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DEPARTAMENTO DE TECNOLOGIA DE REATORES		DATA 3/09/80
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DETR.PD-072/79

TITULO

OCORRÊNCIAS RELACIONADAS COM A SEGURANÇA EM CENTRAIS NUCLEARES

NOTAS CORRELATAS

OBJETIVO

Organizar uma lista de ocorrências relacionadas com a Segurança de Centrais Nucleares.

LISTA DE DISTRIBUIÇÃO

SUPED (1)
ASPC.PD * (1)
DETR.PD (2)
AUTOR(ES) (3)
SEDOTE.PD (1)
EQ.Análise de Acidentes (1)

* Apenas folha de rosto

RESUMO E CONCLUSÕES

São apresentadas algumas ocorrências relacionadas com a Segurança em Centrais Nucleares a água leve dos EUA, selecionadas devido a suas singularidades e/ou ao seu interesse nas operações de reatores, publicadas na "NUCLEAR SAFETY" no período de janeiro/75 a abril/80.

ÍNDICE

Nº. CÓPIAS 9

AUTOR (ES)	VISTO	DATA	APROVAÇÃO	VISTO	DATA
C.V.C.AZEVEDO	[signature]	04/09/80	CHEFE DO LAB. OU GRUPO		
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CLASSIFICAÇÃO

TAREFA: 11.28

OCORRÊNCIAS RELACIONADAS COM A SEGURANÇA DE CENTRAIS NUCLEARES

1. INTRODUÇÃO

Nesta Nota, apresentam-se alguns eventos ocorridos em Centrais Nucleares a água leve, nos Estados Unidos da América do Norte.

Essas ocorrências, relacionadas com a Segurança, foram selecionadas dentre as publicadas na Revista "Nuclear Safety" no período de janeiro de 1975 a abril de 1980. Essa seleção, feita pela equipe do periódico acima mencionado, se baseou nas singularidades dos eventos e/ou no interesse geral dos mesmos para operação de reatores.

Os eventos selecionados são comentados nos Anexos, sendo que uma idéia geral dos mesmos pode ser obtida pela leitura das partes assinaladas.

2. OCORRÊNCIAS EM PWR

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3. OCORRÊNCIAS EM BWR

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ANEXOS

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SELECTED SAFETY - RELATED EVENTS IN NUCLEAR POWER PLANTS - PWR

NUCLEBRÁS

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DATE	EVENT	FACILITY	REACTOR SUPPLIER	MW(e)	ANEXO
02.26.75	Steam-Generator Tube Failure	Point Beach 1	W	485	3.2
05.01.75	Reactor Coolant Pump Seal Water System Fail	H.B.Robinson 2	W	665	4.1
-	Control System Causes Transients	Oconee 3	B&W	860	5.1
-	Noble-Gas Release	Zion	W	1100	5.2
12.07.75	Fuel Assembly Fails	Point Beach 1	W	497	7.1
03.18.76	Supervisor Received Estimated 8-rem Exposure	Zion 1	W	1100	9.2
08.10.76	Hurricane Isolates Plant from Grid	Millstone 2	C-E	870	10.1
10.09.76	Turbine Building Partially Flooded	Oconee 3	B&W	860	10.2
09.18.76	Human Error Causes Diesel-Generator Fire	Zion 2	W	1100	11.3
Dec. 76	Diesel Damaged During Surveillance Testing	Millstone 2	C-E	870	11.2
07.05.76	Set-Point Change Produces Unexpected Results	Millstone 2	C-E	870	11.4
04.15.77	Loss of Instrument air Causes Damage to Reactor Coolant-Pump Seals	St. Lucie 1	C-E	777	12.2

ABBREVIATIONS: B&W - Babcock & Wilcox Co.
C-E - Combustion Engineering Inc.
W - Westinghouse Electric Co.

NUCLEBRÁS

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DATE	EVENT	FACILITY	REACTOR SUPPLIER	MW(e)	ANEXO
July 76	Power-Distribution Anomaly	St. Lucie 1	C-E	777	12.3
07.08.77	Power Oscillations	Oconee 3	B&W	860	13.2
03.20.77	Common-Cause Incident Involving Nonnuclear Instrumentation	Rancho Seco	B&W	913	14.1
10.24.78	Contaminated Water Spill	North Anna 1	W	850	15.1
12.14.78	Feedwater Valving Problems	Oconee 1	B&W	860	16.1
01.05.79	Fast Reactor Cooldown	Rancho Seco	B&W	913	17.1
09.25.79	Gaseous Activity in Auxiliary Building	North Anna 1	W	850	17.2
11.10.79	Non-Class 1E Instrumentation and Control Power Lost During Operation	Oconee 3	B&W	860	18.1
09.25.79	Cascading Events Cause Minor Release of Radioactivity	North Anna 1	W	850	18.2

SELECTED SAFETY-RELATED EVENTS IN NUCLEAR POWER PLANTS - BWR

DATE	EVENT	FACILITY	REACTOR SUPPLIER	MW(e)	ANEXO
06.23.74	Feedwater Piping Damaged	Dresden 3	GE	800	1.1
04.03.74	Resin Gets Into Reactor Vessel	Arnold 1	GE	545	1.2
09.13.74	Cracks Found in Reactor Coolant Piping	Dresden 2	GE	800	1.3
08.31.74	HPCI System Failed to Start	Quad Cities 2	GE	800	1.4
09.12.74	Recurring Leaks on Minimum Flow Line	Dresden 2	GE	800	1.5
12.13.74	Cracks in Primary - System Piping	Dresden 2	GE	800	2.1
10.30.74	Fuel Cladding Ruptured by Rapid Flux Change	Dresden 3	GE	800	2.2
03.27.75	Contamined Plant Heating System	Millstone 1 (2)	GE	660	3.3
03.22.75	Cable Fire	Browns Ferry	GE	1067	3.5
05.22.75	Fuel Failure and Off-Gas Release	Quad Cities 2	GE	800	4.2
-	Feedwater Line Breaks	Quad Cities 2	GE	800	5.3
11.05.75	Hydrogen Explosion Injures Two	Cooper	GE	778	6.2

ABBREVIATION : GE - General Electric Co.

