Reference 2

Licensee Event Followup
Procedure No.: 92700B
Issue Date: 10/1/76

SECTION I

INSPECTION OBJECTIVE

Ascertain whether the licensee's review, corrective action, and report of the identified event and associated conditions are adequate and in conformance with regulatory requirements, Technical Specifications, license conditions, and licensee procedures and controls.

Note: Section II of this procedure has not been made available to the public.

8003110 204

SECTION II

INSPECTION REQUIREMENTS

For events selected for followup, conduct record review, direct observation, or discussion with licensee personnel to the extent necessary to complete the applicable inspection requirements.

1. Corrective Action - Technical

   a. Ascertain that corrective action is appropriate to correct the cause of the event.

   b. Verify that corrective action has been taken.

   c. For corrective action not yet complete, verify that responsibility has been assigned for assuring completion thereof.

   d. Verify that generic implications if identified were incorporated in corrective action.

   e. Determine whether corrective action taken or to be taken is adequate, particularly to prevent recurrence.

2. Safety of Operations - Technical

   a. Ascertain whether the event involved operation of the facility in a manner which constituted an unreviewed safety question as defined in 10 CFR 50.59(a)(2); or, for facilities or operations not covered under 10 CFR 50, in such a manner as to represent an unusual hazard to health and safety of the public or environment.

   b. Ascertain whether the event involved continued operations in violation of regulatory requirements or license conditions.

3. Reporting Requirements - Administrative

   Ascertain that reporting requirements have been met by verifying that:

   a. The report accurately describes the actual event.

   b. The safety significance stated in the report is consistent with details of the actual event determined in 1.a. above.

c. The reported cause is accurate and the LER form, if required, reflects the proper cause code.

d. The report satisfies the reporting requirement with respect to information provided and timing of submittal.

4. Licensee Review - Administrative

a. Verify that the event was reviewed and evaluated as required by approved procedures and administrative controls.

b. Verify that personnel within the licensee organization were notified of the event as required by Technical Specifications, license conditions, or approved procedures.

c. Verify that review and evaluation of the event included assessment of generic implications.

d. Verify that review and evaluation of the event included assessment of personnel error and procedural adequacy.

e. Verify that the event was reviewed to determine whether it is a recurrence of past events.

5. If the information reported to the NRC is found to be significantly in error, verify that the licensee submits a corrected report.

6. Document closeout of event followup in the inspection report.

SECTION III

INSPECTION GUIDANCE

General guidance on the structure of reporting requirements is provided in MC 90712B, Section III, item 1. The depth of onsite followup is based on the safety significance, complexity of technical problems and generic implications of the event. Inspector judgement with concurrence of Regional management should determine the extent of followup needed on each report. It is neither required nor desired that all reports be followed up onsite.

The inspection requirements are divided into technical and administrative categories which serve different purposes. The technical aspects of the event include operational details, cause, corrective action, prevention of recurrence and generic implications. Administrative aspects address the licensee's management system for processing reports. Within each category the inspection requirements are necessarily flexible to the extent that the type of event may cause some individual line items to be inapplicable. It is not necessary that such requirements be completed.

Followup entails onsite verification that couldn't be done during in-office review, and is in addition to, not duplicative of, in-office review.

1. b. Corrective action items of a long term nature, such as a design change, should be tracked to completion by the inspector.

   c. Formal requirements should be established in the licensees' administrative control program to assure that corrective actions have been completed.

   d. The applicability to, or susceptibility of, other systems or components in the affected unit and other units at the site, is the extent to which generic implications should be included in corrective action.

   e. Corrective action should generally include action taken at the time of the event to eliminate the cause or to mitigate consequences, action taken to correct the specific fault or failure (maintenance, repair, replacement, procedure change, special administrative control, etc.), and action taken to reduce the probability of, or to prevent recurrence (design change, operator retraining, maintenance practice, work controls, etc.). These aspects of corrective action apply in varying degrees to a specific event, and as such, inspector judgement is necessary in this determination.

2. a. This item directly supports the IE responsibility to determine whether licensed operations are being conducted safely. 10 CFR 50.59(a)(2) should be used as guidance in assessing safety of operations of facilities not licensed under 10 CFR 50. Even though 10 CFR 50.59 is not a requirement for these facilities or operations, it delineates the types of items that should be considered in assessing safety of such licensed activities.

   b. Examples include safety limits, limiting safety system settings, limiting conditions for operation, limiting control settings and other regulatory requirements associated with the event. Inspection should cover items such as required settings were not exceeded and redundant systems required by Technical Specifications or license conditions were operable.

3. a. In determining that the report is accurate, items such as the following examples that are associated with the event and applicable to the reporting requirement should be verified:

   - Nature and extent of radiation exposure to employees or members of the public.

   - Nature and extent of radioactive releases.

   - Extent to which an instrument was found out of calibration or outside tolerance allowed by Technical Specifications or license conditions.

   d. Refer to the reporting requirement to determine acceptability. MC-Interpretations, R.G. 1.16 amplifies degraded mode and report type as to prompt notification or 30-day timing.

4.a.b. Approved procedures should assign responsibility to personnel for prompt review, evaluation, determination of the cause, and notification of licensee personnel of the event. Safety committee reviews of reportable occurrences will be verified on a sampling basis during the performance of 40700B.

4.c.d. Results of these assessments should be reflected in determination of cause and corrective action for events in which these issues are germane.

4. e. Licensee administrative procedures should be adequate to identify whether an event is first of a kind or of a recurring nature.

5. The licensee should submit a corrected report to the NRC (narrative and/or LER data form, as appropriate). If it is determined that the incorrect information was purposely reported or if the licensee frequently reports misinformation, enforcement action would be appropriate. The threshold of significance of errors including omission, above which a corrected report is required, involves inspector judgement, and should be commensurate with consideration of citing the licensee for failure to report, which infers failure to report accurately. Errors of lesser significance should be discussed with the licensee with the intent that future reports be correct, but insistence on submittal of a corrected report for the specific event is not warranted.

