972

BWR CONTROL ROD DRIVE PROBLEMS

Summary

The events described in this report illustrate different MALFUNCTIONS that have occurred AT BOILING WATER REACTORS INVOLVING CONTROL RODS OR CONTROL ROD DRIVES. None of the malfunctions compromised the safety of the plants. At one facility, ROLLERS FROM BLADE-TYPE CONTROL RODS WERE DETACHED, LODGING IN THE CONTROL ROD DRIVE MECHANISMS. In a second instance, LEAKAGE OF REACTOR WATER PAST SEALS on the stop piston CAUSED PREMATURE LATCHING OF CONTROL RODS. The third case involved an electrical SHORT CIRCUIT IN A TRANSFORMER AS A RESULT OF DECONTAMINATION ACTIVITIES.

Circumstances

Foreign Object in Control Rod Drive Mechanism

During testing of control rod drives at a boiling water reactor (BWR), one of the control rods could not be withdrawn from the fully inserted position. Inspection disclosed that a foreign object was lodged between the index tube and the conical thimble end of the control rod drive mechanism. The foreign object was retrieved and the control rod and drive were retested to assure proper operation.

The foreign object was a roller from one of the older blade-type control rods. Comparison of this roller with others that were still attached revealed that the roller had been detached from its control rod for some time. It was hypothesized that the roller probably had become lodged between the index tube and the conical thimble end of the control rod drive mechanism in the three-month period between the withdrawal of the control rod and preparations for the refueling outage during which tne test was conducted.

A periscopic examination of the rollers on two other control rods that were still in the core disclosed that no excessive wear or degradation of rollers, pins, or castings had occurred. On the basis of this examination, it was hypothesized that the event was an isolated occurrence.

About three months later, during routine testing of the control rod drives, a second control rod could not be withdrawn, although it could be inserted. This control rod was valved out of service, and scheduled for examination during the next refueling outage, at which time it was determined that the roller on this control rod was also detached, in a similar failure.

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Also during the next refueling outage, a detailed examination of the two control rods from which rollers had been retrieved was performed. These two control rods had been replaced about seven years earlier. At the time of the earlier replacement, the rollers were missing on the two control rods that were replaced. Because of the similarities of these occurrences, it was concluded that the loss of the rollers was peculiar to these two locations and that the loss was a flow-induced phenomenon. The rollerless control rods were reinstalled in thir original positions and the plant was returned to service. Subsequent tests verified satisfactory operation.

Control Rods Fail to Insert Fully After Scram

On two separate occasions, at the termination of the scrams at the same reactor, some of the control rods latched six inches from the fully inserted position. The difference in worth of a single rod in this partially withdrawn position, compared to the fully inserted position, was approximately 3.65×10^{-3} percent Δk. Although this amount of reactivity is small, the malfunction does require an additional action by the operator to complete reactor shutdown.

On the first occasion, when the station air supply was interrupted, the reactor was scrammed manually. The reactor operator noticed that two of the rods had not latched in the fully inserted position but instead were six inches away from that position. The operator manually inserted the rods as specified by procedures. On the second occasion, the same two control rods, along with two additional rods, again latched six inches from the fully inserted position. All four rods were fully inserted by the operator as required by procedures.

The failure of rods to insert fully was attributed to increased leakage of reactor water past the seals of the stop piston. Worn or broken stop piston seals were found to be the cause of increased leakage.

The control rod drives in this reactor are positioned and scrammed hydraulically. They are equipped with buffer orifices comprised of a series of graduated holes which allow water to flow from the volume between the upper surfaces of the moving drive piston and the bottom of the stationary stop piston during a scram or normal rod insertion. Upon insertion of the drive piston the series of buffer orifices progressively limits the water flow to decrease the rate of movement of the drives. These orifices, together with spring washers which are mounted on the bottom of the stop piston, cushion the moving drive to reduce the shock of impact at the end of the stroke. With the drive in normal operating condition, the drive piston then settles back to the fully inserted position and latches mechanically. However, when the seals on the control rod drive (CRD) stop pistons leak because of normal wear or any other degraded condition, sufficient water can be trapped between the drive piston and the stop piston to create an added buffer which decreases the rate of rod travel, and allows the rods to latch prematurely.

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Because the leakage past the stop piston seals and the resulting intermittent partial insertion of the control rods had been observed early in the history of the plant, an augmented program of surveillance of the control rod drives had been established for the purpose of verifying the adequacy of their performance. This surveillance program consisted of the following: monitoring and recording, during each scram, the scram times for a selected group of control rods, monthly measurements of the withdraw stall flows for all drives, monitoring drive pressure during operation, exercising of all drives and monitoring the time between the occurrence of a scram and the high scram discharge volume trip. This augmented surveillance program permits early detection of degradation of performance of the drives.

Short-circuited Transformer

During a maintenance shutdown at another BWR, all fuel had been removed from the reactor vessel, and surfaces in the vicinity of the control rod drive mechanisms (CRDMs) had been decontaminated with high-pressure water and detergent. While one of the CRDMs was lowered for maintenance, a short circuit occurred in the 120 volt secondary windings of a transformer in the control power circuit for the control rods. The transformer failed and the 440 volt circuit breaker on the high side of the transformer was tripped automatically by an overcurrent signal. When smoke was observed to be coming from one of the compartments of the motor control center, the main breaker was tripped. Had the transformer failed during operation rather than during maintenance, control power to the CRDMs would have been lost, resulting in automatic shutdown of the reactor.

The affected cubicle of the motor control center was removed and its associated electrical equipment was inspected for damage. The failed transformer was replaced with a spare, the circuit breaker was cleaned, and the cubicle was returned to service.

To reduce the probability of recurrence of similar incidents, a fuse was installed in the control power transformer circuit of each control rod drive to provide added protection for the transformers.

ROE 73-1 February 9, 1973

MALFUNCTIONS OF MAIN STEAMLINE ISOLATION VALVES

Summary

MALFUNCTIONS of MAIN STEAMLINE ISOLATION VALVES have been experienced recently at both boiling water and pressurized water reactors. The malfunctions that are discussed below result from several causes: impurities in either the air or hydraulic systems caused valves to malfunction on four occasions; low air pressure and binding resulted in three other malfunctions; and improperly functioning instrumentation, worn gears, and materials failures are each responsible for at least one failure of the main steamline isolation valves to function as required. The number of malfunctions discussed in each of the sections below varies because, in some cases, an entire system may be affected or one valve may malfunction more than once.

Circumstances

Main Steamline Isolation Valve Failed to Close on Two Separate Occasions

Following a trip from full power at a pressurized water reactor (PWR) caused by an unrelated loss of the feedwater pumps, a gasket on an orifice flange in one of the steamline reheaters failed, allowing steam to escape. In order to stop the leakage, the reactor operator attempted to close the two main steamline isolation valves (MSIV's) from the control room; however, one of the two valves failed to close. The operator then went to the valve and manually tripped the solenoid-operated valves on the air line to the MSIV operator, closing the isolation valve. Subsequent investigations revealed that the linkage of the solenoid valves was binding. The equipment was returned to an operable condition and proper operation was verified by testing prior to returning the plant to operation. Also, a program was begun for testing the MSIV's each time the turbine generator was removed from service.

The MSIV's were tested satisfactorily during ten successive turbine outages over a period of about nine months. The valves were checked on the eleventh turbine outage and, at this time, one of the two MSIV's closed only half way. The packing glands on the valve were loosened slightly, and the valve closed fully. The valve was exercised several times, and gave no indication of further problems.

Impurities in Air Supply Line Cause Main Steamline Isolation Valve Malfunction

At a boiling water reactor (BWR), the main steamline isolation valves (MSIV's) had failed to operate on several occasions because of sticking valves in the pneumatic system which controls the flow of air to the air-operated valves.

An inspection of the valves, after they had failed to operate, showed that the lands of the valve spools were significantly discolored and were coated with a varnish-like substance. These were cleaned, but the spools still did not operate as freely as required. It was hypothesized that, in addition to impurities in the air supply system, the spools and sleeves were binding mechanically because of the high temperature in the environment in which these valves operate. To reduce this difficulty all the pneumatic valves were replaced with valves that had larger clearances between the spools and their sleeves. Also, additional air conditioning equipment was added to the steam tunnel in which the valves were located to reduce temperature in that area.

About six months after these valve modifications were completed, four of the MSIV's again failed to close and one closed slower than permitted by technical specifications. Once again, when the valves were inspected, the varnish-like substance was found on the pilot valves. The source of impurities in the control air was determined to be the oil-lubricated compressors in the instrument air system.

The entire instrumentation system was thoroughly cleaned to remove entrained dirt and oil, and a new cleaning system was installed to ensure that oil and other impurities did not leak back into the air supply.

Impurities and Low Pressure Causes Main Steamline Isolation Valve to Bind

During routine testing prior to reactor startup at boiling water reactor (BWR), a valve failed to close when the control switch for a main steamline isolation valve (MSIV) was placed in the closed position. The control switch then was returned to the open position and the spool on the pilot valve of the MSIV was moved to the closed position by applying force on one end of the spool. Although about 20 pounds of pressure were required initially to move the spool, it subsequently moved freely.

The pilot valve was removed from its mounting, disassembled, and the parts were inspected. A small amount of residue was found on the O-ring and the spool surfaces, which were then cleaned and the valve was reassembled with the original O-ring and parts. The pilot valve was installed for testing the MSIV and there were no indications of abnormal operation.

On a later occasion the pilot valve was removed again and the O-rings and seal gaskets were replaced. When the pilot valve was reassembled, it moved freely so it was reinstalled. At this time the pressure regulator and pressure gage were checked for pressure and calibration. The regulated pressure, as measured, was 37-38 psi instead of the desired 50 psi. Calculations showed that the 38 psi was not sufficient to overcome the frictional resistance of the dirty pilot valve spool and therefore to close the MSIV.

In order to minimize future occurrences of this type, procedural changes were made to have the valves checked and cleaned more often. In addition, the system was redesigned to supply full accumulator pressure to the pilot valve, and the water chemistry practices for the water in the reactor coolant system were changed to substitute hydrazine for a combination of sodium phosphate, sodium chromate and sodium hydroxide. The prior use of these sodium compounds as oxygen scavengers had left undesirable residues on the valves which prevented free movement of the pilot valve spools.

Malfunction of Main Steamline Isolation Valve Control Components Render Valve Inoperable

During periodic tests on the steam system at a boiling water reactor (BWR), the reactor operator noticed a very slow response of the inboard main steamline isolation valve (MSIV) when he initiated valve closure. The valve was cycled again in an effort to determine the cause of the sluggishness. This time the valve opened, but did not close. The air slide valve (a pneumatic valve controlling the flow of air to the MSIV) had failed to move, thus rendering the isolation valve inoperable. The air slide valve in the pilot operator was removed and inspected. Although there were no visible signs of wear or corrosion, the plunger showed evidence of resistance to sliding inside the barrel. A new slide valve was installed and functionally tested, and the MSIV was returned to service.

During tests at a later date, difficulties were again encountered with the same MSIV's. When functional tests were performed on the trip circuits, one of the inboard switches failed to actuate properly (in this particular test the MSIV is not required to be fully closed. Rather, it is operated from 100% open to 90% open and back to 100% open). The limit switch for the reactor protection system (RPS) signal was at the 90% open point, so that a partial closure of the valve should have tripped the switch. However, when the valve was moved to the 90% open position, the switch failed to actuate. Subsequent investigations showed that the switch was operable, but that the test circuit was reopening the valve before it could reach the trip switch. To assure operability, the RPS trip switches were adjusted so that they tripped with the valve at the 92 to 93% open position, thus assuring that the 100-90-100% test cycle would trip the RPS switches.

Worn Gear Causes Malfunction of Main Steamline Isolation Valve (MSIV) Circuitry

During the testing of main steamline isolation valves (MSIV's) at a pressurized water reactor, one of the valves did not respond to the signal to close; however, it could be closed manually. An investigation of the problem revealed that a worn gear in one of the two counter boxes, which actuates the limit switches on the motor operator, had prevented the proper operation of the limit switch.

The counter box was replaced and a different lubricant was applied to reduce the likelihood of a similar failure occurring in the future. The motor operators on the other three MSIV's were also examined. The counter box in one of the operators was replaced because of worn gears and the lubricant in this counter box and one other box was changed. The valve operator for the fourth MSIV was left unchanged because it showed no sign of wear. All four MSIV's were tested to assure satisfactory operation before they were returned to service.

Leakage and Closure Problems of a Main Steamline Isolation Valve

At a boiling water reactor (BWR) the failure of two main steamline isolation valves (MSIV's) to operate within Technical Specifications was discovered during testing. The Technical Specifications for this facility require that the closure times of the MSIV's be between three and five seconds. One of the MSIV's closed too rapidly and one closed too slowly.

An investigation revealed that the external piping to the oil dashpot cylinder on the valve that had exhibited the fast closure time was leaking. The dashpot piping and fittings on all MSIV's were tightened, sealed or replaced to eliminate oil leakage. Also, the oil levels in the dashpots were checked and oil was added where necessary.

In an attempt to ascertain the cause of its malfunction, the valve that had exhibited the slow closure time (>5 seconds) was tested again. It was then discovered that the valve closed slowly only when it was opened and reclosed immediately. Since this valve, located inside the containment building, was the only one that performed in this manner, the containment building was deinerted to allow personnel to enter and further investigate the problem. These investigations revealed that the spool valve controlling the flow of air to the MSIV was not operating properly. When it was disassembled, it was evident that the spool would not travel freely in the spool sleeve. The spool was polished with emery cloth, the spool valve was interchanged with the spool valve on another MSIV, and no further problems developed with the operation of either of the MSIV's.

Subsequent to the checking of all MSIV's, another MSIV was found leaking.

Subsequent testing revealed that four of the eight MSIV's were leaking. Detailed investigation into the leakage revealed four major problems, each of which contributed to the leakage: foreign material in the poppet/poppet-guide assembly, failures of spring-collar tack welds, scratching of a pilot valve during reassembly, and unsatisfactory lapping procedures.

On one of the four leaking MSIV's, there was excessive wear of the lower inch of guide material on one of the three poppets, and there was an indication of wear between the guide and the poppet. This wear was postulated to have been caused by foreign matter which had become wedged between the guide and the poppet or by foreign material that had become lodged under the poppet seat during flushing operations. The worn area of the poppet guide was overlaid with stellite, and the poppet was rotated to provide a new mating surface between the poppet and the guide.

Each MSIV has a spring-seat collar which is screwed to the stem of the pilot valve, and tack welded to the stem to restrict rotation. The tack welds had cracked on all four of the MSIV's that were disassembled, and the collar on one valve had unscrewed about 0.4 inches. The cracked tack welds had been made of 410 stainless steel, a material that loses its ductility as the grain structure changes during hardening. It was hypothesized that this could have caused the cracked welds. The tack welds were replaced with longer welds of 309 stainless steel, an austenitic material that retains its ductility as it hardens.

It was necessary to disassemble three of the MSIV's twice to correct the leakage problem. One MSIV had to be disassembled a second time because, during valve reassembly, the pilot valve was scratched by the very sharp upper edges of the pilot valve guides. When the valve was disassembled the second time, chamfers were machined on the upper edges of the guides, and the assembly procedures were modified to minimize the possibility of scratching the pilot valve. Another MSIV had to be disassembled twice because lapping procedures suggested by the valve maufacturer proved unsatisfactory. Lapping procedures and tools were modified to permit satisfactory lapping of the valve.

Two other MSIV's had individual problems. One of the valves had a chip out of the main seat and was not seating over 25% of the circumference of the valve. Also, the upper guide land of the poppet on this valve was out of round by as much as 20 mils. Both problems were corrected before the valve was returned to service.

The main seat of the other valve was chipped, so the seat was lapped before the valve was returned to service.

Closure-Time and Leakage Problems of a Main Steamline Isolation Valve

During a routine test of the closure times for the main steamline isolation valves (MSIV's) at a boiling water reactor (BWR), one of the valves exhibited a closure time of 3.2 seconds, which was within the limits prescribed by Technical Specifications, but was too close to the lower limit to satisfy operations personnel. (The Technical Specifications at this plant specify closure times (t_c) of 3 sec $\leq t_c \leq$ 10 sec.) The valve was inspected and it was noted that oil was leaking from the adjustment leg for the hydraulic dashpot. The line was repaired and about three pints of oil were added to the dashpot.

Later during the same outage, leak-rate measurements were performed on all four MSIV's. The above-mentioned valve was observed to have a leakage rate of 110 SCFH with 20 psig air pressure in the reactor vessel. This test was performed in the as-found condition following plant shutdown.

The leaking valve was disassembled and inspected. The valve stem, which was 27 mils out of alignment, was straightened, and the seats on both the main valve and the pilot valve were lapped. The MSIV was reassembled and tested to assure that the leakage problem was corrected.

During subsequent surveillance testing, while the reactor was shut down the closed indication for this same valve failed to actuate. An immediate investigation was begun and, after determining that the indicator-circuit logic was not the cause of failure, the drywell was deinerted to allow a physical examination of the MSIV and valve operator. It was noted that the valve operator lacked about 1.5 inches of travel to accomplish full closure. The dashpot section of the valve operator was dismantled, and the cast-iron cushion spud was found crushed between the bottom of the dashpot piston and the base of the cylinder.

The cause of spud failure was postulated to be a shock wave that resulted from a failure to equalize the pressure across the valve before opening it. The shock wave was transmitted to the cast iron spud by the valve stem, thereby causing the spud to fail in compression. Subsequent to the discovery of the failed spud, the remaining three MSIV's were inspected. One additional valve had a failed cushion spud, but this had not interferred with valve closing times. Two new spuds were fabricated and installed in place of the failed spuds, and the repaired valves were tested to assure proper operability before they were returned to service.

ROE 73-2 February 23, 1973

WATER HAMMERS IN ENGINEERED SAFETY SYSTEMS

Summary

The two events discussed below have a single common cause: the WATER HAMMERS in both instances were CAUSED BY LACK OF SUFFICIENT ATTENTION TO the OPERATING DETAIL of assuring that the systems containing water were, in fact, free of air when they were to be operated. In the first case, startups of the core spray pumps during testing resulted in superficial damage from pipe movement in the core spray pump discharge header. Investigation revealed that the core spray lines could drain to the torus, resulting in a water hammer when the pumps were started. Jockey pumps were installed to keep the lines filled continuously. The second case involved some physical damage to pipe hangers and seismic restraints as a result of a water hammer traced to inadequate procedures for venting the residual heat removal system following refill of the system after it had been drained.

Circumstances

Water Hammer in A Core Spray System

Each loop of the core spray system (shown in Fig. 1) at a boiling water reactor (BWR) includes two redundant core spray pumps and two booster pumps. The core spray pumps take suction from the torus under an elevation head of about 12 feet of water and discharge to the booster pumps, which are automatically actuated by the containment pressure. The flow leaving the booster pumps is returned to the torus during testing of the system by means of a bypass line that is located just upstream of the containment isolation valves.

During testing, a team of observers witnessed the startup of both core spray loops. During the startup of the system, the discharge pipe header was observed to move about ± 2.5 inches. No movement was noted downstream of the containment isolation valves and further investigations substantiated that the core spray pumps and booster pumps had suffered no damage. Upstream of the containment isolation valves, minor damage, consisting of paint scrapes and torn insulation, were sustained by the core spray system.

To evaluate the effects of the water hammer on the components of the core spray system, stress and fatigue analyses were performed and the results of these analyses were compared with data from low cycle fatigue tests of similar components. Magnetic particle and dye penetrant tests and wall thickness measurements were performed in the areas of the core spray system where the calculated stresses were high. No compromise of system integrity was detected. Also, ultrasonic tests of the piping

of the piping welds inside the drywell were performed as part of the in service inspection program, and the integrity of this portion of the system was confirmed.

It was hypothesized that the water hammer was caused by starting the pumps with the discharge lines empty. When changes in procedures proved ineffective, the decision was made to install jockey pumps (also shown in Fig. 1) to keep the lines filled continuously. During the investigation, an evaluation of the design of the core spray system disclosed that the core spray lines could drain through the check valves into the torus because of the relative elevation of these lines with respect to the torus. Hence, the need for a continuous fill system.

The jockey pumps are canned rotor centrifugal pumps that are connected across the check valves at the discharge of one of the core spray pumps in each core spray loop. They are below the water level of the torus, and take their suction from the torus water, discharging to the downstream piping. After each extended outage of the core spray loop, proper filling and venting of the system is ensured before the vent valve on the line is closed.

Since the jockey pumps in both core spray loops have been in service for at least 12 monthly tests of the core spray system and no observable vibrations have occurred, the jockey pump modification is considered to have solved the water hammer problem.

Water Hammer in Residual Heat Removal System

At another boiling water reactor, an extensive search for missing sections of vane type flow switches had necessitated the draining of the primary side of the heat exchanger in the Residual Heat Removal (RHR) loop and the removal of the bottom head of the heat exchanger. Subsequent to the replacement of the bottom head and the refilling and venting of the RHR system, tests were conducted to assure proper functioning and leak tightness of the system. The tests were terminated prematurely, however, when a water hammer was experienced in the loop and a leak was observed at the flange on the lower head of the heat exchanger.

A preliminary inspection revealed that pipe motion had occurred at seven hanger and four restraint locations, and that one motor operated valve was inoperative. One pipe hanger base plate was bent and four anchor bolts on each of two other hanger base plates had pulled loose from the supports. Three seismic restraints were damaged and the grout was chipped at the fourth restraint. A misalignment between the motor and valve actuator had resulted from loose motor alignment bolts on one of the motor operated inboard valves in the drywell spray system.

Procedures were then rechecked in an attempt to understand the cause of the water hammer. From this reevaluation it became apparent that the procedure for venting the system was faulty. Although procedures

called for venting the line at high points, only one vent point was used, with a jockey pump being used as a source of water. This procedure left several points for air accumulation, such as upstream from all four discharge check valves or in the tie line to the fuel pool cooling system.

A detailed analysis of the water hammer effects was performed to identify the areas of the RHR system that were subjected to the greatest stress. From this analysis some welds were selected for dye penetrant tests. None of the welds or adjacent piping sustained detectable damage.

The damaged seismic restraints and pipe hangers were repaired, the inoperative valve was replaced with a spare one, all logic systems were rerun, and all valves were exercised. At the same time, a new refill and vent procedure was prepared, approved, and used for functional testing of the RHR system prior to returning it to service. With the new procedure the water hammer did not occur.

Conclusions

In the first event, the problem was observed during startup testing; hence, the damage was only minor scrapes of paint and torn insulation. The second event occurred as the system was being returned to operation following maintenance. Although the damage differed in two cases, apparently according to length of time the system was operated before the damage was discovered, each of the systems were still operable. In case either of these systems had been required, they would have performed their required safety function. Both instances demonstrate, however, the need for careful evaluation of the forces which may result from unusual operating conditions.

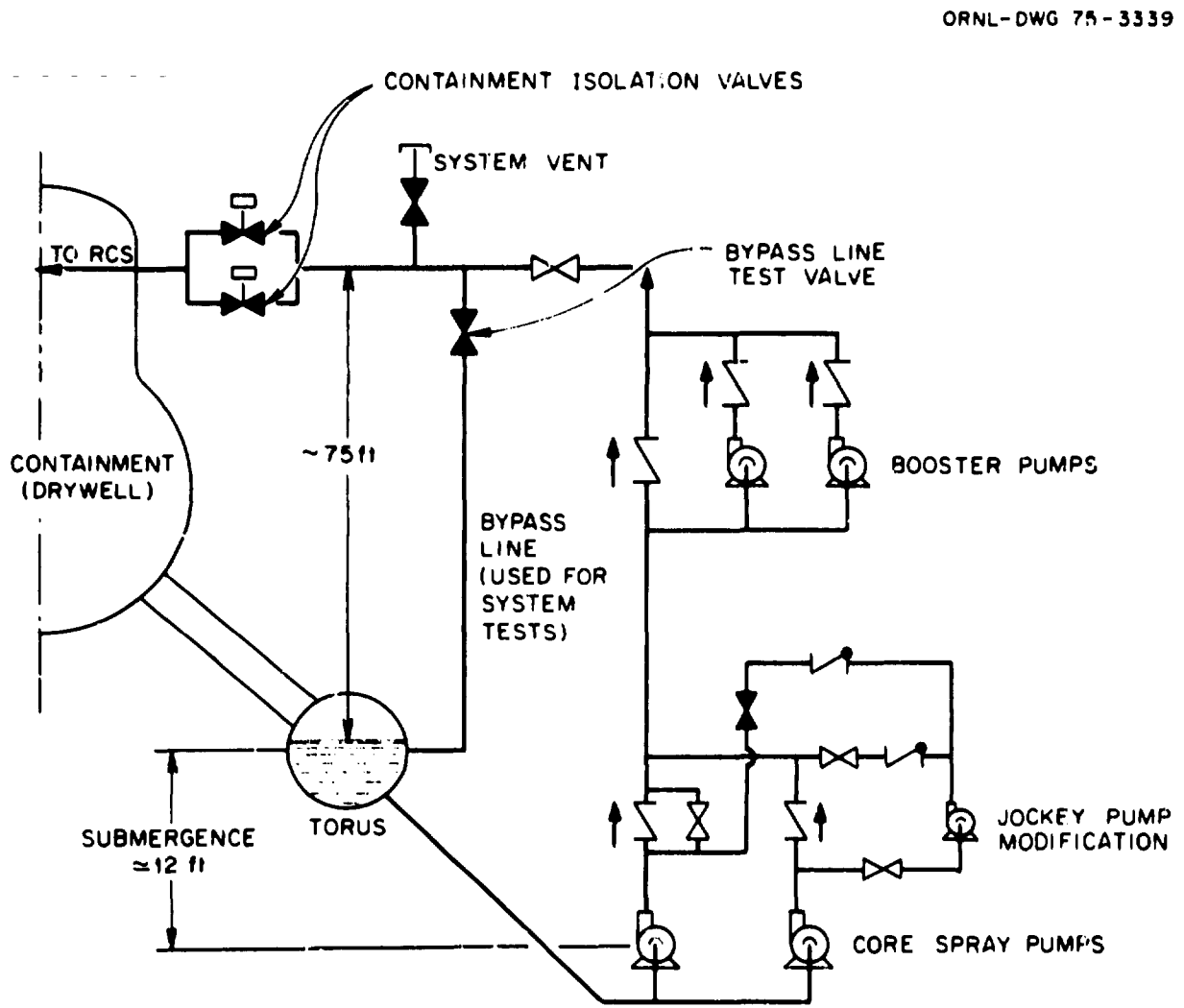

Fig. 1. Core Spray Loop System Schematic

ROE 73-3 March 30, 1973

ABNORMAL FLOW RATES FROM JET PUMPS

Summary

THREE OCCURRENCES of ABNORMAL FLOW RATES from the COOLING SYSTEM JET PUMPS in boiling water reactors (BWR's) have occurred in the last two years. TWO of the PROBLEMS resulted FROM MATERIAL that was LEFT IN the JET PUMPS DURING CONSTRUCTION, and ONE PROBLEM resulted FROM MATERIALS FAILURES. In all three cases, the flow anomalies were discovered during testing so that the safety of the plant was not compromised.

Circumstances

Background

Some BWR's that are operational at present are equipped with jet pumps which mix the recirculated coolant from the recirculation loops and the coolant in the reactor vessel annulus to recover coolant pressure. A schematic of a typical jet pump is shown in Fig. 1.

Circumstances

During startup testing at Dresden-3, calibration data on the flow instrumentation for the jet pumps were being obtained when a low flow indication from one of the 20 jet pumps was noted. Since normal flows from this pump had been observed the preceding day, the problem was tentatively attributed to a faulty transmitter. However, after extensive checks indicated that the problem was within the jet pump, the reactor vessel head and internals were removed so that the jet pump could be inspected.

This inspection revealed that the cause of the reduced flow in the pump was a welding purge dam that was lodged in the transition casting of the pump at a point where the flow is divided from the riser inlet to the nozzles for two jet pumps. The purge dam, which was lodged against the casting, blocked about three-fourths of the flow from the riser to one jet-pump nozzle.

The purge dam was removed and examined. It was a standard plywood and rubber dam, about 16 inches in diameter, which is commonly used in construction for inert gas back purge of pipe-closure root welds. The dam consisted of four 3/8-inch-thick plywood semicircular segments and two 1/8-inch thick, red rubber, circular sheets that are sandwiched together by 1-1/4-inch stove bolts. When the purge dam was retrieved, one of the plywood segments was broken completely and another was badly

damaged. These two segments were joined by a chain that was designed to be a handle for the removal of the purge dam.

After the damaged purge dam was removed, the pumps, primary system, and fuel elements were inspected for debris. The following parts of the purge dam were determined to be missing: about 30 square inches of rubber consisting of small pieces; approximately 16 square inches of plywood consisting mostly of splinters; four nut-screw combinations (1/4-inch · 1-1/4 inch); one washer (1/4-inch); and one nut (1/4-inch). Tests of wood and rubber of the type used in the purge dam, conducted under simulated reactor environment, revealed that these organic materials would disintegrate within 18 hours under operating conditions.

After the system had been cleaned, flushed, and checked, the following additional actions were taken to ensure that the system was safe for operation:

- both core-spray systems were operated to inject water into the vessel; proper operation was verified from examination of photographs of the spray,

- the inside of each of the feedwater spargers was inspected for debris; none was found,

- the HPCI testable check valve was disassembled and the piping near the discharge to the feedwater line was inspected; no foreign material was found,

- proper performance of the LPCI testable check valves was verified by operation of the shutdown cooling system at high flows,

- the lower reactor plenum was inspected at four locations by completely unloading the fuel from these positions and observing the plenum by means of an underwater TV camera; a 2" · 4" piece of rubber was retrieved from the plenum area near the bottom drain of the reactor vessel as a result of this examination.

Subsequent to these extensive investigations, the plant was operated at the nominal rated temperature of 540°F for three days before the 10% power level was exceeded. This was done to ensure that any remaining debris was disintegrated before a substantial power level was reached.

Prior to installing the steam separator, steam dryer, and reactor vessel head at Quad Cities-2, the primary system was checked by means of a jet pump flow comparison test.

This jet pump flow test is performed with both reactor recirculation pumps operating at the same speed and the valves on the crosstie for the recirculation header closed. With the recirculation system in this condition, the indicated flow rates on each of the 20 jet pumps should be approximately the same.

However, during this particular test, two of the pumps had an indicated flow rate of about 50% below the average of the other 18 jet pumps.

When one of these two jet pumps was removed for examination, an obstruction, consisting of a heliarc welding rig, was found. The rig comprised one 5/8-inch rubber hose, 24.5 feet long with fitting attached; one 5/8-inch rubber hose, 12 feet long with a "Chicago" fitting on one end and a copper fitting on the other end; and a 24.5-foot long, two-conductor welding cable that was attached to a TIG welding gun.

When the material was removed from the jet pump riser, the riser was inspected to verify its integrity, and the jet pump was then returned to the reactor vessel. The quality control records, flow test results, and details of the inspection and reinstallation of the jet pump were evaluated and analyzed. The system was determined to be clean and clear of foreign material, and the startup test program was continued.

Also at Quad Cities-2, a flow imbalance was discovered subsequent to a trip and restart of a recirculation pump. Balanced flows had been recorded previously with this recirculation pump operating. A cursory investigation revealed an indicated abnormal flow rate in one of the 20 jet pumps. When a low ΔP across the core was confirmed, an orderly plant shutdown was initiated for investigation and analysis of the apparent flow anomaly.

After the plant had been shut down, flow tests were conducted in the recirculation loop that had exhibited the anomalous behavior. From these tests, and examination of additional flow data, and the routine operating data, it was hypothesized that either an elbow or a nozzle was either plugged or broken.

The reactor vessel head was then removed for further inspections. When the vessel head had been removed, the malfunctioning jet pump was found lying between the adjacent jet pump and the reactor vessel wall. The jet pump had lifted 3 to 6 inches and rotated 45° about its axis. Further investigations disclosed the following: the beam bolt assembly (Fig. 2) and insert washer were missing from the top of the mixer, the retainer and 1/2-inch connecting bolt (see Fig. 2) were missing, and one keeper on one of the clam bolts on a lower restrainer (Fig. 3) was gone. A subsequent search with an underwater TV camera located these parts. The remaining 19 jet pumps were then inspected with the underwater TV camera to verify their integrity.

Detailed metallurgical analyses were performed on the components of the jet pump hold down mechanism. The jet pump beam-bolt assembly had four failed fusion welds. The weld on the restrainer clamp bolt that was to hold the jet pump in place had failed, as had the only weld on the hex head of the retainer bolt.

In the subsequent investigation, two special tests were performed on all the jet pumps to check beam-bolt preload, and to check for proper sizing of welds on all the jet-pump beam bolts. In one test, a 300 ft-lb counterclockwise torque was applied to the lock welds on the keeper. The

welds failed on two of the remaining 19 jet pumps, indicating that inadequate beam preload had been applied to these beam bolts. The second test used a detensioning technique for checking the release point on the beam bolts while a constant 300 ft-lb counterclockwise torque was applied. This test was applied to the beam bolts on four of the remaining 17 jet pumps and the beam bolts on three of these rotated free at tensioner pressures that indicated proper beam preload. The fourth beam bolt failed to release at the maximum tensioner pressure, indicating that the keeper lock welds were larger than required.

Based on these extensive tests and evaluations, the original failure of the jet pump was attributed to inadequate field assembly and installation, i.e., the required preload was not applied to the jet pump hold down assembly and the keeper was inadequately field welded.

In order to preclude this disassembly type of problem from recurring, all beam-bolt keeper welds were broken, the preloads were applied according to original installation requirements, new welds were made, torque tests were performed on the new welds, and the integrity of these new welds was confirmed by an underwater TV camera.