DETR.PD

NUCLEBRÁS

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DATE	EVENT	FACILITY	REACTOR SUPPLIER	MW(e)	ANEXO
01.19.76	Explosion in Stack Filter House	Brunswick	GE	790	7.2
01.07.76	Off-Gas Building Demolished by Explosion	Cooper	GE	778	8.1
02.12.76	Isolation Condenser Tube Failure	Millstone 1	GE	660	8.2
03.29.76	Operator Error Causes Increased Off-Gas Activity	Dresden 1	GE	200	9.1
11.12.76	Inadvertent Criticality	Millstone 1	GE	660	10.3
05.04.77	Unantecipated Short Periods During Shutdown Margin Tests	Quad Cities 1	GE	800	12.1
12.28.76	Short Periods During Reactor Startups	Dresden 2	GE	800	12.4
02.23.77	Short Periods During Reactor Startups	Monticello	GE	536	12.4
12.13.77	Hidrogen Explosions	Millstone 1	GE	660	13.1
06.17.77	Cracks Found in Nozzle Safe Ends	Arnold 1	GE	545	14.2
06.28.78	Examination of Mark 1 Containment Torus Welds	Vermont Yankee	GE	514	14.4
11.24.78	Short Period	Cooper	GE	778	15.2

NUCLEBRÁS

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DATE	EVENT	FACILITY	REACTOR SUPPLIER	MW(e)	ANEXO
12.14.78	Short Period During Startup	Oyster Creek	GE	620	15.3
05.02.79	Loss of Coolant Inventory	Oyster Creek	GE	620	16.2

Selected Safety-Related Occurrences Reported in September and October 1974

Compiled by William R. Casto

Of the incidents reported during September and October, five are reviewed here because of their uniqueness and/or general interest to reactor operations. Incidents selected for discussion include (1) damage to the Dresden 3 feedwater system, (2) demineralizer resin in the reactor vessel at Arnold 1, (3) cracks in a recirculation loop at Dresden 2, (4) failure of the high-pressure coolant-injection (HPCI) system to start at Quad Cities 2, and (5) recurring leaks into the main condenser at Dresden 2.

1.1 FEEDWATER PIPING DAMAGED

On June 23, 1974, at Dresden 3, vibrations in the feedwater system damaged the feedwater piping.[1] This boiling-water reactor (BWR) is owned and operated by Commonwealth Edison Company, Chicago, Ill. At the time of the incident, the load on the unit was being returned from 630 MW(e) to full power after a load drop for weekly surveillance tests. The operators visually inspected the piping and decided to shut the unit down in order to make a more detailed examination. The examination revealed that the system had incurred the following damage:

1. The low-flow feedwater-regulation valve was open and had been rotated approximately 30°. All air lines and electrical feeds to the valve were broken off and bent, the upstream pipe support for the low-flow valve was broken off its pad, and the concrete base was cracked.
2. The A feedwater-regulation valve upstream pipe-support pad was dislodged from its cement base.
3. The B feedwater-regulation valve air-supply line was broken off its main header.
4. All three reactor feed-pump discharge-line pipe supports showed signs of movement. The A feed-pump warming line was bent, the C feed-pump discharge-line flow-element tap appeared to have been bent, and the A pump minimum-flow line to the condenser had loose insulation.
5. In the D heater bay, two pipe hangers on the heater outlet had broken tack welds, and a pipe-support pedestal for a heater line was displaced.
6. In the turbine pipeway in the extraction-steam piping, one pipe-support pedestal had moved about 2 cm, and the pipe-support-pad cement for one line was cracked.
7. Three concrete pads for pipe-support pedestals holding the reactor feed-pump suction header under the hot well were cracked.

The feedwater system was repaired and checked before operation was resumed.

From a review of the recorder charts for feedwater flow, reactor water level, and condensate-demineralizer differential pressure, it appeared that the A feedwater-regulation valve had nearly closed suddenly. No reason could be found for this action, and the investigation was continued. This occurrence in no way jeopardized the safety of the public or the plant.

1.2 RESIN GETS INTO REACTOR VESSEL

During preoperational testing on Apr. 3, 1974, demineralizer resin from the reactor water cleanup system was inadvertently introduced into the reactor vessel of Arnold 1, Palo, Iowa,[2] owned by Iowa Electric Light & Power Company. While the test was in progress, the discharge valve from the reactor water cleanup system to the radwaste system was open while the filter-type demineralizers were in "hold," i.e., they were ready for operation. The operators thought that the demineralizer tanks had partially drained, allowing the resin to drop off the septa, and that, when the system was placed back in operation, the resin passed through the septa and into the reactor vessel. An investigation disclosed the following five mechanisms that individually or collectively could have contributed to the problem; the corrective actions taken in each case are listed:

1. Inadequate pipe venting. A plant-design change was initiated to provide automatic venting of the high-point piping on the discharge lines for the holding pump.
2. No automatic isolation of filter demineralizer. A plant-design change was initiated to provide automatic

isolation of the reactor water cleanup-filter demineralizers in the event of low or no flow.

3. Improper valve lineups. A plant-design change was initiated to provide valve interlocks that prohibit initiation of backwash without the proper valve lineup.

4. No loss of holding-pump alarm. A plant-design change was initiated to provide a holding-pump status light and an alarm that is energized when the flow in the holding-pump loop is less than the minimum required.

5. Diluted precoats. Operations personnel were briefed on the importance of maintaining the proper mixture of water and resin in the resin precoat tank, and a copy of the vendor's operating procedures for reactor water cleanup was posted at the cleanup control panel to assist the operator.

A novel and successful procedure was devised to remove the resin from the reactor vessel. Advantage was taken of the sensitivity of resin to neutron damage and high temperature, both of which cause degradation of the resin, thereby forming sulfuric acid. Therefore a procedure was used that involved heating the reactor coolant to about 240°C, increasing the neutron flux, and controlling the *p*H with trisodium phosphate. While these conditions existed, the coolant was recirculated through one main steam line, through the turbine bypass to the condenser, through the condenser-demineralizer system, and through one of the feedwater regulating valves back to the reactor vessel. From a power-production viewpoint, the plant was down during the cleanup.

1.3 CRACKS FOUND IN REACTOR COOLANT PIPING

On Friday, Sept. 13, 1974, at Commonwealth Edison's Dresden 2 (BWR), a crack was discovered on the B recirculation loop in the 10-cm (4-in.) equalizing line around the discharge valve.[3] Since the crack was on the upstream side of the equalizing valve and the line could be isolated, repair of the crack was relatively easy.

Subsequent ultrasonic tests of the A recirculation-loop equalizing line around the discharge valve disclosed a similar crack. However, the second crack was on the downstream side of the valve at the 71- by 10-cm (28- by 4-in.) Weldolet (reducer) where the 10-cm (4-in.) line ties into the 71-cm (28-in.) recirculation riser and therefore could not be isolated by valves. Repair procedures were developed to isolate the cracked portion of the line with freeze plugs so that it could be replaced.

The planned repair involved the use of a freeze plug and an expandable rubber plug to preclude the loss of primary coolant from the 10-cm (4-in.)-diameter opening in the primary coolant line which occurred when the cracked section of pipe was removed to be replaced. Tests and experience had shown that the proposed plugs could preclude a loss of coolant under conditions more severe than those encountered during the actual repair program.