6. Documentation of findings under this module in the inspection report serves also to close out the particular event report in a traceable manner. If more than one inspection is necessary to complete event followup, final close out should be reflected in the last such inspection.

CURRENT EVENTS

POWER REACTORS

UNITED STATES NUCLEAR REGULATORY COMMISSION

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

AUGUST - SEPTEMBER 1975

CRACKS DISCOVERED IN COLLET HOUSINGS OF CONTROL ROD DRIVES

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

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

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

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

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

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

STEAM GENERATOR TUBE LEAK

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

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

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

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

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

FAILURE OF SAFETY RELIEF VALVE

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

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

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

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

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

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

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

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

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

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

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

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

EXCESSIVE REACTOR COOLANT SYSTEM COOLDOWN RATE

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

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

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

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

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

LOW FLOW FEEDWATER LINE SEVERS AT 6x4 REDUCER

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

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

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

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

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

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

UNPLANNED RELEASE FROM SITE BOUNDARY

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

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

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

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

RELEASE IN EXCESS OF TECHNICAL SPECIFICATION LIMITS

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

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

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

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

TRANSFER OF REFUELING WATER TO CONTAINMENT BASEMENT

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

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

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

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

UNREQUIRED ACTUATION OF EMERGENCY SYSTEMS

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

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

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

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

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

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

REFERENCES

1. Letter, B.B. Stephenson (Commonwealth Edison) to J.G. Keppler, USNRC, Office of Inspection and Enforcement - Region III, July 3, 1975. AOR No. 75-31, Docket No. 50-249.

2. Letter, S. Burstein (Wisconsin Electric Power Company) to B.C. Rusche, USNRC, Office of Nuclear Reactor Regulation, September 26, 1975. Docket No. 50-301.

3. Letters, E.E. Utley (Carolina Power & Light Company) to N.C. Moseley, USNRC, Office of Inspection and Enforcement - Region II, May 16 and 21, 1975. AOR Nos. 75-13 to 16, Docket No. 50-324.

4. Letters, W.O. Parker, Jr. (Duke Power Company) to N.C. Moseley, USNRC, Office of Inspection and Enforcement - Region II. June 27 and August 8, 1975. AOR No. 75-7, Docket No. 50-287.

5. Letter, N.J. Kalivianakis (Commonwealth Edison) to USNRC, Director of Office of Nuclear Reactor Regulation, August 27, 1975. AOR No. 75-31, Docket No. 50-274.

6. Letter, A.E. Lundvall, Jr. (Baltimore Gas and Electric Company) to J.P. O'Reilly, USNRC, Office of Inspection and Enforcement - Region I, July 28, 1975. AOR No. 75-44, Docket No. 50-317.

7. Letter, A.E. Lundvall, Jr. (Baltimore Gas and Electric Company) to J.P. O'Reilly, USNRC, Office of Inspection and Enforcement - Region I, August 20, 1975. AOR No. 75-48, Docket No. 50-317.

8. Letter, L.D. White, Jr. (Rochester Gas and Electric Corporation) to J.P. O'Reilly, USNRC, Office of Inspection and Enforcement - Region I, August 22, 1975. AOR No. 75-13, Docket No. 50-244.

9. Letter, W.G. Counsil (Northeast Nuclear Energy Company) to J.P. O'Reilly, USNRC, Office of Inspection and Enforcement - Region I, September 18, 1975. AOR No. 75-17, Docket No. 50-336.

Reference 4

Table 3 (Continued)

DATE OF REPORT	OCCURRENCE	CAUSE	FACILITY	DOCKET
06-19-75	SLC PUMP FLOW RATE LESS THAN REQUIRED	RELIEF VALVE FAILURE	VERMONT YANKEE	50-271
06-19-75	SLC PUMP FAILS TO DELIVER REQUIRED FLOW	LEAKING RELIEF VALVE	VERMONT YANKEE	50-271
07-21-75	CORE SPRAY VALVE FAILS TO OPEN	TORQUE SWITCH LOCK PIN SHEARS	VERMONT YANKEE	50-271
07-24-75	VAPOR CONTAINER DRAIN LINE VALVE FAILS TO CLOSE	CORROSION ON LINKAGE	YANKEE ROWE	50-29
06-30-75	SET POINT DRIFT IN FEEDFLOW TRANSMITTER	UNKNOWN	ZION 1	50-295
07-23-75	COMPARATOR FOUND INOPERATIVE	UNKNOWN	ZION 1	50-295
06-23-75	DIESEL GENERATOR FAILS TO START	FUEL OIL PRIMING PUMP FAILS	ZION 2	50-304
06-25-75	CONTAINMENT PENETRATION BELLOWS LEAKING	UNKNOWN	ZION 2	50-304
06-27-75	DRIFT FOUND IN TEMPERATURE SUMMATOR	FAILED CAPACITOR	ZION 2	50-304
06-30-75	AIR-OPERATED CONTAINMENT ISOLATION VALVES FAILS TO CLOSE	DEFECTIVE SOLENOID VALVES	ZION 2	50-304

Selected Safety-Related Occurrences Reported in September and October 1975

Compiled by William R. Casto

None of the occurrences reported in July and August 1975 seemed to be consequential enough to review; therefore this section was omitted from the previous issue of *Nuclear Safety*. Of the occurrences reported in September and October, three are reviewed here because of their general interest to nuclear operations: (1) the transients caused by the Oconee 3 control systems; (2) the release of noble gases at Zion; and (3) a feedwater line break at Quad Cities 2.