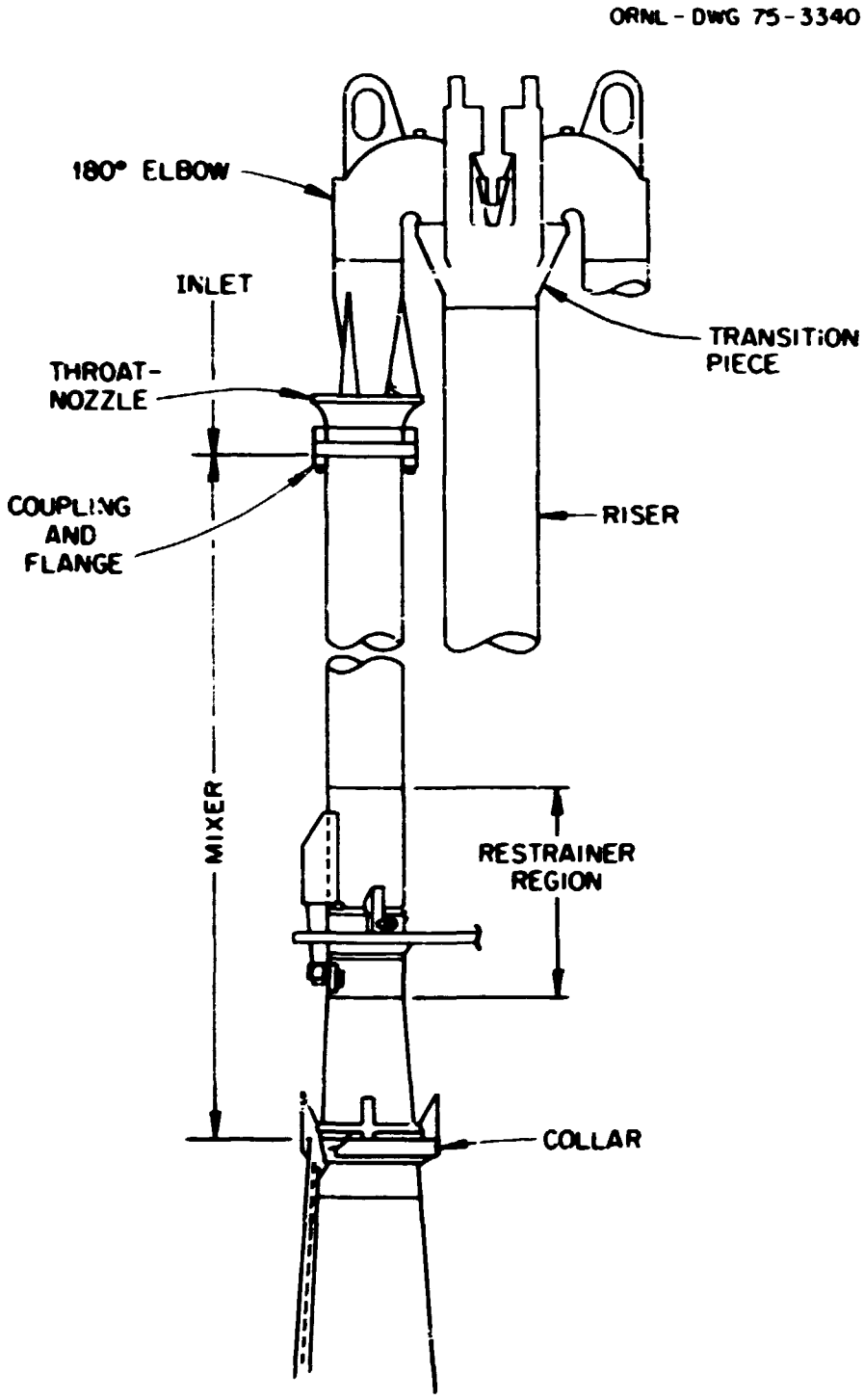

Fig. 1. Jet Pump Assembly

ORNL-DWG 75-3341

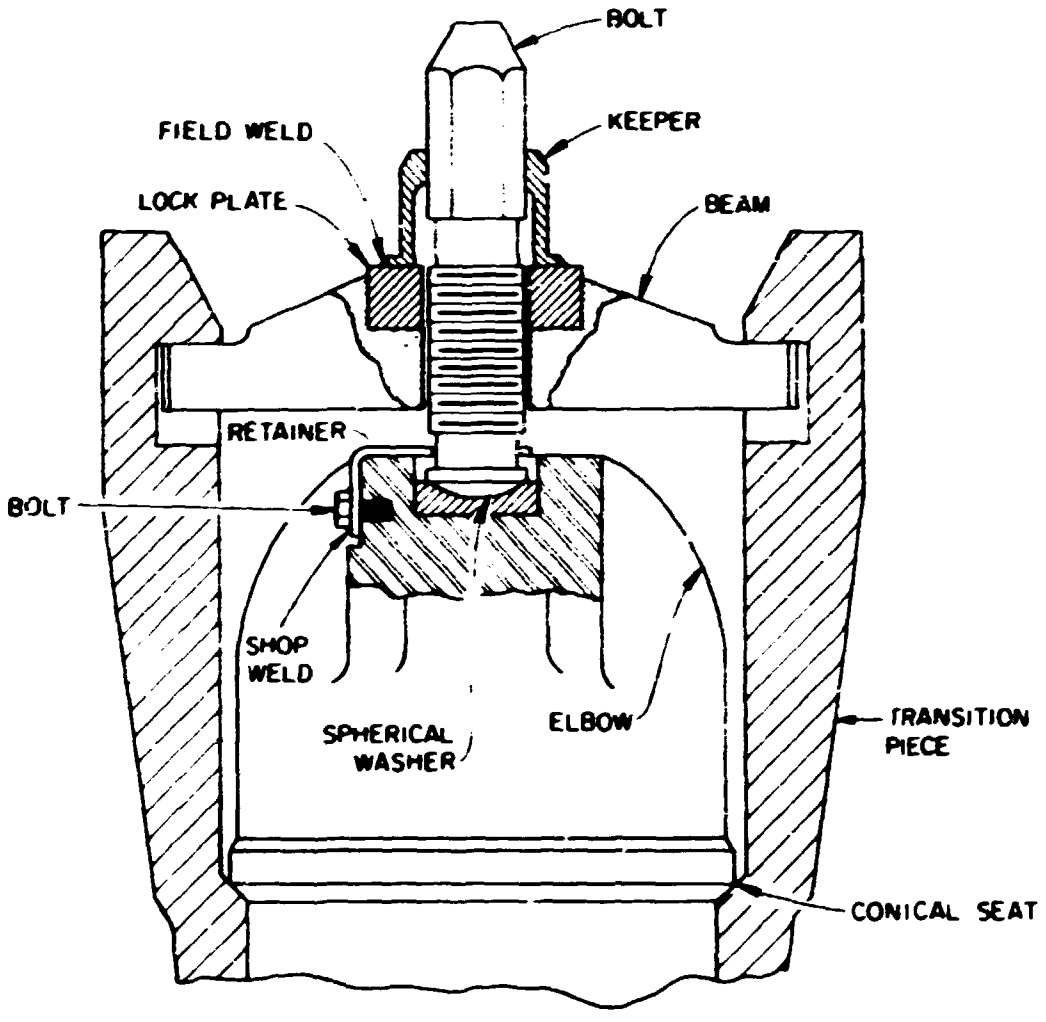

Fig. 2. Beam-bolt Assembly
(Schematic -)

ORNL-DWG 75-3342

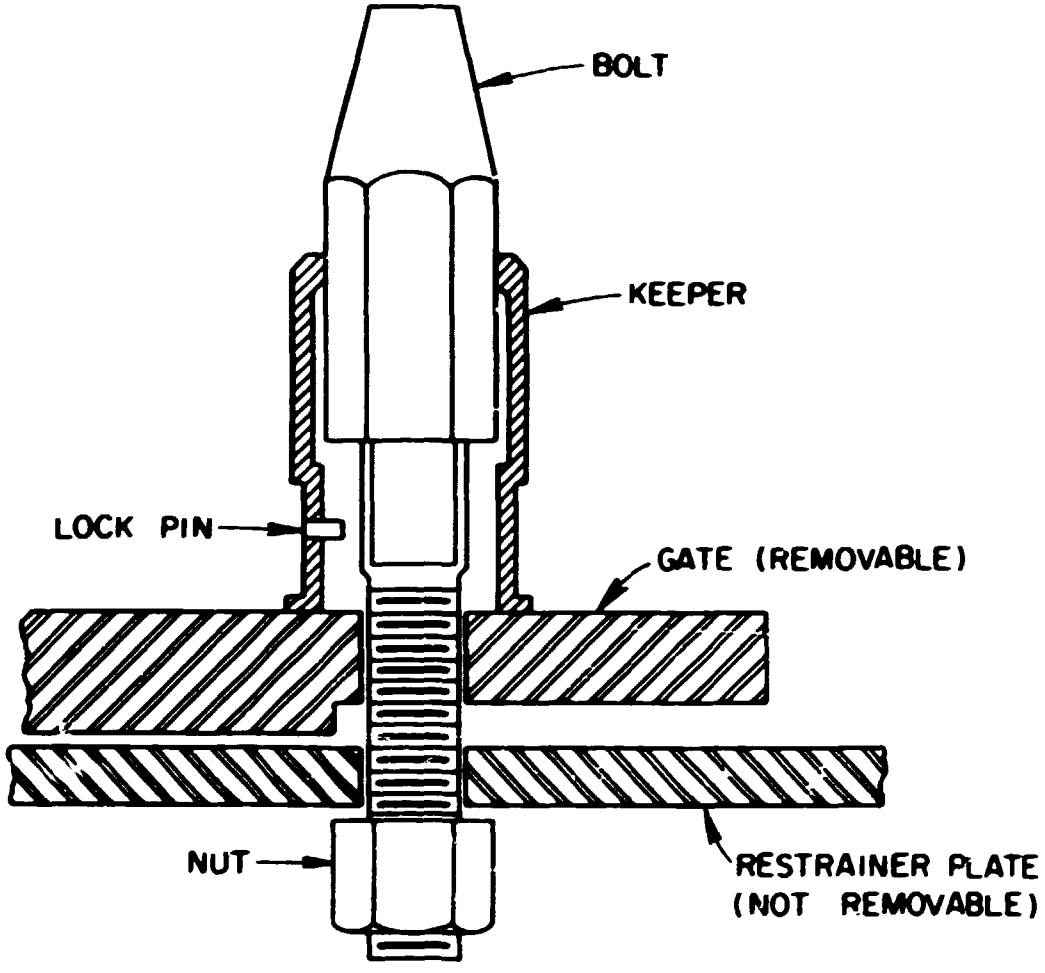

Fig. 3. Restrainer Gate Bolt Assembly

ROE 73-4 April 13, 1973

VALVE PROBLEM CAUSES FLOODING OF TURBINE-BUILDING BASEMENT

Summary

EFFECTS of a VALVE MALFUNCTION in the condenser circulating water system at a boiling water reactor facility are described below. At the time of this occurrence, the REACTOR WAS in a SHUTDOWN condition, so that no threat to the public health and safety existed, despite the fact that the FLOODING of the TURBINE BUILDING BASEMENT RESULTED in loss of engineered-safety systems equipment.

Background

As nuclear power plants have increased in size, the practice of designing the circulating water systems so that flow direction can be reversed regularly to maintain condenser cleanliness has become more prevalent. As a result of the size and system requirements, the designers have generally specified butterfly valves to permit flow reversal of the circulating water through the tubing of the main condenser while the plant is on line. Often the position of these large butterfly valves is controlled by hydraulic or pneumatic positioners.

Circumstances

At Unit 1 of the Quad-Cities station, a boiling water reactor (BWR), the 10-ft diameter butterfly valves in the circulating water system of the main condenser were controlled by hydraulic positioners. These valves had a history of drifting in position, which caused excessive operation of the hydraulic actuator. Consequently, the valves and associated control systems were being modified during a scheduled maintenance outage in June 1972.

During the venting of the hydraulic actuator, a 10-ft diameter butterfly valve in one of the circulating water discharge lines slammed shut, and with three circulating water pumps operating, caused a water hammer in the system. This water hammer, in turn, ruptured a rubber expansion joint that was located in the recirculation line about 16 feet above the valve at the water-box connection. When this expansion joint ruptured, river water from the circulating water system began to flood the condenser room and flow into the condensate pump room in the turbine building basement.

The flooding was immediately reported to the reactor operator who shut down all circulating water pumps. The pump shutdown automatically closed the pump discharge valves. Within about six minutes, all of the supply breakers on all electrical equipment that was housed in the flooded

area had been opened, the discharge gates in the circulating water system had been closed, and the ice-melting gate had been opened to prevent a backflow of water to the condenser and to lower the discharge head. However, during these six minutes, the turbine-building basement filled to a depth of about 15.5 ft. As a result of the flooding, the following equipment was rendered inoperable: four emergency service water pumps in the residual heat removal system, the cooling water pumps for the No. 1 diesel generator and for the No. 1/2 diesel generator, four condensate-condensate booster pumps, three condensate transfer pumps, the seismic detector, four sump pumps in the equipment and floor drains system, the analyzer and sample pump in the hypochlorite system, and the hydraulic power unit for the circulating water valve actuators. The diesel generator cooling water pumps and the residual heat removal system service water pumps comprised the engineered safety features equipment which was incapacitated at this time.

Corrective Action

Unit 2 of this dual-unit facility was immediately shut down and remained in this status until the No. 1/2 diesel generator, which is shared by the two units, was returned to service.

Before the water in the basement was pumped out, samples were taken and analyzed; the activity was found to be typical of river water background. Samples were also taken and analyzed continuously for activity during the pumpout operation. At all times the activity of the samples remained at background levels.

After the water in the turbine building had been pumped out, cleanup and repair work was begun. The diesel generator unit shared by Units 1 and 2 was returned to service, and the condensate transfer pump and the seismic detector were returned to service in less than three days. The instrumentation was cleaned and recalibrated; the electrical motors were removed for drying. After the motors dried and the power cables had been reinstalled, the motors were meggered and operationally tested prior to being reinstalled. One service water pump motor was returned to the factory to be rewound.

In order to preclude recurrence, a new procedure was adopted for venting the hydraulic actuators for the valves in the circulating water system. The new procedure required that all butterfly valves have their lock pins in place before the actuators are vented. In addition, the sealed door to the hotwell area of the condenser was replaced with a water-tight bulkhead door, the 4' × 4' ventilation opening that connected the area under the condenser with the condensate pump room was raised above the flood level, alarms were installed at different levels to indicate flooding under the condenser, a very-high-level trip for the circulating water pumps was installed under the condenser, and a back-up alarm to the existing sump-pump alarms was installed in the condensate pump room.

The engineered safety systems equipment located in the condenser pump room has been protected by water tight vaults around the service water pumps for the residual heat removal system and around the cooling water pumps for the diesel generator.

ROE 73-5 May 25, 1973

COOLING SYSTEM TRANSIENTS-I

Summary

Since the AEC published its Task Force Report on the "Evaluation of Incidents of Primary Coolant Release from Operating Boiling Water Reactors," dated October 30, 1972, several more such incidents have occurred. Of the transients that are discussed below, six occurred at boiling water reactor plants and one occurred at a pressurized water reactor plant. Two of the transients occurred when the turbine tripped; in one of these cases a failure of the loss-of-field relay on the generator caused a generator trip and turbine lockout; in the second event the turbine trip occurred during routine weekly tests because of the failure of a microswitch in test instrumentation. A third transient occurred during startup tests on the main steam line isolation valves when a safety valve actuated prematurely. An internal fault on the startup transformer resulted in the fourth event, a loss of station power and a consequent cooling system transient. A fifth transient resulted from a reactor scram caused by a spurious signal on an average power-range monitor, and the sixth incident resulted from a steam leak through a gasket on the check valve bonnet of a steam generator inside the containment.

Events

Turbine Trip Initiates Lifting of Safety Valve

In July 1972, while the Monticello reactor (BWR) was operating at 100% power, a loss-of-field relay for the generator tripped causing a turbine lockout. When the turbine-lockout relay actuated, it tripped the generator field breaker and the supply breakers to the motor-generator sets for both recirculation pumps, and actuated an automatic closed transfer from the main auxiliary transformer to the reserve auxiliary transformer. The master hydraulic trip solenoid was actuated which, in turn, initiated the closing of the steam inlet valves and the tripping of the control valve fast-closure pressure switches. Also, both diesel generators were started by the power transfer relays. The reactor scrammed automatically, and the main steam lines were isolated. About 1.2 seconds after the turbine trip the reactor high-pressure scram relays tripped, and 1.8 seconds after the turbine trip the low reactor water level trip was actuated. This low water level trip initiated: containment isolation; starting of the standby gas treatment system; isolation of the oxygen analyzer; withdrawal of the traversing incore probes; and an isolation of the reactor building ventilation system.

The reactor water level stabilized above the low-low level trip point, and then returned to near normal; the reactor pressure continued to increase until at least three of the relief valves and one safety valve had lifted. The maximum reactor pressure was 1141 psig.

Two of the four channels of the primary containment isolation and reactor protection systems tripped on high drywell pressure between 8.0 and 8.5 seconds after the turbine trip. Separate containment pressure sensors initiated the low-pressure coolant injection and core-spray pumps, and the automatic relay in the high-pressure coolant injection (HPCI) system received an initiation signal, but since the isolation valves in the HPCI steam line were closed for surveillance testing the HPCI did not actuate.

The primary containment isolation and reactor protection system trip signals and high reactor pressure scram relays reset automatically approximately 12.8 seconds after the turbine trip. Reactor pressure continued to decrease, and the reactor operator observed that one relief valve had not fully closed automatically. He operated the manual control switch and the valve closed. The reactor pressure reached a low point of 600 psi.

About five minutes after the turbine trip, operations personnel observed that an emergency condition did not exist, so operation of the emergency core cooling systems was stopped. About eight minutes after the turbine trip, operations personnel observed that containment isolation was not required, and opened the main steam line isolation valves. Plant conditions were stabilized by following scram-recovery procedures.

Once stable conditions had been achieved, the plant was placed in cold shutdown, the drywell was deinerted, and the event was investigated thoroughly. The following evaluations and corrective actions resulted from the investigation:

Generator — The loss of field which caused the initial turbine trip was caused by a poorly soldered transistor in the voltage error signal amplifier of the amplidyne control circuit for the generator; the amplifier was repaired and tested and the generator was returned to service.

Control Rod — One control rod settled at the 6-inches withdrawn position after the automatic scram (as had happened once previously); the reactor operator noted the control rod position and fully inserted the rod by means of a remote manual control switch on the reactor control console.

Relief Valves — The relief valve that did not reseat properly had rust particles in the second stage piston chamber; since the rust was the only abnormal condition noted it was hypothesized that rust had lodged across the orifice, causing the improper seating of the valve.

A second relief valve appeared not to have opened properly; however, no reason was found for the apparent malfunction. The other two relief valves functioned properly.

Safety Valves – Two of the four safety valves apparently actuated prematurely, and the recorded drywell pressure increased from 14.7 to 15.55 psia. Since a similar premature safety valve actuation had occurred once previously, additional corrective measures to permit more expeditious analysis were initiated. These included placing rupture links on each of the four safety valve discharge nozzles to initiate the sequence-of-events log that is compiled by the plant process computer, and development of analytical models of the steam lines to provide pressure transient information in response to turbine-trip events and valve interaction influences. One of the safety valves that lifted was returned to the manufacturer for specific tests. A field test program was also developed to measure transient responses as a function of either a turbine trip or isolation and compare these measured data with the analytical data.

Drywell Pressure Instrumentation – During the scram and isolation, the maximum drywell pressure that was recorded remotely in the control room was 0.85 psi, but the 2-psi drywell high pressure switches were actuated. Duct tape was found covering the pressure taps on the lines that were connected to the recorder in the control room. The tape was removed and all instrumentation was checked to verify operability and proper functioning.

Recirculation Pump – When the recirculation pump was restarted after the transient, the discharge valve would not open because a limit switch was out of adjustment and had allowed the valve to seat with excessive force. The damaged valve threads were repaired and the pump discharge valve was returned to service.

Turbine Trip During Testing Causes Reactor Scram and Safety Valve Actuation

In November 1972, during the routine weekly tests of the wear detector on the turbine thrust bearing at the Nine Mile Point facility, the turbine was unintentionally tripped, resulting in a reactor scram from about 100% power. The turbine bypass functioned as designed, limiting the pressure rise in the reactor vessel that resulted from the stop valve closure.

However, during the transient, one of the safety valves lifted prematurely at 1080 psig rather than at the design value of 1236 psig. The valve actuated for 9 seconds, and released about 290 gallons of primary coolant into the drain system in the drywell floor. This safety valve operation maintained reactor system pressure at less than the pressure at which the lowest set point for the electromatic relief valve is placed, so that no steam was released to the torus via the electromatic relief system.

The actuation set points for the emergency core cooling systems were not reached during the transient. All systems functioned as they were designed to do with the exception of the safety valve actuation and a recirculation system anomaly.

Forty-five seconds after the trip occurred, a minimum flow condition of 6×10^6 lbs/hr was indicated in the recirculation system. This minimum flow was indicated at a time when the reactor water level was increasing, and the feedwater flow and reactor pressure were decreasing. The flow reduction occurred over an 18 second time span after the reactor was shut down, and was apparently caused by the formation of voids in the recirculation and flow sensing lines.

This event was initiated when a microswitch in the test circuit of the turbine thrust-bearing wear detector circuit failed. This microswitch is activated when the wear detector is in the test mode and blocks the trip signal to the turbine; the microswitch also annunicates an alarm in the control room. However, the reactor operator was not alerted by the lack of annunciation and attempted to proceed with the test. The operator action tripped the turbine.

The corrective actions taken prior to restarting the reactor consisted of:

- installing the most reliable set of safety valves, which had been tested with steam and nitrogen;
- installing an indicator in the reactor control room to signal microswitch operation so that the possible recurrence of a turbine trip during testing would be minimized;
- determining and repairing damage to insulation (on the valve and vent piping to the drywell coolers) near the safety valve that had actuated.

Momentary Actuation of Safety Valve During Startup Tests Causes Cooling System Transient

During startup testing at the Pilgrim Plant (BWR) in November 1972, the main steam line isolation valves (MSIV's) were tripped with the reactor at 96% of rated power, in accordance with one of the startup

test procedures. As expected, an initial pressure spike of 50 psi was observed; the pressure then returned to its normal level of 1020 psig and began to increase slowly at about one psi/second, to a peak value of 1122 psig, at which time the main steam relief valve actuated. The relief valves were allowed to actuate twice in the pressure mode to verify the pressure set points on the valves. About five minutes after the MSIV's had closed, all the systems were operating as they were designed to do when one of the safety valves lifted momentarily while the reactor pressure was in the range of 1100 to 1122 psig. This momentary valve actuation caused drywell pressure to reach the 2-psig set point that actuates the high drywell pressure switches. All systems responded to this high drywell pressure set point trip as they were designed to do and the trip reset in 59 seconds when the drywell pressure had been sufficiently decreased by normal cooling provided by the drywell ventilation system. The amount of moisture that collected in the drywell sumps as a result of the actuation of the safety valve was insignificant.

The corrective action consisted of:

- replacing the safety valve that had lifted prematurely (at 1100 psig) with a spare valve that was set to operate at 1240 psig steam pressure, and

- repairing the minor damage to a 4-foot section of piping insulation, replacing the insulation on an RHR valve, and cleaning of the coils in the drywell cooler which had been plugged by the insulation.

Loss of Normal Station Power Causes Cooling System Transient

The Vermont Yankee reactor (BWR) was operating at steady state at approximately 63% of full power in December 1972, when an internal fault on the startup transformer resulted in a total loss of normal power. This loss of normal power caused an automatic reactor scram which was followed immediately by a manual turbine trip. The MSIV's immediately isolated the primary system.

The initial pressure transient rose to about 1130 psig and caused three of the four relief valves to open and one of the two safety valves to chatter on its seat about 100 psig below the safety valve set point pressure of 1230 psig.

The high pressure coolant injection (HPCI) system failed to start automatically when the drywell pressure momentarily exceeded the 2 psig set point. The HPCI was started manually. The same signal which initiated the HPCI also actuated the residual heat removal system and the core spray system, but these were not required to inject water into the vessel. Both emergency diesel generators started automatically and performed according to design.

After conditions in the plant had stabilized somewhat, a cooldown of the plant was begun. During the cooldown, the HPCI was utilized to remove decay heat and the reactor core isolation cooling system was utilized to maintain water level.

An investigation following plant cooldown led to the following corrective actions:

- the safety valve that had chattered was replaced with a spare valve.

- the relief valve that did not lift was originally set to relieve at 1100 psig; its failure to perform was attributed the differential expansion of components within the pilot valve. The components of the pilot valve and the discharge thermocouple were replaced.

- work was begun on the replacement of the windings in the startup transformer. Since the complete repair was expected to require about four months, a temporary set of replacement transformers was installed to provide normal station power.

Failure of Gasket on Feedwater Check Valve Causes Rapid Cooling of Primary System

At the Surry-1 (PWR) plant, while the reactor was being maintained in a hot shutdown condition prior to startup in October 1972, a noise was heard inside the containment. The shift supervisor and reactor operator noted an automatic initiation of the safety injection system and an increase in containment temperature and pressure. A rapid decrease in the level of one of the steam generators was also noted. It was also observed that as containment sump level, temperature and pressure rose, the radioactivity levels in the containment did not increase. From these facts, operations personnel concluded that steam or feedwater was leaking into the containment.

As containment pressure rose, procedures were initiated to isolate the affected coolant loop, and containment pressure returned to the sub-atmospheric level in about 35 minutes. By about 30 minutes after the initiation of the safety injection system, all the liquid from the steam generator had escaped, and a controlled cooldown was begun.

The ensuing investigation into the incident disclosed that there had been a very gradual steam leak from the steam generator through the gasket on the check valve bonnet. This had caused a flow path from the steam generator feedwater ring back to the check valve which, in turn, had set up a steam-water mixture in the feedwater line and caused a severe water hammer. The water hammer had created sufficient force to increase the opening between the valve body and the bonnet flange. The resulting

direct flow of steam and feedwater from the steam generator into the reactor containment building initiated the safety injection system which operated about 25 minutes and pumped an estimated 11,000 gallons of boric acid solution into the primary system. This boric acid injection raised the boron concentration from 1094 ppm to 1495 ppm.

Physical damage sustained by the feedwater system included:

- the 14-inch feedwater line was displaced approximately seven to ten inches from its normal position.

- all seven spring hanger assemblies and three sliding support assemblies on the feedwater line were displaced by varying degrees.

- the seven hydraulic shock suppressors that provide seismic restraint to the feedwater line had failed in either shear or tension.

- the bolting flange on the valve body was distorted in a convex shape.

- the valve body contained a 1.25-inch long crack and the seating surface on the swinging disk and seat ring on the valve body were damaged.

Detailed evaluations and analyses of the damage and potential effects of the water hammer on the feedwater system were performed. The effects of the cooling system transient and cooldown rates were analyzed, and the effects on the containment were evaluated. A comprehensive inspection of instrumentation, electrical components, and electrical penetrations inside the containment was conducted; no indication of any kind of degraded safety system condition was found. As a result of these extensive inspections and analyses, the following corrective actions were instituted:

- the instrumentation that was damaged during the incident was replaced.

- the valve manufacturer completely rebuilt the damaged feedwater check valve, tested it against the original specifications, and returned it to the plant with a new valve warranty; this rebuilt valve was reinstalled in the feedwater line.

- bonnet gaskets were replaced with a seal-welded membrane on all six feedwater check valves (three valves inside and three valves outside containment).

- the line in the feedwater loop that was involved in the incident was redesigned and modified to preclude draining of condensate in the line to the steam generator; this modification would also prevent siphoning of the feedwater in this line.

- detailed examinations of all equipment and systems involved in the incident indicated no other need of repairs or modifications.

Spurious Flux Spike During Tests Causes Cooling System Transient

During startup tests of the flow control mechanisms of the recirculation pumps at the Pilgrim plant in October 1972, a reactor scram occurred from 60% of rated power when a noise spike occurred on an average power range monitor (APRM) channel. The high reactor water level tripped the main steam line isolation valves (MSIV's) forty-one seconds after the scram.

The feedwater pumps were stopped according to procedures, and, since the reactor pressure was greater than 600 psig, operations personnel manually operated the main steam line safety relief valves to control water level. When reactor pressure had been reduced to less than 600 psig, the scram was reset and the main steam drain lines were used to attempt a repressurization of the main steam lines. However, the pressure in the main steam lines continued to decrease, and it was discovered that one of the safety relief valves had failed to reclose. When attempts to close the malfunctioning valve failed, the operator closed one of the main steam line drain valves to isolate the primary system as required under these conditions.

About 10 hours after the start of the depressurization of the plant, the reactor pressure had decreased to 2 psig. At this time the malfunctioning safety relief valve closed, and reactor pressure began increasing slowly because of fission-product decay heat and the heat from the operation of the recirculation pumps. When reactor pressure had increased to 6 psig, the safety relief valve opened again. The valve continued to cycle fourteen times until the system could be cooled sufficiently to permit removal of the faulty safety relief valve. The residual heat removal (RHR) system was used in the torus – cooling mode to keep the torus water below 115°F. Seventy-five thousand gallons of water that were released to the torus by means of the safety relief valve actuation was subsequently processed through filters and demineralizers and returned to the process system. The water in the reactor vessel was maintained at normal levels by the periodic use of the condensate pump.

After the reactor was placed in a cold shutdown condition, the following evaluations and corrective actions were taken:

- the malfunctioning main steam relief valve was replaced by a spare. The malfunctioning valve was disassembled and inspected by the valve vendor and General Electric engineers. This inspection showed that the second stage disc had been held in the open position by the remote air actuator because of interference and galling between the air actuator stem and its surrounding packing gland.

- Subsequent investigation revealed that the air actuator stem would stroke toward the open position but that the return spring on the actuator was unable to withdraw adequately to allow the second stage disc to close because of the frictional force between the galled actuator stem and the packing gland.

The fatigue life of critical reactor components was evaluated by the vendor at the request of Boston Edison Company so that the fatigue life analyses for these components could become a part of the records on the reactor vessel history. The transient, treated as additional usage, was determined to produce an extra usage factor on the control rod drive (CRD) nozzles of 0.0015, and an additional usage factor for other areas of the vessel as 0.006.

The usage factor that is allowed for all specified normal and upset cycles for Section III of the ASME Boiler and Pressure Vessel Code is 1.0. This transient brought the total usage factor for the CRD nozzles to 0.8415, and the total usage factor for the most limiting component (the recirculation inlet nozzle thermal sleeve) to 0.976.

Additionally, at the recommendation of the vendor, the torque switch was also replaced with an improved model although the original switch was not faulty.

ROE 73-6 June 8, 1973

MALFUNCTIONS OF TORUS-TO-DRYWELL VACUUM BREAKER CHECK VALVES

Types of MALFUNCTIONS of the TORUS-TO-DRYWELL VACUUM BREAKER CHECK VALVES are illustrated by the occurrences that are discussed below. One malfunction required a redesign of the actuating system to effect proper closure, while another required only removal of the packing that was outside the bushings. In both cases, the malfunction of the valves impaired the function of the primary containment system for suppression of steam-induced pressure inside the containment vessel.

Background

Vacuum breaker check valves are installed between the containment drywell and the free volume above the water in the torus (suppression chamber) in some boiling-water reactor (BWR) plants. Figure 1 shows, in idealized form, the valving and piping arrangements in this type of containment system. The purpose of the vacuum breaker check valves is to provide a flow path for noncondensible gases to return from the free volume above the suppression chamber to the drywell in the event the drywell is vented. After the steam-air mixture has passed into the drywell through the torus water, the open path through the vacuum breaker check valves thus prevents excessive negative pressure differential between the torus and the drywell. The check function of the valves is to force the steam that is vented from the drywell to be released under the torus water instead of allowing the steam to enter the air space in the torus. As the steam then rises through the torus water, the potential energy in the steam is dissipated in the torus water.

The number of valves per plant ranges from 4 to 14 and the sizes range from 14 to 36 inches in diameter.

Circumstances

Unit 2 of the Quad-Cities Nuclear Power Station was shut down for a routine inspection of the interior of the torus during August 1972. During a check of operability of the torus-to-drywell vacuum break check valves, seven gave sporadic open/closed indications and one failed to indicate actuation during remote test operations. Subsequent visual inspections revealed that four of the valves which had given a closed indication after the test were open an inch or more and others had faulty position indicator switches. The valves were dismantled to determine possible faults and causes of malfunction. The inspection revealed excessive friction and improper alignment. Further review of the design of the valves disclosed that adjustments of the counterweight and of the indicating switches would be necessary to improve the reliability of the system.

The modifications consisted of the adjustment of the counterbalance so that a positive closing moment was applied to the vacuum breaker valve. This corresponded to a positive differential pressure set point for opening the valve, which was well within design limits.

The limit switches on the indicating device were replaced with switches that have a tolerance of ±0.01 inches. The mounts for the switches were changed to accommodate the new switches and to allow proper setting. Relays were also added to provide control room annunciation if all valves were not fully closed.

Because of the problems with the vacuum breaker valves at Unit No. 2, the containment system at Unit 1 was checked and three of these valves were found to be open while the position was indicated as closed.

The reactor at Unit 1 was shutdown, and the plant was cooled down so that the torus could be entered for an inspection of the vacuum breakers. During the inspection, the valves were cycled to verify operability. This time six vacuum breaker valves failed to close; of these six, two were valves that had previously indicated an erroneous position.

The same modifications were made to the vacuum breaker valves on Unit 1 as were described above for Unit 2.

After the modifications were made to the valves on each Unit, the valves were tested, cycled, and inspected to verify valve operability before the plants were returned to the line.

During a maintenance shutdown at the Monticello reactor during December 1972, the torus-to-drywell vacuum breaker valves were checked for proper operation because of problems that had been experienced at Quad-Cities. One of the ten valves was found to be open 1.25 inches although its position was indicated as closed. During further cycling of the valves, four more failed to close fully. Also, two of the test operators failed to operate properly.

Manual exercising of the valves indicated that excessive friction between the shaft and shaft packing was occurring. Consequently, the teflon packing was removed and penetrating oil was applied. The vacuum breakers were then leak tested and surveyed for leaks with a sonic probe. No shaft leakage was detected; the minor seat leakage that was detected was eliminated by cleaning the resilient seating surfaces on the valve discs and polishing the metal areas with emery cloth.