Backup plugging techniques to stop the minor loss of coolant that could have occurred in the event of a failure of a primary plug were developed and demonstrated. In addition, Commonwealth Edison has postulated and analyzed the failure of both the primary and backup plugging techniques. It was concluded that use of only a portion of the emergency core-cooling system (ECCS) would maintain the coolant level above the top of the fuel in this event. Operability of ECCS equipment and the diesel generators was demonstrated prior to starting the repair. The cause of the cracking is being investigated.

1.4 HPCI SYSTEM FAILED TO START

Commonwealth Edison's Quad Cities 2 (BWR)[4] scrammed at 2:07 a.m. on Aug. 31, 1974. A signal from the average-power-range monitor high-high flux system caused the shutdown when trouble occurred in the reactor recirculation system. During this time the Unit 2 breaker between the charger and the battery tripped spuriously, and the trip alarm was indicated in the control room. An operator visually checked the breaker and incorrectly reported that it was closed. The "Breaker Tripped" alarm indication was thus considered to be faulty.

By 5 a.m. the startup checklist was complete, including the item on operability of the batteries and chargers, which was checked as okay. Technically, this could be considered to be true at that time because the 250-V battery probably should not have been depleted, and the charger was operable but was not connected to the battery. The reactor went critical at 3:05 p.m. By 11:00 p.m., owing to equipment operation (including the emergency bearing-oil pump which is powered by this battery and which should have been secured shortly after the 2:07 a.m. turbine trip), the 250-V battery had been discharged to 70 V. At this time, problems developed in controlling the water level in the reactor vessel due to failure of the low-flow feedwater-regulation-valve air supply. Attempts were made to control the reactor water level by intermittently operating the reactor feed pumps. Subsequently, trouble with the reactor feed-pump ventilation-fan dampers prevented restarting a feed pump when it was needed, and the reactor scrammed. A further attempt was made to control the water level by trying to start the HPCI system, but the voltage from the battery was too low to actuate the valves. The reactor-vessel water level was restored to normal by manually operating the reactor-core isolation cooling (RCIC) system.

The following five operator errors caused this occurrence:

1. Incorrect observation of the position of the 250-V battery charger to battery breaker as closed and not tripped.

2. Incorrect determination that the "Breaker Tripped" alarm was a faulty alarm based on item 1.

3. Failure to report or cause subsequent investigation of observed dim HPCI valve lights on Unit 2.

4. Failure to notice dim valve lights on Unit 1 RCIC and other equipment. (Any of the above should have prompted investigation of low voltage on the 250-V battery and delay of startup until the problem was resolved.)

5. Failure to secure operation of the main-turbine emergency bearing-oil pump shortly after the turbine trip, causing unnecessary drain on the 250-V battery.

The "Abnormal Occurrences Report" was circulated to all licensed operators with an additional statement from the station management.

1.5 RECURRING LEAKS ON MINIMUM FLOW LINE

On Sept. 12, 1974, at Commonwealth Edison's Dresden 2 (BWR), increased air inleakage to the main condenser became apparent.[5] Prior to the occurrence the unit was in steady-state operation at 670 MW(e), and preparations were being made to shut down in order to investigate a leak into the dry well.

The leak of air into the condenser was found in the 2B reactor feed-pump minimum-flow line. Similar leaks had occurred on June 12 and Aug. 23, 1974, and in each case a patch had been welded over the affected area. This time the leak was at the edge of the most recent patch. Apparently the leaks were caused by erosion of the minimum-flow line, resulting from leakage past the normally closed valve on this line between the pump and the condenser. Another patch was welded over this latest leak, but the carbon-steel sections of pipe will be replaced with a chromium–molybdenum alloy steel to alleviate corrosion and erosion.

REFERENCES

1. Letter from B. B. Stephenson, Commonwealth Edison Company, to J. F. O'Leary, AEC Director of Licensing, Docket 50-249, July 2, 1974, available at AEC Public Document Room.
2. Letter from G. G. Hunt, Iowa Electric Light & Power Company, to AEC Director of Licensing, Docket 50-331, Aug. 13, 1974, available at AEC Public Document Room.
3. Letter from J. S. Abel, Commonwealth Edison Company, to Edson G. Case, AEC Deputy Director of Licensing, Docket 50-237, Sept. 23, 1974, available at AEC Public Document Room.
4. Letter from N. J. Kalivianakis, Commonwealth Edison Company, to John F. O'Leary, AEC Director of Licensing, Docket 50-265, Sept. 10, 1974, available at AEC Public Document Room.
5. Letter from B. B. Stephenson, Commonwealth Edison Company, to James G. Keppler, AEC Director of Regulatory Operations, Docket 50-237, Sept. 20, 1974, available at AEC Public Document Room.

Selected Safety-Related Occurrences Reported in January and February 1975

Compiled by William R. Casto

Of the incidents reported during January and February 1975, four are reviewed here because of their general uniqueness and/or their general interest to nuclear operations: (1) the through-wall cracks found at Dresden 2 both in the 10-in. core spray piping and in the 4-in. bypass lines on the recirculation system, (2) the fuel-cladding ruptures caused by rapid flux change at Dresden 3, (3) the plutonium contamination incident at Kerr-McGee Nuclear Corporation, and (4) a shipping accident involving a heavy cask.

2.1 CRACKS IN PRIMARY-SYSTEM PIPING

In the last two issues of *Nuclear Safety*,[1,2] the problem of cracks in the 4-in. bypass lines around the discharge valves of the recirculation pumps on boiling-water reactors (BWRs) was discussed. On Dec. 13, 1974, after the Dresden 2 BWR had been shut down for its third refueling, another crack was discovered during routine in-service inspection. Dresden 2 is owned and operated by Commonwealth Edison Company, Chicago, Ill.[3]

On Jan. 28, 1975, Commonwealth Edison notified the NRC's Region III Office of Inspection and Enforcement that five through-wall cracks had been found in the 10-in.-diameter core spray piping system at Dresden.[4] In view of all these cracking problems, the Nuclear Regulatory Commission (NRC) responded on January 30 with an IE Bulletin[5] requiring the operators of 23 licensed BWRs to complete within 20 days a prescribed inspection and test program on affected piping. The NRC subsequently announced[6] that inspections at 21 of the 23 reactors revealed no cracks in either the primary reactor piping or backup emergency core-cooling-system piping. However, an additional through-wall crack was discovered at Dresden 2 in the core spray system. The last of the 23 plants, Dresden 1, asked for and received an extension of time for the required inspection. The pipe cracking, which is apparently limited to Dresden 2, is discussed in more detail below.

Cracks in Dresden 2 Core Spray System

In its January 28 report to the NRC, the licensee, Commonwealth Edison Company, reported[5] that three cracks were identified in the A core spray loop and two in the B core spray loop. The cracks were revealed when moisture was observed seeping from them after the pipe insulation was removed in preparation for in-service inspection. The cracks range from ⅛ to ¾ in. in length on the outside surface.