CONTROL SYSTEM CAUSES TRANSIENTS

At Oconee 3, a pressurized-water reactor (PWR) owned and operated by Duke Power Company near Clemson, S. C., a transient occurred while the reactor power level was being decreased for a routine maintenance shutdown.[1,2] Prior to the unintentional transient, the reactor power was being reduced from 100% to 15% of full power by the control system. When 15% of full power was reached, the unit load demand was 65 MW(e), but the power being generated was 115 MW(e). This disparity between the unit load demand and power generation by the reactor existed because the reactor was operating at its low limit of 15% of full power while being controlled completely automatically and could not continue following the further decreasing load demand. At this point the operator placed the turbine control in manual, thus placing the control system in the "load tracking" mode. This led to an automatic rapid increase in the unit load demand to match the reactor power output. In the meantime the main steam bypass valves opened because of excess reactor power; and, as the main steam pressure decreased, the valves closed. The control system for the feedwater flow to the steam generator could not follow the rapid change in unit load demand, and feedwater flow lagged. This caused the feedwater flow and the steam-generator water level to oscillate, which in turn caused temperature and pressure transients in the reactor coolant system. When the reactor-coolant-system pressure reached 2255 psi, a power-operated relief valve opened, as required; but the valve failed to close at 2200 psi as it should, even though the open/closed lights in the control room did not indicate that the valve was still open. The reactor coolant pressure continued down because of this open valve;

the reactor tripped on low pressure, and the high-pressure safety-injection system automatically actuated.

Although the operator closed the isolation valve on the line with the failed power-operated relief valve immediately after the reactor trip to terminate the depressurization, the valve was reopened because the water level in the pressurizer was rising rapidly. The isolation valve was reclosed when the reactor coolant pressure reached 800 psi. A cooldown of 101°F occurred during the first hour when the temperature was below 530°F. The transient and associated events also caused the quench-tank rupture disk, which received the blowdown from the power-operated relief valve, to blow. This caused the insulation to separate from the bottom nozzle of the pressurizer, releasing 1500 gal of reactor coolant to the reactor-building sump.

There was no significant increase in the radiation level in the reactor building, nor was any radioactivity released to the environment. Also, the cooldown rate did not affect the safety of the reactor.

The power-operated relief valve stuck in the open position because of heat expansion, buildup of boric acid crystals on the valve lever, rubbing of the lever against the solenoid brackets, and bending of the solenoid spring bracket.

The valve was repaired and reinstalled, and the problem with the valve position indicator cleared up.

The following corrective actions have been completed:

1. The unit shutdown procedures for all Oconee units have been revised to include a change that will prevent decreasing unit load demand below 120 MW(e) before placing the control system in the tracking mode. This minimizes the error between the unit load demand and generated power and reduces the possibility of feedwater flow and reactor-coolant-system transients.

2. The power-actuated pressure-relief valves of Units 1 and 2 will be inspected as soon as possible for any indication of buildup of boric acid crystals.

3. To verify the proper functioning of power-actuated pressurize-relief valves, they will be cycled prior to startup with a test signal corresponding to 2255 psi.

4. The quench-tank rupture disk was replaced, the bottom nozzles on the pressurizer were dye penetrant tested, and the insulation was replaced.

5. Operating personnel were advised of this incident and given specific instructions to immediately close the isolation valve.

NOBLE-GAS RELEASE

A calculated total of 63.7 Ci of radioactive gas was released at Zion power station during venting of a mixed-bed demineralizer.[3] This station has two PWRs that are owned and operated by Commonwealth Edison Company, Chicago, Ill. The maximum release rate was calculated to be 105,600 μCi/sec, and the rate was estimated to have exceeded the technical-specifications limit of 60,000 μCi/sec for 6.5 min. The procedure for venting these demineralizers requires the use of primary makeup water that contains no radioactive gases. However, this time the venting was mistakenly done with the demineralizer connected to the reactor coolant system. This resulted in a direct pathway for releasing radioactive gas from the reactor coolant system to the auxiliary building through a loose manhole cover on the equipment drain tank in the auxiliary building. Although the release had no measurable consequence off site, the operating procedures for venting the demineralizers have been strengthened, and the manhole cover has been tightened.

The calculated release, based on the long-lived radioactive gases in the reactor coolant, was about 1 Ci of mixed noble gases. However, the noble gases with very short half-lives in the coolant system were also released. An attempt will be made to determine the quantity of these gases more accurately.

FEEDWATER LINE BREAKS ON BWR

At the Quad Cities Nuclear Power Station, owned by Commonwealth Edison Company, Chicago, Ill., Unit 2 suffered a break in the body of a 4- by 6-in. reducer on the downstream side of the low-flow regulator valve in the feedwater system.[4] Unit 2 was coming up in power after an outage and was producing 170 MW(e) at the time of the incident. Operators were on the scene observing the transfer of flow from the low-flow feedwater regulating valve to the main feedwater regulating valve because problems in vibration during this operation had been experienced. A feedwater vibration alarm sounded when both valves were partially opened. The unit was manually scrammed when the low-flow line just downstream of the low-flow regulating valve started to sever. Not only did the line break, but cracks occurred in the low-flow piping at the low-flow riser junction with the main feedwater line and in the reducer upstream of the regulating valve.