The two improperly functioning air operators for the valves were disassembled and cleaned, the seating rings on the actuator piston were replaced, and the operators were reassembled. When the valves were checked following this maintenance, the valve operators functioned properly. Subsequent to the tests, the proper valve positions were verified by visual inspection. Procedures were also modified to include monthly testing using the air operators to remotely operate the vacuum breakers, followed immediately by leak-rate testing to verify that all valves are fully closed.

Remedial Actions

In addition to the specific items of maintenance, repair and surveillance that were discussed above, other more general maintenance and surveillance procedures have been instituted at the plants that have experienced problems with the vacuum breaker valves. Some other BWR's are instituting these same practices at their own plants in an effort to preclude some of the problems discussed above. The additional maintenance and surveillance practices include more rigorous preoperational testing to verify that valve leakage is within design limits and more frequent preventive maintenance and testing. These practices often can indicate potential problem areas, and serve as an early warning to the operations staff.

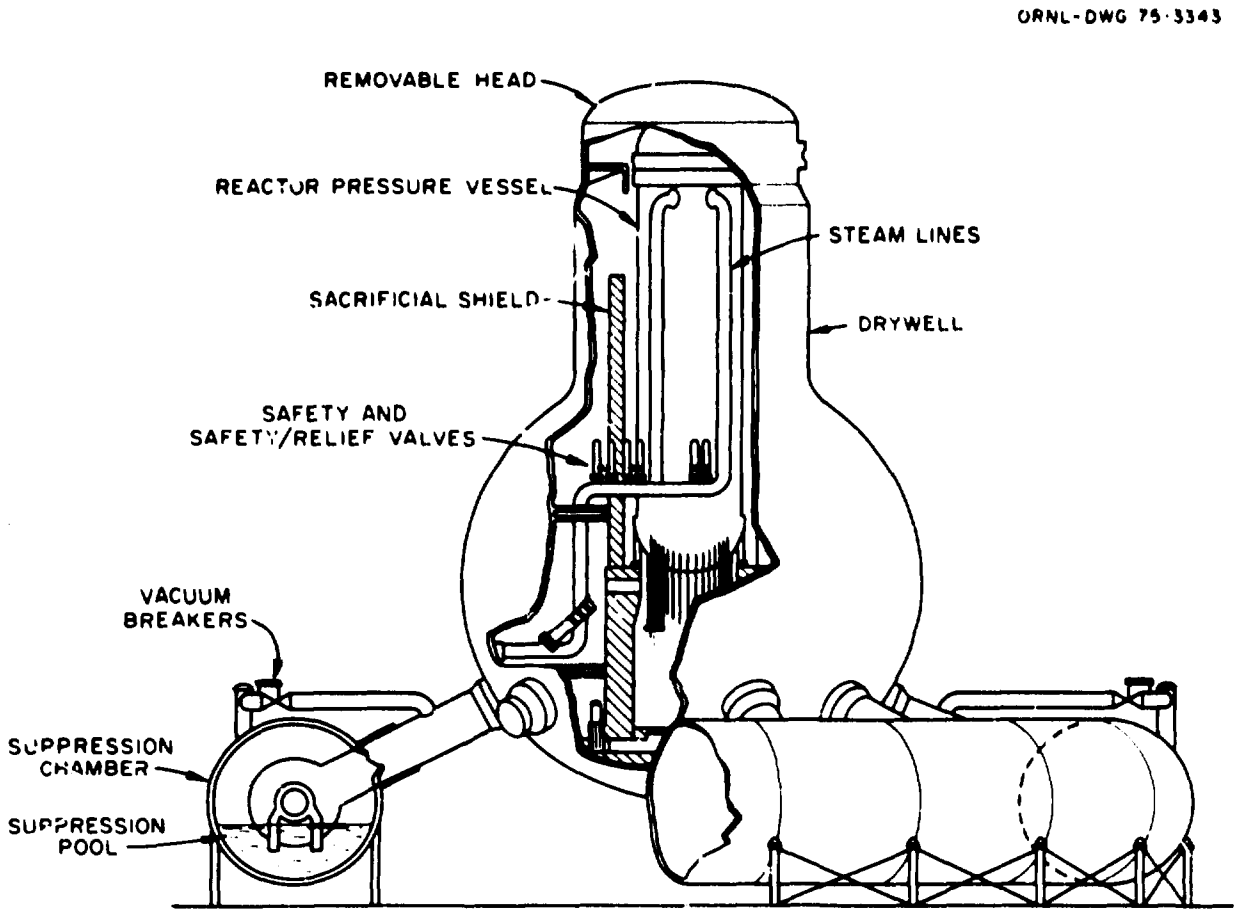

Fig. 1. Typical Arrangement of BWR Containment System

ROE 73-7 August 31, 1973

COMMON MODE FAILURE OF INCORE INSTRUMENTATION

Summary

Two instances of common mode failures are discussed. One incident involved the FAILURE OF 120 LOCAL POWER RANGE MONITORS (LPRM) as a direct result of seawater entering the reactor coolant system through leaks in condenser tubes. The second incident involved the LOSS OF FUNCTION OF ONE STRING OF FOUR FISSION CHAMBERS, caused by a single short circuit of a common electrical lead.

Circumstances

Common Mode Failure of Local Power Range Monitors

During the startup of Unit 1 of the Millstone Nuclear Power Station in September 1972, the plant had reached operational temperature and pressure, with the reactor power at 100 MW(t). When the operator noted an indication that the resins in one of the demineralizers were becoming depleted, he switched a second demineralizer into service. Since only condensate was being recirculated and no addition to the reactor coolant was necessary at the time, the operator proceeded with the startup. Half an hour later, high conductivity of the feedwater was noted, and the operator initiated a deliberate reactor shutdown. Ten minutes after reactor shutdown was begun, resins in both condensate demineralizers were completely depleted. An hour later, the operations supervisor ordered the reactor to be scrammed manually because of excessive chlorides in the primary system. The main steam line isolation valves were shut and the isolation condenser was placed in service to continue cooldown of the plant.

About 30 minutes after the isolation condenser was placed into service, the first LPRM failed. Within the next 24 hours, all of the LPRM's had failed.

Of the 120 failed detectors, 116 showed low detector-to-cable resistance, indicating that the seal weld on the detector-to-cable shields had failed. This was substantiated by the upscale failures of the detectors, indicating very low resistance between the detector signal wire and the cable shield. Subsequent metallographic investigations revealed that chloride stress corrosion had caused the failures. No significant indications were obtained from dye-penetrant testing of the LPRM cables. This led to the conclusion that the route for entry of moisture into the cables was provided through the cable collars, through the chamber fill tubes, or through both paths.

The source of the moisture and high chloride content in the reactor coolant was in-leakage of about 17 gpm of seawater into the hot wells of the main condensers through leaking condenser tubes. The resulting chloride concentration in the reactor coolant caused the demineralizer resins to become depleted rapidly and resulted in rapid buildup of chloride concentration in the reactor cooling system.

All the LPRM detectors were replaced while the plant was shut down for maintenance and cleanup of the affected systems.

To prevent recurrence of this type of event, all 40,000 aluminum-brass condenser tubes were replaced with copper-nickel tubes to provide better resistance to chloride corrosion attack. Also, instrumentation was added to monitor condenser water chemistry.

Procedures for reactor operation have been changed and additional technical specifications have been effected.

Common Mode Failure of Four Chamber Amplifiers

The reactor core of the Dresden Nuclear Power Station, Unit 1 contains 164 fission chambers in 41 strings of four chambers each. The chambers in each string are distributed axially on four planes and the strings are radially distributed on sixteen rays.

In April 1973, with the reactor at 407 MWt and with no control rod movement in progress, all four chambers on one of the incore strings failed upscale simultaneously.

An investigation into the cause of the failure of the detectors revealed that a 100-volt DC electrical lead to the amplifiers for the four failed channels had become pinched between the amplifier chassis and the support frame. The insulation on the pinched wire had worn sufficiently to short the common 100-volt line to ground. The pinched wire was replaced by a shorter one and the failed amplifiers were repaired.

ROE 73-8 August 31, 1973

STEAM GENERATOR PROBLEMS AT PWR'S

Summary

Primary-to-secondary COOLANT LEAKAGE through FAULTY STEAM GENERATOR TUBES poses frequent OPERATING PROBLEMS at Pressurized Water Reactors (PWR's). Although the effects of these steam-generator tube failures generally are adverse only to plant availability, these failures may present unnecessary radiation hazards to maintenance personnel when extensive repairs or modifications are needed. In the problems at six PWR's that are discussed below, the CAUSES OF the steam-generator tube FAILURES HAVE BEEN ATTRIBUTED to a combination of POOR SECONDARY WATER CHEMISTRY CONTROL and STEAM GENERATOR DESIGN. Generally, the failures have occurred in one or more of three general areas where steam blanketing is most likely to occur because of poor circulation: near the tube sheet, adjacent to tube supports, or in the U-bend area near the top of the steam generator.

Circumstances

H. B. Robinson Steam Electric Plant, Unit 2

The steam generators at the H. B. Robinson nuclear plant comprise 3260 tubes of Inconel 600. In May, 1972, during startup after a week's outage, a primary-to-secondary leak was confirmed by noting an increased water inventory and increased radioactivity levels in the secondary system. The leak rate was measured to be about 12 gpm as contrasted with a 55 gpd leak rate that had been experienced prior to shutdown. The startup was discontinued and the plant was returned to the cold shutdown condition for inspection and repairs of the steam generators. Subsequent evaluation of the incident and of data from eddy current inspections of the steam generator tubes indicated that some tubes in each of the three steam generators were cracked. These cracks were intergranular in nature and penetrated into the wall from the outside of the tubes. Corrective action involved plugging a total of thirty-three tubes in three steam generators; twenty-seven tubes were plugged in one steam generator, four tubes in the second steam generator, and two tubes in the third. All leaks were located within four inches of the top of the tube sheet (made of ASME-SA-336-Mn-Moly-Steel clad with Inconel on the primary side).

Metallographic examination of the tubes that were removed from one of the steam generators revealed tight intergranular longitudinal cracks a maximum of 0.6-inches long.

The cause of the problem was suspected to be poor secondary water chemistry resulting from restricted blowdown, low phosphate concentration, and a reduction of secondary coolant circulation rate within the steam generator resulting from a change in the steam generator design that was made to improve moisture separation. When the steam generator was returned to service in June 1972, continuous blowdown was resumed and the circulation rate was returned to the original design value. The phosphate concentration was also increased and the Na/PO_4 molar ratios were carefully maintained between 2.0 and 2.6, averaging 2.2.

During the refueling outage in March 1973, 99% of the tubes in all three steam generators were eddy-current tested. Two defective tubes were found in one steam generator; one was in an area that had not been previously inspected and the other was a tube that had been left unplugged unintentionally after the earlier tests. A penetration of about 75% of the tube wall thickness was observed in the tube that had been left unplugged in June 1972, indicating that the corrosion had been stopped by the changes in the secondary chemistry that had been instituted at that time. No eddy current indications were found in any tubes in the other two steam generators. Following startup after this refueling outage, a comprehensive surveillance program was begun at the Robinson plant because of the apparent success in eliminating corrosion problems in the steam generators. The secondary-system chemistry surveillance program includes: daily sampling and analysis for pH, Na^+, $PO_4^{\equiv}$ and Cl ions and for hydrazine. Both the Na/PO_4 molar ratio and the ratio calculated from the pH and $PO_4^{\equiv}$ measurements are determined and recorded daily. The analyses of the secondary system are plotted as a function of time to indicate trends. As of July 1973 no indications of incipient steam generator leakage had been detected by these methods, and no actual leaks had been observed.

San Onofre Nuclear Generating Station, Unit 1

Each of the steam generators at Unit 1 of the San Onofre Nuclear Generating Station have 3?94 tubes which are fabricated from Inconel 600.

During the first 4.5 years of operation only one tube experienced leakage (about 15 gpd). The steam generator that had been leaking was hydrostatically tested during the refueling outage of October 1970, and four tubes that were suspect were plugged in addition to the leaking tube.

In January 1972 the plant was shut down for the second refueling outage. During this outage, eddy current inspections showed that one tube in one steam generator was leaking about four feet from the tube sheet near the first support plate. Eddy current examinations of 1000 adjacent tubes showed no other defects. In July 1972, a second leak developed in the same steam generator. The plant was shut down to locate the leak and repair it. Eddy current examinations of 819 tubes adjacent to the failed tube revealed eight more defective tubes. All of these were plugged before the plant was returned to service.

In September 1972, a failed tube was detected in another steam generator. The leakage at this time was determined to be about 2.4 gpd. Sampling of the secondary system continued until October 13, 1972. By this time the leakage had increased to about 122 gpd, so the plant was removed from service to effect repairs of the leaking steam generator tubes. One-hundred-twenty-seven adjacent tubes were tested by eddy current techniques, and none were found to be defective. However, in January 1973, the plant was removed from service again to repair a leaking tube in the same steam generator.

All the tube failures occurred just above the tube sheet near the first support plate, in the U-bends and near the antivibration bars, and have tentatively been attributed to mechanical conditions rather than any chemical conditions in the feedwater. An extensive investigation of the cause is underway.

Indian Point Nuclear Station, Unit 1

The four horizontal steam generators at Unit 1 of the Indian Point Nuclear Station have experienced varying degrees of leakage in the Type 304 stainless steel tubes for about nine of the eleven years that the unit has been in operation.

In July 1972, while the reactor was being brought up to normal operating pressure and temperature, the radiation monitor in the blowdown system of one of the steam generators indicated an unusually high secondary coolant activity level. Samples of steam generator coolant were taken and subsequent analyses confirmed the high level of radioactivity, so the steam generator was isolated. At this time, tube leakage in two of the other three steam generators became apparent. The plant was returned to the cold shutdown condition so that all three leaking steam generators could be repaired. The leaking tubes were plugged and the steam generators were returned to service. About a week later, one of the three steam generators that had been repaired was isolated again because of excessive leakage. This steam generator remained isolated for six weeks before it could be repaired.

Between July and September 1972, a total of 25 tubes were plugged in the four steam generators: four tubes were plugged in each of two steam generators, one tube was plugged in a third, and sixteen in the fourth. By July 1973, about 200 more tubes had been plugged. Of these 200 tubes, 148 were leaking and 45 were plugged as a precautionary measure. Most of the 200 leaking tubes that were plugged by July 1973, were in the U-bend area of the bottom quadrant in one steam generator.

Palisades Nuclear Power Station

The Palisades plant was shut down in January 1973, about a year after it first started to produce electricity, because of excessive leakage in

one of the two steam generators. Pressure tests and eddy current tests indicated that three tubes had failed in the U-bend area in the sixth and seventh rows from the channel partition and that all tubes in the first eleven rows had varying degrees of thinning of the wall thickness; a minor eddy current indication of thinning was found in row 12. The first eleven rows of the other steam generator also showed the same tube wastage, but to a much lesser degree.

All the failures and indications occurred in the 180-degree bend area which is enclosed by divider strips on either side. In the immediate vicinity of the first eleven rows of tubes the three divider strips form a "Y" shape, resulting in a tight configuration. It has been hypothesized that this tight compartmentation leads to steam blanketing which concentrates the impurities in the steam generator water.

One of the leaking tubes and one that had thinned, but intact, walls from the first steam generator were examined by special radiographic techniques. Results of this examination showed a relatively broad area of attack of varying depth and irregular shape.

The wall thinning was caused by accelerated localized corrosion of the Inconel 600, and was characterized by general tube wastage in a specific area. No intergranular corrosion was evident. The most likely corrosion mechanism was postulated to be a concentration of free caustic at a pseudostagnant steam-water interface. The alternate wetting and drying caused by the tight configuration resulted in tube degradation in the localized region.

About 600 tubes were plugged in the first eleven rows of each steam generator, and the plant was returned to the line in March 1973 with provisions for continuous monitoring of phosphate concentrations and pH.

Point Beach Nuclear Power Plant, Unit 1

About two years after Unit 1 of the Point Beach Nuclear Station was placed in service, hydrostatic tests were performed on the steam generators to check the tubesheet cladding. During these tests, a group of 15 to 20 tubes in one steam generator and approximately eight tubes in a second steam generator were found to be weeping. Subsequent eddy current tests of 1597 steam generator tubes showed 75 tubes with crack indications, of which 1, ere full penetration cracks; eddy current tests of 874 tubes in the second steam generator revealed 108 tubes with crack indications, of which 9 were full penetration cracks. The majority of defects in the tubes were found in a central area bounded by the fourteenth to twentieth rows. All defects were located from one to five inches above the tubesheet on the primary side.

The defects were attributed to a failure of condenser tubes during the early operation of Point Beach 1. This conclusion was reached because, at this time, maintenance of recommended phosphate concentrations in the

feedwater was not possible because of the condenser tube in-leakage. All the tubes with eddy current indications of cracks were plugged and the plant was returned to service.

Beznau Nuclear Station, Unit 1

The steam generator tubes at Unit 1 of the Beznau Nuclear Station (which is similar in design to some of the 350-MWe class PWR's in the U.S.) are of Inconel 600. Substantial in-leakage of river water through the condenser to the secondary coolant system had caused scale to form on the steam generator tubes. During a maintenance shutdown, a number of leaking or significantly corroded tubes were found. The faulty tubes were located in the central third of the tubesheet where the tubes penetrate the tubesheet. Seventeen tubes were plugged in one steam generator and 45 tubes were plugged in a second steam generator. Also, several tubes were removed for a detailed metallographic examination. This examination confirmed that intergranular corrosion was attacking the secondary side of the steam generators from the outside diameter of the tubes.

The plant had originally operated using a zero-solids conditioning of the secondary system with the addition of hydrazine to control the oxygen level. After the 62 steam generator tubes in the two steam generators had been plugged, the plant was returned to service in September 1971, with phosphate additions to the secondary system. However, it was not possible to add sufficient amounts of phosphate to obtain a Na/PO_4 molar ratio of <2.6, because the phosphate reacted readily with the scale that had already formed. As a result of excessive tube leakage the plant was again shut down in December 1971. The tubes were plugged and the plant was returned to service with a water chemistry program specifically designed to maintain the phosphate level at <2.6 Na/PO_4 ratio. No further tube failures were reported in the next nine months although present plans call for the replacement of these steam generators because of apparently unrelated tubesheet cladding problems.

Conclusion

Intergranular stress corrosion of Inconel 600 in steam generators often is caused by high concentrations of hydroxyl radicals coupled with high stresses. Although concentrations of impurities in the primary coolant are carefully maintained at <1 ppm in accordance with Technical Specifications to maintain the integrity of the reactor coolant pressure boundary, no such rigor is presently applied to water quality for the secondary system. A concentration mechanism for any impurities can exist on the secondary side because of poor secondary coolant circulation. Areas where poor water circulation may permit steam blanketing are crevices where the tube joins the tubesheet, low flow areas near the inlet tubesheet, and where the tubes pass through tube supports or divider strips. Some metallurgists have postulated concentrations factors of 10^3

and 10^{4} in these areas. Concentration factors of this magnitude indicate the desirability of avoiding free caustic. This free-caustic condition can be avoided by a zero-solids water treatment process, which also requires careful monitoring of the condensate and demineralizer effluent; or the coordinated phosphate water treatment process, which also should be accompanied by careful monitoring to detect condenser leakage.

Suggested secondary-coolant chemistry conditions have been given as:

(a) phosphate ion concentration should be maintained between 10 and 80 ppm with a fresh-water-cooled condenser, and between 25 and 80 ppm for a seawater-cooled condenser;

(b) the molar concentration of sodium ions should be less than 2.6 times the molar concentration of phosphate ions (most plants seem to get best results by averaging about 2.2 over a given period of time);

(c) the pH of the water should be kept within the range given in Fig. 1; and

(d) the oxygen concentration should be kept below 0.10 ppm.

In addition, careful steam generator design to minimize areas that are subject to steam blanketing due to poor flow conditions has been found to be helpful in reducing the likelihood of steam generator tube leakage.

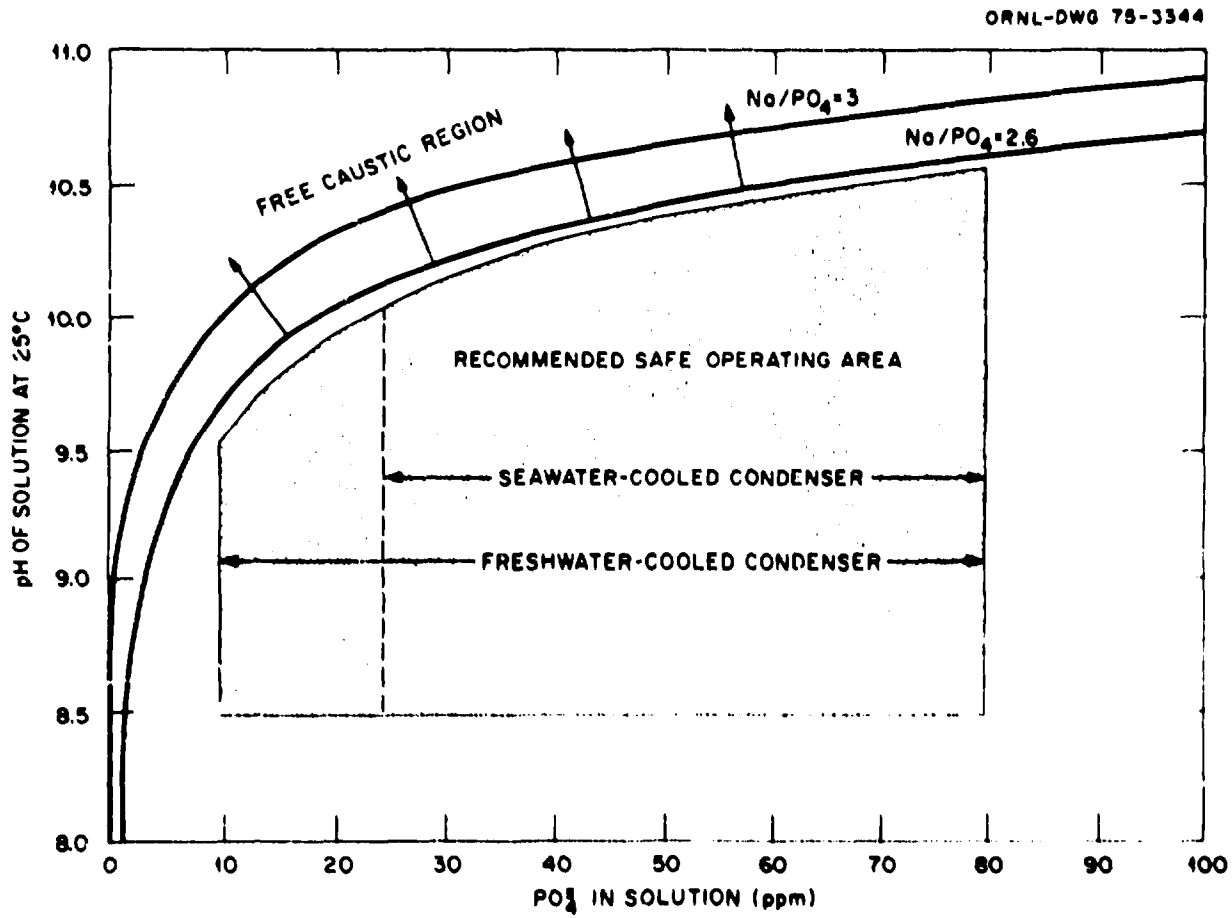

Fig. 1. Recommended Ranges of pH and Phosphate Concentrations in PWR Steam Generator Water.

ROE 73-9 October 19, 1973

REFUELING INTERLOCK-CIRCUITRY DAMAGE

Summary

Failure to adhere to established operating procedures and a lack of adequate communications resulted in an IMPROPERLY WIRED, UNTESTED CABLE being ENERGIZED. An overvoltage occurred which RESULTED IN ELECTRICAL DAMAGE TO THE REFUELING INTERLOCK CIRCUITRY.

Circumstances

In March 1972, a new retractable cable for the refueling bridge was being assembled at Quad Cities Unit 1 nuclear power plant. The new cable was to be longer than the one it replaced and some wiring changes were necessary for the cable to conform with the manufacturer's drawings. Assembly of the cable had been completed by contractor personnel at the end of the day shift. However, wiring checks had not been performed. For this reason, the cable was not plugged into its receptacle.

During off-shift operations, plant personnel found that they could not move the control rods because of a refueling rod block interlock. The cause of the interlock was determined to be the disconnected refueling bridge cable, and plant personnel plugged the cable into its receptacle. Wiring errors existed in the new cable such that 277 volts were applied to circuits which were designed for 120 volt service. In addition to blowing several fuses and burning out nine relays in the refueling interlock, some wiring in the rod worth minimizer buffer was damaged.

The electrical damage was a direct result of the failure to adhere to established procedures and a lack of adequate communications. Specifically, the contractor foreman had not informed the plant shift engineer of the incomplete status of the cable work at the end of the shift. Further, the foreman had also failed to identify the cable with an "out-of-service" tag. As a result of these deficiencies the communication link to all shift supervisors was broken and the cable was assumed to be operable.

The wiring errors in the cable were corrected and all defective circuit components were replaced. The completed circuit was tested to verify that the system was properly wired and functioning as designed. Also, the necessity of adhering to established procedures was reemphasized to all station and contractor personnel and the importance of these procedures to the safety of personnel and equipment was stressed.

ROE 73-10 October 19, 1973

COOLING SYSTEM TRANSIENTS - II

Summary

COOLING SYSTEM TRANSIENTS have been the subject of one Task Force Report, "Evaluation of Incidents of Primary Cooling Release from Operating Boiling Water Reactors," dated October 30, 1972, and of ROE 73-5, "Cooling System Transients - I," dated May 25, 1973. These two reports and the four additional transients discussed below provide an accounting of the cooling system transients that have occurred in the past three years during the operation of thirty-three nuclear power stations.

Of the FOUR INCIDENTS that are discussed BELOW, TWO WERE CAUSED BY COMPONENT MALFUNCTION and TWO WERE CAUSED BY PERSONNEL ERROR. In one case a deenergized breaker in the reactor protection system caused an electromatic relief valve to open; in a second instance a malfunctioning continuous power supply for the reactor protection system caused relief valve actuation; an inadvertent bumping of the high/low water level sensors caused a turbine trip/reactor scram; and the opening of an interlocked door to a fuse panel resulted in the fourth cooling system transient.

Circumstances

Deenergized Breaker to Reactor Protection System Causes Electromagnetic Relief Valve to Open

In September 1971, preparations were underway for an approach to criticality at the Palisades Nuclear Power Plant with the plant in the hot shutdown condition, when a technician deenergized breakers to the reactor protective system to make minor modifications to the system. When these breakers were deenergized, the electrical input to the pilot valve solenoids of the two electrically operated pressurizer relief valves also were deenergized, causing the two relief valves to open. One of the valves had been isolated previously, but the operable valve opened and released steam to the quench tank. A decrease in primary system pressure resulted from the relief valve actuation. One minute after the inadvertent opening of the breaker, a safety injection system (SIS) signal actuated both SIS channels.

One of the charging pumps was started manually about two minutes after the breakers had been deenergized. By this time, the operator had closed the other isolation valve and stopped the steam flow to the quench tank. The decay in system pressure reached a low point of 1280 psia (about 820 psia below starting pressure) within the next minute. About one minute later the safety injection pumps were stopped.

Five minutes after the pumps were stopped, the breakers were closed and power was restored to the relief valve control circuits. The charging and letdown rates returned to normal, and twenty-five minutes after the beginning of the incident (the inadvertent opening of the breakers), the system pressure had increased to more than 1700 psia. At this point, the operator reset the second SIS channel and returned all equipment to its normal operating state. The primary system temperature and pressure were back to normal within 55 minutes of the opening of the breakers.

Since the depressurization design rate for the reactor vessel and the pressurizer had taken into account 200 pressurizer safety valve transients, it was concluded that the integrity of the primary system had not been compromised in any way.

The cause of the transient was determined to be the use of nonstandard designation of relay contacts on one of the drawings for the system. This designation misled the technician into believing that the relief valves would not open when he opened the breaker. The drawing was corrected to reflect the "as built" condition using standard notation. The operating personnel were also furnished with revised procedures for minimizing any future depressurization that might occur.

Malfunction of Continuous Power Supply Results in Cooling System Transient

With the Nine Mile Point Nuclear Station, Unit 1, operating at about 600 MWe on February 28, 1972, a motor-generator set in the continuous power supply (CPS) to the reactor protection system malfunctioned causing the reactor to trip. The malfunction of the power supply resulted in a loss of electrical power to half of the reactor protection system and part of the feedwater control system. This loss of power resulted in a fluctuation in reactor vessel water level, a reactor low water level scram, and the subsequent actuation of the electromatic relief valves accompanied by a spillage of reactor vessel water into the main steam lines. Just prior to the scram, an underfrequency relay on one of the motor-generator sets had caused a transfer to the DC power provided by the station battery. This transfer normally trips the AC power supply to the motor drive and closes the contactor on the DC motor drive. However, a malfunction in the DC drive control prevented the transfer to the DC drive power supply, and consequently the motor-generator set began to coast down. This coastdown

resulted in the loss of power to half of the reactor protection system and part of the feedwater control system. The motor-generator set then transferred back the AC drive power after two minutes as it is designed to do, but transferred a second time to DC power. Because of the malfunction in the DC drive control, the motor-generator set continued to coast down and power was lost for two more minutes.

As a result of the loss of the motor-generator output, the control valves on the feedwater pumps locked open, resulting in the inability to control feedwater flow after the scram. The loss of control of the feedwater system resulted in the subsequent increase in water level in the reactor vessel and the overflow into the main steam lines. During this time relief valve cycling occurred. Therefore the controls for the reactor water level and reactor pressure were placed under manual control. The relief valves were then deliberately operated to reduce cooling system pressure and the emergency condenser was placed into service manually.

Since the cleanup system is the only means for removing water from the primary system following a reactor trip, and this system isolated automatically on loss of control circuit power from the malfunctioned CPS MG set, the water that was added via the control rod drive (CRD) system could not be removed. It was postulated that this additional water also contributed to the overflow into the main steam lines because of the inability to remove any water added by the CRD system. The overflow occurred 13 minutes after the scram and the cleanup system was returned to service 20 minutes after the scram, following restoration of control circuit power from the maintenance bus. The malfunction of the DC drive power was caused by a blown fuse in the control circuit for the DC drive. A 6-amp fuse had been installed in the circuit rather than the required 10-amp fuse because stamping on the fuse was difficult to read. No other problems could be found in the circuits. The cause for the transfer from the AC power to DC power was a 59.75-Hz underfrequency relay with a seventy millisecond delay. This short delay time made the system sensitive to spurious electrical noises resulting in frequent transfers.

In order to preclude recurrence of this type of incident, the time delay on the underfrequency relay was changed from 70 milliseconds to 100 milliseconds. The fuses in all motor-generator sets were checked to make sure that proper sizes were installed. Also, surveillance procedures were developed to include the motor-generator control panels so that a blown fuse and loss of the transfer control circuit could be readily detected. In addition, the feedwater lockup circuits were rewired so that all of them are not powered from the same motor-generator set. This change assures manual feedwater flow control with at least one pump in the event of a loss of power, from one of the CPS systems.

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Personnel Error Causes Turbine Trip and Subsequent Cooling System Transient

During routine surveillance December 31, 1971, at the Nine Mile Point Nuclear Station, Unit 1, the reactor was at about 600 MWe when a support for the high/low water level sensors was bumped, causing a turbine trip/reactor scram. About 20 seconds after the scram, the operator placed two of the feedwater pumps in the manual control mode.

Because of the slow manual action on feedwater control, the water level in the reactor vessel rose above normal before the operator could reduce the flow to zero. Four of the electromatic relief valves actuated during the twelve minutes before the water level in the reactor vessel was brought under control. During this time, water overflowed into the main steam lines producing steam which caused the steamline break sensor to operate, closing the main steam isolation valves. Although investigations had shown that the automatic control response of the feedwater system is adequate to handle a feedwater transient after a scram, the reactor operator made the decision to shift the control of the feedwater system from automatic to manual based on his interpretation of the instrumentation that he was observing. With the system on manual control, some feedwater addition continued for about four minutes after the scram. About two minutes after the scram, water had overflowed into the steam lines, and feedwater flow continued for about two more minutes before it was reduced to zero.

To minimize the effects of any future transients that occur, the system response characteristics were reviewed with the reactor operators. Also, the emphasis on the response and capability of the automatic control of the feedwater systems has been incorporated as part of the continuing education program for operations personnel.

Operator Error Results in Turbine Trip/Reactor Scram

On December 29, 1972, with the Oyster Creek Nuclear Plant at 650 MWe, an operator opened the door carrying the protective fuses for the generator monitoring relays and caused a turbine trip/reactor scram. The trip resulted in a cooling system transient during which the water level dropped to about 10.7 feet above the core and the pressure rose to the actuation point for the relief valves. Within a few seconds after the trip at least two of the relief valves actuated. During the transient the reactor operator attempted to switch the reactor from the run to the startup mode to prevent a containment isolation when system pressure dropped below 850 psig, but the bypass key broke off in the switch, preventing the transfer.

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Three out of the four main steamline isolation valves (MSIV) closed as soon as the primary system pressure decreased below 850 psig, and this removed the main condensers from service. Consequently, both isolation condensers were actuated to minimize the volume of water that was released to the torus as a result of one of the relief valves failing to close. However, a condensate drain valve on one of the isolation condensers failed to open, rendering one of the isolation condensers inoperable. While the relief valves were open, 53,000 gallons of water were added to the torus, increasing drywell pressure to one psig. The containment spray system was initiated to reduce pressure and temperature in the torus.

The relief valve that had failed to close was discovered by operating each valve manually and listening for the sound of condensing steam because of difficulties based by the logic of the temperature indicating instrumentation. When the malfunctioning valve was found, the reactor was placed in cold shutdown and the causes of the malfunctions were investigated.