The three cracks in the A loop are in an approximately 9-in.-long "dutchman" insert that is welded on one end to the reactor-vessel nozzle safe end and on the other end to the core spray inlet piping. The safe end and dutchman insert are reportedly fabricated from 316 stainless steel, and the core spray piping is 304 stainless steel. Two of these cracks are longitudinal and in the heat-affected zone of the weld between the safe end and dutchman insert. The other crack is circumferential and in the heat-affected zone of the weld between the inlet piping and dutchman insert.

The two cracks in the B loop are circumferential and on the pipe side of the heat-affected zone of the weld between the inlet piping and the dutchman insert.

The additional through-wall crack at Dresden 2 was discovered[4] on Feb. 9, 1975, in the core spray-injection line in the heat-affected zone of the butt weld. Ultrasonic testing showed the crack to be about 1½ in. long on the inside of the pipe from about 10 to 12 o'clock.

The exact cause of the failures at Dresden 2 has not been determined, but the investigation is continuing.

Cracks in 4-in. Bypass Lines at Dresden 2

The several cracks found in the 4-in. bypass lines around the discharge valves of the recirculating pumps all resulted in small leaks. The latest crack[3] (Dec. 13, 1974) was in the weld at a 4- to 6-in. Weldolet. Since the crack was downstream of the bypass valve, it could not be isolated from the reactor vessel. Leaks were visible at 8 and 6 o'clock around the circumference of this pipe. Ultrasonic and radiographic testing revealed that the cracks started at the inside surface of the pipe and progressed to the outside surface.

Although the exact cause of these failures is still unknown, intergranular stress-corrosion cracking was indicated by the analysis of specimens taken from the lines that failed on Unit 2 in September 1974. The investigation of the problem continues.

2.2 FUEL CLADDING RUPTURED BY RAPID FLUX CHANGE

At Commonwealth Edison's Dresden 3 BWR, operation for the last two cycles had been with the peak of the neutron flux and exposure toward the top of the core. Therefore it was decided to redistribute the flux, and the resulting sequence of events led to some ruptures of fuel cladding.[7]

The procedure for flux redistribution was started on Oct. 30, 1974, by lowering the power to 50% of full power. At 2:40 a.m. the next day, the control-rod sequence was initiated to alter the rod positions. By 5:00 a.m. the resulting load was 520 MW(e), and the power distribution in the core was satisfactory with the power peaked toward the bottom of the core. However, during this time, the xenon (poison) transient had reached its peak. When the xenon started burning out (introducing positive reactivity), the power peak increased rapidly, and by 6:24 a.m. excessive power peaking occurred in the lower region of the core. In an attempt to increase the effective volume of the core and thereby decrease the power peaking, the operator followed instructions and withdrew the control rods. This action, however, resulted in a 10% increase in the power peak, and the high off-gas radiation alarm sounded and caused the nuclear engineer to call for an immediate insertion of control rods. Even though the reactor power and peaking were reduced, the "hi-hi" off-gas radiation alarm tripped and started the 15-min isolation timer. Additional control rods were inserted, and at 7:35 a.m. the hi-hi off-gas radiation alarm cleared. An off-gas sample taken at 2:21 p.m. showed a release rate of 81,634 μCi/sec. The estimated maximum instantaneous off-gas release rate during the transient was about 300,000 Ci/sec. For the day, October 31, the estimated average release rate was about 45,000 μCi/sec, which is less than half of the Technical Specifications limit.

Since this occurrence, it has been necessary to operate at 50% or less of full power in order to control the release rate to desirable levels. It appears that the cladding of several fuel rods ruptured during this event owing to rapid changes in local power in areas of low fuel exposure. The cause is evidently a fuel and cladding interaction since no fuel safety limits were even approached. An isotopic analysis of the off-gas disclosed an approximate 75% "recoil" distribution which implies little or no holdup in the pellet or fuel column of fission-product gases. Therefore probably a few relatively large cladding perforations occurred during the power-peaking transient.

The nuclear engineers will be retrained in nuclear reactor engineering. Also, a new procedure for the review and approval of control-rod sequences for insertions and withdrawal has been placed in effect along with a new procedure for changing control-rod-sequence schedules.

2.3 AEC INVESTIGATIONS OF KERR-McGEE[8]

The Directorate of Regulatory Operations and the Division of Inspection of the U.S. Atomic Energy Commission have completed investigations[9] into a series of allegations made by members of the Oil, Chemical, and Atomic Workers International Union. The allegations were about working conditions and improper quality-assurance procedures at the Kerr-McGee Nuclear Corporation plutonium processing facility near Crescent, Okla.

Inspectors from the AEC Regulatory Operations Offices investigated 39 items reported by the union members dealing with four areas of concern. Only two of those items, and a third which was not among the allegations, were found to be in apparent noncompliance with AEC requirements. Eighteen others among the 39 items were found to have some substance and were called to the attention of Kerr-McGee.

The three items of apparent noncompliance—failure of the company to report to the AEC about a processing equipment problem; exceeding on two occasions the amount of plutonium permitted in a specific work area; and use by the licensee in a work area of a small quantity of plutonium in a form different from that authorized by the license—did not pose a hazard to workers or the public. Enforcement action will be taken by the AEC against Kerr-McGee concerning those items of apparent noncompliance.

During the time of this investigation, Ms. Karen Silkwood, an employee of Kerr-McGee who had been involved in the investigation, was killed in an automobile accident.[10] The circumstances surrounding her death and the allegations concerning the death prompted the AEC to make a special investigation into the plutonium contamination that Ms. Silkwood experienced.[11] The specific details from both AEC investigations are reported below.

Working Conditions and Quality-Assurance Procedures[8]

On the matter of quality-assurance procedures investigated by the Division of Inspection, four allegations were made by the union concerning falsification of records and other related irregularities in connection with the production of fuel for the AEC's Fast Flux Test Facility (FFTF) at the Hanford plant in Washington State. The investigation was for fact-finding purposes, and no conclusions are set forth in the report. An AEC task force has been established to review all quality-assurance and inspection procedures related to the fabrication of FFTF fuel by Kerr-McGee. If this review raises any question about the integrity of any of the fuel, that fuel will be rejected.

Kerr-McGee has a contract with the AEC to provide 18,500 plutonium fuel rods for the FFTF, a facility for testing components in the breeder reactor development program. None of the fuel has yet been used in the reactor. The FFTF is scheduled to go into operation in early 1978.