FACILITY/ SYSTEM/ COMPONENT/ CAUSE CODE	DOCKET NO./ CONTROL NO.	EVENT DATE/ REPORT DATE/ REPORT TYPE	EVENT DESCRIPTION/ CAUSE DESCRIPTION
OCONEE-3 OTHER COOLANT SUBSYS + CONTROL VALVE OPERATORS PERSONNEL ERROR	050-0287 012876	061375 062775 2-WEEK	(AO-75-7) EXCESSIVE REACTOR COOLANT SYSTEM COOLDOWN RATE. DURING A ROUTINE SHUTDOWN (15% POWER) A POWER ACTUATED PRESSURIZER RELIEF VALVE OPENED, THEN REMAINED OPEN UNTIL AN ISOLATION VALVE WAS SHUT. THE 101 DEGREE F COOLDOWN IN THE FIRST HOUR EXCEEDED THE 100 DEGREE F LIMIT. PERSONNEL ERROR: PROMPTER OPERATOR ACTION COULD HAVE PREVENTED EXCESSIVE COOLDOWN. RELIEF VALVE WAS REPAIRED (BORIC ACID BUILDUP ON OPERATOR).
OCONEE-3 CNTMNT ISOLATION SYS + CONT INSTRUMENTATION + CONTROLS COMPONENT FAILURE	050-0287 012809	061975 070375 2-WEEK	(AO-75-8) REACTOR BUILDING ENGINEERED SAFEGUARDS PRESSURE TRANSMITTER FOUND OUT OF CALIBRATION (BY 6.6 PSIG) DURING ROUTINE TESTING DURING COLD SHUTDOWN. THE 2 OF 3 ACTUATION LOGIC WAS NOT AFFECTED. COMPONENT FAILURE: SETPOINT DRIFT.
OYSTER CREEK-1 EMERG CORE COOLING SYS + CONT INSTRUMENTATION + CONTROLS COMPONENT FAILURE	050-0219 012622	061475 062475 2-WEEK	(AO-75-16) SURVEILLANCE TESTING ON THE 5 ELECTROMATIC RELIEF VALVE PRESSURE SWITCHES WHILE THE REACTOR WAS IN THE REFUEL MODE REVEALED 2 SWITCHES (1A83B & 1A83E) TO TRIP AT 5 AND 3 PSIG ABOVE THEIR MAXIMUM ALLOWABLE TRIP POINTS OF 1089 AND 1085 PSIG. INSTRUMENT SET POINT DRIFT. SWITCHES WERE RESET TO ALLOWABLE LEVELS.
OYSTER CREEK-1 EMERG CORE COOLING SYS + CONT CIRCUIT CLOSERS/INTERRUPTERS COMPONENT FAILURE	050-0219 012899	061975 062775 2-WEEK	(AO-75-17) DURING SURVEILLANCE, CORE SPRAY SYSTEM PARALLEL ISOLATION VALVE (V-20-15) FAILED TO CLOSE. A BROKEN MOTOR BREAKER STAB WAS REPLACED AND THE VALVE TESTED SATISFACTORILY. A REDUNDANT VALVE WAS OPERABLE. THE TAB ON THE "B" PHASE OF THE VALVE MOTOR BREAKER STAB WAS BROKEN RESULTING IN INTERMITTENT BUS BAR CONTACT. THE LOSS OF ONE PHASE CAUSED THE VALVE MOTOR TO TRIP.
OYSTER CREEK-1 CNTMNT COMBUS GAS CONTROL SYS FILTERS DEFECTIVE PROCEDURES	050-0219 012898	062375 070175 2-WEEK	(AO-75-18) DURING OPERATION, TWO HANDHOLE COVERS IN THE STANDBY GAS TREATMENT FILTER TRAIN WERE NOT IN PLACE. THE COVERS WERE IMMEDIATELY SECURED IN PLACE. THIS REDUCED THE ABILITY OF THIS SBGTS TO FUNCTION PROPERLY. A REDUNDANT TRAIN WAS AVAILABLE. UNDETERMINED. PROCEDURES FOR FILTER TESTING WERE REVISED.
PALISADES-1 OTHER AUX WATER SYS + CONTROLS OTHER COMPONENTS DEFECTIVE PROCEDURES	050-0255 012773	060375 061375 2-WEEK	A REVIEW OF CHLORINATION TREATMENT OF THE CLOSED CYCLE CONDENSER COOLING SYSTEM SHOWED THAT T.S.3.9.26 THROUGH 3.9.30 WERE NOT CONSISTENTLY MET AND SOME REQUIRED MEASUREMENTS NEVER TAKEN. CHLORINE DISCHARGE INTO LAKE MICHIGAN COULD HAVE REACHED 0.06 PPM COMPARED TO T.S. LIMIT OF 0.02 PPM. (AO-75-12). NOT ACCOUNTING FOR CONTRIBUTION FROM COOLING TOWER, PROCEDURE PROBLEMS, AND BEGINNING OPERATION OF NEWLY INSTALLED CLOSED CYCLE COOLING SYSTEM. PROCEDURES ARE BEING UPDATED. ALSO T.S. CHANGES ARE BEING CONSIDERED.