The malfunctioning relief valve was removed and disassembled. An inspection showed that a piece of steel from the thread of the disc retainer was lodged between the pilot valve seat and disc, causing the pilot valve to remain open. In addition, the locking arm for the disc retainer, the set screw for the locking arm, and the tie wire that prevents the lock screw from backing out were missing.

The set screw was found in a drain valve off the 30-inch steam header. The tie wire and locking arm were not found; however, analyses indicated that these would be stopped by the screens in front of the turbine stop valves.

As a result of the inspections and findings from this relief valve, the other four relief valves were removed and disassembled. The subsequent inspections showed that a piece of the lock arm on another relief valve was broken off. This missing part was not recovered. In addition, the solenoid plunger and spring guide on another relief valve was misaligned, although the misalignment would not have prevented the relief valve from opening. The solenoid plunger and guide were realigned to assure proper operation. In addition, the mating threads on the disc retainer and the valve bodies of all the valves were drilled for a set screw so that the disc retainer would be locked in place when the set screw was installed. All relief valves were functionally tested for proper operability at plant system temperature and pressure prior to returning the plant to service.

An inspection of the malfunctioning MSIV showed that the air piston was sticking in the cylinder of the air operated pilot valve. All four pilot valves on the MSIV's had been replaced during the September–October 1971 outage because problems with sticking pilot valves had been reported at another facility. The new pilot valves that were installed had larger

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clearances to preclude sticking. To assure proper operation in the future, full closure tests are now performed at six-week intervals rather than three-month intervals, the daily 10% closing test program which utilized the test pilot valves was changed so that the normal pilot valves could be utilized, and the suitability of the MSIV's for the environment in which they are operating was assessed.

An investigation of the failed condensate valve on the isolation condenser showed that the motor for the valve had burned out. Since the same motor had burned out and had been rewound and returned to service about a month earlier, the valve and valve motor were disassembled and inspected. The 10-inch DC operated condensate valve was manufactured by Anchor Valve Company and had a rated hydrostatic test pressure of 2175 psig. The cause for the valve failure was traced to the fact that the valve was designed to operate with the stem vertical, but the valve had been installed horizontally with the stem traveling horizontally. Weld buildup was added to the lower guide to give the disc a horizontal run into the valve, thus preventing the disc from rotating and locking into the valve body. The valve was tested satisfactorily and has continued to operate satisfactorily.

ROE 73-11 October 26, 1973

INTRUSION OF CHLORIDES INTO PRIMARY SYSTEM

Summary

During a routine startup of a BWR, seawater entered the condenser system through many leaks in the main condenser tubing. The magnitude of the CONDENSER TUBE LEAKAGE and the high ionic concentration of the intruding seawater caused the demineralizers to become depleted very rapidly and allow seawater to enter the primary system. The chloride content of the water in the primary system exceeded the operational limit of 1 ppm and reached a maximum of 15 ppm with the primary system at rated operating pressure and temperature.

The SEAWATER INTRUSION RESULTED IN extensive plant damage from CHLORIDE STRESS-CORROSION CRACKING.

Background

The Millstone Unit No. 1 condenser system has a total surface area of over 444,000 square feet composed of 7/8-inch outside diameter tubes each 48 feet long. The condenser tubes are aluminum-brass ASTM B-11 alloy 687, (alpha-type) with an 18 BWG wall thickness. This choice of tube alloy was based on the operating experience at other Northeast Utilities Plants. Copper-nickel (70/30) tubes were used in the condenser inlet and air removal sections as an added protective measure against the corrosive environment of steam and water impingement. A total of 38,412 aluminum-brass tubes were installed along with 2,036 copper-nickel tubes.

When the plant was initially placed into service in December 1970, some tube vibration was noted in the upper periphery of the main condenser. This vibration was attributed to a combination of high steam loading and impingement of moisture droplets. Consequently, these condenser tubes were staked with 10-guage metal strips to reduce vibration to an acceptable operating level.

During the first year of operation, condenser tube leakage necessitated that 118 tubes be plugged. An additional 260 tubes were plugged between January and August 1972. Further tube leakage was relatively minor, and high quality reactor water was maintained by the addition of "stopleak" to the condenser seawater intake and the high deionization capacity of the demineralizer beds.

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Circumstances

The plant was undergoing a routine startup in September 1972. All nuclear instrumentation was operable with the exception of three local power range monitors (LPRM) which previously had been removed from service. All specific conductivity elements were operable and registering normal operating conditions. The primary coolant flow path was through the condensate pump minimum flow line using one condensate pump (bypassing the demineralizer). A much smaller volume was flowing through the demineralizer into the minimum flow line of the feedwater pump. No water was being added to the reactor vessel.

Two hours after startup, specific conductivity in the hotwell increased to the alarm point. The reactor operator, correctly noting that the condenser tubes had developed a seawater leak, dispatched personnel to the seawater intake structure to place sawdust in the intake in an attempt to plug the tube leak, and continued with the startup.

After another hour of operation, the operator received two additional alarms from specific conductivity meters that indicated the demineralizer in service was becoming depleted. Since condensate was still being recirculated and no makeup water to the reactor vessel was necessary, the operator continued with the startup with the intent of valving a new demineralizer into service prior to injecting water into the reactor vessel.

At five hours and 40 minutes after startup, the reactor had reached normal operating pressure of 980 PSIG and it was obvious to the reactor operator that feedwater would have to be added periodically to the reactor vessel because steam had begun to flow from the vessel into the condenser. At this time, all specific conductivity instrumentation except those in the reactor vessel and the feedwater system were pegged full scale. The operator valved off the expended demineralizer and placed two fresh beds into service. He then added water to the reactor from the feedwater system. The reactor vessel feedwater specific conductivity indicator alarmed at full scale. However, the specific conductivity meter in the demineralizer effluent started to decrease from full scale, and the reactor operator interpreted this to mean that the new demineralizers were effective. Consequently, he continued to feed the reactor vessel as required. The conductivity of the reactor water increased very slightly from these feedwater additions.

Forty minutes after the two new demineralizers had been placed into service, both beds suddenly became exhausted and "broke through," allowing high conductivity water into the reactor vessel. The high conductivity alarm for the reactor vessel water actuated, and the operator shut down the reactor. An attempt to place other demineralizers into service was unsuccessful because these beds rapidly became depleted while the

primary system water was being recycled. The reactor continued to cool down normally with a high concentration of chloride ions in the primary system. The plant reached the cold shutdown condition approximately 13 hours after the high reactor vessel water conductivity alarm.

Corrective Actions

The main condenser was retubed entirely with 70/30 copper-nickel tubing because this alloy has better resistance to a salt-water environment. Also, the new condenser tubes were restaked to minimize fatigue cycling wherever vibrations were apparent.

Additional high range specific conductivity instrumentation that will indicate gross changes in conductivity was added to the inlet and discharge of the demineralizers. This will provide sufficient information so that proper evaluation of rapid changes in conductivity can be made, and immediate corrective action can be taken.

Also, revised procedures have been developed to assure appropriate and prompt operator response to alarms that indicate increasing conductivity in the feedwater. These procedures list the symptoms of a possible high conductivity condition and delineate the immediate operator action that is required.

The technical specifications for Millstone 1 have been revised in the areas of reactor water chemistry, allowable seawater inleakage rate, pump operation, and demineralization capacity.

ROE 73-12 November 2, 1973

FAILURE OF SAFETY-VALVE SEAT BUSHINGS

Summary

On two separate occasions at the same BWR facility, SAFETY VALVES were found to be LEAKING FROM CRACKED VALVE SEAT BUSHINGS caused by TRANSGRANULAR CHLORIDE STRESS CORROSION. The exact source of chloride contamination has not been identified, but the attack is believed to be isolated to the safety valves. Preventive measures include replacement of the defective bushings, control of potential sources of chlorine by careful handling and cleaning procedures and safety valve inspections during all refueling outages.

Background

The Oyster Creek Nuclear Power Plant has a total of sixteen, six-inch spring-loaded safety valves on the two main steam lines between the reactor and the main steam line isolation valves. The safety valves are attached to the steam line by flanged connections. The steam line and the inlet safety valve flanges are insulated, but the valve bodies above the inlet flange are not insulated.

The safety valves are normally subjected to a reactor operating pressure of 1020 PSI. The relief setting of the valves is between 1200 and 1250 PSI.

The valve seat bushings are machined from 304 austenitic stainless steel, and the valve discs are fabricated from 422 stainless steel. The valve bodies are carbon steel. At the time of manufacture, both the seat bushings and discs were ultrasonically and liquid dye-penetrant inspected and found to be free of defects.

Circumstances

The technical specifications for the plant require that a minimum of five safety valves be bench checked or replaced with bench checked valves during each refueling outage. During the October 1971 refueling outage, five safety valves were replaced with five clean, tested spare valves. The safety valves that were removed had been in service since full power operation began in December 1969.

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It was found that two of the removed valves could not be decontaminated to suitable levels for shipment to the manufacturer. The seat bushings were unscrewed from the valve bodies and were subjected to a liquid dye-penetrant examination. This examination revealed cracks in the seat bushings of these two valves.

One valve seat bushing had radial cracks at the valve seat and circumferential cracks at a fillet radius above the lower threads. The radial cracks started at the outside surface and extended partway across the seat face. Circumferential cracks were located around a major portion of the outer bushing diameter. The maximum depth of the circumferential cracks was 0.120 inch. There were no crack indications on the inside diameter of the seat bushing.

The other defective seat bushing had approximately 15 radial cracks. There were numerous longitudinal cracks on the outer diameter and circumferential cracks at the fillet radius above the lower threads. Again no crack indications were found on the inside diameter. This seat bushing was sent for destructive testing. A metallographic examination disclosed that the cracks were typical of those associated with transgranular chloride stress corrosion cracking. A section of one crack was examined by microprobe in two areas and chlorine, sulphur and potassium were detected in each crack area. The valve seat bushing was tested and found to meet the requirements of ASTM A-182, 304 stainless steel.

The remaining three valves removed in October 1971 were also disassembled and dye-penetrant checked, but did not show crack indications.

When the plant was shut down for refueling in May 1972, all sixteen safety relief valves in service were removed, disassembled and inspected. All valves had scale or rust deposits on the outside of the seat bushing. A water level ring at the low point of the outlet discharge pipe indicated that all valves had leaked or vented. A dye-penetrant examination of the seat bushings and discs from the valves disclosed that seat bushings on seven of these sixteen valves were cracked. On three seat bushings, the cracks were across the seat and on the outside surfaces. Two of the seat bushings had cracks only across the seat, and the two remaining seat bushings had cracks only on the outside surface.

On each cracked seat bushing there was a hard scale deposit about 1/32-inch thick that had partially flaked off. The scale was light tan in color and was located below the water level mark on the valve base. The contact gamma-radiation dose rate at the thick scale was 200 to 2000 mR/hr. Three of the valves with the scale had been in the plant only from November 1971 to May 1972.

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In addition, four of the seat bushings had damaged threads at the connection between the seat bushing and the valve base. However, metallurgical examination of two of these seat bushings indicated that the thread damage was mechanical in nature and had probably occurred during valve assembly or disassembly.

Discussion

The high gamma dose rate and the hard scale deposits on the downstream side of the valves indicate that the valves with the cracked seat bushings were leaking steam in service. The scale deposits are believed to have been deposited by a repetitive cycle of condensation and boiling inside the valve body. The escaping steam leaking through the valve seat would condense on the uninsulated valve body. The condensate would return by gravity to the lower valve base and be revaporized as steam by the hot seat bushing which was in contact with reactor steam at its inner surface.

The environment at the seat bushing during plant operation was hot steam, free oxygen, free chloride ions and stress in the seat bushing from the reactor pressure of 1020 PSIG. The chloride concentration of the reactor water is normally less than 0.1 ppm with an operating limit of 1.0 ppm (the exact source of the chloride contamination is unknown). Under these conditions, stress corrosion cracking of 304 stainless steel can occur.

In both occurrences, the valves with the cracked seat bushings were the valves located closest to the reactor.

Corrective Actions

All cracked seat bushings were replaced with new, type 304 stainless steel bushings of the same design as originally provided.

After parts were dimensionally checked, they were cleaned with alcohol and demineralized water. The valves were reassembled using graphite and castor oil as lubricants. All materials were checked for chloride and fluoride contamination.

To eliminate the possibility of water standing in the lower part of the valves, where the cracking had occurred, a drain hole was added just above the inlet flange.

The inlets and outlets of the reworked valves were covered during shipping and in all handling operations. Prior to installation, the outlet discharge pipe for each of the refurbished valves was washed with demineralized water.

Conclusion

The valve manufacturer indicated that cracking of the seat bushing is a rare occurrence in thousands of similar valves in service. According to the valve manufacturer, in each previous failure case, the cracking of the valve seat bushings was attributed to chloride contamination and in no instance had a seat bushing failed catastrophysically. The corrective measures were to replace the defective parts and to control further exposure of the valves to potential sources of chloride contamination.

Other operating facilities were advised to perform inspections to determine if this condition might exist on similar valves at their plants. No abnormal conditions in the safety valves were found in these inspections.

ROE 73-13 December 14, 1973

FAILURE OF VANE TYPE FLOW SWITCHES

Summary

SEVENTEEN FAILURES of VANE TYPE (PADDLE) FLOW SWITCHES have occurred at FIVE BWRS. ALL FAILURES were SIMILAR with either the ENTIRE VANE or a PORTION OF THE VANE BECOMING DETACHED from the switch. These flow switches were used to detect minimum flow conditions. The failure mechanism was postulated to be excessive vibrational stress imposed on the vane from normal flow turbulence.

Wherever possible, the vane flow switches have been replaced with differential pressure flow sensors. Where replacement was not feasible, the vanes were removed from the installed flow switches. Owners of BWRs now under construction have been advised to use alternative flow sensing devices.

Circumstances

Background

All the vane flow switches involved in the events reported here were manufactured by Power Engineering and Equipment Co., Inc., (PEECO) of Torrance, California. The switches varied in size and construction depending on their application and set point. However, all switches were on/off type with the vane physically located in the fluid flow path. The purpose of these nonindicating switches was to monitor for minimum flow conditions and thereby to function as a permissive signal.

The flow switch vanes were fabricated from laminated stainless steel sheets and tapered so that the greatest thickness was at the attachment end. The laminations were banded and secured by spot welds and the vanes were attached to the switches by mounting screws.

Quad Cities Unit 2

In January 1972, one of four switches that monitors minimum flow conditions in the residual heat removal (RHR) loop did not actuate with reduction of flow below the set point on the switch. When the flow switch was removed from the system, it was discovered that the flow-sensing vane was missing. The broken vane was approximately 4-inches long, 1-inch wide and 3/32-inches thick.

After an extensive recovery effort, the missing vane was found in the RHR heat exchanger. All four vane flow switches in the RHR system were replaced with differential pressure flow sensors, and the other systems with vane flow switches were checked to verify that the vanes were still intact.

Quad Cities Unit 1

Because of the flow-switch failures at Unit 2, all four vane-type flow switches in the RHR system of Unit 1 were examined. Two switches were defective. The entire vane of one switch was broken off at the point of attachment to the actuating lever and a 3-inch long portion of the vane and the assembly band were missing on the other defective switch.

After an extensive recovery effort, the missing vane was found in the lower head of the RHR heat exchanger, and the 3-inch vane section was recovered from the discharge check valve of the cleanup pump.

Since several defective switches had been found in the RHR systems, similar switches in other systems at the station were examined. This investigation resulted in the removal of four switches, two from each reactor water cleanup system. Each of these switches had failed. The entire flow vane was missing from two of the switches; the third switch had a portion of the flow vane and the assembly band missing; and the assembly band was missing on the fourth switch. The vanes were approximately 10-inches long by 7/8-inch wide. One vane section was retrieved from the discharge check valve of the cleanup system pump. However, the two remaining vanes and the two assembly bands were not recovered. The missing flow switch components had no potential for entering the primary system of the reactor. All vane type flow switches were replaced by pitot tubes to prevent a recurrence of this type of failure.

Dresden Unit 2

In April 1972, when the plant was shutdown for a partial refueling outage, four of thirteen vane type flow switches installed in the plant were inspected because of the failures that had been discovered at the Quad Cities plants. When one of the four High Pressure Coolant Injection (HPCI) system flow switches was removed, it was discovered that the 3-inch long vane and two mounting screws were missing. Since this switch showed no other apparent signs of damage, it was concluded that the vane mounting screws had vibrated loose and backed out of their tapped holes, allowing the vane and screws to fall into the piping. The mounting screws of the other three flow switches were intact so they were peened to prevent them from vibrating loose.

An extensive search, including both dissassembly and radiography of inaccessible piping, failed to locate the missing flow switch parts. A safety analysis was performed to evaluate the possible effects of leaving the pieces in the system. It was concluded that there was only a remote possibility of the parts entering the vessel through the feedwater sparger and that the parts were too small to compromise coolant capabilities.

Further investigation revealed that all three flow switches in the shutdown cooling system (SDCS) were each missing their entire vane. An extensive search succeeded in recovering two full vanes and half of the third vane. One complete and one half vane were found in the SDCS heat exchanger and the other complete vane was found in the SDCS pump suction strainer. The missing 9-3/8-inch long vane segment could not be located. Failure of all three of these switches occurred at the point of vane attachment to the body of the switch. This was the same failure mode that had been noted at the Quad Cities plant. The remaining six flow switches were found to be intact. Their mounting screws were peened to prevent vibrational loosening.

Because of recurring flow switch failures, an inspection of the HPCI flow switch at Unit 3 of the Dresden Nuclear Power Station was conducted immediately and the switch was found to be intact. The mounting screws were peened to insure continued vane integrity. The vanes were removed from the flow switches in the shutdown cooling system of Unit 3.

Monticello

In September 1972, during an inspection of the RHR loop, one flow switch was found with the entire vane missing, and a partial vane section was missing from another switch. A review of operating records indicated that the vanes probably had become detached and had remained in the system for about one year with no adverse effects. The vanes of all switches in the RHR loop have subsequently been removed.

Oyster Creek

In June 1973, during a refueling outage, all four vane type flow switches in the reactor water cleanup system were examined. It was found that each vane had broken off and was lodged in the switch mounting tee because it could not escape without additional vane breakage. The vanes of these switches were removed and their function was replaced by a revision to the operating procedures that now requires a field check prior to opening the bypass recirculation lines when starting the recirculation pump.

A flow switch in the standby liquid control system was found intact and subsequently reinstalled because this switch is subject to flow only during annual inspections or during emergency conditions.

ROE 74-1 February 1, 1974

VALVE YOKE FAILURES

Summary

After a FRACTURED YOKE ON A BYPASS ISOLATION VALVE CAUSED A LOSS OF CONTAINMENT AIR, an improved data logging monitor was installed to detect rapid changes in the containment volume and to provide an alarm whenever the volume of containment air is not within a specified tolerance condition. The yoke failure was caused by thermal stresses induced by seasonal temperature variations.

Following the installation of the data logger alarm system, the SAME VALVE YOKE FRACTURED AGAIN, with the plant at essentially the same conditions. This time the IMPROVED MONITOR DETECTED the CONTAINMENT LEAK WITHIN 20 MINUTES, as opposed to a 186 minute detection delay with the unalarmed system. This second failure was caused by freezing of moisture accumulated in the valve internals.

Following the second failure, electrical heat tracing and insulation were installed and a low point drain was added downstream of the affected valve to prevent moisture accumulation.

Circumstances

In January 1972, while the Connecticut Yankee Nuclear Plant was at 100% power, the control room operator noticed a decrease in the weight of containment air as he scanned the trend printout from the data logger. A systematic investigation disclosed that the yoke on an 8-in. bypass isolation valve in the containment purge exhaust system had fractured, permitting the valve to open approximately 0.75 in. This allowed containment air to escape through the partially open valve. A temporary closure mechanism was applied to the valve to stop the air leakage. Before making permanent repairs to the valve, a temporary blank flange was installed in the 42-in. purge air exhaust penetration upstream of the defective valve.

The broken valve yoke was removed and a new yoke was installed. The broken yoke was examined by the manufacturer (Mason-Neilan) and the failure was attributed to thermal stresses caused by seasonal temperature variations (the valve was located outside the reactor containment building).

A review of the data logger printout revealed a total loss of 3894 pounds of containment air over a period of about four and one-half hours. From the time the leak started, it was slightly over three hours till it was discovered.

An automatic alarm was added to the data logger trend recorder to provide a more rapid detection of containment air losses. Provisions were made for an alarm message (together with actuation of the main control

board annunciator) to be printed on the message trend typewriter whenever the weight of containment air is not within a specified tolerance range. This range check is performed automatically once per minute.

In December 1972, this automatic check for "Reactor Containment Air Out of Range" registered an alarm. The control room operator scanned the data logger printout and confirmed the decrease in weight of containment air. An immediate investigation revealed cracks in the same valve yoke that had failed previously. Again, the cracked yoke permitted the valve to open approximately 0.75-inch. The same procedure of first applying a temporary closure mechanism to the valve and a blank flange on the upstream side of the purge air exhaust penetration permitted a safe and deliberate repair of the valve.

The fractured valve yoke was removed and replaced. After a successful leak test, the temporary blank flange was removed from the containment purge exhaust line.

The second valve yoke failure was attributed to moisture accumulation within the valve internals, followed by freezing and expansion of the accumulated water. To prevent recurrence, both the bypass valve and the main purge valve have been electrically heat traced and insulated, and low point drains have been installed immediately downstream of both valves to prevent moisture accumulation.

An analysis of the data logger printout for the period following the second yoke fracture indicated a total loss of 1100 pounds of containment air. The time between the second fracture of the valve yoke and installation of the temporary closure mechanism was 52 minutes. Only 20 minutes elapsed between the fracture of the valve yoke and detection of the leak.

RGE 74-1 (Corrected) March 1, 1974

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The broken valve yoke was removed and a new yoke was installed. The broken yoke was examined by the manufacturer (Mason-Neilan) and the failure was attributed to thermal stresses caused by seasonal temperature variations (the valve was located outside the reactor containment building).

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The fractured valve yoke was removed and replaced. After a successful leak test, the temporary blank flange was removed from the containment purge exhaust line.

The second valve yoke failure was attributed to moisture accumulation within the valve internals, followed by freezing and expansion of the accumulated water. To prevent recurrence, both the bypass valve and the main purge valve have been electrically heat traced and insulated, and low point drains have been installed immediately downstream of both valves to prevent moisture accumulation.

An analysis of the data logger printout for the period following the second yoke fracture indicated a total loss of 1100 pounds of containment air. The time between the second fracture of the valve yoke and installation of the temporary closure mechanism was 52 minutes. Only 20 minutes elapsed between the fracture of the valve yoke and detection of the leak.

ROE 74-2 February 8, 1974

MALOPERATION OF HPCI SYSTEMS

Summary

Events at boiling water reactors (BWRs) in which HIGH PRESSURE COOLANT INJECTION (HPCI) systems either were declared inoperable or failed to perform satisfactorily are discussed. The EVENTS INCLUDE MISALIGNED LIMIT SWITCHES, IMPROPER ELECTRICAL WIRING, JAMMED VALVES, IMPROPER INSTALLATION, FOREIGN MATERIAL IN VALVES AND PERSONNEL ERROR.

Operating Experiences

Limit-Level Switches

(a) During routine surveillance in August 1971, with Unit 2 of the Dresden Nuclear Power Station at 50% power, it was discovered that the High Pressure Coolant Injection (HPCI) system turbine stop valve would not open. Subsequent investigation detected a misaligned limit switch on the HPCI control valve. This valve provides a permissive signal for the HPCI turbine stop valve to open. Because the HPCI control valve failed to trip its limit switch when the valve closed, the actuating circuit for the HPCI stop valve could not be energized.

Repositioning of the limit switch corrected this problem, and the HPCI system was tested successfully.

(b) In November 1971, with Unit 2 of the Dresden Nuclear Power Station at 62% power, the HPCI system was declared inoperable when the hydraulic control system could not be reset from the control room. The problem was traced to a loose limit switch on the HPCI control valve which kept the circuit to the hydraulic solenoid valve open. The inability to reset the control system could have prevented automatic start of the HPCI turbine.

The adjusting screw on the limit switch was tightened, and a double lock nut was added to prevent its loosening. The HPCI system was satisfactorily tested and declared operational following this modification.

(c) In June 1973, at Unit 1 of the Browns Ferry Nuclear Power Station, two level switches which initiate transfer of the HPCI water supply from the condensate ring header to the torus did not actuate during a scheduled test. Upon investigation, the contacts of the switches were found to be badly burned and stuck in the closed position. This allowed HPCI coolant water to be taken from the torus only.

An investigation determined that the electrical contacts on the affected switches were undersized. The installed switches were Robertshaw Model 83481 Levelac level switches with an electrical rating of 0.25 ampere at 250-volts DC. Switches with ratings of 0.50 ampere at 250-volts DC should have been installed. The two defective level switches were replaced with switches of the correct electrical rating.

Electrical Wiring Errors

(a) In May 1972, at Unit 3 of the Dresden Nuclear Power Station, the HPCI turbine could not be reset from the Control room during the monthly surveillance test, although the indicator light that monitored the reset circuit was energized indicating a normal condition for this circuit throughout the test. The turbine was reset locally, and the surveillance test was completed.

The following day, an electrician found a loose wire in the reset solenoid. The cause of the loose wire was a brittle failure of a terminal on the solenoid causing the wire to become electrically grounded. This permitted the indicating light to be dimly lit. The faulty solenoid was replaced.

(b) In May 1972, the turning gear motor on the HPCI turbine failed to start on demand at Unit 2 of the Quad Cities Nuclear Power Station. The system was declared inoperable, and the reactor was shut down immediately.

An inspection indicated that the windings of the turning gear motor had burned out. The turning gear motor had a two-winding field circuit that permitted the motor to be wired for either 125-volt or 250-volt DC service. At the time of installation, a wiring error had been made which connected 250-volt electrical power to the field circuit for the 125-volt windings. The motor had performed properly during periods of relatively short duration operation. However, with prolonged usage the windings overheated and burned out.

The turning gear motor was rewound and the wiring error was corrected. When the motor was returned to service, it performed satisfactorily.

HPCI Valve Problems

(a) In July 1972, following maintenance on the HPCI exhaust line check valves at the Monticello Nuclear Power Station, a simulated automatic fast start of the HPCI system was unsuccessful. Instrumentation indicated that the turbine control valve was not responding to its governor control signal. Inspection of the hydraulic actuating system for the control valve revealed several pieces of a plastic pipe cap in the oil inlet port

of the pilot valve. The plastic fragments were removed from the pilot valve. The remainder of the valve, power piston and governor servo-mechansim were disassembled, inspected, and found to be satisfactory.

After reassembly, several successful fast starts demonstrated system operability.

(b) In November 1972, at Unit 2 of the Dresden Nuclear Power Station, the HPCI steam supply valve would not open during a post-maintenance surveillance test. The reactor was critical and the reactor vessel pressure was 85 psi at the time.

An investigation disclosed that the proper actuation signal was provided to the valve motor. On each attempt to open the valve the thermal overload contacts opened preventing the valve from receiving a sustained power signal. After the control rods were inserted to shut down the reactor, the valve was acutated twice and each time the valve cycled normally. After these successful tests, the routine startup continued.

It was postulated that, prior to startup, system pressures associated with a hydrostatic test of the primary system had caused the valve plug to become jammed into its seat. To prevent recurrence, a procedural step was added to require successful cycling of these motor operated valves after completion of hydrostatic tests and prior to plant startup.

(c) In February 1973, during a post-maintenance surveillance test on the HPCI system at the Pilgrim Nuclear Power Station, the steam supply valve to the HPCI turbine failed to open. The control room annunciator indicated that the valve motor had been overloaded.

Investigation disclosed that the valve motor had burned out. The valve plug was closed tightly into the valve seat and manual opening of the valve required more than normal force to break the valve free. After the valve was opened it was operated manually several times and each time the valve operated freely. It was concluded that the motor failure occurred because the valve had been jammed into the seat when it had been last closed. Later, when the actuation signal was received, the valve remained continuously energized until the motor burned out.

By design, there was no protection to limit or disconnect the motor from the operator when the valve was moved in the open direction. A new valve motor was installed and the valve closing torque was adjusted to a lower setting to reduce the possibility of recurrence.

(d) In July 1972, with the Pilgrim Nuclear Power Station at 20% power, the HPCI turbine was started as part of the startup test program. Following this test, the reactor operator observed that the high water level alarm in the drain pot on the drain line of the HPCI turbine exhaust did not clear in the usual time period. Since the outlet of the turbine exhaust drain line was submerged in the torus, it was immediately suspected that the two-inch check valves in the line were leaking, permitting torus water to be siphoned back to the drain pot through the steam trap. The

manual steam trap valves were closed. This cleared the alarm and confirmed that the check valves had been leaking. The manual steam trap valves were left closed and startup testing continued.

During an outage four days later, the check valves were removed from service. One valve was stuck open, while the other valve appeared to be properly closed. Upon disassembly of the valves loose rust was found in each valve. This apparently caused the valve plugs to bind. These check valves are rising plug type valves with only a small clearance between the plug and the valve body. Both valves were cleaned, reassembled and leak tested.

It was postulated that the rust was in the piping when it was installed; and that testing and operation had eventually flushed the rust from the system. Subsequent HPCI system tests were performed with no indication of check valve leakage.

(e) In October 1972, with Unit 2 of the Quad Cities Nuclear Power Station at 45% power, the HPCI system was activated for a special test to measure pressure waves and resulting displacement of the torus during electromatic relief valve actuation and HPCI operation. The hydraulically operated HPCI turbine stop valve would not open, so the HPCI system was declared inoperable.

An investigation revealed that the valve could be reset locally, but it could not be held open remotely. During reactor cooldown, the HPCI turbine stop valve operated correctly when several unsuccessful attempts were made to duplicate the previous malfunction and the original cause of the valve malfunction could not be determined. During further investigations numerous alarms were activated and all the indicating lights on one annunciator panel blinked each time the motor operated steam inlet valve for the HPCI turbine was cycled to the closed position.

The switch on the steam inlet valve was actuated several more times to determine the cause of the alarms. This valve has a seal-in feature to close the valve and a torque switch (limitorque) to stop closure. Each time the valve was cycled to the closed position, the valve motor started and applied a momentary closing torque until it was tripped by the torque switch. Later in the day, the stem on the steam inlet valve was discovered to be bent 1.5-inches out of alignment. The bent valve stem was attributed to repeated closures during testing. A replacement valve stem was obtained and the motor operated steam inlet valve was returned to service the following day.

The cause of the spurious alarms was traced to an electrical ground on the strip heaters inside a DC bus cabinet. These heaters were disconnected and all reactor operators were cautioned against attempting to close an already closed valve equipped with a seal-in feature.

(f) In September 1973, during routine testing of the HPCI system with auxiliary steam at Unit 1 of the Browns Ferry Nuclear Power Station, the steam supply valve to the HPCI turbine failed to operate. A preliminary

investigation indicated that the trouble was in the valve gearbox; removal of the limitorque drive motor revealed several damaged pinion gear teeth. The clutch gear, which meshes with the drive motor pinion gear, also had three chipped teeth. It was concluded that the gears were not properly aligned axially because only 0.20 to 0.25-inch engagement of the teeth was observed. The misalignment was attributed to improper installation of the motor pinion gear, which had been placed on the motor shaft backwards.

The corresponding gears were removed from a similar valve operator on Unit 2, which was under construction, and installed properly in the Unit 1 motor operator. After this modification, the HPCI surveillance test was successfully completed.

Procedural Error

In January 1973, as part of a routine surveillance test at the Pilgrim Nuclear Power Station, the HPCI system turbine tripped from an overspeed signal while pump operability tests were being performed. When the turbine was restarted, the gasket on the gland seal steam exhauster failed, so the HPCI system was removed from service to repair the gasket and investigate the cause of the overspeed trip.

It was determined that the overspeed trip of the HPCI turbine resulted from a change in a test procedure that led to the test potentiometer setpoint being reset downward to 2000 rpm prior to the turbine start. This allowed the turbine to accelerate to the overspeed trip point before the control valve could respond to the speed indication.

The starting procedure was changed to allow the control valve to take control and regulate the HPCI turbine at a lower speed. The gasket on the gland seal steam exhauster was replaced and the pump operability test was performed successfully later the same day.

Water Hammer and Pipe Vibration

(a) In October 1972, the first coupled operation of the HPCI pump-turbine assembly was made at Unit 1 of the Brown's Ferry Nuclear Power Station. The operation resulted in a severe water hammer and violent movement of the turbine exhaust line, although the line had been braced with a five thousand-pound (five-kip) hydraulic snubber. An additional ten-kip snubber was then installed on the exhaust line. However, this snubber also had little effect on pipe movement during additional pre-operational testing.

The next attempted corrective action for reducing pipe vibration was to install 2.5-inch check valves as vacuum breakers on the HPCI exhaust line. Testing with this modification resulted in a considerable

decrease in turbine exhaust line vibration. The noise of the exhausting steam still caused some concern, however.

The final. and successful, corrective measure was to add a condensing sparger to the HPCI turbine exhaust line. This sparger was a vertical extension of the existing line in the suppression pool. The extended line was capped at the bottom, and contained 1296 1-inch diameter holes. The ratio of total hole area to cross sectional pipe area was approximately 2.5 to 1. The uppermost row of holes was submerged under approximately two feet of water while the lower row of holes was located under eight feet of water.

(b) In November 1971, during a preoperational test of the HPCI turbine at the Vermont Yankee Nuclear Power Station, a vacuum was created in the turbine exhaust line causing water from the suppression chamber to be drawn into this line at high velocity, resulting in very fast closure of the check valves in the exhaust line. This produced a pronounced water hammer. To prevent recurrence, the swing check valve in the turbine exhaust line was relocated from a vertical to a horizontal run of pipe. An additional 2.5-inch check valve, which acts as a vacuum breaker, was installed inside the suppression chamber between the exhaust line penetration and the suppression chamber high water level. These modifications resulted in satisfactory operation of both turbine systems in subsequent HPCI tests.