The investigation findings show some evidence to support two of the allegations—falsification of photomicrograph negatives of weld test samples and improper use of sample analytical data. The photomicrographs are used for verifying and recording the thickness of the fuel cladding next to the weld, and they supplement metallographic examinations for determining weld quality. In addition to the required inspections conducted by Kerr-McGee, the fuel is subjected to stringent overinspection after it arrives at Hanford; both destructive and nondestructive examinations are made of samples from each shipment. Of the fuel pins delivered to Hanford, about half have been so inspected with the result that less than 2% have been rejected.

Although the investigation showed some violation of quality-assurance procedures, the Hanford inspections have revealed no evidence or indication to date that the quality of the fuel pins has been compromised.

The investigation reports were released Jan. 7, 1975. Copies will be available for public inspection at the local Public Document Room in the Guthrie, Okla., Public Library, at the AEC's Regional Regulatory Operations Office in Chicago, and at the AEC's Public Document Room in Washington, D. C.

Plutonium Contamination of Karen Silkwood[11]

Ms. Karen Silkwood, a laboratory analyst at the company's plutonium-processing facility, was reported to be contaminated on November 7. Plutonium was first detected on Ms. Silkwood's skin on November 5 while she was working at the plant. The radioactive material was removed, but additional localized contamination was identified on her skin on November 6 and 7. Her apartment also was found to be contaminated.

Immediately after the November 7 report, an AEC investigation team began its study of this case. The team has found no evidence of any incident or accident at the Kerr-McGee facility that released plutonium and could account for the contamination found on Ms. Silkwood's skin and clothing.

Laboratory tests conducted as part of the investigation indicated Ms. Silkwood had ingested some plutonium. Additionally the investigation concluded that plutonium had been added to two of Ms. Silkwood's urine samples, the two submitted on November 5 and November 7, which showed high levels of plutonium contamination. No firm evidence was found to indicate by whom or in what manner the activity was added. Fecal samples showing evidence of plutonium contamination appear also to have resulted from the ingestion of insoluble plutonium by Ms. Silkwood.

Although the radioactive count was high and easily detectable, the actual amount of plutonium found in personal and apartment contamination was very small. The weight of plutonium involved was less than 0.0003 g (0.3 mg), or about $\frac{1}{100,000}$ of an ounce.

Kerr-McGee employees cleaned the plutonium contamination from Ms. Silkwood's apartment in Edmond, and the Oklahoma Department of Health has approved further use of the property. A very slight amount of plutonium contamination was found in Ms. Silkwood's car, but no other radioactivity was found outside the apartment. Ms. Silkwood later died in an automobile accident on November 13.

Another Kerr-McGee employee, Ms. Sherri Ellis, who lived with Ms. Silkwood, was found to have skin contamination on two areas of her body at the time the apartment contamination was discovered. The skin contamination was removed, and later tests showed evidence of some internal contamination with insoluble plutonium—apparently from ingestion.

Dr. George L. Voelz of Los Alamos (N. Mex.) Scientific Laboratory, who examined Ms. Ellis, reported the internal contamination was sufficiently low that it would not present a "significant health hazard from this exposure either now or in the future."

A much lower level of internal contamination, also thought to result from ingestion, was found by laboratory tests of samples taken from Drew Stephens, a friend of Ms. Silkwood.

Only one violation of AEC regulations was found during the investigation. It involved the company's failure to maintain proper records on two urine samples taken in October following a previous plutonium contamination incident involving Ms. Silkwood.

2.4 RADIOACTIVE WASTE SHIPPING ACCIDENT

On Oct. 15, 1974, at approximately 10:50 a.m., an accident occurred with a shipment of radioactive waste from the Pilgrim Nuclear Power Station.[12] The shipment consisted of one radwaste shipping cask containing 30 ft^3 of radioactive waste with an activity of 34 Ci and weighing approximately 17 tons. According to Section 9 of the Final Safety Analysis Report for the Pilgrim Station, the solid-pack internal filter contained approximately 600 lb of collected particulate material in the dry state. The container was secured to the flatbed truck body with three hold-down chains. Nuclear Engineering Company, Inc., has a contract with Boston Edison Company to transfer and dispose of radioactive wastes from the Pilgrim Station, and one of their trucks was making a routine delivery of radioactive wastes to Morehead, Ky.

The accident occurred at the intersection of routes 44 and 105 (near Middlesboro, Mass.) when the truck driver had to stop at a red traffic light. While the truck was stopping, the three hold-down chains broke and the container shot forward, lurched through the right front corner of the flatbed trailer, bounced three times on the road and made about an 18-in. depression in the blacktop on the first bounce, rolled in front of a stopped car, and finally came to rest in a triangular-shaped depressed grass and gravel area approximately 250 ft from the truck.

Since there was not much damage, the container was reloaded onto the truck, which returned to Pilgrim for a more complete inspection.

The container liner on the outside of the lead shield was slightly damaged, but the inner liner was not. The cask will be repaired. All future shipments of radioactive waste in such containers will be on low-boy trailers to prevent accidents of this type.

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Selected Safety-Related Occurrences Reported in March and April 1975

Compiled by William R. Casto

Five of the occurrences reported during March and April 1975 are summarized here because of their uniqueness and/or general interest to reactor operations. Relief valves failing to close at two boiling-water reactors (BWRs) in Europe caused suppression-pool damage, and a single tube failure in a steam generator at Point Beach caused a leak rate of 125 gal/min from the primary to the secondary systems. In an event that attracted some publicity, the plant heating system at the Millstone nuclear power station became contaminated. Monticello appears to have solved its problem of explosions in off-gas systems through a number of system-design modifications. The cable fire that occurred at the Browns Ferry nuclear power station will inactivate the plant for several months.

3.1 RELIEF-VALVE DISCHARGE TO SUPPRESSION POOL

On Nov. 14, 1974, th: Atomic Energy Commission (now NRC) issued Bulletin 74-14 to all boiling-water reactor (BWR) operators to alert them to a potential problem that could be caused by extended discharge from one or more steam-relief valves into the suppression pool. This problem was highlighted to all BWR operators because of difficulties experienced in Europe at two BWRs designed by General Electric Company (GE) and because of similar recent blowdowns at two U. S. facilities. A recent operating-experience bulletin summarizes these events and the actions requested of BWR operators by NRC.[1]

The first incident occurred in Germany while a relief valve was being tested with the reactor at 60% power. When the valve was given a signal to close, it did not respond. Attempts were made to close the valve for about 30 min while the reactor remained at power. During this period, the suppression-pool temperature continued to rise owing to the discharge of steam from the open relief valve. When the suppression-pool temperature exceeded 160°F, excessive vibrations occurred and increased until the suppression-pool metal liner separated from the reinforcing beams that had been bolted to the inside of the liner. The relief-valve discharge pipe at this facility is directed downward into the pressure-suppression pool; this design is different from that used in BWRs operating in the United States.