FACILITY/ SYSTEM/ COMPONENT/ CAUSE CODE	DOCKET NO./ CONTROL NO.	EVENT DATE/ REPORT DATE/ REPORT TYPE	EVENT DESCRIPTION/ CAUSE DESCRIPTION
OCONEE-2 REACTOR TRIP SYSTEMS INSTRUMENTATION + CONTROLS COMPONENT FAILURE	050-0270 013130	060575 061975 2-WEEK	(75-15) SURVEILLANCE TESTING DURING REACTOR TRIP RECOVERY REVEALED A FAILURE OF REACTOR PROTECTIVE SYSTEM (RPS) CHANNEL "D". RPS WAS PLACED IN A 2 OF 3 LOGIC BY BYPASSING CHANNEL D. NO REPLACEMENT AMPLIFIER WAS AVAILABLE. COMPONENT FAILURE: FAULTY AMPLIFIER IN THE POWER IMBALANCE CIRCUIT.
OCONEE-2 CNTNMNT HEAT REMOV SYS + CONT COMPONENT CODE NOT APPLICABLE PERSONNEL ERROR	050-0270 013180	080875 082275 2-WEEK	(75-16) DURING UNIT STARTUP, FAILED TO PROVIDE AN OPERABLE REACTOR BUILDING SPRAY TRAIN WHEN REQUIRED. PERSONNEL ERROR: THE CONTROL OPERATOR MISUNDERSTOOD THE PURPOSE OF THE "OUT OF NORMAL" CHECKLIST AND THUS FAILED TO FOLLOW THE STARTUP PROCEDURE.
OCONEE-2 COOL SYS FOR REAC AUX + CONT HEAT EXCHANGERS COMPONENT FAILURE	050-0270 013203	082475 090875 2-WEEK	(75-17) THE COMPONENT COOLING SYSTEM RADIOACTIVITY SUDDENLY INCREASED ABOUT 20 MINUTES AFTER A REACTOR SCRAM. THE "A" LETDOWN COOLER WAS ISOLATED AND THE "B" COOLER USED. NO RADIOACTIVITY WAS RELEASED. COMPONENT FAILURE: THE "A" LETDOWN COOLER HAD DEVELOPED A LEAK (0.2 GALLON PER MINUTE).
OCONEE-2 REACTIVITY CONTROL SYSTEMS CONTROL RODS COMPONENT FAILURE	050-0270 013202	082575 090875 2-WEEK	(75-18) LOSS OF REQUIRED OVERLAP BETWEEN OPERATING CONTROL ROD GROUPS FOR 5 MINUTES. DURING NORMAL OPERATION AT 95% POWER, THE GROUP 7 RODS DROPPED INTO THE CORE. THE INTEGRATED CONTROL SYSTEM WITHDREW GROUP 6 RODS TO MAINTAIN POWER; THE REQUIRED OVERLAP WAS LOST. COMPONENT FAILURE: NO PROBLEM WAS FOUND, AND NORMAL CONDITIONS WERE RESTORED. NO CORE SAFETY LIMITS WERE EXCEEDED.
OCONEE-3 OTHER COOLANT SUBSYS + CONTROL VALVE OPERATORS COMPONENT FAILURE	050-0287 013125	061375 080875 OTHER	(75-7) EXCESSIVE COOLDOWN RATE OF REACTOR COOLANT SYSTEM (161 DEGREES F IN ONE HOUR VS. 100 DEGREES MAX ALLOWED.) IMPROPER OPERATION OF THE INTEGRATED CONTROL SYSTEM (ICS) CAUSED FEEDWATER OSCILLATIONS, RESULTING IN LEVEL AND PRESSURE TRANSIENTS; THIS OPERATED RELIEF VALVE 3RC-66 WHICH FAILED TO CLOSE. COMPONENT FAILURE: THE RELIEF VALVE STUCK OPEN BECAUSE OF (1) HEAT EXPANSION, (2) BORIC ACID CRYSTAL BUILDUP (EXTERNAL), AND (3) COMPONENT MALADJUSTMENT.
OCONEE-3 REACTOR CONTAINMENT SYSTEMS PENETRATIONS, PRIMRY CONTAINMNT DESIGN/FABRICATION ERROR	050-0287 013191	071075 082575 2-WEEK	(RE-75-9) THE PERSONNEL HATCH DOOR INTERLOCK FAILED DURING A REACTOR BUILDING ENTRY AT FULL REACTOR POWER ADMINISTRATIVE PROCEDURES WERE USED TO PREVENT SIMULTANEOUS OPENING OF INNER AND OUTER DOORS. DESIGN ERROR: INSUFFICIENT SPRING TENSION ON THE INTERLOCK CABLE. DESIGN MODIFICATIONS HAVE BEEN IMPLEMENTED.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
230 PEACHTREE STREET, N. W. SUITE 818
ATLANTA, GEORGIA 30303

Reference 7

AUG 27 1975

In Reply Refer To:
IE:II:TNE
50-269/75-9
50-270/75-10
50-287/75-10

DUPLICATE DOCUMENT

Entire document previously entered into system under:

ANO 8001031026

No. of pages: ____________

Duke Power Company
ATTN: Mr. William O. Parker, Jr.
Vice President
Steam Production
P. O. Box 2178
422 South Church Street
Charlotte, North Carolina 28242

Gentlemen:

This refers to the inspection conducted by Mr. T. N. Epps of this office on July 29-31, 1975, of activities authorized by NRC Operating License Nos. DPR-38, DPR-47 and DPR-55 for the Oconee 1, 2 and 3 facilities, and to the discussion of our findings held with Mr. J. E. Smith at the conclusion of the inspection.

Areas examined during the inspection and our findings are discussed in the enclosed inspection report. Within these areas, the inspection consisted of selective examination of procedures and representative records, interviews with personnel, and observations by the inspector.

We have examined actions you have taken with regard to previously reported unresolved items. These are identified in Section IV of the summary of the enclosed report.

During the inspection, it was found that certain activities under your license appear to be in noncompliance with NRC requirements. These items and references to pertinent requirements are listed in Section I of the summary of the enclosed report. Additional information on Abnormal Occurrence AO-287/75-7 in your letter dated August 8, 1975, was received by this office. No additional response is requested.

In accordance with Section 2.790 of the NRC's "Rules of Practice," Part 2, Title 10, Code of Federal Regulations, a copy of this letter and the enclosed inspection report will be placed in the NRC's Public Document Room. If this report contains any information that you believe

AMERICAN REVOLUTION BICENTENNIAL 1776-1976

Dupe of
8001031026
2pp.

to be proprietary, it is necessary that you submit a written application to this office requesting that such information be withheld from public disclosure. If no proprietary information is identified, a written statement to that effect should be submitted. If an application is submitted, it must fully identify the bases for which information is claimed to be proprietary. The application should be prepared so that information sought to be withheld is incorporated in a separate paper and referenced in the application since the application will be placed in the Public Document Room. Your application, or written statement, should be submitted to us within 20 days. If we are not contacted as specified, the enclosed report and this letter may then be placed in the Public Document Room.

Should you have any questions concerning this letter, we will be glad to discuss them with you.