Complex Failures Involving Multiple Causes

(a) In May 1973, at the Monticello Nuclear Generating Station, the HPCI system isolated because of high steam flow during a "quick start" full flow surveillance test. Recording instrumentation indicated an intermittent instability in the electrical control circuitry, a slow response of the electro-hydraulic valve actuator and a malfunction of the turbine speed feedback signal. These problems collectively contributed to excessive opening of the HPCI turbine control valve, resulting in steam flow which exceeded the isolation trip point for the HPCI turbine.

An intermittent short circuit was discovered on the bias speedsetting potentiometer. It was replaced by a fixed resistor.

The drive gears in the electro-hydraulic valve actuator were found to be worn to the point that they were not engaging properly.

The excessive wear had been caused by insufficient lubrication that resulted from an improperly located lube oil supply line. The gears were replaced, the lubrication system was thoroughly cleaned and flushed to remove metal fragments, and the oil line was extended to supply an ample quantity of lubricant directly to the gear teeth.

The spur gear which provides the turbine speed signal to the control system was loose on the drive shaft. Pilot holes were drilled in the drive shaft at the location of the set screws and the spur gear was reinstalled with self-locking set screws. The drive coupling for the electro-hydraulic valve actuator also was found to be loose on the drive shaft. Self-locking set screws were installed to prevent future loosening of this connection.

After completion of these repairs, the HPCI system was tested, control settings were adjusted to optimize performance and the HPCI system operated satisfactorily.

(b) In July 1971, during initial startup testing of Unit 3 of the Dresden Nuclear Power Station, the reactor pressure was being increased for hot functional testing. When the reactor pressure had increased to above 100 psi, the HPCI steam isolation valve could not be opened to prepare for warming of the turbine. The HPCI system was declared inoperable, and reactor pressure was reduced to below 90 psi, a condition for which the HPCI system was not required.

The contacts of the permissive relay for the steam isolation valve were discovered to be wired in reverse, eliminating the "open" logic for both HPCI steam isolation valves. This wiring error would not allow the 100 psi interlock relay to energize so that the system was incapable of providing steam to the HPCI turbine.

The steam isolation valves in the HPCI system had not been tested since October 1970. At that time, operation of the valves and logic circuitry had been normal. Records failed to indicate any additional work on the relay, so the source of the wiring error could not be identified. The wiring was corrected and the system tested satisfactorily.

On the following day, with the reactor pressure at 150 psi, the HPCI system was again declared inoperable when the steam admission control valves could not be opened to admit steam to the HPCI turbine. Again, the reactor pressure was reduced to below 90 psi.

Investigation revealed that the oil-actuated interlock valve that controls the turning motor gear and control valves during HPCI operation was sticking. Cycling of the motor speed changer, which operates as the automatic speed controller for the turbine, freed the interlock valve and allowed the control valves to actuate normally. Since the HPCI turbine had not been actuated since completion of the preoperational tests in November 1970, the valve operability problem was attributed to extended idle time. To prevent recurrence, the exercising of the HPCI valves was included in the monthly surveillance testing of the HPCI system. Prior to plant startup following extended refueling outages when the routine monthly HPCI tests are postponed, the HPCI valves will be actuated to verify that the valves are free to move and can be operated properly.

On the day after successful completion of hot functional tests of the HPCI system and preliminary startup tests, it was found that the water volume in the suppression chamber (torus) exceeded the maximum capacity by 1900 cubic feet. The excess water had been accumulated by the extended operations of the HPCI system resulting from the previous failure of the oil-actuated interlock valve. The suppression chamber level was lowered by pumping the water to the condenser hotwell.

Three days later, with the reactor at a pressure of 350 psi, it was discovered that the HPCI turbine stop valve would not open. Subsequent investigation detected a misaligned limit switch on the HPCI control valve which was in the same solenoid circuit as the turbine stop valve.

After the solenoid valve was repositioned, the post-critical, pre-operational phase of the HPCI tests was completed successfully.

ROB [illegible] February 3, 1974

MECHANICAL VIBRATIONS OF REACTOR INTERNALS

Summary

After several months of SUSPECTED MOVEMENT OF REACTOR VESSEL INTERNALS based on analysis of noise measurements from the ex-core detectors, the Palisades Nuclear Power Plant was shut down for inspection of core internals and repair of one of the steam generators. Significant wear of some internal restraining components on the core internals was observed and wear was detected on the lower outside shims on the reactor vessel. Wear was also evident on the alignment keys for the reactor vessel head and six fasteners that held the expansion/compensation ring were broken.

The movement of the reactor vessel internals has been ATTRIBUTED TO a RELAXATION OF the PRELOADING OF THE VESSEL HEAD STUDS AND the consequent RELAXATION OF THE MATING SURFACES BETWEEN THE REACTOR VESSEL AND THE VESSEL HEAD. This reduced the clamping force and allowed the normal primary coolant flow to impart a kind of "rolling teacup" motion to the core barrel assembly, resulting in the observed wear and fractured fasteners.

Background

The reactor core support barrel in the Palisades plant was restricted laterally at the upper flange by four alignment keys, the upper guide structure, the expansion/compensation ring shim, and the vessel flange assembly. The flange assembly provided compression force between the upper guide structure and the ring shim on the core barrel. The lower end of the core support barrel was restrained laterally by six snubber assemblies. Alignment lugs on the upper guide structure provided lateral restraint between the base of the upper guide structure and the core support barrel. The fuel assemblies were laterally restrained by pins which projected into the fuel alignment plate at the top and into the core support plate at the bottom of the core structure.

Six neutron flux (power range) detectors, located outside the reactor vessel (ex-core), extended the length of the core so that the neutron-flux signal represented an average flux rather than a spatially-dependent flux value. These power-range neutron flux detectors provided an early clue that the reactor vessel internals might be vibrating. The vibration-induced changes in the core-to-detector water thickness had resulted in an apparently anomalous behavior of the detectors. Removal of the vessel head confirmed that the noise patterns associated with the detectors were indications of motion within the reactor vessel.

Circumstances

In May 1972, the reactor vessel head was removed to inspect the upper guide structure after a cap screw (fastener) from the expansion/compensation ring was found in the primary side of one of the four steam generators. At this time it was discovered that another expansion/compensation ring fastener had also failed, so the remaining six fasteners were secured by welding keeper bars across their counterbore recesses. The failure of the two cap screws was attributed to gouges on the top surface of the ring shim, which had been damaged during a shipping accident. The broken fasteners in the expansion/compensation ring were not replaced because they served only as locators for the correct placement of the expansion/compensation ring. A thorough inspection of all exposed reactor internals did not show any indication of movement, and no evidence of damage or wear was present.

By September 1972, flux variations of $\pm$ 0.5 percent noise level were noted in measurements from the ex-core detectors. By December, 1972, the flux variations had reached $\pm$ 1.0 percent. The flux variations in December 1972, as contrasted to those of April 1972, when the ex-core detector signals had been relatively stable with an approximate $\pm$ 0.1 percent noise deviation, led operating personnel to suspect motion of the reactor internals.

Efforts to understand the apparently anomalous behavior of the ex-core detectors began in September 1972, when amplified strip chart recordings of the detector channel noise were made. The subsequent evaluation of these recordings revealed a 180-degree phase shift between signals from detectors on opposite sides of the core. The maximum noise amplitude occurred in the east/west detectors. These observations led to the tentative conclusion that the major axis of possible core internals movement was primarily in the east/west direction. It was further determined from these recordings that the amplitude of the ex-core detector noise varied linearly with reactor power.

The plant was shut down in January 1973 to plug approximately seven percent of the steam generator tubes, which reduced the primary coolant flow by approximately three percent. After tube plugging, the reactor was restarted in March 1973 and the ex-core detector channels were again monitored by amplified strip chart recordings. The amplitude of the ex-core detector noise had decreased by approximately thirty percent. Core support barrel snubbers were monitored at this time for audible indications of core barrel movement. None was found.

The dependence of the ex-core detector noise on primary flow conditions was further demonstrated by tests between May 30 and June 2, 1973.

These tests revealed that any combination of three-pump operation reduced the noise amplitude to approximately one fifth of that experienced with four-pump operation.

After the initial decrease in noise amplitude following plugging of the steam generator tubes, the noise amplitude steadily increased by approximately forty percent from June to August 1973. Extensive noise analyses were performed during this period, both to characterize the noise and to identify any changes. On August 7 the facility was placed in three-pump operation to diminish the amplitude of the flux oscillations.

On August 11, 1973, the plant was shut down to investigate related primary-to-secondary system leakage in the steam generators and to remove the reactor vessel head for inspection of the reactor internals. The initial examination of reactor internals revealed that the six remaining expansion/compensation ring fasteners were broken and that the core support barrel flange had worn a 0.25-inch-deep step into the ledge on the reactor vessel flange, allowing the core support barrel to be displaced downward by this distance. A corresponding 0.06-inch-deep area had been worn in the reactor vessel head flange where the expansion/compensation shim ring makes contact with the vessel head. In addition, the four upper alignment keys which served as lateral restraints to the core barrel had worn the vessel and the vessel head key-ways. Upon removal of the core barrel minor wear of the coolant outlet nozzle was detected where it appeared to contact the core support barrel. The Inconel shims of the six snubbers that were attached to the vessel wall to provide lateral restraint near the bottom of the core barrel also showed evidence of wear. No damage to the fuel, control rods, upper guide structure or the core support assembly was found.

Conclusions and Remedial Actions

It was postulated that the core barrel was vibrating in a rotational, rocking, "rolling teacup" motion which resulted from normal flow turbulence and coolant impingement on the inadequately clamped core barrel.

As an interim measure to preclude subsequent wear problems, the expansion/compensation ring was replaced by a thicker ring and the clamping force on the flanges of the upper grid structure and core barrel support was increased from the original 3,400 pounds to between 500,000 and 1,000,000 pounds. Also, the alignment keys and snubbers were replated to restore them to their original dimensions. Additional surveillance and continued monitoring of ex-core flux measurements are planned to verify the adequacy of these corrective measures.

ROE 74-3

This report is based on information contained in the following documents:

1. Summary of meeting held on November 28, 1973, to discuss core internals inspection, T. V. Wambach, Directorate of Licensing, USAEC.

2. Notification of incident or occurrence No. 98 to Directorate of Regulatory Operations, USAEC, October 12, 1973.

3. Letter, R. B. Sewell (Consumers Power Co.) to J. F. O'Leary Directorate of Licensing, USAEC, July 20, 1973.

4. Letter, R. B. Sewell (Consumers Power Co.) to P. J. Schemel (Directorate of Licensing, USAEC), August 20, 1973.

5. RO Inspection Report No. 050-255/73-05, August 24, 1973.

6. Memorandum, R. J. Cook and W. J. Collins to E. L. Jordan, April 19, 1973.

7. Memorandum, G. Fiorelli to J. G. Keppler, August 7, 1972.

VALVE FAILURES RESULTING FROM UNDETECTED INSTALLATION ANOMALIES

Summary

The two valve failures discussed below illustrate events resulting from failure to perform routine quality control inspections of components prior to installation. In one case, the body of a CHECK VALVE LEAKED FROM SUSTAINED HIGH PRESSURE/TEMPERATURE OPERATION. This defective check valve had successfully passed a preoperational hydrostatic test although the valve had TWO CASTING FLAWS.

In the second instance, a VALVE DESIGNED TO OPERATE only IN a VERTICAL ORIENTATION was INSTALLED with the stem in a HORIZONTAL POSITION. As a result, this manual gate valve could not be operated because the seats and discs galled.

Circumstances

Casting Flaws Cause Valve Body to Leak

A check valve in the main steam trip valve bypass line at Unit 1 of the Surry Power Station is used to permit manually equalizing the pressure differential across the trip valve since the main steamline trip valve cannot be opened with a back pressure greater than 4 psi. The swing-gate check valve in the six-inch bypass line had a 600 pound rating with a cast carbon steel body and buttweld connections. The valve was one of a shipment of 26 valves, 24 of which were installed in secondary systems at the facility. The valve body had been hydrostatically tested to 2175 psi by the manufacturer (Crane-Chapman Co.) prior to shipment and its 600 pound rating (1200 psi at 545°F) was commensurate with the maximum plant operating conditions of 1005 psi at 545°F.

In November 1972, while Unit 1 of the Surry plant was being cooled down from a hot shutdown condition, water was observed to be dripping from the metal-covered thermal insulation that covered the bypass line check valve. The insulation was removed and a small steam leak was found in the upstream side of the valve body casting, mid-way between the weld joint and the bonnet flange. The leaking valve was removed and replaced by a spare.

Visual inspection of the defective valve body revealed fissuring on the interior valve surface. The fissure had fused metal-sand aggregate in the area of the leak. A second metal-sand casting flaw was also observed on the internal surface of the body-to-bonnet flange transition of the valve. The valve was returned to the manufacturer for analysis to determine the cause of failure.

The manufacturer reported that the failure of the valve body had resulted from finely distributed shrinkage voids in the casting which gradually degraded to provide the leak path after the valve had been subjected to a sustained high pressure and temperature environment. This type of defect should have been detected by visual inspection of the interior of the valve body prior to actual valve installation.

Improperly Installed Valve Causes RHR Inoperability

The valves in the pump suction line of the residual heat removal (RHR) system of Unit 4 of the Turkey Point Nuclear Station are Darling 14-in manual gate-type valves. The gate assembly for the valve consists of a double disc gate separated by a two piece spreader. The upper spreader is fastened to the valve stem, and raises and lowers the gate assembly. During valve closure, the lower spreader strikes the bottom of the valve body and as the stem travels further toward fully closed, the spreaders contact each other forcing the gate discs out against the valve seats. As the valve opens, the spreaders first separate and allow the discs to lift off the seats before the gate moves out of the flow path.

In May 1973, while attempting to isolate one of the RHR pumps, the gate valve in the pump suction line could not be closed. The valve was disassembled and it was observed that the valve seats and discs were galling each time an attempt was made to close the valve. The valve was then reassembled in the closed position to permit isolation and repair of the pump.

Subsequent communications with the valve manufacturer revealed that the pump suction valve was designed to be installed with the stem vertical although it had been installed in the Turkey Point 4 facility with the valve stem horizontal. With the stem installed horizontally, the spreaders could not separate properly resulting in the galling of the discs and guides. A similar valve in the other RHR loop also had been installed with the stem in a horizontal position.

To correct this condition, the gate assembly was modified by installing a spring between the spreaders, parallel to the stem, so that the spreaders separate as the valve is opened. This allows the gate to lift off the seats with a minimum of friction on the guides. The valve body seats were then replaced with the valve in place; no difficulties have been encountered with the modified gate assembly.

ROE 74-5 March 15, 1974

EFFECTS OF LOSS OF OFF-SITE POWER AT NUCLEAR POWER PLANTS

Summary

The incidents described below illustrate some of the possible effects of a loss of off-site power.

In the first case, a series of malfunctions of minor electrical systems components eventually led to a DROP OF THE WATER LEVEL IN THE SPENT FUEL POOL; in the other two cases, WIRING ERRORS IN THE AUXILIARY POWER CIRCUITS RESULTED IN FAILURE TO TRANSFER POWER FROM AUXILIARY TO STARTUP TRANSFORMERS following turbine trips.

Circumstances

Water Level in Spent Fuel Pool Dropped as a Result of Loss of Off-Site Power

In January 1972 ice-laden transmission lines to the Big Rock Point Nuclear Plant failed as they were buffeted by high winds during an intense storm. As a result of a momentary loss of off-site power to the plant, the generator tripped on overspeed, and the reactor was automatically shut down by a high neutron flux signal. The loss of off-site power occurred when the breaker to a 138-kV incoming line tripped automatically.

Normally, power to the station would have been transferred automatically to a second line rated at 46 kV. However, a contact in one of the overcurrent relays on this line had stuck. This stuck relay, coupled with the operation of the undervoltage bus fault-detector relay had tripped the breaker on the 46-kV line also. This line was deenergized for about two hours because repair crews were hampered by the blowing, drifting snow.

When the loss of both normal and backup incoming power lines occurred, the diesel generator started and closed onto the station bus to provide power for essential equipment. The 138-kV line was returned to service about 20 minutes after the shutdown and after the intermittent interruptions of power to the line had ceased. The diesel generator was left running for about two hours as a precautionary measure.

The first indication of an abnormal condition in the spent fuel pool appeared about 24 hours after the shutdown, when a reactor operator observed a slight increase in the readings from the radiation monitors in the fuel pool area. Inspection revealed that the water level in the fuel pool was two to three feet below normal. An investigation determined that the decrease in fuel pool level had been caused by a siphoning action which, in turn, had been caused by the piping configuration and valve alignment and indirectly by the loss of off-site power.

At the time of the outage the fuel pool had been valved so that the water from the pool was recycled through the radwaste system. When off-site power to the station was interrupted, the pumps in the fuel pool, radwaste, and treated waste systems tripped off and the isolation valves in the radwaste system closed automatically.

When the transmission line fault had been cleared and the isolation valves in the radwaste system were opened, the piping configuration created a hydraulic head of about 11.5 feet from the fuel pool to the waste receiver tanks. This was enough to siphon the water from the fuel pool to the waste receiver tanks. The decrease in fuel pool level caused the radiation dose rate to increase slowly because of the reduced water shielding. After the reason for the siphoning action was determined, the valve to the radwaste system was closed and the water level in the fuel pool was restored.

To prevent a recurrence of this condition, a siphon breaker was added to the inlet piping of the spent fuel pool. This siphon breaker consisted of three 7/16-inch holes that were drilled in a horizontal pattern on the vertical section of inlet piping about two feet below the normal fuel pool level.

Failure to Transfer from Auxiliary Transformer to Startup Transformer

In March 1972, both output breakers from the generator opened and tripped the Palisades Plant from 30% of rated power after this power level had been achieved for the first time earlier the same day. The plant trip, caused by a trip of a pilot wire circuit for two of the 345-kV breakers and a failure of the plant protection relays to trip, was further complicated by failure to transfer the electrical load to the startup transformer following manual trips of the reactor and the turbine.

When the generator output breakers opened, the turbine immediately dropped the load to the required station power level and reactor operators immediately began inserting control rods. In about 30 seconds, the reactor was shut down manually; the turbine tripped automatically. The diesel generators had been started prior to the reactor scram to provide backup power.

When the turbine tripped, the operators noted that power had not been transferred to the startup transformer and that the generator had not tripped from the auxiliary transformer. The auxiliary transformer was tripped from the generator bus manually and then the 2400-volt busses were connected to the startup transformer.

After the plant was brought to a stable shutdown condition, an investigation revealed that the generator output breakers had opened from a pilot wire trip, when the pilot wire circuit detected an apparent ground fault. This ground fault subsequently proved to be the result of a wiring error in the pilot wire trip circuit. A review of the protection logic for the plant revealed that no direct trip of plant protection relays could have occurred when the pilot wire tripped the generator output breakers. As a result, one of the two emergency power busses was unavailable until it was transferred manually to the startup transformer.

The wiring error was corrected and the pilot wire relaying scheme was taken out of service temporarily while an improved protection scheme was developed and implemented.

Failure to Transfer from Auxiliary Tran former to Startup Transformer-II

In July 1973, Unit 3 of the Turkey Point Station was operating at 600 MWe when the reactor and the turbine both tripped. At this time, the pressure transmitters on the steam line were being calibrated. One of the differential pressure channels on one of the main steam lines was in the "tripped" position to permit it to be calibrated. A second differential pressure transmitter in the same line received a spurious trip signal and provided the necessary two-out-of-three logic for the steam line instrumentation to actuate the safety injection system. All plant systems and engineered safety systems functioned as designed, except that automatic transfer from the auxiliary transformer to the startup transformer did not take place.

A controlled shutdown of the plant was begun because the effect of the failure to transfer to the startup transformer was the same as that which would have resulted from a loss of off-site power. Constant monitoring of the parameters for the nuclear steam supply system provided assurance that conditions requiring the safety injection system were not present. Consequently, equipment in the engineered safety systems was shut down. The startup transformer breakers that had failed to close automatically were closed manually and the plant was placed in the hot shutdown condition so that the cause of the loss of off-site power could be investigated thoroughly.

The subsequent investigation determined that the cause of the failure to transfer auxiliary power to the startup transformer automatically was an incomplete circuit to the relay that closes the breaker to the startup transformer.

During the construction of Unit 3 of the Turkey Point Station, the original circuit design had been modified to provide automatic transfer of the auxiliary power supply to the startup transformer when the safety injection system was actuated but one wire inadvertently had not been installed. The missing wire was immediately installed and the circuit was tested to verify proper operation.

The modifications that had resulted in the wiring error were completed prior to the licensing of Unit 3. Present administrative procedures at the plant require complete documentation and approvals for any and all changes.

References

This report is based on information contained in the following documents:

1. RO Inspection Report No. 50-250/73-3, September 4, 1973.

2. Letter, A. D. Schmidt (Florida Power & Light Co.) to J. F. O'Leary, USAEC, Directorate of Reactor Licensing, July 13, 1973.

3. Letter, R. B. Sewell (Consumer Power Co.) to P. A. Morris, USAEC, Directorate of Reactor Licensing, March 22, 1972.

4. Letter, W. E. Caldwell, Jr. (Consolidated Edison Company of New York, Inc.) to J. F. O'Leary, USAEC, Directorate of Licensing, August 18, 1972.

5. Letter, R. B. Sewell (Consumer Power Co.) to P. A. Morris, USAEC, Directorate of Reactor Licensing, March 3, 1972.

ROE 74-6 March 22, 1974

MALFUNCTIONS OF CONTROL RODS AND CONTROL ROD DRIVES

Summary

In the first instance discussed below the BOLTED CORE SHROUD for the original plant, which had operated some twelve years without difficulty, OBSTRUCTED REPLACEMENT OF SHIM RODS following an outage for inspection and refueling. In the second case, extensive testing was required to determine the cause of ANOMALOUS BEHAVIOR OF A SINGLE CONTROL ROD. The third event involved APPARENT UNCOUPLING OF A CONTROL ROD: in a fourth incident SEAL LEAKAGE inhibited proper control rod functioning.

In most cases, the events took place either during plant startup or shutdown, and were noted immediately. No hazard to the public occurred during any of the occurrences.

Circumstances

A Misaligned Shroud Tube Caused Shim Rod Insertion Difficulties

After routine inspection of one shim rod was completed during a scheduled outage of the Yankee Nuclear Power Plant in November 1972, difficulties were encountered in reinserting the rod. A periscopic inspection of this shim rod revealed abnormal wear about nine inches below the normal wear area on the guide block. The four fuel assemblies adjacent to the shim rod were removed to allow inspection of the shim rod slot in the lower core support plate. An underwater television inspection revealed that: a cap screw and locking cup, which was later proven to be a shroud tube mounting bolt, was lying on the lower core support plate (this was later retrieved); the shroud tube had shifted to the east; and the slots of the north and south vanes were nearly closed.

When the misaligned shroud tube and shroud tube bolt were found, all the fuel was removed from the reactor to permit inspection of the lower reactor internals. This inspection showed that seven bolts which connected the lower core support plate to the shroud tubes were missing. Four locking cups also were missing. Four of these missing bolts and two locking cups were subsequently found in the bottom of the reactor vessel.

About two weeks after discovery of the problem, the reactor vendor performed independent inspections and analyses at the site. Prior to these inspections, the lower core support barrel had been removed to permit acess to the shroud tube structure. The inspections revealed that

the tie bar between two of the shroud tubes had worn through and that the outside lower quarter of the shroud tube was scratched for about one to two feet. Also, another (eighth) bolt was missing and one bolt was partially withdrawn at the bottom tie plate of another shroud tube.

It was subsequently determined that the scratch on the lower outside quarter of the shroud tube had occurred earlier in plant life and had no connection with the missing bolts and locking cups.

The bolted shroud structure was replaced by a unitized structure, the fuel was reloaded and the plant was returned to service on April 10, 1973. To date, no problems with the new structure have been experienced.

Control Rod Slippage

On March 12, 1973, the Maine Yankee Nuclear Power Plant was in the process of being shut down for a scheduled maintenance outage when control rod No. 19 slipped from 180 to 50 steps withdrawn. The plant was placed in the hot shutdown condition and the control rod drive was exercised. During the exercises the rod slipped from 130 to 30 steps. Analyses of electrical current traces from the drive mechanism coil indicated that the upper gripper was not engaging properly with each step demand. The voltage on the upper gripper was increased and the current was applied for a longer time period in an attempt to correct the control rod slippage. Subsequent exercising of the rod drive produced no irregularities in the current traces from the drive mechanism coil.

The plant was still in the hot shutdown condition approximately ten hours after the above adjustments were made, when control No. 19 again slipped from 180 to 158 steps. An hour later the rod slipped from 160 to 141 steps, and during an attempted insertion to the lower electrical limit, the rod slipped an additional 20 steps. At this time the coil power programmer was deenergized and the power switch for the upper gripper coil was replaced. The electrical resistance of the coils for control rod No. 19 and an adjacent rod (No. 14) were measured; no coil deterioration was evident. Control rod No. 19 was reenergized; coil current traces indicated proper operation.

About three hours later, with the reactor at approximately 20% power, control rod No. 19 slipped from 180 to 159 steps. The rod was returned to the 180-step position and then inserted to the lower limit so the timer module on the coil power programmer could be replaced. During subsequent withdrawal, the breaker on control rod No. 19 tripped when the rod had been withdrawn to 19 steps, causing full insertion of the rod. The breaker was reclosed and current traces on the control rod coil were recorded. These traces revealed no irregularities in coil and card current and indicated no reason for tripping of the breaker. The power level was increased to 60% of rated power, and plant conditions were stabilized at that point.

Subsequent to stabilization of plant conditions, the 15-volt DC power sources that supply the control power programmers were monitored. The output from these power supplies oscillated approximately ± 0.5 volt, with sporadic oscillations as high as ± 1.0 volt. The current traces on the gripper coil showed coincident oscillations. These traces were sent to the manufacturer for evaluation.

On March 14, 1973, control rod drive No. 19 was successfully exercised, and no irregularities in the gripper coil current were evident. Reactor power level was increased to about 75% power and stabilized there. The control rod exhibited no unusual behavior for three days.

Six hours after a reactor and turbine trip on March 17, 1973 the 240-volt power supply breaker to control rod No. 19 tripped, causing full insertion of the rod. Since control rods 19 and 24 were controlled by the same control power programmer, comparative performance tests were begun with these two rods while the reactor was maintained in the just critical state (10^{-4}% power). After the tests were completed, the power and reed switch leads for rod Nos. 19 and 25 were switched at the connection plate in the containment and the two control rods were fully withdrawn. When the breaker was closed, control rod No. 25 (now assigned to the control rod No. 19 control power programmer) dropped, indicating that the problem was directly associated with the programmer. Control rod No. 25 was fully withdrawn and the reactor was returned to 75% power. The following day, after the reactor had reached the 75% power level, the power supply breaker again tripped, causing full insertion of control rod No. 25. The rod insertion automatically initiated a turbine runback to 65% power. Control rod No. 25 was withdrawn fully and the power level was maintained at 65% to prevent another turbine runback. Also a spare 15-volt DC power supply was substituted for the suspect power supply. On March 20, 1973, the plant was returned to the 75% power level. The suspect 15-volt DC power supply was returned to the reactor manufacturer for additional tests to determine the cause of the continuing malfunctions.

Problems of a similar nature with control rods of a similar design at another plant are discussed in ROE 72-18, "Design Problems with Control Rods at PWR's", dated December 1, 1972.

An Apparent Uncoupling of a Control Rod During Plant Startup

In February 1973, Unit 2 of the Dresden Nuclear Power Station was being restarted when a control rod drive (CRD) overtravel annunciator alarm tripped. The position indication and red backlighting on the annunciator panel were observed, indicating the apparent uncoupling of a control rod.

The CRD was successfully recoupled with the rod and the assembly was checked for positive coupling. During subsequent rod withdrawals, similar occurrences were noted with two additional rods. Again, the rods were recoupled and tested, with no indicated problems.

A surveillance program was begun requiring the performance of decoupling check once daily on each rod for the four weeks prior to a scheduled outage. During these tests, no uncoupling of control rods was experienced.

Subsequent inspection of the three affected CRD's showed that two of the three had damaged filters. Further evaluations showed that this damage had occurred when the filter was installed without using the proper rotating technique. Also, one CRD flange was decoupled. This condition was tentatively attributed to a failure to lock the filter onto the connector following installation.

Because the damage to the springs on the inner filter of the CRD was the only damage observed, tests were performed to compare the force required to install an old filter to that associated with installing a new filter. The undamaged old filter required about 25 pounds of force for installation, whereas the new filters required about 36 pounds of force.

New control rods were installed in place of the three rods that had been removed. The correct procedure for installing the filters were obtained from the vendor, and the three control rods that had been removed were rebuilt to be used as spares. Additional surveillance tests also were developed for implementation during scheduled maintenance on control rods and control rod drives.

A Control Rod Failed to Insert Completely

During a routine startup on November 20, 1973, at the Nine Mile Point Nuclear Station, the reactor was at 77% power when a reactor scram/turbine trip occurred. All systems operated properly, except that as the reactor operator reset the scram, he observed that eleven of the rods had stopped at the 02 position (six-inches withdrawn) instead of fully inserting. The operator immediately inserted the rods manually.

The cause for the failure of the control rods to insert fully was determined to be excessive leakage past deteriorated piston seals. The damage was confirmed by stall leakage flow tests and scram tests on each of the control rods. No repairs to the piston seals were made at this time. It was determined that even with the eleven rods at the 6-inches withdrawn position, there was no possibility of the reactor becoming critical.

On November 25, fifteen rods again failed to insert fully following a reactor scram. Seven of these rods were in the group of eleven that had failed to fully insert earlier. The reactor operator immediately inserted the rods manually. The cause of the failure of the control rods to insert fully again was identified as leakage past the stop piston seals.

To correct the piston seal leakage, the control rods will be overhauled during the outage scheduled for spring 1974. On a generic basis, the rate of deterioration of the piston seals in the CRD's of this generation of BWR's has been noted to increase when the operating drive pressure or the control rod has been increased. Consequently, administrative procedures at this plant were changed to require that drive pressure for the control rods be maintained within normal limits. The deterioration of these seals has been tentatively attributed to normal wear.

Problems with leakage past the stop piston seals were discussed in ROE 72-19, "Design Problems with Control Rods at BWR's", dated December 15, 1972. The Nine Mile Point Station is of the same general design as the plants discussed in that ROE.

References

This report was prepared from the following documents:

1. Notification of Incident or Occurrence No. 74, dated November 22, 1972, Directorate of Regulatory Operations, USAEC.

2. Letter, Herbert A. Autio (Yankee Atomic Power Company) to Directorate of Licensing, USAEC, dated December 14, 1972.

3. Letter, L. H. Heider (Maine Yankee Atomic Power Company) to Directorate of Licensing, USAEC, dated April 10, 1973.

4. Letter, W. P. Worden (Commonwealth Edison Company) to Mr. A. Giambusso (Directorate of Licensing, USAEC), dated March 13, 1973.

5. Letter, W. P. Worden (Commonwealth Edison Company) to Mr. A. Giambusso (Directorate of Licensing, USAEC), dated July 17, 1973.

6. Letter, R. R. Schneider (Niagara Mohawk Power Corporation) to Mr. Donald J. Skovholt (Directorate of Licensing, USAEC), dated November 28, 1973.

7. Letter, R. R. Schneider (Niagara Mohawk Power Corporation) to Mr. Donald J. Skovholt (Directorate of Licensing, USAEC), dated December 3, 1973.

ROE 74-7 March 22, 1974

OFF-GAS EXPLOSIONS

Summary

DETONATIONS IN THE OFF-GAS SYSTEMS have occurred at two or more different Boiling Water Reactors (BWR's). Lightning has been directly responsible for at least three of the five detonations in which the gas column above the stack has been ignited, despite the apparent protection by a lightning arrestor system.

In one case, no further problems were encountered after the first detonation. In a second case, however, four detonations were experienced over a period of about three months before the condition was brought under control. Two of these four detonations occurred when there was no evidence of lightning or electrical storm in the area.

In no instance were abnormal levels of radioactive discharge or overexposure of personnel associated with any of the off-gas system detonations.

Circumstances

Detonation in Off-gas System Caused By Lightning

On March 6, 1973, during a lightning storm at Unit 2 of the Quad Cities Nuclear Power Station, the control room operator observed that the reading of the flow indicator on the stack discharge line was oscillating in an erratic manner. The power output from the plant was reduced and the flow indication stabilized after about one minute of erratic variation. Approximately one minute later, several area radiation monitors in the turbine building alarmed and the standby gas treatment system (SGTS) started automatically. At this time it was observed that the continous air monitor, which samples the turbine building exhaust air, indicated an increasing radioactivity level and the radiation monitors in the off-gas system indicated a decreasing level. With this combination of indications, operations personnel were relatively certain that the rupture disc in the off-gas line had blown.

Approximately twenty minutes later, personnel entered the turbine building and confirmed that the rupture disc had blown. A different air ejector was placed into service and the rupture disc was replaced. The area outside the building was surveyed; no abnormal radiation levels were measured and no evidence of mechanical damage was detected.

The next day, the two off-gas high efficiency filters that had been in service during the lightning strike were analyzed to determine their efficiency. These tests indicated zero efficiency on both filters. When the filters were removed, they were charred and their upper support beams were deformed, indicating definitely that an explosive recombination of hydrogen and oxygen had occurred in the off-gas line.

A detailed examination showed some of the filter media had melted in the lower portion of the filter vessel. Each damaged filter was weighed and found to be essentially the same as the weight of a new filter. This confirmed that very little, if any, filter material had escaped the vessel.

It was discovered that the filter element retainers had not been installed during construction of the facility. They were subsequently found in the site warehouse and installed.

Although the exact cause of the detonation cannot be positively determined, no other source of ignition except the lightning storm in the vicinity of the station could be identified.

Recurrent Off-Gas System Detonations

On June 12, 1973, with the Vermont Yankee Nuclear Power Station at 78% power, a direct lightning strike to the top of the plant ventilation stack was observed during a severe electrical storm. This caused the plant stack gas monitoring system and the gamma radiation monitor on the perimeter fence to become inoperable. Since this instrumentation is required at all times, an orderly shutdown of the plant was initiated. The lightning also resulted in a detonation in the off-gas system which caused sufficient back pressure to fracture the rupture disc in the air ejector.