The second incident occurred in Switzerland while relief valves were being tested with the reactor at 40% power. While one relief valve was being operated for 5 min, a second adjoining valve was opened by the operator. Within 2 min, suppression-pool vibration was heard; approximately 1 min later the test was terminated by closing both valves. The vibrations caused displacement of the catwalk sections and failure of an instrument line in the suppression pool.

The vibrations at both foreign reactors were associated with steam condensation when the steam jetted into the suppression-pool water when the pool temperature was at or about 160°F. The high-temperature condensation created destructive impulses produced by the rapid collapse and formation of steam bubbles in the hot suppression-pool water.

In two events at U. S. BWRs, stuck relief valves caused suppression-pool temperatures to rise to at least 120°F. One of these two events was at the Peach Bottom Atomic Power Station, Unit 2, owned by the Philadelphia Electric Company and located in York County, Pa. The other event was at the Cooper Nuclear Power Station, located in Nemaha County, Nebr., and owned by the Nebraska Public Power District. Neither resulted in vibration or damage to the pool because temperatures remained within a range of 120 to 145°F, which is about 15°F below what appears to be the critical temperature.

The NRC requested BWR licensees to review operating procedures applicable to this problem to determine if those procedures should be modified in any of the following ways:

1. Limiting bulk suppression-pool temperatures during normal operation and during controllable transients.

2. Requiring reactor trips if the bulk suppression-pool temperature exceeds that established as a limit of controllable transients or if one or more relief valves fails to reseat properly.

3. Taking prompt steps in case of inadvertent relief-valve actuation or failure to reseat to minimize the duration of steam discharge to the suppression

pool; in case of relief-valve discharge, promptly initiating suppression-pool circulation to dissipate local peaking of water temperatures.

4. Conducting visual internal and external inspection of the suppression-pool structure for evidence of damage in instances where one or more relief valves fail to reseat properly or discharge to the suppression pool for an extended period of time.

Licensees also were requested to ensure that procedural changes made to minimize the effects of steam discharge to the suppression pool had no adverse effects in other areas.

In addition to Bulletin 74-14, licensees received information from GE on interim operating procedures and pool temperature limits to assist them in relating this problem to their own operation. Specifically, GE recommended a limit of 110°F for the torus temperature, followed by a scram.

3.2 STEAM-GENERATOR TUBE FAILURE

On Feb. 26, 1975, Point Beach Unit 1 was operating normally at full power, 485 MW(e), when the radiation monitor at the air ejector indicated a burst of high radiation.[2] The pressurized-water reactor (PWR) is owned by Wisconsin Electric Power Company of Milwaukee. Various other control-room indicators in turn showed primary water loss that peaked in 0.5 hr at 125 gal/min. This loss was suspected, and subsequently confirmed, to be a tube failure in steam generator B. A combination of automatic and operator actions with the charging pumps maintained reactor pressure and a normal main coolant inventory of water. Some radioactivity, principally xenon, leaked into the steam and condensate systems, but no in-plant evacuation of personnel was necessary. Cooldown of the primary system was normal. It is estimated that 2 to 3 weeks will be required for repair.

3.3 CONTAMINATED PLANT HEATING SYSTEM

On Mar. 27, 1975, an inadvertent injection of contaminated liquid into the condensate-return systems of the plant heating boilers occurred[3] at the Millstone Nuclear Power Station, owned by the Northeast Nuclear Energy Company and located near Waterford, Conn. The plant heating piping for both units (a BWR and a PWR) was contaminated, as were the boiler-room floor, portions of the adjacent maintenance shop, and a portion of the transformer yard outside the boiler room. Also, unmonitored radioactive water was released to the discharge canal of the circulating water system. The incident received some unanticipated publicity when construction workers were ordered to leave the site in order to facilitate contamination control.

Unit 1, a BWR, had a 1200-ft^2 floor area contaminated to about 80,000 dis/min per 200 cm^2. At Unit 2, a PWR, the floor contamination around the steam-condensate surge tank was 100,000 dis/min per 100 cm^2, and that in the area of the heating-steam condensate recovery tank was 80,000 dis/min per 100 cm^2. The steam piping generally read 1 mR/hr at Unit 2, with local points and traps reading 5 to 6 mR/hr. The contaminated areas were small. Although 12 pairs of work shoes became contaminated, no personnel were directly contaminated. The average concentration of contamination in the boiler makeup water was 5×10^{-3} μCi/ml. To facilitate the survey that developed the above results, all Unit 2 construction workers were directed to leave the site after being checked for contamination.

The spread of contamination occurred as follows. In an evaporator, high-activity liquid waste is concentrated by passing boiler steam through a coil bundle to heat the waste. This steam is also used in a ring sparger in the bottom of the evaporator to reduce the viscosity of the concentrate when the system is in the hot-standby mode. Condensate from the steam line and from the coil bundles is collected in a recovery tank in the radwaste building. Discharges from this tank are monitored for conductivity and returned to the boiler makeup system if the conductivity is less than 15 μmhos/cm. In addition to positioning two valves associated with the two flow paths, this conductivity cell indicates the quality of the water to the radwaste operator and supplies a signal to an alarm at a level of 15 μmhos/cm.

The contamination occurred when the evaporator concentrate was being blown down. The isolation valve on the steam line to the sparger leaked, and as a result the high-activity concentrate flowed to the condensate-return tank in the radwaste area. Because the conductivity-cell wiring for the protective division system had been wired incorrectly during maintenance in January, the valves were in the wrong aspect, and the concentrate flowed to the boiler makeup system rather than to the radwaste system. Contaminated water then spilled to the boiler-room floor from the boiler makeup deaerating tank. This water ran from the boiler-room floor drain to a clean sump in the turbine building, from which it was pumped unfiltered and unmonitored to the discharge canal. Even though the calculated concentration of the release was 1.4×10^{-6} μCi/ml, compared to the allowable 10^{-6} μCi/ml, the belief is that the release was less because of the conservative assumptions used in the calculation.

The contamination was cleaned up, and the necessary repairs were made. Instructions were issued that sumps be sampled before being pumped down and, if found to be contaminated, be pumped to the radwaste system. An engineering analysis of the auxiliary steam systems to determine safety implications was started. Other systems with similar interconnections or with the possibility of this type of interaction will be investigated.

3.4 IGNITIONS IN OFF-GAS SYSTEM ELIMINATED

Hydrogen ignitions occurred[4] on May 20, 1974, and June 10, 1974, during tests of the modified off-gas system at the Monticello nuclear generating plant, a BWR owned by the Northern States Power Company, Minneapolis, Minn. These occurrences were reported in an earlier issue of *Nuclear Safety*.[5] Prior to resumption of modified off-gas system testing in July 1974, special monitoring instrumentation was installed between the air ejectors and the recombiner-train eductors. The instrumentation included fast-response pressure transducers, off-gas flow-control-valve position indicators, fast-response strain gages, and thermocouples. In addition, the air-ejector rupture disks were blank flanged to preclude the inadvertent release of activity in the event of another detonation.