Very truly yours,

Norman C. Moseley
Director

Enclosure:
IE Inspection Report Nos.
50-269/75-9, 50-270/75-10,
and 50-287/75-10

cc: J. E. Smith, Plant Manager
Oconee Nuclear Plant

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
230 PEACHTREE STREET, N. W. SUITE 818
ATLANTA, GEORGIA 30303

IE Inspection Report Nos. 50-269/75-9, 50-270/75-10 and 50-287/75-10

Licensee: Duke Power Company
Power Building
422 South Church Street
Charlotte, North Carolina 28201

Facility Name: Oconee Units 1, 2 and 3
Docket Nos.: 50-269, 50-270 and 50-287
License Nos.: DPR-38, 47 and 55
Category: C, C and B2

Location: Seneca, South Carolina

Type of License: B&W, PWR, 2568, Mw(t)

Type of Inspection: Routine, Unannounced

Dates of Inspection: July 29-31, 1975

Dates of Previous Inspection: May 27-30 and June 3-6, 1975

Principal Inspector: T. N. Epps — 8-27-75
T. N. Epps, Reactor Inspector
Facilities Operations Branch
Date

Accompanying Inspectors: None *

Reviewed by: 8/27/75
F. J. Long, Chief
Facilities Operations Branch
Date

* See Details II

Dup of
8001031028
8 pp.

SUMMARY OF FINDINGS

I. Enforcement Items

A. Deficiencies

1. Contrary to Technical Specification 6.6.2.1.a, abnormal occurrence report AO-287/75-7 did not include an analysis and evaluation of the safety implications involved in the blowdown of the Unit-3 reactor coolant system nor did the report address the causes and corrective actions taken to prevent recurrence of the incident. (Details I, Paragraph 2) (Unit 3)

II. Licensee Action on Previously Identified Enforcement Matters

Not inspected.

III. New Unresolved Items

None

IV. Status of Previously Reported Unresolved Items

Oconee 1, 2 and 3 (50-269, 50-270 and 50-287)

74-10, 03, 11/7 NSRC Review Capability

This item is closed. (Details I, Paragraph 6)

75-3/1 Analysis of Liquid Waste Samples

This item is closed. (Details II, Paragraph 2)

74-7/2 Activity in the Component Cooling System

This item is closed. (Details I, Paragraph 7)

V. Other Significant Findings

None

VI. Management Interview

A management interview was held on July 31, 1975, with Mr. J. E. Smith and members of his staff. Items discussed included the noncompliance item in Section I of the summary of this report, surveillance testing, two unresolved items in this summary and settlement of Class I structures.

Further discussions were held with licensee corporate management on August 5, 1975, concerning additional information on the Unit 3 blowdown that occurred on June 13, 1975.

DETAILS I Prepared by: T. N. Epps 8-21-75
T. N. Epps, Reactor Inspector Date
Facilities Operations Branch

Dates of Inspection: July 29-31, 1975

Reviewed by: F. J. Long 8/22/75
F. J. Long, Chief Date
Facilities Operations Branch

1. Individuals Contacted

Duke Power Company (DPC)

J. E. Smith - Manager, Oconee Nuclear Station
J. W. Hampton - Director, Administrative Services
L. E. Schmid - Operating Superintendent
O. S. Bradham - Maintenance Superintendent
R. M. Koehler - Technical Services Superintendent
T. S. Barr - Technical Services Engineer
R. P. Bugert - Training Supervisor

2. Unit 3 RCS Blowdown

Oconee Technical Specification 6.6.2.1.a requires that written abnormal occurrence reports describe, analyze and evaluate safety implications and outline the corrective actions and measures taken or planned to prevent recurrence.

Contrary to the above the licensee's abnormal occurrence report (AO-287/75-7) did not fully describe, analyze and evaluate safety implications and outline all corrective actions. The licensee's report primarily addressed the excessive cooldown rate of 101°F in one hour rather than addressing the entire reactor coolant system blowdown and the safety implications of the incident.

Apparently the initial transient was caused by a transfer of the turbine into manual while the unit load demand (ULD) was at 65 MWe and reactor power (automatically controlled) at 115 MWe. This eventually caused levels in the once through steam generators to swing, causing RCS temperature, pressure and power swings. RCS pressure spiked to 2267 psi which caused the power actuated relief valve, on the pressurizer, to open. The valve malfunctioned and remained in the open position. In addition a solenoid operated plunger that actuates position indication lights in the control room for the pressurizer relief valve malfunctioned.

As a result of this incident reactor coolant system (RCS) pressure decreased from 2250 psi to 720 psi within 26 minutes. The reactor tripped at 1800 psi and high pressure injection (HPI) initiated at 1500 psi.

The transient was terminated when a block valve was closed isolating the opened relief valve.

During this transient the rupture disc in the quench tank ruptured due to steam from the relief valve building up pressure in the quench tank. Approximately 1500 gallons of primary water were lost through the quench tank to the containment. Insulation on the bottom of the pressurizer was damaged when the rupture disc ble

The licensee's report did not address the initial cause of the transient and corrective action to prevent recurrence; why the block valve that isolates the pressurizer relief valve was not closed sooner; corrective action to prevent recurrence on all 3 Oconee Units of the problems with the pressurizer relief valve and position indication equipment; possible damage to the pressurizer; or activity released.

The inspector stated to Oconee site personnel and later to Duke Power Company corporated personnel that whenever rapid uncontrolled depressurization of the primary system occurs causing HPI initiation and loss of some primary coolant, abnormal degradation of the primary coolant boundary has occurred even if blowdown is through an isolable fault if the fault is not isolated.

The licensee agreed to submit supplemental information on this subject.

3. Surveillance

The inspector reviewed several surveillance testing procedures and results including the following subject areas.

RCS Chemistry
RCS Leakage
Control Rod Movement

Emergency Feedwater Pump Testing
Secondary Coolant Activity
Spent Fuel Pool Water Samples
Electrical Systems
HPI and LPI Pumps
Some Reactor Building Local Leak Tests

Within the scope of this review no noncompliance items were identified.

4. Operator Requalification Program

A licensee representative stated that NRC licensing personnel reviewed some operator requalification examinations that were given at Oconee.

The requalification program received final approval June 18, 1975.