Temporary repairs were made to the rupture disc to minimize gaseous radioactivity in the turbine building, and the plant was placed in the cold shutdown condition the following day.

During the shutdown period, the rupture disc in the air ejector and the stack particulate filter were replaced. The off-gas piping was inspected for damage and none was found. All defective off-gas instrumentation was replaced and recalibrated, and the plant was returned to service.

The ventilation stack had received a direct lightning strike which ignited the gas column issuing from the stack. The flame propagation continued down the stack to the piping at the base of the stack. The failure of the electronic equipment had been caused by inadequate grounding.

To increase the probability of intercepting electrical discharges above the top of the stack by the lighting arrestor system instead of the gas column, the lightning rods were extended to approximately 15 feet above the top of the stack from a previous additional height of 2.5 feet. Two additional grounding circuits were installed on the inside surface of the ventilation stack and connected to the station ground system. Additional grounding straps were also installed on the off-gas piping near the base of the ventilation stack.

On August 31 with the plant at 50% power lightning again struck the top of the ventilation stack during a severe electrical storm. Again, both the plant stack gas monitoring system and the area gas radiation monitor became inoperable from the lightning strike. An apparent detonation in the off-gas system also occurred with sufficient back pressure to blow the rupture disc on the air ejector.

Approximately 15 minutes after the lightning strike, the reactor scrammed because of a high flux trip from the average power range monitor. Because the flux recorder indicated a value lower than the scram setpoint, it was postulated that the trip was caused by an electrically induced spike on the monitoring system power supplies. The lightning strike also caused the interim off-gas system to trip from a loss of power.

During the shutdown period, the rupture disc on the air ejector was replaced and one stack particulate filter was tested and met required efficiency standards. The plant was returned to operation on September 1. The interim off-gas system (a charcoal bed) was valved out of service until it could be ascertained if the electrical components in the system were a possible cause of detonation.

On September 3, while the plant was operating at approximately 68% power, another apparent detonation in the off-gas system caused sufficient back pressure to blow the air-ejector rupture disc. There was no evidence of lightning or electrical storm in the area at the time. The plant was immediately shut down and the rupture disc was replaced.

It was theorized that possible smoldering in the off-gas system had caused this explosion and that the smoldering could have been started by the explosion two days earlier. On inspection of a disassembled filter cartridge, a black gum-like substance was found deposited on the inlet surface of the filter.

The rupture disc was replaced and the off-gas system was charged with carbon dioxide to extinguish any latent smoldering fires. Then the plant was returned to service.

On September 9, while the plant was operating at 65% power, an apparent detonation in the off-gas system again caused sufficient back pressure to blow the air ejector rupture disc. Again there was no evidence of lightning or an electrical storm. An orderly shutdown of the plant was initiated and the rupture disc and the stack particulate filter were replaced.

All instrumentation associated with the off-gas system was tested and recalibrated to assure that it was not the spark-producing agent. The filter cartridge and inner cover plate of the stack particulate monitor were positively grounded to prevent any metallic component from acquiring a static charge. A thorough ground conductivity check was made on bolted pipe flanges, bolted valve bonnets, tubing and ground straps associated with the off-gas piping system. No indication of faulty grounding was found.

A continous air purge was installed in the off-gas line in an attempt to reduce the hydrogen concentration below 15% by volume concentration. In addition, an emergency operating procedure detailing the proper actions for handling a detonation in the off-gas system was written, and the plant was returned to service on September 13. To date, no further explosions have been experienced at the Vermont Yankee Nuclear Power Plant.

References

This report is based on information in the following documents:

1. Letter, B. B. Stephenson (Commonwealth Edison-Quad Cities) to A. Giambusso USAEC, Directorate of Licensing, March 16, 1973.

2. Letter, G. S. Thomas (Vermont Yankee Nuclear Power Corp.) to USAEC, Directorate of Regulatory Operations, Region I, June 13, 1973.

3. Letter, B. W. Riley (Vermont Yankee Nuclear Power Corp.) to USAEC, Directorate of Regulatory Operations, Region I, June 13, 1973.

4. Letter, B. W. Riley (Vermont Yankee Nuclear Power Corp.) to USAEC, Directorate of Licensing, September 7, 1973.

5. Letter, B. W. Riley (Vermont Yankee Nuclear Power Corp.) to USAEC, Directorate of Regulatory Operations, Region I, August 31, 1973.

6. Letter, B. W. Riley (Vermont Yankee Nuclear Power Corp.) to USAEC, Directorate of Regulatory Operations, Region I, September 4, 1973.

7. Notification of An Incident or Occurrence No. 93, USAEC, Directorate of Regulatory Operations, September 9, 1973.

8. Letter, G. W. Reinmuth (USAEC, Directorate of Regulatory Operations) to R. T. Carlson (USAEC, Directorate of Regulatory Operations, Region I), September 18, 1973.

9. Letter, B. W. Riley (Vermont Yankee Nuclear Power Corp.) to USAEC, Directorate of Licensing, September 17, 1973.

10. Letter, B. W. Riley (Vermont Yankee Nuclear Power Corp.) to USAEC, Directorate of Regulatory Operations, Region I, September 10, 1973.

ROE 74-8 March 29, 1974

CRACKED FEEDWATER SPARGERS

Summary

Extensive CRACKING of FEEDWATER SPARGERS in a boiling water reactor (BWR) was DISCOVERED subsequent to intrusion of seawater into the primary system. The FAILURE WAS ATTRIBUTED to RELAXATION of the INITIAL PRELOAD on the spargers, which allowed the spargers to fail from high frequency mechanical vibration.

A MODIFIED SPARGER with HEAVIER HEADERS AND AN ADJUSTABLE JACKING BOLT SYSTEM to assure adequate preload was installed. This sparger system FAILED after a brief period of operation. The failure was again attributed to a LOSS OF PRELOAD followed by mechanical fatigue.

A THIRD SPARGER SYSTEM was installed WITH A RIGID MOUNTING TO THE VESSEL WALL to eliminate sparger preload considerations. This third design also was instrumented to allow evaluation of its performance under service conditions. The instrumented spargers vibrated significantly at full power operation, so that plant output had to be reduced to 85% power for continued operation. The plant is currently operating at reduced power and a resolution of the sparger vibrational problem will be reached subsequent to plant shutdown.

Circumstances

On September 1972, Unit 1 of the Millstone Point Nuclear Power Station was in the process of a routine startup when operations personnel noted that seawater had entered the main condenser through tube leaks and had been introduced into the full-flow demineralizers. The magnitude of the condenser tube leakage caused the demineralizers to deplete very rapidly and allowed high conductivity water to enter the primary system. This intrusion of seawater into the primary cooling system resulted in extensive plant damage from chloride-ion stress corrosion cracking accompanied by a prolonged plant outage (see ROE 73-11).

During the outage, a visual examination of the reactor internals revealed that each feedwater sparger had extensive cracking at the connection of the tee box-to-header transition, and at the tee box-to-thermal sleeve transition. The cracks tended to be singular, and all the cracks were on external surfaces of the sparger transitions except for two open cracks. The sparger headers were relatively free of cracks. The sparger brackets showed wear patterns indicative of excessive movement.

An extensive metallographic and analytical investigation was performed to determine the cause of the sparger failure. This investigation concluded that each sparger had failed prior to the chlorine intrustion. The

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failure was attributed to high frequency fatigue caused by inadequate preload on the spargers. It was presumed that the spargers were either installed without adequate preload or that the preload had relaxed because of thermal stresses. The extensive damage to the spargers and the heavy oxide residue in the cracks were indicative of a considerable period of operation after initial crack propagation. This evidence tended to confirm that the sparger failure was not a result of chloride stress corrosion cracking. The original sparger design was standard for BWRs and the sparger installation was considered routine.

An inspection of the feedwater spargers at two similar nuclear plants, after about 10,000 and 15,000 hours of operation, showed the other spargers were performing as designed. No visible cracking in these spargers were observable and all preload wedges were properly in contact with the vessel wall. One sparger was tested for preload, and a 2000 pound force did not move the sparger from engagement with the preload point.

A new sparger system that would permit both a higher preload and greater flexibility to movement was installed at Unit 1 of the Millstone Nuclear Power Plant. The new sparger headers were fabricated from six-in. schedule 80 pipe (the old spargers were schedule 40 pipe); the new tee boxes were reduced from a 1-in. to 0.5-in. wall thickness to provide greater flexibility and to reduce the stress in the attachment welds to the sparger header. Also, the new sparger headers had a shop welded saddle to which a jacking bolt was mounted. These design changes allowed considerable adjustment at the preload point and provided compensation for any weld distortion after installation. The redesigned spargers were installed with approximately twice the initial preload of the original spargers.

Prior to a planned outage in April 1973, two of the feedwater spargers were inspected by an underwater television camera and found to be cracked at the tee box. Examination of the remaining two spargers by a dye penetrant test also disclosed cracking. This set of four spargers had been in service for only six weeks. Subsequent tests on the installed spargers showed that only one sparger had maintained its original preload. The other three spargers showed a resistance to movement, but none exhibited any significant preload. Further investigation revealed wear to the sparger pin slots, the top of the sparger support brackets and the support pad for the thermal sleeve. Broken tack welds were also observed on the two lower jack bolts of one sparger. The jack bolts were loose on the other spargers without preload and could readily be turned by hand.

This sparger failure was attributed to a loss of preload because of thermal relaxation of the components. The loss of preload allowed high frequency vibrations, and the sparger ultimately failed from mechanical fatigue. The second failure of the sparger confirmed that the initial failure was not caused by the chlorine intrusion incident.

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A third set of spargers of fundamentally different support design were installed. The new sparger installation had an additional load bearing member to provide essentially rigid attachment of the sparger to the reactor vessel. This welded attachment eliminated the dependence of the spargers on preloading and on the jack bolt arrangement that had been employed in the second sparger design.

All four of this set of feedwater spargers were instrumented with varying combinations of accelerometers, strain gages and resistance temperature detectors (RTDs) so that sparger performance could be evaulated under service conditions.

The plant was returned to service in July 1973, and sparger vibration data taken at 25-, 50-, and 75-% power showed only background vibration. However, significant vibrations were observed on one sparger at 90% power and on a different sparger at 100% power. These were the only two spargers that were instrumented with accelerometers.

After three hours of full power operation, the plant was reduced to 85% power and vibration of one sparger was virtually eliminated. Also, the amplitude of the second vibrating sparger decreased to an acceptable level. The plant has continued to operate at this power level.

Preliminary data from the instrumented spargers indicate that sparger vibration is not the result of pressure fluctuations in the feedwater system. It is now theorized that sparger vibration is flow induced and self-exciting from normal coolant flow operation.

References

This report is based on information in the following documents:

1. Millstone Nuclear Power Station Unit 1, Interim Report, no date.

2. Millstone Nuclear Power Station Unit 1, Interim Report, Addendum 1, June 29, 1973.

3. Millstone Nuclear Power Station Unit 1, Interim Report, Addendum 2, September 21, 1973.

4. RO Inspection Report No. 50-245/73-18, T. Young, Jr., USAEC Directorate of Regulatory Operations, Region I, August 10, 1973.

ROE 74-9 March 29, 1974

COOLANT PUMP GUIDE-VANE FAILURE

Summary

The FAILURE of resistance temperature detector (RTD) WELLS at a nuclear power plant was TRACED TO FAILURE OF a GUIDE VANE ON A PRIMARY COOLANT PUMP. The failure of the guide vane was ATTRIBUTED TO HIGH FREQUENCY FATIGUE, followed by CRACK PROPAGATION FROM A DEFECTIVE WELD.

Background

Each of the three reactor coolant loops at the Maine Yankee Nuclear Power Station was equipped with two guide vanes to reduce the formation of vortices at the pump inlet. Each guide vane was approximately 7-inches high by 19-inches long by 1.5-inches thick, was fabricated from stainless steel, and weighed 26 pounds. The guide vanes were designed by Byron-Jackson and field welded by Stone & Webster according to S&W procedure.

The cold-leg suction lines, which connected the steam generators to the reactor coolant pump, were U-shaped loops, each approximately 25-feet long and 33.5-inches in inside diameter. This carbon steel pipe had a 0.5-inch thick cladding to prevent corrosion. Six resistance temperature detectors (RTDs) were located in wells penetrating the pipe wall at the top of the U-bend.

Circumstances

On July 5, 1972, near the end of hot functional testing, a clattering noise was heard near one reactor coolant pump and its cold-leg suction piping. An initial inspection revealed that water was leaking from an RTD cable conduit. Furter investigation disclosed that all six of the RTD wells were leaking.

On July 8, the steam generator manways were opened and the water boxes were visually inspected. Approximately one cup of metal chips were found and removed from the cold leg of the steam generator; a few metal chips were retrieved from the hot leg side also. The following day, two more cups of chips were removed from the cold leg side, and four RTD wells (approximately 3-inches long) were retrieved. The piping temperature was still too high for direct physical inspection, but a visual check from the steam generator showed that the pipe cladding was gouged. This gouging was readily identified as the source of the metal chips.

On July 10, plant personnel entered the cold leg suction piping and discovered that the pipe cladding was extensively gouged over the entire surface area. One of the two guide vanes from the pump was found directly

over the drain nozzle at the bottom of the suction piping. Five of the six RTD wells were severed; the sixth was bent, but still in place.

The gouges in the cladding started about two feet from the steam generator and extended almost to the pump volute. This required the 26-pound guide vane to have traveled more than 25 feet upstream and uphill into the steam generator elbow. The periphery of the recovered vane was extensively peened apparently from repeated contact with the suction leg piping. There was no damage to either the steam generator or to the pump impeller.

Four RTD wells were recovered from the cold leg side of the steam generator. The missing RTD well could not be located after an extensive search throughout the primary cooling system. It was postulated that the well had been pulverized by the guide vane and removed in the form of metal chips.

The four RTD wells that were recovered showed marks indicating that they had withstood several impacts by the vane before breaking off. The bent well that was still intact had a number of marks on it, but apparently they had not been struck with enough force to break off.

Corrective Actions

The cladding surface on the suction piping was ground until no further dye indications could be found. The cladding was then checked using copper sulfate as a reagent to ascertain whether it had been penetrated to the carbon steel base. No exposed carbon steel was found. The deepest gouges were then checked by direct depth measurements and it was determined that the deepest penetration was only halfway through the cladding. Since the cladding was needed only for corrosion protection, the suction pipe was still acceptable for continued use.

A metallurgical examination of the detached coolant pump guide vane showed that the failure was propagated by high frequency fatigue (above 10,000 cps). The major cracks originated on the side of heaviest loading near the primary pump. It was estimated that between 100,000 and 1,000,000 load cycles occurred between crack initiation and failure, because a significant portion of the fractured surfaces were oxidized.

Metallographic and radiographic examinations revealed a number of defects (porosity, linear indications and inclusions) on both sides of the vane. The majority of defects occurred in the area of fusion of the weld metal to the base metal.

It was postulated that the initial crack began in one of the defects in the weld area and progressed by fatigue mode through the interface of the weld metal to the base metal. Because of the total number and types

of defects observed, it was concluded that the weld was in violation of code requirements.

Additional dye checks were made on the intact guide vanes. These vanes and their attachment welds were acceptable.

The remaining guide vanes were removed from the coolant pumps because flow model tests indicated that their removal would have little or no effect on total pump head and efficiency. The pump manufacturer also did not believe that removal of the vanes would affect detrimentally either mechanical or hydraulic performance.

A program to compare actual performance of the pumps without guide vanes to previously acquired pump data indicated no significant change in overall performance.

The six damaged RTD wells were replaced.

References

This report was based on information in the following documents:

1. Letter, W. P. Johnson (Main Yankee Atomic Power Company) to USAEC, Director, Division of Compliance Office, August 9, 1972.

2. Letter, W. P. Johnson (Main Yankee Atomic Power Company) to USAEC, Director, Division of Compliance Office, September 11, 1972.

3. Memorandum, Evaluation of Interim Report on Guide Vane Failure (8-9-72); final report on Guide Vane Failure (9-11-72), U. Potapovs to G. W. Reinmuth, Directorate of Regulatory Operations, USAEC, September 25, 1972.

4. Letter, R. F. Heishman, Region I: Directorate of Regulatory Operations, USAEC, to J. B. Henderson, Chief, Reactor Construction Branch, Directorate of Regulatory Operations, USAEC, November 1, 1972.

5. RO Inquiry Report No. 50-309/72-01, November 7, 1972.

ROE 74-10 April 5, 1974

TORUS PROBLEMS

Summary

The pressure suppression chamber used to absorb energy contained in steam released to the drywell in the event it becomes necessary to relieve the pressure in the reactor coolant system rapidly at some boiling water reactor (BWR) power plants has the shape of a torus. Forces involved in venting steam from the drywell to the torus are often very large.

In the first instance described below, the TORUS SUPPORTS were NOT IN full CONTACT WITH the SUPPORT PADS, allowing the torus to vibrate when the relief valves were actuated. Temporary shims and new vertical loadings on the ring header were used to reestablish contact and reduce the vibration to acceptable levels.

In three other instances, TORUS BAFFLE SECTIONS WERE DAMAGED by SAFETY/RELIEF VALVE DISCHARGES.

The DEGRADATION of the submerged portion OF a TORUS COATING is described in the fifth event.

Circumstances

Torus Not in Proper Contact with Support Pads

In November 1973, at Unit 1 of the Browns Ferry Nuclear Power Plant, a significant noise was heard from the torus and drywell area when the relief valves were actuated. When the torus was entered three days later, it was evident that a discharge pipe from a relief valve had been vibrating against the floor grating within the drywell. The clearance between the discharge pipe and grating was increased to eliminate the interference.

Ten days later, during testing, it was noticed that three of the torus supports were not in full contact with their support pads. The next day, the lack of full contact of six additional torus support saddle feet with their support pads was also discovered.

The spaces between the torus supports and their support pads were temporarily shimmed. The relief valves were actuated individually, and although the shimming reduced vibration, the movement of torus and ring header were still excessive. The ring header support was modified to reduce vertical movement of the header to an acceptable level. Each torus support was subsequently permanently shimmed and loaded.

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All Baffle Sections Removed from Torus

On November 1971, during an inspection of the torus at the Monticello Nuclear Generating Plant, 11 of the 72 large double I-beam baffle sections were found to have been displaced. Some bolts were sheared on the baffle sections that remained in place, the 3/4-inch diameter U-bolts that anchored the relief valve discharge lines were stretched, and the air line to the actuator of a torus-to-drywell vacuum breaker valve was severed. Paint on the torus wall was blistered and missing from surfaces directly below the discharge lines and some of the catwalk support legs were either bent or broken. A total of 114 bolts were found to have sheared. The damage was concentrated around the relief valve discharge lines and the HPCI turbine discharge line.

The failure was postulated to have been caused by a slug of compressed air trapped by water in the relief valve piping. With the discharge of the relief valve, this mass of compressed air was suddenly injected into the suppression pool. The pressure forces arising from the resulting water hammer were sufficient to displace the baffles near the valve discharge.

All the baffles from the torus were removed and the discharge lines for the relief valves were extended to the deepest region of the torus to cause the steam to be discharged under about nine feet of water. At the discharge point, a rams head tee was installed to direct discharge flow so it does not impinge directly on the torus walls.

Partial Baffle Removal from Torus

As a result of torus damage at the Monticello Power Station described above, the torus at the Oyster Creek Nuclear Power Station was inspected in May 1972. Five baffles in the vicinity of the relief valve discharge lines were found displaced from their proper position. Several other baffles had loose nuts and bolts, and in some cases the bolts were missing. The remaining baffles downstream of the two sets closest to the relief valve discharge pipes were inspected and it was determined that 44 bolts were missing and 11 were broken. The broken bolt pieces that were retrieved appeared to have failed from overtorquing during construction of the plant. In most cases where bolts were missing, it was obvious that an alignment problem had existed between the baffle and the support bracket and the bolts had never been inserted.

The torus shell was carefully inspected for damage to the coating. With the exception of scraped paint where the baffles contacted the torus shell, no damage was apparent to the coating or to the special coating belt at the water-air interface of the torus shell. The small areas where paint had been removed were not considered significant because the corrosion inhibitor solution of the torus would prevent subsequent corrosion.

As a result of the inspections, the first three sets of baffles in front of each relief valve discharge line were removed, leaving a total of

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72 of the original 90 baffles still in place. All broken and missing fasteners in the remaining baffles were replaced with new fasteners and lock washers. The fasteners were properly torqued to the recommended value.

Damaged Baffle Sections Allowed to Stay in Place

In August 1972, during a refueling outage at Unit No. 3 of the Humbolt Bay Power Plant, an inspection of the torus was performed. This investigation was prompted by notification of torus baffle damage in the vicinity of safety/relief valve discharge lines at other BWRs. This inspection revealed that two upper baffle sections adjacent to the relief valve discharge line had failed attachment welds at one end of the baffle section. In addition, the baffle closest to the end of the relief valve discharge piping was deformed. However, both baffles remained firmly attached to their bracket at the other end of the baffle. The damage was theorized to have occurred in July 1970 when one of the four reactor relief valves discharged.

Analysis of the possible results of removing the two damaged baffle sections led to the conclusion that their removal might cause the next nearest baffles to become detached in the event of a relief valve discharge. Therefore, the damaged baffles were retained in place. As a precautionary measure, the torus will be inspected following any future relief valve discharge.

Replacement of Underwater Torus Coating

During a refueling outage in the spring of 1971 at Unit No. 2 of the Dresden Nuclear Power Station, an inspection of the torus revealed some pinpoint rusting, blistering and delamination of the Phenoline 368 coating above the water line. The torus was drained and extensive areas of degradation of the coating were found in the underwater portion. Large delaminations from one to sixteen square feet in area existed, in which the coating had separated from the primer coat. The delaminated areas were discolored and a thin film of water was behind the coating. There were also 6- to 18-inch long cracks in the paint surface at the bottom of the torus.

An interim repair to the small isolated areas of pinpoint rusting and blistering was made by grinding these areas to bare metal and reapplication of the coating. The deliminated areas were shot blasted to remove the separated material. The shot blasting did not disturb the prime coat, which in all cases was still firmly bonded to the metal surface. The perimeter of the delaminated area was ground to a smooth transition to the coating-primer interface. The edges of the coating interface were sealed with 4- to 6-inch wide strips of Phenoline 368 to prevent water seepage under the coating. The remaining prime coat was left exposed.

During inspections in February and March 1972, the coating system above the normal water line was found to be still in good condition.

However, the coating below the normal water level had continued to deteriorate. Consequently, the coating was removed from the torus shell and ring girders below the normal water line and replaced with an inorganic zinc coating (Carboline Carbo Zinc #11). The baffles were not recoated, but all of the distressed top coating was removed to the primer surface. The Phenoline 368 coating was not replaced in the above water portions of the torus shell.

Although extensive laboratory testing was done to duplicate the failure pattern of the Phenoline 368 coating that was experienced at Dresden, no conclusive results could be ascertained. Some specimens performed well; others failed in an identical fashion to the torus failures for no clearly discernible reason. The failure phenomena were also investigated by chemical analysis of failed coating specimens taken from the torus. The results of these tests were also inconclusive in identifying the failure mechanism.

References

This report was based on information in the following documents:

1. Abnormal Occurrence Report No. BFAO-7343W, November 28, 1973

2. Vibration in Torus and Torus-Ring Header, Interim Report. December 17, 1973

3. Inspection and Modification of Suppression Chamber Baffles, F. T. Searls (Pacific Gas and Electric Co.) to USAEC, Directorate of Licensing, October 2, 1972

4. Letter, L. O. Mayer (Northern States Power Co.) to P. A. Morris, USAEC, Division of Reactor Licensing, February 15, 1972

5. Letter, L. O. Mayer (Northern States Power Co.) to P. A. Morris, USAEC, Division of Reactor Licensing, December 15, 1971

6. CO Inquiry Report No. 050-263/71-23

7. Torus Baffles Inspection and Repair Report, Oyster Creek Nuclear Generating Station, Jersey Central Power and Light Co., May 1972

8. Supplemental Information to Special Report #12, B. Lee, Jr. (Commonwealth Edison Co.) to P. A. Morris, USAEC, Division of Reactor Licensing, May 21, 1971

9. Memorandum, Dresden Unit 2 Torus Coating Problem, R. L. Tedesco, USAEC, Division of Reactor Licensing to Files

ROE 74-10

10. Report No. 17. Torus Coating Inspection of the Dresden 2 Reactor, Commonwealth Edison Co., May 9, 1972

ROE 74-11 April 12, 1974

SAFETY INJECTION SYSTEM PROBLEMS

Summary

Three events that have occurred involving SAFETY INJECTION SYSTEMS are reported to illustrate the nature and type of EQUIPMENT MALFUNCTIONS AND PERSONNEL ERRORS that may be encountered with these systems.

In the first case, the BORIC ACID SOLUTION in the safety injection tank was DILUTED below the minimum concentration specified in the Technical Specifications because of recurring failures of a valve in the safety injection system to close. In the second occurrence, a FALSE HIGH LEVEL SIGNAL was registered on the standby liquid control tank because BORIC ACID CRYSTALS had plugged the bubbler tube and CREATED A FLOW RESTRICTION. In the third instance, an OPERATOR MISTAKENLY VALVED DEMINERALIZED WATER INTO THE SAFETY INJECTION TANK.

Circumstances

Safety Injection Tank Dilution Caused by Valve Leakage from the Refueling Water Storage Tank

On July 7, 1972, at Unit No. 2 of the H. B. Robinson Nuclear Power Station, operating personnel observed that the position indicators on the control board for two valves in one of the safety injection loops were indicating an intermediate valve position. A visual inspection indicated that each valve was apparently fully closed. The valves were cycled and appeared to operate normally. The control board light indication was noted for future investigation. On July 11, as a result of a more thorough investigation, it was determined the two safety injection valves were, indeed, partially open and a correct signal had been displayed on the control board.

Complete closure of the valves apparently had been prevented by an accumulation of solidified boric acid under the valve seat. The valve insulation was removed and heat was applied to the valve body to dissolve the crystals. The valves were operated successfully through their full stroke, and a proper control board indication was received with each actuation.

On July 13, it was noted that the level in the supply tank increased each time the contents of the tank was recirculated. (This recirculation was performed daily to assure that the boric acid content in the injection tank was at the required concentration of 20,000 to 22,500 ppm or 12% solution.) An investigation disclosed that one of the safety injection valves was again partially open. The torque limit switch was adjusted and the valve operated and seated correctly. The concentration of the boric acid in the tank was measured and found to be only 12,641 ppm. Because proper

recirculation between the boric acid tank and the safety injection tank was assumed, the operators concluded that both tanks were at the same relative concentration, and batching operations were begun to bring them to a proper concentration.

On July 16, when personnel attempted to recirculate between the boric acid tank and the safety injection tank, it was discovered that the recirculation line was plugged. It was now evident that proper recirculation had not been taking place since at least July 12, and the concentration of the solution in the boron acid tank was not necessarily representative of the safety injection tank. The safety injection tank was sampled and its concentration was found to be 3045 ppm (3.5%). A temporary hose was connected from the boric acid tank transfer pump to the safety injection tank and the safety injection tank was brought to a proper concentration. The recirculation line was subsequently cleared.

It was concluded that the primary cause of dilution of the boron injection tank was leakage through the valves by gravity flow from the refueling water storage tank. The malfunction of these valves had been caused by the blockage of several sections of the normal recirculation flow path by boric acid.

To prevent recurrence, personnel have been instructed to verify recirculation flow by observing a local flow meter. The results of the flow verifications are recorded in a daily log. The sampling frequency for the safety injection tank has been changed from monthly to weekly and provisions have been made to clear the recirculation lines by means of a nitrogen stream should further crystallization occur.

An investigation into the effectiveness of heat tracing on the system piping also revealed large areas of heat sinks. Low sections of pipe, uninsulated valve bonnets and piping supported by large hangers were significantly lower in temperature than the adequately insulated components. The temperature of the safety injection valves was low because of their installation configuration and lack of insulation. This condition was corrected by insulating all valves from the bonnet to the packing gland, insulating pipe hangers where the piping could not be adequately insulated because of interference with the hangers, adding strip heaters to large area heat sinks and recording thermometers to obtain representative loop temperatures. The setpoint of the temperature controller for the bottom of the boric acid tank also was increased to preclude precipitation of the boric acid crystals in the bottom of the tank.

On October 19, with the plant at 99.5% power, a routine sampling showed that the safety injection tank and one of the three boric acid tanks were slightly below technical specification requirements for boron content. A measurement taken three days earlier had shown that all three safety injection loops were at proper concentration. It was concluded, therefore, that the dilution occurred during a safety injection test that was performed just after the verification of loop concentration. The most

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probable cause of dilution was agin improper seating of the safety injection valves that allowed refueling water to enter the safety injection tank during this test.

To correct the problem, the safety injection tank was recirculated with one of the boric acid tanks that was at the proper concentration. After the safety injection tank was verified to be within specifications, a fresh batch of boric acid was prepared and added to the boric acid tank used for recirculation. Two additional batches of solution were reprocessed through the boric acid evaporator to restore the depleted boric acid tank to its proper concentration.

A procedural change now requires that an analysis of the safety injection tank and the boric acid tanks be made immediately following any test of the safety injection system that could cause dilution.

False Level Indications of Boric Acid Tank

On December 17, 1972, with Unit No. 2 of the Quad Cities Nuclear Power Station at 80% power, a "high/low level" alarm was received from the standby liquid control tank. A confirming indicator panel light showed the tank level to be high. While personnel were verifying the high tank level, they noticed the air flow through the level indicating device on the bubbler was near zero. When the air flow was restored, the tank level indicated 68% of capacity. The cold air in the bubbler pipe had caused local crystallization of the boron solution and restricted flow in the tube. This restriction caused a high back pressure and created a false high level indication.

After a review of the volume/concentration requirement of the storage tank, a decision was made to increase the tank level and sample the concentration. Subsequently, a fresh batch of boric acid was added to increase the tank concentration. A more thorough investigation of the bubble indicating device revealed that the transmitter was not calibrated over the real usable volume of the tank. The zero indication on the instrument was 6 inches above the bottom of the tank, or 2.75-inches above the bottom of the pump suction line. The volume of solution below the pump suction, which is not usable, was 128 gallons. The true net usable volume of the tank was decreased by this amount for future volume/concentration requirements.

As an interim measure the bubbler was blown out each time a tank sample was obtained to prevent a crystal buildup. As a permanent corrective action, a sight glass was installed to allow level determination to within 10 gallons.

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Operator Error Results in Dilution of Safety Injection Tank

On January 3, 1973, at Unit No. 3 of the Dresden Nuclear Power Station, an attendant valved sparging air into the boron tank in preparation for a routine monthly boron concentration analysis. Two hours later, operating personnel were informed that the boron tank was overflowing. At this time the power station was increasing load after completion of routine surveillance tests. Upon notification of the tank overflow, the power level was held stationary at 745 MWe.

An investigation showed the sparging air had been valved in properly, but the demineralized water had also been valved into the boron tank. Both valves were normally locked closed; however, the equipment attendant mistakenly unlocked and opened both valves, which he thought were in series in the air sparge line.

As soon as the problem was reviewed, the standby liquid control system was declared inoperable and a plant shutdown was initiated. During the shutdown process, the boron tank was sampled. Its concentration had been diluted to approximately one-half of the required concentration. A portion of the solution was drained from the tank and batch mixed to a higher boron concentration and then returned to the tank to restore proper concentration.

The valve checkoff list was revised so that a second valve on the demineralized water line will have to be opened before water can be added to the boron tank.

References

This report is based on information in the following documents:

1. Letter, E. E. Utley (Carolina Power & Light Company) to D. J. Skovholt, USAEC, Directorate of Licensing, September 28, 1972.

2. RO Inquiry Report No. 50-261/72-12, July 20, 1972.

3. Letter, E. E. Utley (Carolina Power & Light Company) to J. F. O'Leary, USAEC, Directorate of Licensing, November 29, 1972.

4. RO Inquiry Report No. 50-261/72-130, October 27, 1972.

5. Letter, E. E. Utley (Carolina Power & Light Company) to J. F. O'Leary, USAEC, Directorate of Licensing, November 10, 1972.

6. Letter, B. B. Stephenson (Commonwealth Edison Company) to A. Giambusso, USAEC, Directorate of Licensing, January 9, 1973.

7. Letter, W. P. Worden (Commonwealth Edison Company) to A. Giambusso, USAEC, Directorate of Licensing, January 9, 1973.

ROE 74-12 April 19, 1974

INADVERTENT CRITICALITY DURING REFUELING

Summary

AN INADVERTENT CRITICALITY OCCURRED during a refueling outage at a nuclear power plant WHEN TWO ADJACENT CONTROL RODS WERE WITHDRAWN. A REACTOR SCRAM was INITIATED by a high-high flux signal FROM THE INTERMEDIATE RANGE NEUTRON MONITORING (IRM) SYSTEM. The scram signal resulted in the rapid, full-rod insertion of the two withdrawn control rods. The shutdown instrumentation functioned as designed and terminated the undesirable sequence of events.

THE INCIDENT ILLUSTRATES A FAILURE OF PERSONNEL TO FOLLOW ADMINISTRATIVE PROCEDURES, THE INADEQUACY OF SOME EXISTING PROCEDURES, AND A BREAKDOWN IN INTERDEPARTMENTAL COMMUNICATIONS.

Circumstances

On November 7, 1973, the Vermont Yankee Nuclear Power Plant was in the refueling mode, with the reactor vessel head off, for both partial refueling and installation of an off-gas treatment system of an advanced design. The planned outage, which began September 28, 1973, had progressed to the point where the final fuel loading had been completed and core verification tests, concurrent with control rod friction and timing tests, were underway. The simultaneous performance of both tests was not possible unless the refueling interlock circuit of the manual control system for the reactor was jumpered. Jumpers were installed to allow the control rod friction and timing tests; however, these jumpers also defeated the interlock that prevented the simultaneous withdrawal of two or more control rods. The existence of the jumpers was recorded in the Lifted Leads Log, but it was not noted in the General Plant Log (which was contrary to administrative procedures) and the scope of interlock defeat was not fully communicated to operations personnel.