Shortly after the plant reached 25% power on July 8, 1974, a third off-gas hydrogen ignition occurred, and the off-gas system was automatically isolated owing to high pressure. The plant was immediately shut down, the off-gas holdup system was returned to the original design configuration, and the plant was returned to operation. Since no physical damage or radioactivity releases resulted from the ignition, the event was determined not to represent an abnormal occurrence. An analysis of data received from the special test instrumentation disclosed that the hydrogen ignition originated in the train B inlet piping near the off-gas flow-control valve. The detonation wave traveled to train A, causing the bypass valve to open slightly, and through the piping to the air-ejector discharge. The shock wave traveled at 7000 to 10,000 ft/sec with instantaneous pressures as high as 200 to 00 psi existing for 1 to 2 sec and then decreasing to within ±3 psi of the initial pressure in 5 to 6 sec. The air-ejector suction isolation valves were automatically tripped closed approximately 3 sec after the detonation. Analysis of temperature data disclosed that limited recombination had been occurring in the off-gas 24-in.-diameter holdup pipe and in the vicinity of the inlet flow-control and bypass valves of both recombiner trains. This recombination action had been most significant in the vicinity of the train B inlet flow-control valve.

Material samples from the off-gas piping and valves were analyzed for the presence of catalyst using neutron activation and differential scanning calorimetry; both techniques gave positive indication. Further investigation revealed catalyst pellets in both recombiner vessels below the retention screen, in both preheaters, in the train A pressure-control valve, and in two capped low-point drains. The catalyst pellets were postulated to have been transported from recombiner A during a system flush and from both recombiners during system operating transients.

An extensive mechanical and chemical cleaning program was developed to remove all traces of catalytic material from the off-gas piping and valves. The program involved excavating below the recombiner building, cutting sections of the 6-in. inlet return piping from the 24-in. delay pipe, and removing one end of the 24-in. delay pipe. These lines were cleaned using a 10,000-psi hydro laser, dry and wet sandblasting, and a final chemical cleaning using a solution of phosphoric acid. The off-gas piping inside the recombiner building was cut into sections and cleaned using a 10,000-psi hydro laser and a final chemical cleaning using a phosphoric acid solution. The bonnets and internals of control and isolation valves were removed and hand cleaned. After completion of all cleaning and flushing operations, material removed from off-gas-system pipes and valves, when tested for the presence of catalyst using the differential scanning calorimetry technique, exhibited a response less than or equal to that received from material removed from the control (uncontaminated) piping. This was considered as positive evidence that all catalyst had been removed.

Steps were taken to prevent recurrence of catalyst contamination of the off-gas piping: both recombiners were unloaded and the catalyst-retention screens modified to prevent pellets from leaving the recombiner. Additionally, a second screen was installed at the recombiner inlet nozzle.

No further ignitions have occurred, and off-gas inlet piping temperatures have remained at normal levels during operational testing conducted following completion of the cleanup and recombiner modifications.

3.5 CABLE FIRE AT BROWNS FERRY NUCLEAR PLANT

On Mar. 22, 1975, a fire started[6,7] at the Browns Ferry Plant in the cable spreading room at a cable penetration through the wall between the cable spreading room and the reactor building for Unit 1. There are three BWRs at this site, which is owned and operated by the Tennessee Valley Authority. A slight differential pressure is maintained as designed across this wall around the Unit 1 reactor, with the higher pressure being on the cable-spreading-room side. The penetration seal originally present had been breached to install additional cables required by a design modification. Site personnel were resealing the penetration after cable installation and checking the air flow through a temporary seal with a candle flame prior to installing the permanent sealing material. The temporary sealing material was highly combustible and caught fire. Efforts were made by the workers to extinguish the fire at its origin, but they apparently did not recognize that the fire, under the influence of the draft through the penetration, was spreading on the reactor-building side of the wall. The extent of the fire in the cable spreading room was limited to a few feet from the penetration; however, the presence of the fire on the other side of the wall from the point of ignition was not recognized until significant damage to cables related to the control of Units 1 and 2 had occurred.

Although control circuits for many of the systems which could be used for Unit 1 were ultimately disabled by the fire, the station operating personnel were able to institute alternative measures by which the primary system could be depressurized and adequate cooling water supplied to the reactor vessel. Unit 1 was shut down manually and cooled using remote manual relief-valve operation, a condensate booster pump, and control-rod-drive-system pumps. Unit 2 was shut down and cooled for the first hour by the reactor core isolation coolant system. After depressurization, Unit 2 was placed in the residual heat-removal shutdown cooling mode, with makeup water available from the condensate booster pump and control-rod-drive-system pump.

All reactor licensees were directed[6] to take a variety of actions intended to minimize the possibility of the occurrence of this type event elsewhere. Further action may be required once the accident and its ramifications have been fully investigated and evaluated. Detailed information on the cause of the fire and the operability of the various reactor systems during the fire is being developed by NRC inspectors. Information developed thus far indicates the following facts:[8]

1. Although some instrumentation was lost, certain critical instrumentation (such as reactor water level, and temperature and pressure indicators) continued to function, and both plants were safely shut down.

2. The nuclear fuel remained covered by cooling water at all times.

3. Control of some systems normally used for cooling the reactors was impaired or lost owing to the fire, and alternate methods of cooling, principally the control-rod-drive pumps and the redundant condensate booster pumps, were used. The reactors were depressurized.

4. On Unit 1, although a loss-of-coolant accident had not occurred, the emergency core-cooling system (ECCS) was activated, and that system then supplied additional water to the reactor. The ECCS was manually shut down to prevent overfilling. Later, during cooldown, when the ECCS was called for manually as one of several alternate means of supplying cooling water, it did not activate; the alternate methods had more than sufficient capability to cool the core. The ECCS behavior is under specific investigation.

5. On Unit 2, although four pumps in the low-pressure ECCS were inoperable, adequate cooling from the ECCS was available since redundant pumps were functional. Emergency core-cooling water was provided initially as in Unit 1, but emergency core-cooling systems were not called back into operation to cool the reactor. The core was cooled during the first several hours by a high-capacity pump. After several hours the pump was shut off, and Unit 2 was cooled essentially as was Unit 1.

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ANEXO 4

Selected Safety-Related Occurrences Reported in May and June 1975

Compiled by William R. Casto

Of the incidents reported during May and June 1975, two are reviewed here because of their uniqueness and/or their general interest to nuclear operations: (1) a reactor coolant pump seal failure at H. B. Robinson 2 and (2) a fuel failure and off-gas release at Quad Cities 2.