5. Settlement of Class I Structures

The inspector inquired as to whether the licensee has a program for measuring differential settlement of class I structures, such as, the reactor building and auxiliary building. The licensee stated that such a program does not exist at Oconee since the facility is built on solid rock.

6. NSRC Review Capability

The licensee furnished information to the effect that one permanent member of the NSRC has an M.S. degree in Materials Engineering and provides capability for reviewing metalurgical considerations. This item is closed.

7. Activity in the Component Cooling System

The licensee's letter to the NRC's Region II office dated May 9, 1975, stated that a modification had been installed which added additional isolation valves between the component cooling drain tank pump discharge header and the miscellaneous waste transfer pump discharge header. The level of activity in the component cooling system has decreased. The licensee stated in the letter that monitoring of component cooling system activity will continue until the activity decays to normal background. This item is closed.

8. Bingham Pump Bolts

The inspector questioned licensee personnel about testing done on Bingham Pump hold-down bolts. A licensee representative stated that during ISI baseline testing these bolts were UT tested and found to be acceptable. Samples of these bolts will be retested at regular intervals such that all will be tested in the 10 year ISI cycle.

DETAILS II Prepared by: W L Britz 8-21-75
W. L. Britz, Radiation Specialist Date
Environmental Protection, Materials
Radiological Protection, and
Special Projects Section
Radiological and Environmental
Protection Branch

*Date of Inspection: July 22, 1975

Reviewed by: R L Bangart 8/22/75
R. L. Bangart, Senior Health Physicist Date
Environmental Protection, Materials
Radiological Protection, and
Special Projects Section
Radiological and Environmental
Protection Branch

1. Individuals Contacted

J. W. Hampton, Director, Administrative Services (Acting Plant Manager)
D. L. Davison, Assistant Health Physics Supervisor

2. Analysis of Liquid Waste Samples (75-3/1)

A. The licensee is required to measure quantities and concentrations of radioactive material in effluents from his facility. During previous independent measurement checks of June, September, and October, 1974, the licensee's ability to measure radioactivity in test standards and plant effluent split samples was evaluated. Some results of the licensee's measurements of gamma emitters and strontium in liquid were in disagreement. It was also determined that gross beta analyses had not been normalized against results of total isotopic analyses when used to determine values for reporting releases of liquid effluents. See IE Report Nos. 50-269/75-3, 50-270/75-3, and 50-287/75-3.

B. On March 18, 1975, liquid and gas split samples were collected by the Division of Radiological Health, State of South Carolina and analyzed by the licensee's laboratory and the NRC's reference laboratory. There were eighteen measurement comparisons. Twelve comparisons were in agreement, four were in possible agreement, and two in disagreement. The disagreements were on antimony-124 in the liquid sample and krypton-85 in the gas sample which were not detected by the licensee, but were reported present in concentrations greater than 10% of 10 CFR 20 Appendix B, Table II, by the NRC's reference laboratory. It appears that these two isotopes were not detected due to the short counting times used. The licensee has committed to count future split samples for about one hour to achieve lower sensitivities. The gamma emitting measurements are now resolved.

* The inspection action was an in-office evaluation of analytical results, which were discussed by telephone with the licensee representative on July 22, 1975.

C. On April 3, 1975, strontium test standards in a liquid sample and on a particulate filter were sent to the licensee's laboratory for analysis to resolve the disagreements of June and September, 1974. The licensee's laboratory procedures were also reviewed by the NRC's reference laboratory. Comments provided to the licensee's laboratory by the NRC's laboratory included: use of Sr-85, Ba-133, and Y-88 as gamma tracers to check various steps in the procedure for removal or yield factors, more exact control of pH, filtering rather than centrifuging in one step, and controlling temperature in another step. The results of four measurement comparisons for Sr-89 and 90 were three agreements and one possible agreement. The previous strontium measurements on the March 18 liquid analysis were also in agreement. The strontium measurements are now resolved.

D. The licensee in a letter of April 11, 1975, reported he has now determined and is using a normalization factor on the gross beta analysis, based on total isotopic analysis, when making radioactive liquid releases based on the gross beta analysis. This item is now resolved.

DUKE POWER C Reference 8

POWER BUILDI

422 SOUTH CHURCH STREET, CHARLOTTE, N. C. 28242

WILLIAM O. PARKER, JR.
VICE PRESIDENT
STEAM PRODUCTION

TELEPHONE: AREA 704
373-4083

June 27, 1975

Mr. Norman C. Moseley, Director
U. S. Nuclear Regulatory Commission
Suite 818
230 Peachtree Street, Northwest
Atlanta, Georgia 30303

Re: Oconee Unit 3
Docket No. 50-287

Dear Mr. Moseley:

Pursuant to Sections 6.2 and 6.6.2 of the Oconee Nuclear Station Technical Specifications, please find attached Abnormal Occurrence Report AO-287/75-7.

Very truly yours,

William O. Parker, Jr.

MST:vr
Attachment

cc: Mr. Angelo Giambusso

DUKE POWER COMPANY
OCONEE UNIT 3

DUPLICATE DOCUMENT

Entire document previously entered into system under:

ANO 8 7905100301

No. of pages:

Report No.: AO-287/75-7

Report Date: June 27, 1975

Occurrence Date: June 13, 1975

Facility: Oconee Unit 3, Seneca, South Carolina

Identification of Occurrence: Excessive Reactor Coolant System cooldown rate

Conditions Prior to Occurrence: Shutdown in progress

Description of Occurrence:

On June 13, 1975, a routine shutdown for maintenance was in progress on Oconee Unit 3. When reactor power had decreased to approximately 15 percent, a minor system transient occurred which resulted in the opening of power-actuated pressurizer relief valve 3RC-66. Valve 3RC-66 remained open and a Reactor Coolant System depressurization continued until isolation valve 3RC-4 was shut. The Reactor Coolant System temperature and pressure were 480°F and 720 psi, respectively, when the depressurization was terminated. The shutdown was continued with a cooldown rate of 100°F/hr as specified in Technical Specification 3.1.2.3; however, when the initial drop in temperature due to depressurization was combined with the subsequent cooldown, the cooldown rate for the first hour was 101°F.