As the control rod friction and timing tests continued, one of the control rods was inadvertently left in the fully withdrawn position. The reactor operator then selected a control rod for withdrawal that was adjacent to the one that was fully withdrawn. As the second rod was being withdrawn for a timing test, the reactor operator noted a rapid increase in the indications of the source range monitors. He immediately inserted the rod, but a full scram from the intermediate range monitoring system was initiated simultaneously.

The Shift Supervisor immediately notified plant management and ordered the readout of dosimeters of the five people that were working on the re-

fueling floor, although none of the men were near the reactor vessel at the time of the incident. The maximum dosimeter reading was 25 millirem. This exposure had been accumulated over a five hour work period and thus was not attributable to the incident alone. Neutron exposures to all five personnel were measured to be zero. Also, there were no indications of increased radiation levels at the local area monitors, the continuous air monitor on the refueling floor, or at the ventilation exhaust monitors for the reactor building.

A detailed analytical evaluation of the incident resulted in the following: from starting conditions, the peak fuel center-line temperature would have increased no more than 50 degrees and the peak temperature of the cladding would have increased no more than 5 degrees. Therefore, the fuel center-line temperature was no higher than 135 degrees and the peak clad temperature was no higher than 90 degrees.

Remedial and Corrective Actions

After the arrival on site of the Assistant Plant Superintendent and the Reactor Engineer, the jumpers that had been installed on the rod-block interlock were removed and tests were conducted to verify the restoration of the interlock. Subcriticality tests were performed separately on each of the two control rods which verified the reactivity worth of these rods. On November 8, 1973, the five fuel assemblies that surrounded the two control rods were removed and examined for evidence of leakage or degradation. This examination revealed no damage.

Plant management discussed the significance of the incident with all involved personnel, stressing areas of inadequate personnel performance. Also, a review was made of past and present performance of employees directly involved. No evidence of intentional misconduct was revealed and it was concluded that the personnel involved are capable, sincere, and conscientious.

An in-depth evaluation of the incident determined that no single event or circumstance was the cause, but that a series of coincident circumstances and events were precipitating factors.

a) The final condition resulting from the installation of the jumpers was beyond the preliminary intent, and the installed jumpers should have been removed immediately following the completion of core verification. A new procedure detailing requirements and instructions for installation and removal of jumpers has been prepared.

b) The procedures that were being used for control rod friction tests were the same that had been used in the initial plant startup, but

had not been approved as plant operating procedures. Approved procedures with data sheets for control rod friction and timing tests are now being developed.

c) An apparent lack of definition of the interface of responsibilities at the interdepartmental level was a contributing factor. This interface has now been specifically defined and personnel have been required to become familiar with these definitions.

d) Training and retraining of operations personnel has been completed. This included emphasis on the responsibility of personnel to follow procedures, methods available to prepare acceptable deviations from procedures, and supervisory review of procedural deficiencies.

References

This report is based on information in the following documents:

1. Letter, L. E. Minnick (Vermont Yankee Nuclear Power Corp.) to USAEC, Directorate of Licensing, February 28, 1974.

2. Letter, L. H. Heider (Vermont Yankee Nuclear Power Corp.) to D. F. Knuth, USAEC, Director of Regulatory Operations, February 22, 1974.

3. Letter, G. S. Thomas (Vermont Yankee Nuclear Power Corp.) to D. F. Knuth, USAEC, Director of Regulatory Operations, February 19, 1974.

4. Letter, L. E. Minnick (Vermont Yankee Nuclear Power Corp.) to D. F. Knuth, USAEC, Director of Regulatory Operations, January 14, 1974.

5. Letter, B. W. Riley (Vermont Yankee Nuclear Power Corp.) to USAEC, Directorate of Regulatory Operations, Region I, November 8, 1973.

6. Letter, B. W. Riley (Vermont Yankee Nuclear Power Corp.) to USAEC, Directorate of Licensing, November 14, 1973.

7. Directorate of Regulatory Operations Bulletin No. 73-6, November 26, 1973.

ROE 74-13 April 2[illegible], 1974

FRACTURE OF REACTOR MAIN COOLANT PUMP SHAFT

Summary

A reactor MAIN COOLANT PUMP SHAFT FRACTURED at a machined reduction in the shaft diameter DURING a controlled plant shutdown. There was no apparent fuel damage.

Circumstances

In November 1973, with Unit 1 of the Surry Nuclear Power Station operating at 95% of rated power, the reactor operator noticed a coolant flow reduction from 100% to 96% of indicated flow accompanied by a high vibration indication (12 mils) on one of the main reactor coolant pumps. A controlled shutdown was initiated to investigate the problem. During the shutdown with the unit at 42% power, the reactor tripped on low steam generator level concurrent with a sudden loss of all flow indications from the same coolant loop. The reactor operator further observed that the coolant pump was not drawing any electrical load and the loop was immediately isolated to prevent any damage from potential scattering of pump internals that may have broken.

After disassembly, an inspection of the reactor coolant pump internals showed that the pump shaft had broken about 15 inches above the impeller, between the thermal barrier and the radial bearing. The break occurred in the nine-inch diameter shaft at a 1/4-inch machined reduction in diameter and followed along the diameter transition radius, estimated to be 1/16 to 1/8 inch.

An examination of the fracture surface showed the characteristics of fatigue failure. The fatigue progression extended completely around the reduced shaft circumference with the final rupture located at the center of the shaft. The fracture surface showed "ratchet marks" around the periphery; this implied the failure started at several points which is typical of relatively high load and stress concentration failures. The central location of the final rupture together with the break occuring in a stress riser section of the shaft confirmed the suspicion of a relatively high nominal stress on the shaft at time of failure.

The examination did not show any indication of material or manufacturing defects that could be associated with the shaft failure. The only other evidence of damage to the pump internals was slight scarring of the pump seals.

It was postulated that the complete severance of the shaft occurred with the sudden loss of flow indication concurrent with the low level trip of the steam generator while the reactor was operating at 42% of rated power. An accident analysis concluded that for these conditions, the departure from nucleate boiling ratio for the fuel was less severe than those evaluated in the Final Safety Analysis Report and Review for the facility for a locked rotor incident at 100% of the rated power. No increase in reactor coolant activity was observed, as evidence that no fuel damage occurred.

Ten pumps were manufactured using the same shaft design. Six of these pumps are at Surry Units Nos. 1 and 2, and the other four are at the Salem Nuclear Generating Station.

Corrective Actions

Work is currently in progress to rebuild the Surry Unit 1 pumps with shafts manufactured for the North Anna Power Station. The replacement shafts have a different design configuration in the area of the break. After Surry 1 has been returned to operating status, a similar pump shaft replacement will be made at Surry 2.

On December 10, an administrative limit of 84% of rated power was placed on Surry 2 operation pending a detailed examination of the adequacy of the present pump shaft configuration. Based on a reevaluation of the problem the authorized power was increased to 92% on December 31, 1973, and is currently being maintained at this level.

References

This report is based on information in the following documents:

1. RO Inspection Report Nos. 50-280/73-10 and 50-281/73-11, January 25, 1974.

2. RO Inspection Report Nos. 50-280/74-2 and 50-281/74-2, March 1, 1974.

3. Letter, C. M. Stallings (Virginia Electric and Power Co.) to A. Giambusso, USAEC, Directorate of Licensing, January 9, 1974.

4. Memorandum, Examination of Surry 1 Reactor Coolant Pump Shaft, U. Potapovs to R. C. Lewis, USAEC, Directorate of Regulatory Operations, Region II, January 4, 1974.

RDE 74-14 May 24, 1974

RECURRING PUMP COMPONENT FAILURES

Summary

A BROKEN POPPET VALVE DISCHARGE SPRING ON A CHARGING PUMP in the primary coolant system led to the determination that the spring was not necessary for proper operation of the pump and the spring was removed. A subsequent investigation disclosed that the corresponding spring was broken on a second charging pump. At the same facility, the REPEATED CRACKING OF both repaired and as-received IMPELLER HUBS on pumps in the component cooling water system led to a change in material and improved procurement specifications.

Circumstances

Unnecessary Poppet Valve Springs Fractured in Safety Injection System Charging Pump

In November 1973, while the Fort Calhoun Nuclear Power Station was at 70% power, one of the primary coolant system charging pumps was disassembled to inspect valves within the pump to verify that their seating surfaces were in proper condition. During disassembly of the pump, it was discovered that a spring that loads the poppet discharge valve was broken into several pieces. Approximately two and one-half turns of the spring could not be found. The spring was 1/16-inch diameter, type 302 stainless steel wire wound to a 5/8-inch outside diameter.

It was learned from the pump manufacturer that this was not a unique problem with this particular pump design. The manufacturer recommended removal of the springs. This recommendation was based on the fact that the pump was of a design to provide compatibility with many different fluids. For this reason, the spring was not necessary for a fluid having the viscosity of reactor coolant water.

The pump was reassembled without the poppet discharge valve springs. A safety analysis of the implications of leaving the missing spring section in the reactor coolant system concludes that the small size of the piece involved would probably be further worn significantly from abrasion with the coolant system walls, and even if swept into the reactor vessel, its size and shape would not block any flow channels within the fuel.

As a result of this incident, it was decided to inspect the other two charging pumps. One had two of its three springs broken; the springs of the other pump were intact. The intact springs and spring fragments were removed from these two pumps.

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Recurrent Cracking ooling Water Pump Impeller Hub

In July 1973, at ort Calhoun Nuclear Power Station, maintenance was being performed on a led outboard seal of a pump in the component cooling water system. Dur ng disassembly of the pump it was observed that each side of the impeller a crack at the keyway.

The pump manufacturer w cte n an attempt to obtain a replacement impeller. Since none were for immediate shipment, an impeller was placed on order. Two repairs were considered for the defective impeller. One suggestio to machine a ledge into the outside diameter and to shrink fit a ring onto the impeller hub. The alternative repair technique propo as to braze the cracks. Brazing was selected after consultation with an expert in brazing cast metals. Repairs were completed; the impeller was balanced and replaced on the pump and operability tests were performed successfully.

On November 20, the same pump was disassembled to install the newly received impeller. When the repaired impeller was removed from the pump, new cracks at the hub keyway and a small crack in the area of the previous repair were noted. Close inspection revealed that the new impeller also had small cracks in the keyway corner identical to those previously discovered.

The pump manufacturer was informed of the situation. He again recommended the procedure of shrink fitting a steel ring over a ledge machined into the impeller hub to reinforce the area where the cracks existed. Based on this recommendation and because the braze repair had failed, it was decided a better repair would result from the shrink fit steel ring procedure. The new impeller had more cast iron in the area of the keyway than the previously repaired impeller.

Independent mechanical experts concurred with the pump manufacturer that the ring repair would add considerable hoop strength to the impeller hub and more than compensate for the stress lost because of the cracks. During the repair, stress concentration points were eliminated as much as possible and the ring was blended into the hub contour to eliminate unnecessary flow turbulence in the impeller eye. Operating characteristics of the pump were measured after repairs were completed and pump performance was consistent with previous pump data.

Because of the recurring nature of this problem, the other two component cooling water pumps were inspected to determine if cracking had occurred in the impellers. None was found in one of these pumps. However, inspection of the remaining pump revealed cracks at the same location on the hub. This impeller was also repaired by shrink fitting a steel ring over the impeller hub. Each of the three pumps involved will be disassembled and inspected on a periodic basis.

RGE 74-14

Replacement impellers made of bronze will be ordered to provide more ductility. Revised purchase specifications are more stringent in their requirements for inspection at the manufacturer's plant.

References

This report is based on information in the following documents:

1. Letter, W. C. Jones (Omaha Public Power District) to J. F. O'Leary, USAEC, Directorate of Licensing, December 10, 1973.

2. Letter, W. C. Jones (Omaha Public Power District) to J. F. O'Leary, USAEC, Directorate of Licensing, October 23, 1973.

3. Letter, W. C. Jones (Omaha Public Power District) to J. F. O'Leary, USAEC, Directorate of Licensing, December 17, 1973.

RDE 74-15 May 31, 1974

WATER HAMMER DAMAGES VALVE OPERATOR

Summary

Rapid cooldown of the primary cooling system of a pressurized water reactor (PWR) resulted in the unnecessary initiation of the safety injection system because the reactor operator failed to switch the feedwater control from automatic to manual mode during the plant shutdown. The shutdown, being performed under routine procedures, had been necessitated by an indication of turbine problems. A WATER HAMMER, resulting from an air pocket, DAMAGED THE MOTOR OPERATOR OF A VALVE AND a HANGER on one loop of the safety injection system.

Circumstances

On October 20, 1973, a turbine vibration alarm was annunciated on the control panel of Unit 1 of the San Onofre Nuclear Generating Station. One minute later, saltwater intrusion was indicated by high conductivity alarms from monitors located in the condenser. An investigation to determine the cause of both alarms was started immediately. Approximately 40 minutes after the turbine vibration alarm, a systematic load decrease was begun; and one hour and 15 minutes after the alarm was received, the plant was removed from the line and the plant load was switched to the auxiliary transformers.

Approximately eight minutes after the plant load had been switched, a noload turbine trip alarm was received, although the turbine had been removed from service. The trip alarm caused the turbine stop valves to close. During removal of the plant from the line, the operator had failed to switch the feedwater control system to manual. This sequence of events caused the feedwater regulating valves to open automatically to 9% of full open because the average primary coolant temperature was greater than 540°F. The switching of the feedwater control from automatic to manual is a standard requirement for a routine shutdown.

The opening of the feedwater valves allowed the average temperature and pressure of the reactor coolant to drop rapidly. The water level in the steam generators was observed to be increasing rapidly, the pressurizer level had decreased to 10% and the letdown valve had closed. The rapid filling of the steam generators resulted in a rapid cooldown and decrease in the total pressure of the primary system.

The primary system controls were placed in the manual mode and one of the control rod banks was pulled to mitigate further drops in primary system pressure and temperature. Feedwater control was also changed to the manual mode, the feedwater control valves were closed, and the feedwater block valves were manually closed.

BOE 74-15

This rapid cooldown and decrease in total primary system pressure resulted in the automatic initiation of the safety injection system (SIS). Although no Safety Limits or other Technical Specifications had been exceeded, approximately 1300 gallons of borated water from the refueling tank entered the primary system through the charging pump. The borated water did not enter through the safety injection lines because the system pressure still had not dropped below the actuation point.

After normal shutdown conditions were established, the inside of the containment was inspected. The safety injection valve had operated properly during initiation, but had not returned to the fully closed position when the loop was returned to the normal shutdown configuration. The valve had failed to reclose fully because the valve motor operator and some pipe support equipment in one of the SIS loops were damaged.

The failures of the valve motor operator and pipe support equipment were attributed to a water hammer that occurred in the SIS loop caused by trapped air accumulated by normal inleakage. The motion of the piping generated sufficient force to shear the turnbuckle-type hanger and to cause the tensile failure of four bolts (0.17-inch diameter) that hold the casting of the valve motor operator to the safety injection valve. The failure of these four bolts resulted in the motor casing, stator, and end bell dropping from their mountings.

Corrective Actions

The piping in all three SIS loops were tested by dye penetrant and ultrasonic techniques, and no indications of damage were found.

Piping changes were made to the SIS loops to facilitate on-line venting. Also, procedures for frequent venting of the SIS piping were developed and implemented. As a precautionary measure, the section of the SIS piping in which the water hammer occurred was replaced although no damage to the piping was apparent.

The valve that failed to close fully was disassembled and tested. Its failure to perform properly was attributed to the tensile failure of the bolts and the resulting separation of the motor operator from the valve.

In addition, training sessions were conducted to emphasize the importance of placing the feedwater control in the manual mode before the turbine is removed from service. The adequacy of the SIS piping to sustain water hammer loading was evaluated thoroughly. These evaluations also were applied to other safety-related systems that are not in continuous use.

ROE 74-15

A preliminary examination of the turbine indicated that a separated turbine blade and resulting debris had penetrated the condenser tubes and was responsible for the indicated saltwater intrusion.

References

This report is based on information in the following documents:

1. Letter, Robert N. Coe (Southern California Edison Co.) to John F. O'Leary, USAEC, Directorate of Licensing, October 31, 1973.

2. Inspection Report No. 50-206/73-05, USAEC (RO:V), November 14, 1973.

ROE 74-16 June 14, 1974

PREMATURE CRITICALITY WITH CONTROL RODS BELOW MINIMUM INSERTION LIMIT

Summary

A PREMATURE CRITICALITY of a pressurized water reactor (PWR) occurred during a routine startup BECAUSE THE BORON CONCENTRATION of the reactor feedwater HAD BEEN INCORRECTLY DETERMINED. The reactor feedwater was low in boron concentration because analysis had been performed with a defective burette. The reactor was immediately shut down; the incident did not jeopardize the safety of the plant or the public.

Circumstances

In April 1974, Unit No. 2 of the Zion Nuclear Power Generating Station was in the process of a routine startup. Prior to the startup, it had been determined that the estimated critical position of Control Rod Bank C was 160 steps withdrawn (the low-low insertion limit was calculated at 109.5 steps). During the startup, an apparent criticality occurred with Control Rod Bank C at less than 109 steps withdrawn. Because criticality was attained below the minimum insertion limit, the control rods were immediately inserted and in accordance with the Technical Specifications, 100 gallons of borated solution were added to the reactor coolant system. An additional 50 gallons of borated solution were subsequently added after the first boron addition. The estimated critical position of Control Rod Bank C was recalculated; no errors were found and a sample of the feedwater was taken.

Analysis of the sample determined that criticality apparently had been achieved at 109 steps rather than the estimated 160 steps because the previously determined boron concentration measurement was incorrect. The value of the boron concentration used to determine the estimated critical position was 1108 ppm. Analysis of the sample of the reactor coolant after compensating for the boron additions revealed that the actual boron content was 1053 ppm.

An investigation into the cause of this anomaly disclosed that the burette used to perform the analysis for boron content was leaking. The operator responsible for determining the boron concentration was aware of the condition of the burette, but felt the leakage was not of sufficient magnitude to affect the results appreciably.

As a result of this occurrence, personnel performing boron analyses have been instructed to check for leakage of the burette before performing a boron concentration analysis. If leakage is detected, the burette is to be repaired or replaced and rechecked for leakage before another analysis is performed.

ROE 74-16

The boron concentration of the reactor feedwater was properly determined and adjusted; the reactor startup was resumed without event.

References

This report is based on information in the following documents:

1. Letter, J. S. Bitel (Commonwealth Edison) to J. F. O'Leary, USAEC, Directorate of Licensing, May 16, 1974.

2. RO Inspection Report Nos. 050-295/74-06 and 050-304/74-06, May 14, 1974.

3. Mailgram, J. S. Bitel (Commonwealth Edison) to J. F. O'Leary, USAEC, Directorate of Licensing, May 7, 1974.

ROE 74-17 June 14, 1974

WATER HAMMER CAUSES FEEDWATER-LINE RUPTURE

Summary

LOW FEEDWATER FLOW to one of four STEAM GENERATORS at a pressurized water reactor (PWR) resulted in a WATER HAMMER that CAUSED RUPTURE OF THE FEEDWATER LINE. The auxiliary feedwater pumps operated as designed and the other three steam generators did not drop below the low-low-level alarm point. The blowdown of the steam generator caused no appreciable rise in vapor pressure in the containment since the plant was at only 7% power. The containment structure was designed to cope with a blowdown of the primary cooling system at full power. No risk to public health and safety resulted from the event.

Circumstances

In November 1973, with Unit 2 of the Indian Point Station at about 7% power, a turbine trip occurred because of high water level in steam generator No. 23. The turbine trip interrupted the normal feedwater flow as designed. Auxiliary feedwater flow supplied three of the steam generators. However, the water level in steam generator No. 21 dropped to the low-low steam generator level before the auxiliary pumps started and the reactor tripped as a result.

The auxiliary feedwater pumps began to restore the levels in steam generator Nos. 21, 23 and 24, but the water level in steam generator No. 22 continued to drop. As the water level decreased, vibration of the feedwater line to steam generator No. 22 was observed, accompanied by a loud noise.

Within fifteen minutes of the reactor scram, the presence of moisture in the containment atmosphere was indicated. The level in steam generator No. 22 was still decreasing, indicating that sufficient flow from the auxiliary boiler feed pumps apparently was not reaching the steam generator. About forty-five minutes after the reactor trip, a second vibration of the No. 22 feedwater line was recorded, also accompanied by a loud noise.

Within 1.5 hours after the reactor trip, further indications of leakage inside the containment vessel were evident. The containment temperature had increased to a maximum of 110-degrees Fahrenheit, all five containment fan coolers had started, the humidity inside the containment was increasing and the weirs in the condensate collection system indicated rising levels. At this time, isolation valves to and from steam generator No. 22 were closed.

When the steam driven auxiliary feedwater pump was started about two hours after the reactor scram, additional shaking and noise were noted on the No. 22 feedwater line. At this time, it was concluded that a break in the feedwater line inside the containment vessel had probably occurred. A cooldown of the plant to the cold shutdown condition was begun to permit inspections and repairs.

During the cooldown process, a high differential steam pressure between steam generator No. 22 and the other three steam generators resulted in initiation of the safety injection system.

About three hours and fifteen minutes after the reactor scram, steam generator No. 22 was completely isolated by shutting the manual stop valves in the auxiliary feedwater and chemical feed lines.

When entry into the containment was made, a break in the No. 22 steam generator feedwater line was confirmed.

Effects Of Incident Of Plant Equipment

Feedwater Line

The 18-inch diameter (0.75-inch wall thickness) carbon steel feedwater line to the No. 22 steam generator fractured adjacent to a fillet weld between the feedwater line and the end plate welded into the penetration sleeve in the containment wall. The fracture extended approximately 180 degrees around the pipe. The maximum measured width of the crack was 5/32 inch. In addition, localized bulging was noted in a horizontal section of the line near steam generator No. 22, and the pipe was displaced by 3/4 inch at one restraint. It was noted that the structural steel shimming for the pipe whip restraints had not been installed. However, a subsequent analysis demonstrated that the lack of shimming did not contribute to the failure of the feedwater pipe.

Containment Vessel Damage

The 3/8-inch thick containment liner showed an inward deformation away from the containment wall in an area approximately 2 feet high and 40 feet in circumferential length approximately 20 feet above the feedwater pipe penetration. The bulge was estimated to be a maximum of 1.3 inches. The liner was displaced from some of the studs that anchor the liner to the containment vessel wall; nine of 28 studs in the buldged area were broken. Construction drawings indicated that the liner had been inadequately attached to the containment vessel wall. Specifically, the studs at this elevation were spaced 28 inches apart rather than the specified 14 inches. Further examination revealed that two rows of studs was also missing around the entire circumference of the containment liner immediately above the transition weld.

Despite the construction deficiences and the failure of the studs, no evidence of breach of containment integrity was found. To evaluate the damage to the containment liner, profile tests were performed, the studs were tested with an ultrasonic scanner, and the liner was inspected by magnetic particle techniques and by bend and pressure tests. There were no indications of any material defects.

About six hours after the failure of the feedwater line, an inspection team found that water had collected in the reactor vessel cavity to a depth of over 4-1/2 feet.

Other Systems and Components

The check valve in feedwater loop No. 22 was hydrostatically checked and leakage past the seat was negligible. Steam generator No. 22 was inspected internally, and found to be intact. A chemical analysis of surface deposits on the tube sheet indicated that feedwater chemistry had been properly maintained and that no further action was necessary. The support structure for the steam generator was inspected; no evidence of unusual wear was found.

Electrical equipment within the containment vessel was inspected. The cabling in the upper areas were dry but cables at the 46-foot elevation were partially covered with water. No water damage resulted to either the cables or cable splices, because these cables were designed and tested for submerged conditions. Other areas within the containment were unaffected since they were well above the water level.

Causes and Remedial Actions

Feedwater Line Rupture Caused by Water Hammer

The rupture of the feedwater line was attributed to dynamic loading from a water slug that had resulted from a water-steam reaction in a horizontal section of line adjacent to the steam generator. The feedwater ring in steam generator No. 22 had been uncovered and the feedwater piping had been drained partially. The water hammer, which occurred about the time the water level in steam generator No. 22 fell below the centerline on the feedwater ring, caused the vibration of the feedwater pipe, and the rattling noise.

Remedial Actions

A. Feedwater Piping. The failed section of feedwater piping was replaced. The new section extended from the first elbow outside the containment through the penetration to the first elbow inside the containment. The containment penetration end plates and expansion joints were also replaced.

The horizontal run of piping inside the containment leading to the feedwater nozzle on the No. 22 steam generator was lowered about 1.3 feet immediately outside the feedwater inlet nozzel to preclude the possibility of water draining into the steam generator. Additional restraints on each of the feedwater lines were added near the first elbow inside the containment.

To preclude a possible water hammer resulting from the rapid closure of the main feedwater regulating valves under maximum feedwater flow conditions, hydraulic dampers were added to the main feedwater regulators. The plug on each of the main feedwater regulating valves was modified to improve their ability to control feedwater flow during plant startup.

Another measure to provide feedwater flow stability during startup was the installation of a six-inch bypass line on each of the four feedwater regulating valves.

B. Containment Liner. Additional insulation was added to the containment vessel to reduce local heating of the liner in the vicinity of the feedwater line penetrations.

References

This report is based on information in the following documents:

1. Letters, William J. Cahill, Jr. (Consolidated Edison Co.), to James P. O'Reilly, USAEC – RO: I, November 14, and November 30, 1973.

2. Inspection Report No. 50-247/73-23, USAEC (RO:I), December 6, 1973.

3. Letter (transmitted detailed report of investigation), William J. Cahill, Jr. (Consolidated Edison Co.), to John F. O'Leary, USAEC, Directorate of Licensing, January 14, 1973.

4. Letter, William J. Cahill, Jr. (Consolidated Edison Co.), to John F. O'Leary, USAEC, Directorate of Licensing, January 16, 1973.

BOE 74-18 June 17, 1974

FUEL HANDLING PROBLEMS

Summary

Four events are reported involving fuel transfer operations. In the first two cases, the general purpose GRAPPLES CAME LOOSE FROM THE JIB CRANE CABLES DURING IRRADIATED FUEL TRANSFER OPERATIONS. In the third case a fuel bundle was unintentionally lowered while being moved from the core area to the spent fuel pool, causing the FUEL ELEMENT to STRIKE THE SIDE OF THE REACTOR PRESSURE VESSEL. The last case involved a FUEL BUNDLE which became detached from the main grapple and FELL APPROXIMATELY 20 FEET TO THE BOTTOM OF THE SPENT FUEL POOL.

Circumstances

Loose Grapples

In February 1973, during fuel transfer operations in the spent fuel area at the Vermont Yankee Nuclear Plant, the general purpose fuel grapple became detached from the jib crane hoist cable when tension was applied to the cable. At the time, the grapple was attached to a fuel element which remained seated in the fuel rack. Prior to this event, numerous fuel elements had been moved as part of the fuel transfer operations.

In January 1974, while fuel channel inspections were in progress in the spent fuel pool at the Pilgrim Nuclear Plant, the general purpose grapple came loose from the jib crane as the grapple was being attached to an irradiated fuel bundle. The fuel bundle was seated in a fuel storage rack, and was being prepared for movement to an inspection stand. In this case, as in the previous occurrence at Vermont Yankee, spent fuel had been moved prior to the event.

No damage resulted in either occurrence since the grapples became detached prior to actual movement of the fuel bundle. In both instances, the cable end stud, threads and grapple were undamaged.

In both cases, lock nuts had been installed on the studs after attachment to the grapples. Repeated rotation of the grapples during attachment to and removal from fuel, or during fuel inspection, apparently loosened the locking nuts, and allowed the studs to become disengaged from the grapples.

The corrective action in each case involved drilling a hole through the end stud and installing a locking pin through the grapple and end stud after each reassembly.

Fuel Bundle Strikes Reactor Vessel

In January 1974, while an irradiated fuel bundle was being transferred from the reactor core to the spent fuel storage pool at the Pilgrim Nuclear Plant, the main refueling grapple was lowered without knowledge of the operator. This caused the fuel bundle to strike the side of the reactor vessel. Subsequent examination revealed that the fuel bundle was not damaged and that no fission gases had escaped. Investigation disclosed that the "Return to Normal" spring in the grapple up-down control was broken. Evaluation of the occurrence led to the conclusion that as the operator raised the grapple to the fully retracted postion and released the up-down switch, the switch fell through the neutral position to the "down" position due to the broken spring, lowering the fuel grapple. The switch was repaired by replacing the defective spring.

Dropped Fuel Bundle

In January 1974, while transferring an irradiated fuel bundle from its storage position in the spent fuel pool to the channel inspection facility at the Pilgrim Nuclear Plant, the fuel bundle became detached from the main grapple and fell approximately 20 feet to the bottom of the spent fuel pool.

Examination of the fuel bundle revealed that the channel had slipped down over the end of the nose piece approximately one inch and that the nose piece and lower end of the channel were crushed. There were no indications of any broken fuel rods nor of any release of fission gas. The dropped bundle had a burnup of 3600 MWD/ton and had cooled radioactively for 23 days. There were no indications of damage to the fuel pool liner.

The main grapple was also inspected and tested and found to be in satisfactory operating condition. Repeated unsuccessful attempts to simulate the failure was made using a dummy element. Analysis of the problem led to the conclusion that the grapple hook had not been completely latched under the handle of the fuel element that was dropped, and that the operator was able to lift the fuel element with only a friction grip on the fuel element handle.

In order to prevent recurrence a procedure was established requiring a visual check of the closure of the grapple hook. Subsequently, a switch was installed on the grapple to indicate closure of the hook by actuating a light on the bridge console.

References

1. Letter, B. W. Riley (Vermont Yankee Nuclear Power Corporation) to Directorate of Licensing, USAEC, dated March 6, 1973.

2. Pilgrim Abnormal Occurrence Report No. AO-74-1, dated January 11, 1974.

3. Pilgrim Abnormal Occurrence Report No. AO-74-2, dated January 23, 1974.

4. Pilgrim Abnormal Occurrence Report No. AO-74-3, dated January 30, 1974.

ROE 74-19 June 28, 1974

MECHANICAL VIBRATIONS OF REACTOR INTERNALS

This report updates and corrects information in ROE 74-3, dated February 8, 1974, and is based on a more detailed investigation of the problem.

Summary

After about nine months of SUSPECTED MOVEMENT OF REACTOR VESSEL INTERNALS based on analysis of noise measurements from ion chamber neutron detectors located outside the core (ex-core detectors), an inspection of core internals at the Palisades Nuclear Power Plant was completed during shutdown for unrelated repair of one of the steam generators. SIGNIFICANT WEAR OF SOME RESTRAINING COMPONENTS ON THE CORE INTERNALS was observed. Wear was also evident on the alignment keys for the reactor vessel head and on the lower outside shims on the reactor vessel. Six fasteners that locate the ring shim were broken.

Movement of the reactor vessel internals was determined to have been the result of loss of holddown clamping force at the upper flange region, attributed to a combination of a loss of a hot interference fit in the internals flange stackup, interference of the core support barrel alignment keys with the pressure vessel flange key slots and rotation in opposite directions of the inner edges of the flanges on the reactor vessel and vessel head about axes tangent to the outside flange edges, thus opening a space between the inner edges of the flanges.

A new holddown concept for restraining the internals has been employed to correct the problem. The new holddown design eliminates the ring shim and the dependence on a hot interference fit of the flanges. Instead, Belleville springs are used to achieve the necessary holddown force.

Circumstances

In May 1972, the reactor vessel head was removed after a cap screw fastener from the ring shim was found in the primary side of one of the four steam generators. At this time it was discovered that a second ring shim fastener had also failed, so the remaining six fasteners were secured by welding keeper bars across their counter-bored recesses and installing locking pins in the fasteners. The broken fasteners were not replaced because they served only as locators for the placement of the ring shim and not as structural members for positive clamping of the reactor internals. A thorough inspection of all exposed upper reactor internals and the upper support structure did not reveal evidence of significant wear or fretting. Review of previous reactor internals visual inspections indicated that internals movement had not occurred

prior to the May 1972 inspection. However, a more recent review of photographs taken during a June 1970 inspection disclosed interference between the bottom edges of the core support barrel alignment keys and the reactor vessel key slots.

The first symptom of motion of the reactor internals was the gradual appearance of noise in the signals from the six ex-core detectors. The phenomenon was recognized as a possible problem in December 1972, when simultaneous Brush recorder traces of the noise were studied. As a group, the detector noise signals showed a strong azimuthal relationship. Detectors to the right of a reference line registered power increasing pulses at the same time those on the left side were registering power decreasing pulses. The maximum peak-to-peak magnitude of the noise variations was approximately 6% of the total signal.

Following a shutdown that began in January 1973, during which a small number of tubes were plugged in each steam generator, it was found during the startup in March 1973 that the system flow had decreased by 2.4%, and the noise magnitude had decreased by a third, to about 4%, peak-to-peak.

Following the March startup, simultaneous magnetic tape recordings of various reactor instrumentation signals were made for subsequent spectral and statistical analyses, including signals from selected ex-core and in-core detectors, externally mounted reactor vessel accelerometers, and several process instruments. Examination of the data at reactor power levels up to 80% confirmed the earlier observations of the strong azimuthal character of the ex-core noise, but the accelerometer data showed no indication of impact of internals with support structures or shims. No correlation was seen between the ex-core and process instrumentation signals. The much lower noise level of the in-core detector signals indicated that the primary source of the ex-core noise was not nuclear in character.

From March to June 1973, the magnitude of the ex-core noise was observed to decrease gradually. By the end of May, it was approximately 3% of the total signal.

In late May 1973, data were obtained at 100% power and at 40% power in the four possible three-pump operating configurations. These observations supported the previous recorder data. Again, none of the accelerometers gave any indication of impacts of the internals. However, the three-pump operation resulted in more than a threefold reduction in the magnitude of the noise.

In late June 1973, the noise level again began increasing in magnitude with continued four-pump operation. In order to follow the changing situation more closely, a mini-computer was programmed to calculate the root mean square (rms) noise from each ex-core detector. These new data confirmed the increase in noise to a peak of about 5-1/2% noise, reached

during July. The relative variation between detectors, and even between subchannels of one detector, suggested that the hypothesized motion of the core support barrel was changing slightly in both character and direction in this period.

Also, in late June, limits on the magnitude of the noise were established beyond which plant operation was to be restricted.

During the latter part of July and early August, the noise level decreased slightly. In this period, measurements confirmed that the character of the noise was changing; unidirectional oscillation was now quite pronounced, and intermediate amplitude pulses had become much less frequent. In addition, for the first time, the accelerometer on the vessel head flange had occasional bursts of activity, indicating that some rubbing of internals was occurring. Also, for the first time, noise data were obtained from the external intermediate range fission chambers. These data confirmed that the phenomenon seen by the ex-core power level ion chamber detectors was not something unique to the ion chambers.

On August 11, 1973, the plant was shut down for steam generator inspection. When it appeared that the plant would be down for an extended period, it was decided to inspect the reactor vessel internals during the outage.

Examination of the underside of the reactor vessel head showed full circumferential wear of 12 to 15 mils where the vessel head cladding had contacted the ring shim. Wear was evident in the reactor vessel head key slots on the surfaces that interfaced with the core barrel keys. Measurements of silicon rubber molds made of the key slots disclosed maximum wear of the key slots of approximately 80 mils. The molds did not exhibit striation that would confirm a preferential direction of motion of the core support barrel.

Examination of the installed upper guide structure revealed that the top surface of the ring shim had displaced downward relative to the reactor head mating surface by approximately 1/4-inch. There was no perceptible wear on the ring shim surface that interfaces with the reactor vessel head. All of the remaining ring shim positioning cap screws had fractured but were retained by their lock bars.

Upon removal of the ring shim, the contact surface between the ring shim and the top surface of the upper guide structure was found to be polished with no perceptible wear on the upper guide structure flange surface. However, burnish marks were observed on the underside of the ring shim.

The alignment key slots in the upper guide structure and the core barrel alignment keys showed no evidence of contact, indicating that no

relative motion had occurred between the upper guide structure assembly and the core barrel. A close examination of the instrument stalks, fuel alignment pins and their guide lug inserts and the fuel alignment plate showed no significant wear and provided confirmatory evidence of the lack of motion of the upper guide structure relative to the fuel assemblies or to the core support barrel.

Measurement of the thickness of the core support barrel flange disclosed that approximately 50 mils of wear had occurred on the underside of the flange. However, as determined by a later inspection, most of the wear at the interface of the core barrel and reactor vessel occurred on the reactor vessel support ledge. The maximum wear to the vessel support ledge was determined to be slightly less than 1/4-inch. Two alignment keys for the core support barrel were found to be secure in their respective alignment slots. The remaining two alignment keys were loose, but were still held in position by their locking pins. Wear was observed on the underside of each key where the keys bottomed in the reactor vessel key slot.

Examination of the outlet nozzle on the core support barrel showed evidence of contact. However, wear was not uniform and the most pronounced wear spot was only approximately 8 mils deep. The face hardened surfaces of the twelve snubbers for the core support barrel had a maximum wear of 26 mils. The wear areas were generally less, however, and two snubbers were free of any indication of wear. Wear was also observed on the reactor vessel outlet nozzles, with spot wear depth of up to 50 mils.

Inspection of the Inconel snubber shims attached to the vessel snubber lugs indicated insignificant wear on some shim faces and wear greater than 250 mils on other shim faces. The attachment bolts of the snubber shims were intact and no contact with the bolt heads was evident.

Examination of the fuel assemblies revealed no evidence of damage to any fuel assembly component. Only the spacer grids and guide bars showed indications of wear and these were slight. No fretting or wear between grid fingers and fuel rods was observed. All nuts appeared to be properly torqued and, with one exception, all nut retainers remained in place. No fuel assembly distortion or fuel rod bowing was evident.

Conclusions

The inspections led to the conclusion that most of the wear occurred between the interfaces of the reactor vessel internals and the reactor vessel; no perceptible wear between the upper guide structure assembly,

fuel assemblies and core support barrel assembly was evident. No structural attachments were broken nor was there any loss of structural integrity of the reactor vessel internals components. It was concluded that the vibration of the internals had had no effect on the integrity or performance of the fuel assemblies.

The motion of the reactor internals and fuel was the result of essentially rigid body motion of the internals induced by hydraulic loads. This motion took place after the clamped support at the core support barrel flange was lost as a result of a reduction in core support barrel holddown load.

The holddown load was dependent, in large part, on a hot interference fit between the stainless steel internal flanges (core support barrel, upper guide structure and ring shim), and the carbon steel clamp formed by the reactor vessel support ledge and closure head. Because the stainless steel components expanded on heatup more than the carbon steel reactor vessel flange, differential growth resulting from thermal expansion was designed to cause the hot interference fit. This method of developing a holddown load is very sensitive to changes in dimensions and a small reduction in the hot interference can result in significant or complete loss of holddown load.

It was theorized rotation of the flange resulted from bolt-up and pressurization, increasing the dimension between the reactor vessel support ledge and closure and reducing the hot holddown interference fit.

From an examination of the wear patterns, it was postulated that the core support barrel was seated on the reactor vessel support ledge with high spots located at two diametrically opposed alignment keys and that the required hot interference fit occurred mainly at these locations on the flange. Inlet flow impinging on the core support barrel produced varying loads with a resultant oscillating force primarily in the direction perpendicular to the two unintended main points of support. These conditions combined to produce a slight rocking motion of the core support barrel.

The resulting wear on the reactor vessel support ledge allowed an increase in the amplitude of motion which gradually transferred increasing amounts of the core support vertical load from the flange to the two supporting alignment keys. As a result of the continued rocking motion and the resulting transfer of load, the shrink fit of the alignment keys in the core barrel flange was relieved. This relieving of the shrink fit transferred the core support load directly to the radial pins securing the alignment keys to the core support flange. The radial pins could not sustain the loading and failed in bearing. The resulting loss of the remaining hot interference fit allowed the barrel to be forced into a combination of rocking and sliding lateral motions.

It was concluded that the reactor internals and fuel moved essentially as a unit relative to the reactor vessel, in a complex combination of rocking, translation and nutation with the core support barrel rocking primarily about one axis, translating generally in a direction perpendicular to the axis about which the rocking occurred, and nutating on the surface of the reactor vessel ledge. The coherence of signals from both the in-core and ex-core detectors supports this conclusion.

The driving force for the motion was random hydraulic pulsations acting on the barrel in the downcomer annulus, in the core support structure region and in the upper plenum. These pulsations occurred from a combination of flow turbulence, inlet coolant impact on the barrel and excitation of the known 0.5 hz. natural frequency of the system.

Corrective Actions

Smooth surfaces were restored on the worn areas of the reactor vessel core support ledge and keyways by local grinding. New alignment keys with additional thickness to compensate for the ground areas on the reactor vessel and reactor vessel keyways were installed in the core support barrel. Although wear was not evident on all snubber shims, new shims were installed at all snubber locations.

A new holddown concept was developed for restraining the internals, modeled after a design used in Germany. This design does not depend on interference fit for achieving holddown load, but rather on a series of Belleville spring units contained within pockets in the flange of the upper guide structure and compressed against the reactor vessel closure head.

Four inverted "L" shaped ring segments were added to the upper guide structure to contain the Belleville spring units. The 308 stacks of Belleville springs positioned around the circumference of the holddown ring were designed for a holddown preload of 820,000 lbs. and a minimum holddown force of 733,000 lbs. at full power operation.

A spacer shim was added between the core barrel and the upper guide structure flanges.

To determine the long-term success of the internals repair, a program to monitor reactor instrument signal noise has been developed. This program requires an initial set of measurements to obtain data to judge subsequent reactor behavior, followed by a bimonthly repetition of a set of simpler measurements and a yearly repetition of the initial measurements. The information will yield an on-the-spot qualitative analysis of the noise character, magnitude and azimuthal dependence; it will also serve as an information base for judging future data.

Long-term magnetic tape recordings of various instrument channels also will be made to establish relationships among the various signals in either the frequency or time domain. Amplitude problability densities will be determined to identify the statistical magnitude of the noise and to identify any noise character which could be indicative of internals motion.

References

This report is based on information in the following documents:

1. Letter, R. B. Sewell (Consumers Power Co.) to P. A. Morris, USAEC, Office of Operations Evaluation, April 18, 1974.

2. Palisades Reactor Internals Wear Report, Combustion Engineering, Inc., Report CEN-5 (P), (Proprietary information), March 1, 1974.

3. Palisades Reactor Internals Wear Report, Combustion Engineering, Inc., Report CEN-5 (P) Rev. 01, April 10, 1974.

4. ROE 74-3, Mechanical Vibrations of Reactor Internals, February 8, 1974.

OE-9/4/74 September 4, 1974

DEFECTIVE WELD ON 12" GLOBE VALVE — DEFECTIVE 2" GATE VALVE

Regulatory Operations Bulletin No. 74-1, issued on January 3, 1974, identified two valve problems with possible generic implications. The first problem occurred at Unit 2 of the Peach Bottom Nuclear Plant. It involved a weld failure on a 12-inch, 300-pound, motor-operated globe valve (Walworth) used in the High Pressure Service Water line on the discharge side of one of the Residual Heat Removal heat exchangers. The weld failure, which occurred between one of the legs of the valve yoke and the mounting plate for the motor operator, was caused by an undersized weld resulting from installation of unauthorized shims between the yoke leg and the mounting plate.

After the problem was identified, the licensee, Philadelphia Electric Company, inspected all 108 similar valves installed at Peach Bottom Units 2 and 3. This investigation led to the discovery of four more valves that had been welded with shims. Each valve was repaired by removing the shims and rewelding the mounting plates to the yoke legs with full penetration welds.

The second problem occurred at Unit 1 of the Point Beach Nuclear Plant. It involved two two-inch gate valves (Darling) of the double disc type. The first defective valve was discovered during an investigation of leakage from the excess letdown line. Inspection of a valve (1MOV-1299) that functioned as the line shutoff valve (root valve) disclosed that the downstream seat was protruding from the valve body, causing the disc to rub against the lip of the downstream seat ring when the disc was reinserted following full withdrawal. Four marks were found on the lip of the seat ring indicating that the disc had caught this ring during previous valve closings. A vertical crack in the upper portion of the seat ring and some scratches on the disc were also noted. As a temporary corrective measure, the valve was repaired by rounding the lip of the seat ring to prevent further interference. Since the thin vertical crack could not be completely lapped out during repair, another valve was added downstream of the repaired valve. The permanent corrective action planned is to replace the affected valve during an extended shutdown.

The second valve experienced a similar but less severe problem. This valve appeared to be sticking during manual manipulation. Inspection of the valve internals revealed no damage except some markings on the upper edge of the seat ring. This defect also was corrected by rounding the seat ring edges so that the valve disc could be guided smoothly between the seats.

RO Bulletin 74-1 was issued to 49 utility companies that hold operating licenses or construction permits for ninety-five facilities that could have had affected valves. Of these 95 facilities, 18 had used Walworth valves similar in design to the 12-inch, motor operated globe valve.

In no instance had any welds failed as at the Peach Bottom Nuclear Plant. However, inspection of 52 valves at two other facilities disclosed other problems with ten valves, such as undersized and undercut fillet welds or cracks in the fillet throat. Each of these deficiencies was repaired on site in accordance with procedures recommended by the manufacturer.

None of the facilities contacted had experienced any problems like those experienced at the Point Beach facility.

Two facilities under construction had either Walworth or Darling valves of the types originally affected, crated and in storage. Each of these facilities plans to inspect the crated valves over the next twelve months and before using them. If there are any significant findings resulting from these inspections, a supplement to this report will be issued.

OE-9/27/74 September 27, 1974

MALFUNCTION OF SAFETY RELIEF VALVE

Regulatory Operations Bulletins No. 74-4 and 74-4A issued during March and May 1974, respectively, identified a problem with safety relief valves. A malfunction that prevented the second stage disc from reseating occurred at Unit 1 of the Brown's Ferry Nuclear Power Plant. This in turn held the main disc open, resulting in a rapid depressurization of the primary system. Eleven relief valves of this type are located on the main steam lines within the drywell between the reactor vessel and flow restrictor. All eleven valves discharge to the suppression pool.

The malfunction occurred while the reactor was shut down, following a reactor isolation that occurred as a result of high temperature in the main steamline tunnel. During the resulting blowdown, one of the pressure relief valves failed to reseat after it had lifted at 1080 psig. Operators tried to recycle the valve manually but it would not close. When the reactor pressure dropped to 300 psig, the feedwater booster pumps started and supplied sufficient water to maintain reactor water level. At no time did the reactor vessel water level drop to the point at which the High Pressure Coolant Injection or Reactor Core Isolation Coolant automatically would have been initiated. The valve reseated when reactor pressure reached 20 psig. During this blowdown, approximately 91,000 gallons of reactor coolant was discharged to the suppression pool.

The malfunctioning six-inch Model 67-E valve was manufactured by the Target Rock Valve Company. It has a 10-inch discharge line and a 1200 psig design pressure. The valve was set to actuate at 1080 $\pm$ 11 psig and has a flow capacity of 80,000 lb/hr of saturated steam.

Figure 1 is a simplified drawing of this valve. The valve has three main sections: (1) a pilot valve section, containing a small self-actuated relief valve that senses pressure, and controls operation of the main valve; (2) a remote air-actuated pilot valve, used for manual control of the main valve, actuated by externally supplied air pressure applied to a diaphram; and (3) the main valve section, a hydraulically operated reverse seating globe valve. When actuated by either pilot valve, the main valve opens to permit venting of steam to the suppression pool.

Inspection of the valve internals revealed that the keeper that retains the lock nut on the second stage piston had become disengaged and had traveled up the second stage disc stem over the securing wire. In this position, the keeper prevented the second stage disc from reseating and the main valve from closing.

RO Bulletins 74-4 and 74-4A, requested that certain temporary modifications developed by the General Electric Co. be made during cold shutdown periods. These modifications are noted in Figure 2 and included the following:

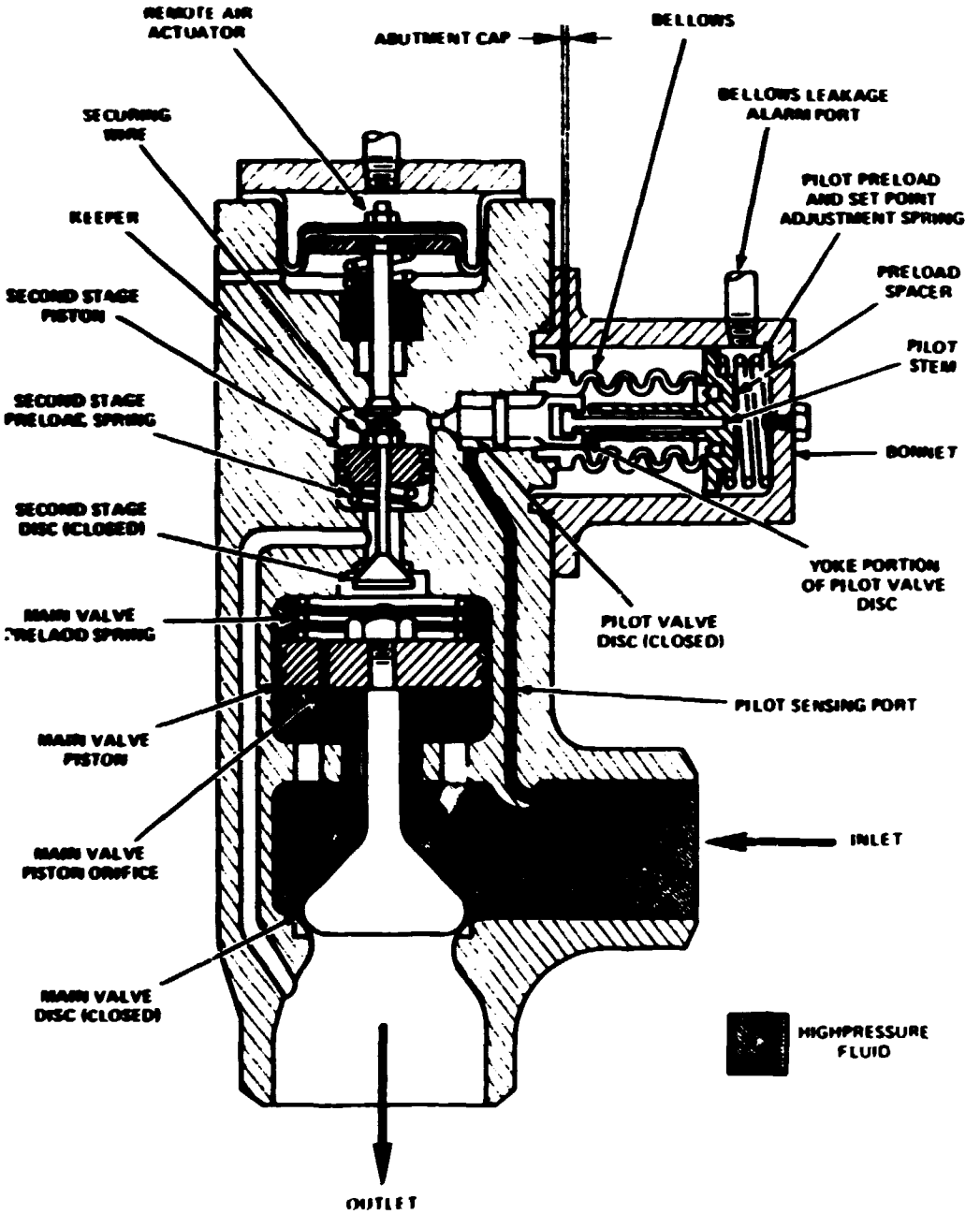
1. Removal of the tie wire and keeper from the stem of the second stage piston.

2. Drilling a 1/16 in. diameter hole through the nuts and threaded portion of the stem.

3. Inserting a pin in the hole and peening the edges of the hole.

Permanent modifications involving the second stage piston and shaft have been developed by Target Rock and GE. The newly designed parts required for these modifications are scheduled to be available by December 1974.

RO Bulletins 74-4 and 74-4A were issued to 32 BWR facilities, 13 of which are under construction. Fifteen of these facilities had Target Rock valves. All fifteen facilities will complete the requested temporary modifications during cold shutdown periods and make the permanent modifications when the appropriate parts become available.


REMOTE AIR ACTUATOR
ABUTMENT CAP
BELLOWS
BELLOWS LEAKAGE ALARM PORT
SECURING WIRE
KEEPER
PILOT PRELOAD AND SET POINT ADJUSTMENT SPRING
PRELOAD SPACER
SECOND STAGE PISTON
PILOT STEM
SECOND STAGE PRELOAD SPRING
BONNET
SECOND STAGE DISC (CLOSED)
YOKE PORTION OF PILOT VALVE DISC
MAIN VALVE PRELOAD SPRING
PILOT VALVE DISC (CLOSED)
PILOT SENSING PORT
MAIN VALVE PISTON
INLET
MAIN VALVE PISTON ORIFICE
MAIN VALVE DISC (CLOSED)
HIGHPRESSURE FLUID
OUTLET

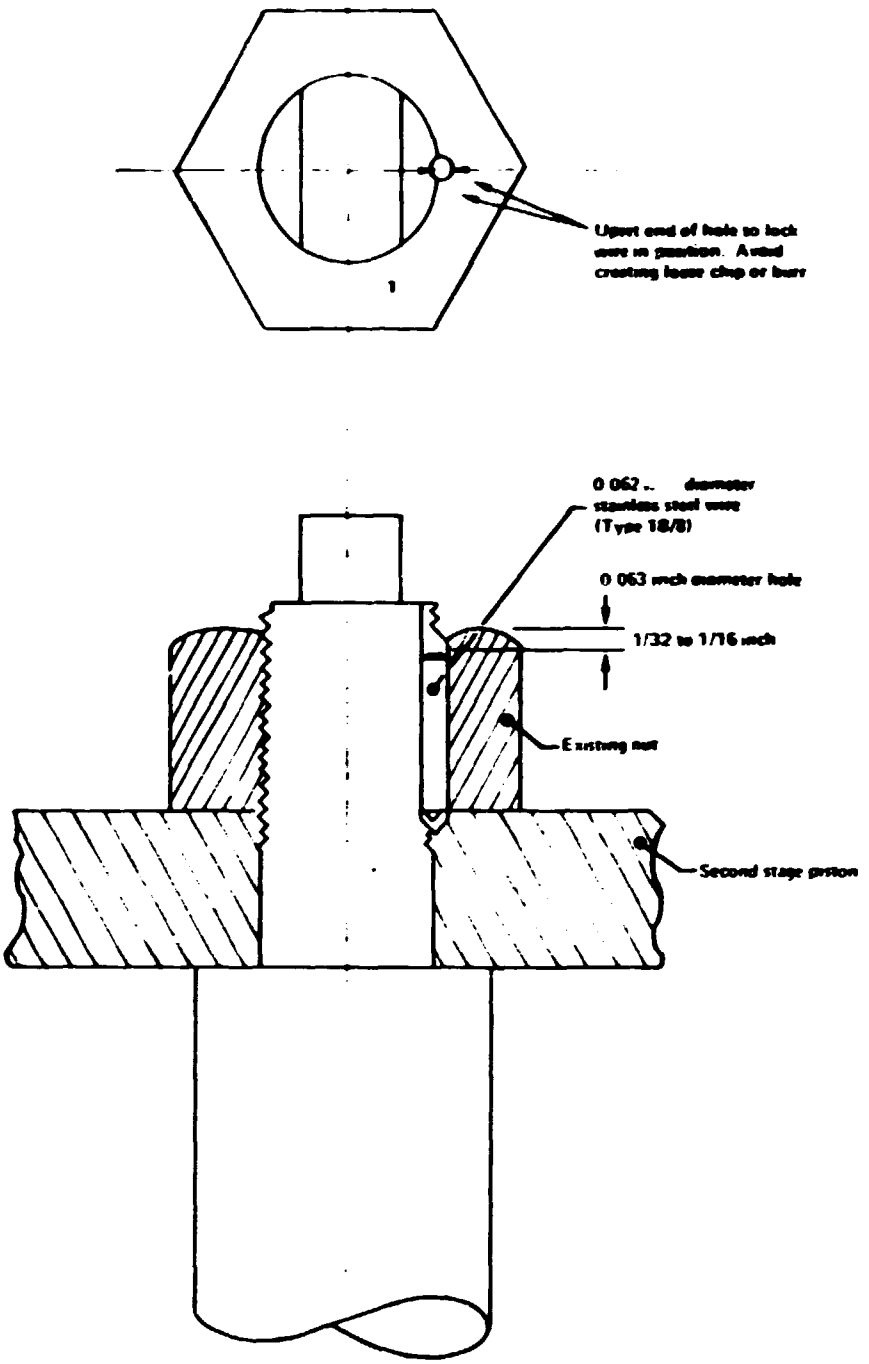


Figure 2 Enlarged View of Nut Retaining Device, Second Stage Disc & Piston Assembly

OE 10/25/74 October 25, 1974

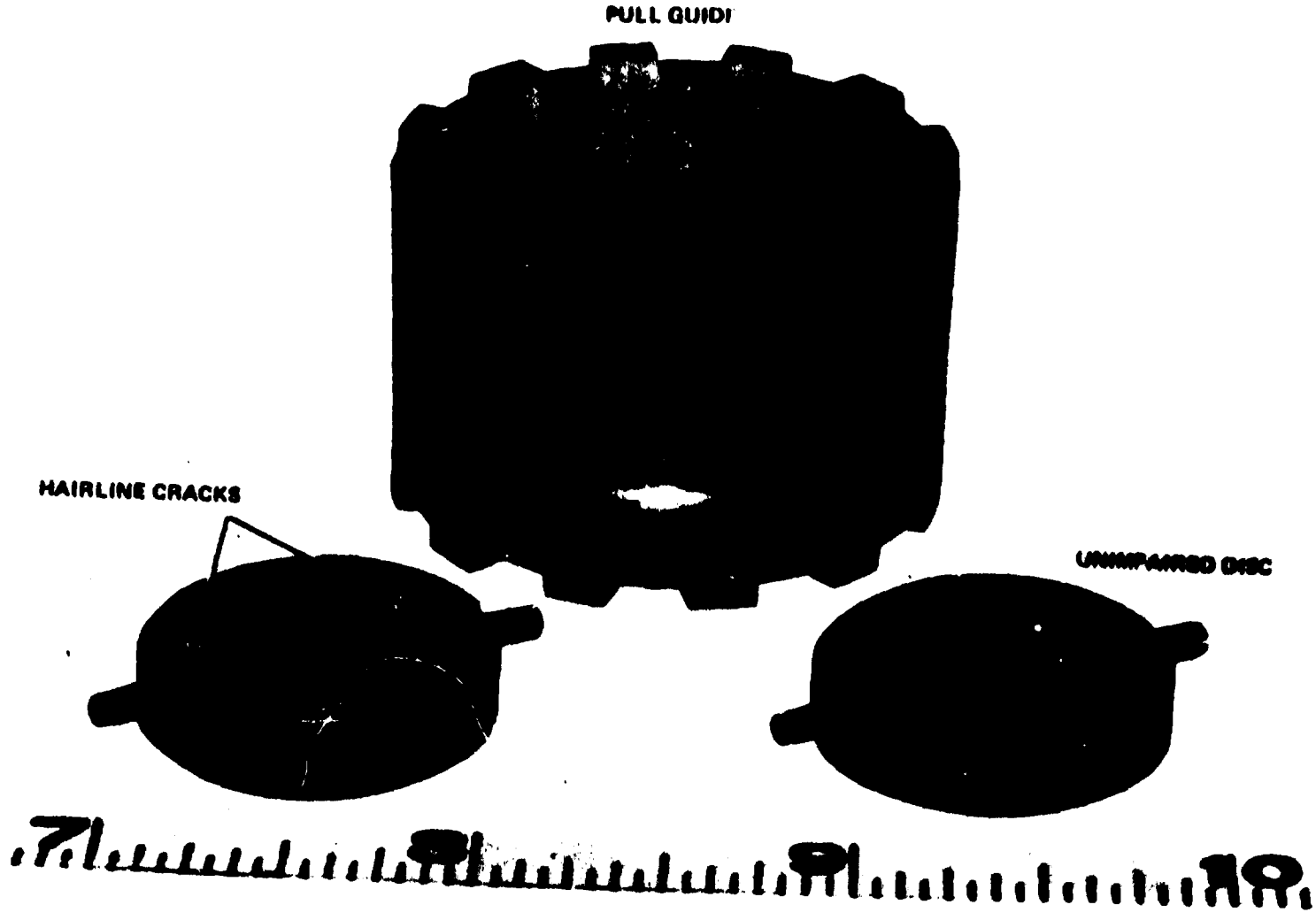
DEFECTIVE PARTS IN TYPE W-2 CONTROL SWITCHES

Regulatory Operations Bulletin 74-6 issued during May, June and July 1974 identified a problem with Westinghouse Type W-2 control switches used in some nuclear power plants with pressurized water reactors (PWRs). The bulletin also was distributed for information to utilities with boiling water reactor (BWR) facilities.

The problem discussed in Bulletin 74-6 was preceded by another problem experienced earlier at a PWR under construction. This earlier problem involved a defective switch that had contact alignment difficulties which could have resulted in loss of circuit continuity through certain contact pairs. Intermittent loss of electrical contact was reported when torque was applied to the handle of the switch while the handle was in the locked position. This was caused by the single pin pull lever disc located at the end of all W-2 switches that were manufactured in the latter part of 1971. To correct this problem, Westinghouse redesigned the pull lever disc so two pins were located opposite each other. This pull lever disc together with two other parts was offered to utilities in a repair kit that was to be used for modifying Type W-2 control switches. Many utilities purchased these kits. One utility, the Rochester Gas and Electric Company, found eight out of 14 of the newly designed pull lever disc to have hairline cracks in line with the expansion pins as shown in the attached figure. Other utilities, subsequently alerted by the AEC, found similar defective discs in their replacement kits. Based on these reports, the AEC issued Regulatory Operations Bulletin No. 74-6.

Of the 91 facilities contacted, 39 used Type W-2 control switches. An analysis of a sampling of responses indicated that 80 of 468 switches examined contained defective discs and approximately half of the switches were used in safety-related systems.

The manufacturer determined that hairline cracks in the pull lever discs were caused by excessive forces produced by an impact tool during insertion of the pins into the discs. To understand the effect of cracked discs on the operation of W-2 switches, Westinghouse subjected four switches to a series of fatigue tests to determine if the existence of cracks degraded performance of the discs. The results indicated that cracked discs failed before intact discs when the switches were tested to failure. For less severe tests consisting of a 40-pound static pull preload, no failures were experienced after cycling switches with cracked discs up to 30,000 times. Based on these tests, Westinghouse concluded that the reliability of W-2 switches remained acceptably high even with cracked discs. Although none of the licensees contacted had experienced any problems with switches using cracked discs, all licensees were requested by the AEC to replace any cracked discs found in W-2 switches. This has been accomplished at all facilities known to have these switches.


PULL GUIDE
HAIRLINE CRACKS
UNIMPAIRED DISC

OE-12/9/74 December 9, 1974

DEFICIENCIES INVOLVING CIRCUIT BREAKERS

Regulatory Operations Bulletins 74-8 and 74-9 concerning ITE Type HE-3 and General Electric 4-KV circuit breakers were distributed by the AEC because of various problems experienced with these breakers. A description of each problem together with summaries of replies is discussed.

Regulatory Operations Bulletin 74-8 issued July and August 1974 identified a problem with the magnetic trip elements in a number of ITE Type HE-3 molded case circuit breakers. The deficiencies were discovered during preoperational testing conducted at the Portland General Electric Company's Trojan Nuclear Plant. The current rating of these breakers was 20A, 30A, 40A, 60A, 70A, and 90A. The time current curves of the breakers are normally verified by testing the individual breakers at 135%, 200%, and 600% of rated current and then observing the breaker current interrupting capability at these ratings. In order to determine whether the magnetic trip coils would respond instantaneously, the circuit breakers were overloaded to 1000% of rated current. It was during these tests that the trip elements did not respond in accordance to the published ITE time-current characteristic curves for these breakers. The problem was significant because the relay setting points of the instantaneous magnetic trip elements could have led to undetected cable damage due to overheating in case of excessive current drain by a component. In addition, the trip coordination of these breakers with the upstream load center breakers also could have been affected adversely. The corrective action involved replacing the Type HE-3 breakers and the associated trip elements with units of a modified design.

Bulletin 74-8 was issued to approximately 103 facilities. However, only 5 facilities reported having ITE Type HE-3 breakers. Representatives of those facilities indicated that they would test their breakers and take appropriate corrective action if any of the Type HE-3 breakers were found defective.

Regulatory Operations Bulletin 74-9 issued August 1974 discussed two deficiencies of General Electric 4-KV Magne-Blast air circuit breakers and associated equipment. The first problem was discovered at Units 1 and 2 of the Calvert Cliffs Nuclear Power Plant and was found after it was noticed that some 4-KV breakers were inadvertently tripping open for no apparent reason. Investigations of the malfunctions determined that the cause was an oversized roller bar mechanism which interfered with the breaker switch linkage. The bars were 1/4-inch longer than their designed length. The purpose of the roller bar (which actually functions as a mechanical trip) is to trip open the breaker in the event the breaker is unintentionally inserted into the cubicle in a closed mode after maintenance. Should the breaker remain in the closed mode, it could be a serious safety hazard to maintenance personnel.

OE-12/9/74

Approximately 116 circuit breakers were found to have faulty roller bars at these two facilities. Inasmuch as 4-KV Magne-Blast air circuit breakers are used in both PWRs and BWRs the AEC issued Regulatory Operations Bulletin 74-9 to licensees at both types of facilities.

The second problem involving 4-KV circuit breakers was discovered at the Vermont Yankee Nuclear Plant when an electrician noted that a rear mounting bolt associated with the breaker stationary auxiliary switch assembly had loosened. The loose bolt was one of two bolts that maintained the switch contact alignment necessary for proper contact operation. Inspection of 47 other similar switch assemblies installed on the 4-KV circuit breakers at Vermont Yankee revealed that they all had loose bolts. The cause of the loose bolts appeared to be a deficiency in the manufacturer's quality control inspection procedures which did not require that the bolts be torqued to 20 inch-pounds as required in the General Electric design specifications.

RO Bulletin 74-9 was issued to 101 licensees. Thirty-five indicated that they had GE Model 4-KV Magne Blast circuit breakers. About 10 of these licensees have experienced similar problems with their switchgear equipment as described in RO Bulletin 74-9 while another 11 found their equipment free of these problems. Approximately 14 of the licensees contacted plan to test their switchgear equipment in the near future and take the appropriate corrective action if any breaker is found defective. The attached table numerically summarizes this information.

SUMMARY INFORMATION FOR
RO BULLETIN 74-9

Problems Discussed In Bulletin 74-9	No. of Licensees Having Problem Noted in Bulletin	No. of Licensees That Had Trouble Free Equipment	No. of Licensees Planning Tests In Near Future	Totals
Oversized Roller Bar	3	2	5	10
Loose Mounting Bolt	7	9	9	25
Totals	10	11	14	35

PERMUTED TITLE INDEX

THIS INDEX LISTS ALPHABETICALLY ALL SIGNIFICANT WORDS IN EVERY REPORT TITLE IN CONTEXT WITH THE COMPLETE TITLE. THE INDEX WORDS APPEAR IN A COLUMN IN THE CENTER OF THE PAGE WITH THE TITLES PERMUTED AROUND THEM. THE ROE REPORT NUMBER FOR EACH TITLE APPEARS IN A COLUMN ON THE RIGHT SIDE OF THE TITLE FOLLOWED BY THE PAGE NUMBER.

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•ROD	CONTROL ROD DRIVE PROBLEMS•	SRP 7.7-13 B-75
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