Designation of Apparent Cause of Occurrence:

The apparent cause of this occurrence was operator error, in that the operator did not consider the initial RC temperature drop, which occurred during depressurization, when establishing the subsequent cooldown rate.

The reason 3RC-66 remained open was due to boric acid crystal buildup on the connecting pin of the lever arm of the pilot valve. In addition, a solenoid-operated plunger was stuck in the open position.

Analysis of Occurrence:

This incident resulted in exceeding the allowable cooldown rate of 100°F/hr by 1°F/hr. Due to the design conservatism of the reactor vessel, and transients which have previously been analyzed, it can be concluded that the health and safety of the public was not affected.

Corrective Action:

In the future after such a transient, an evaluation will be performed to determine the maximum allowable cooldown rate to be utilized. Valve 3RC-66 was removed, repaired, and replaced.

Dupe of
7905100302
1p

DUKE POWER COM
POWER BUILDING
422 SOUTH CHURCH STREET, CHARL...

Reference 9

WILLIAM O. PARKER, JR.
VICE PRESIDENT
STEAM PRODUCTION

TELEPHONE: AREA 704
373-4083

August 8, 1975

Mr. Norman C. Moseley, Director
U. S. Nuclear Regulatory Commission
Suite 818
230 Peachtree Street, Northwest
Atlanta, Georgia 30303

Re: Oconee Nuclear Station
Docket No. 50-287

Dear Mr. Moseley:

My letter of June 27, 1975, transmitted to you Abnormal Occurrence Report AO-287/75-7, Excessive Reactor Coolant System Cooldown Rate. The following information provides additional information relating to this occurrence and associated corrective action.

As stated in AO-287/75-7, when reactor power level had decreased in the course of a routine maintenance shutdown, a minor system transient occurred, which resulted in the opening of the power-operated relief valve 3RC-66. Prior to the system transient, reactor power was being reduced from 100% FP to 15% FP in an orderly manner by the Integrated Control System. When 15% FP was reached, unit load demand was 65 MWe, and power generation was 115 MWe. This difference between unit load demand and power generation existed because the reactor was operating at its low limit of 15% FP while in automatic ICS control and could not further follow unit load demand. Meanwhile the control operator placed the turbine control station in manual, leaving the ICS in the "load tracking" mode. This led to a rapid increase in unit load demand to match the generated megawatt output. In the meantime, the main steam bypass valves opened; and when the main steam pressure decreased, the valves closed. The ICS control of feedwater flow could not follow the rapid change in unit load demand and steam pressure; consequently, feedwater flow and steam generator level oscillated, resulting in the Reactor Coolant System temperature and pressure transient.

The power operated relief valve, 3RC-66, opened when RCS pressure reached 2255 psi but failed to close when the pressure dropped below 2220 psi, although the open/closed lights in the control room did not indicate that the valve was open. Consequently, RCS pressure dropped, the reactor tripped on low pressure, and the HPI system actuated.

Dupe of
7905100303
38p.

II
COPY SENT REGION

8578

Although the operator closed the isolation valve, 3RC-4, immediately after the reactor trip to terminate the depressurization, the valve was reopened because of the rapidly rising pressurizer level. Valve 3RC-4 was finally closed when RC pressure reached 800 psi, terminating the pressure transient. The subsequent controlled cooldown of the Reactor Coolant System, when combined with the temperature drop during the transient, resulted in a cooldown of 101°F during the first hour when temperature was below 530°F, contrary to the provisions of Technical Specification 3.1.2.3. The transient and associated events also caused the quench tank rupture disc to blow open, Mirror insulation to be separated from the bottom nozzle of the pressurizer, and the release of approximately 1500 gallons of reactor coolant to the Reactor Building sump.

The release of reactor coolant did not cause any significant increase of radiation level in the Reactor Building, and no radioactivity was released into the environment.

As addressed in AO-287/75-7, the excessive cooldown rate associated with the transient has been evaluated and it was determined that the health and safety of the public was not affected. No other system limits were exceeded.

The failure of 3RC-66 to close and the malfunctioning of the valve position indication in the Control Room have been investigated. It has been found that the valve was stuck in the open position because of heat expansion, boric acid crystal buildup on the valve lever, rubbing of the level against the solenoid brackets, and bending of the solenoid spring bracket. The valve was repaired and reinstalled. The malfunctioning of the valve position indication was not observed when the repaired valve was reinstalled. This malfunctioning was apparently caused by the sticking of the solenoid plunger at slightly less than the full open position or by the crud buildup around the plunger operated microswitch to the open/closed lights.

Additionally, to prevent recurrence of this incident, the following corrective actions have been or will be implemented.

1. The unit shutdown procedures for all Oconee units have been revised to include a change that will prevent decreasing unit load demand below 120 MWe before placing the ICS in the tracking mode. This would minimize the error between the unit load demand and generated power and thus would reduce the possibility of feedwater flow and RCS transients.

2. The Units 1 and 2 power-actuated pressurizer relief valves will be examined as soon as possible for any indication of boric acid crystal buildup.

3. To verify the proper functioning of RC-66, a test to cycle RC-66 prior to startup with a test signal corresponding to 2285 psi will be incorporated into the station operating procedures.

4. The quench tank rupture disc has been replaced, and the bottom nozzles on the pressurizer were dye penetrant tested and the Mirror insulation replaced.

5. Operating personnel have been advised of this incident with specific instructions that immediate closure of 3RC-4 is the proper corrective action for such an occurrence.

Very truly yours,

William O. Parker

William O. Parker, Jr.

PMA:vr

cc: Mr. Angelo Giambusso