4.1 REACTOR COOLANT PUMP SEAL WATER SYSTEM FAILS

At the H. B. Robinson 2 nuclear power plant, the seal water system for one of the three reactor coolant pumps failed. This pressurized-water reactor plant, owned and operated by the Carolina Power & Light Co., is located in Hartsville, S. C. During the incident the leak rate exceeded the capacity of the charging pumps, but water levels in the reactor coolant system were maintained by the safety-injection pumps. Before the leak was stopped, the containment floor had been flooded to a height of 12.5 in., a total of 132,500 gal of water. However, since the plant had been designed to handle such an incident, there was no damage beyond that sustained by the reactor coolant pump.[1].

The trouble began May 1, 1975, after the plant had just reached full power following a maintenance outage. Naturally, xenon was building up in the core, and the boron dilution procedure was under way to compensate for the gradual reactivity loss due to the xenon. During the dilution process the operators observed that the seal leakoff flow from pump C was sensitive to all additions of water to the primary system. Seal water is supplied by the charging pumps that return the letdown flow after cleanup back to the reactor coolant system. Since the seal leakoff flow was within limits and since the variations were gradual (not spiking), operation continued. Sometime later the flow spiked several times, but the reactor coolant pump vibrations were normal. The seal leakoff flow then oscillated full range several times and stabilized at greater than 6 gal/min. At this point, load reduction at 10% of total power per minute was started. When the load reached 36% of full power, power reduction was stopped and the reactor coolant pump C was shut down. Soon thereafter the reactor scrammed when the turbine tripped because of a high water level in one of the three steam generators.

Failure of the seal No. 1 on pump C permitted 540°F primary coolant to flow through the seal, heating its thermal barrier. Heating of the thermal barrier caused steam to form suddenly in the component cooling water used to control temperature in the thermal barrier. This steam formation resulted in high flow indications in the component-cooling-water return line from the pumps and automatically closed the common component-cooling-water return valve. This time, the shift foreman ordered pumps A and B stopped when flashing of primary coolant in the No. 1 seal-water leakoff line, which is common to all pumps, threatened to cause loss of seal flow. When the first section of the C pump seal system failed, the resulting flow of primary coolant past the seal caused the flashing in the seal leakoff line. The leakoff isolation valve for the No. 1 seal of pump C was not closed prior to stopping pumps A and B, and the No. 1 seal flow was then lost on pump A. The No. 1 seal leakoff return isolation valve from pump C was shut to reduce pressure surges in the common return lines. The No. 1 seal flow was then lost on pump B.

Owing to the failure of the No. 1 seal and the subsequent failure of the thermal barrier's cooling function, hot water was entering the reactor coolant drain tank via the normal No. 2 seal leakoff line. Since this water was flashing to steam, causing a pressure buildup in the drain tank, a valve was opened to drain the tank to the containment sump.

After it was determined that the thermal-barrier cooling coils were not leaking, the common automatically controlled outlet valve on the component-cooling line for the thermal barriers was blocked open to reduce temperatures to below boiling in the thermal barrier of pump C. After temperatures were reduced, the valve was unblocked and it stayed in its normal open modulating position.

When seal-water flow could not be reestablished on pumps A and B, it was decided to operate pump C as long as the second section of its seal continued to function. Primary coolant flow was desirable for proper mixing of the boron that was being added in preparation for cooling down the system. The pump was started and operated for 93 min before failure of the second and third portions of its seal caused the pump to be shut down. The leak rate through the completely failed seal system decreased the pressurizer level drastically, and it was necessary to use the safety-injection system to maintain the pressurizer level while the leak to the containment system was being stopped.

The occurrence resulted in no off-site releases or exposures, and at no time were the plant personnel in any danger. Failure of the seal caused overheating of the pump shaft and seal housing. The seals and their housing, the pump shaft, and associated equipment were replaced before the plant was again started up.

As a result of the containment flooding to a height of 12.5 in., approximately 650 ft of stainless-steel piping was submerged. Portions of this piping were flooded for 2 days in water that had a chloride concentration of 0.25 ppM. Consequently, there was concern for the saturation of the insulation with chlorides, possible leaching out on piping, and the potential for chloride stress corrosion.[2]

A chemical analysis of each pipe and insulation at its lowest elevation showed that both met the requirements of Westinghouse specification PS 83336 KA, which corresponds to Fig. 1 of Regulatory Guide 1.36, "Nonmetallic Thermal Insulation for Austenitic Stainless Steel." Thus the results indicate that sufficient leachable sodium and silicate ions were present to assist in minimizing the effects of chloride and fluoride.

On the basis of this evaluation, it was deemed unnecessary to remove and replace the wetted insulation; however, further sampling of the piping and insulation will be performed at the next scheduled outage.

4.2 FUEL FAILURE AND OFF-GAS RELEASE

On May 22, 1975, at Quad Cities Nuclear Power Station Unit 2, an unplanned off-gas release occurred as a result of fuel failure due to pellet–cladding interaction.[3] Following a 24-hr forced outage, the reactor had been brought up to power [560 MW(e)] using a combination of in-sequence rod withdrawals that produced abnormally high power peaking at the bottom of the core due to a low-xenon condition; this was followed by a power increase with core flow to 700 MW(e) [2120 MW(t)]. The net effect was a local power-level increase at a rate greater than that which would allow the fuel pellet-to-cladding stresses to relax without cladding failure.

Since no fuel safety limits were exceeded, the primary cause must be attributed to equipment failure (fuel damage). High-exposure fuel is evidently subject to failure from the pellet–cladding mechanical interaction if the local rate of power increase is excessive.

As a result of the fuel failure, the instantaneous peak release of off-gas was estimated to have been 0.19 Ci/sec, which is below the Technical Specification (license) limit of 0.506 Ci/sec. There were no effects on the health and safety of the public.

The initial corrective action to the off-gas release was to decrease reactor power with flow and to insert control rods to reduce the power peaking at the bottom of the core. The final corrective action will take the form of more detailed and formal instructions and information for use by the operating department in determining when a power increase should be slowed or halted owing to the possibility of causing fuel failure. Consideration is also being given to the possibility of reduced ramp rates or power soaks following outages of 25 hr or more in order to allow the buildup of a larger xenon inventory during nonemergency load conditions.

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ANEXO 5

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.

5.1 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 2285 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.

5.2 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.

5.3 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.

All reactor systems responded satisfactorily. There was no excessive exposure to plant personnel or contamination to the environs. An estimated 12,500 gal of water was released, about 8500 from the severed line and about 4000 from the service-water deluge system. An estimated 2500 gal of water with an average activity of about 1.9×10^{-2} μCi/ml flowed to the Unit 2 oil separator. This water was released by batches, so that the activity at the release point was less than the technical-specifications limit of 10^{-7} μCi/ml.

The following immediate corrective actions were taken:

1. Four snubbers were added to the piping at the feedwater regulating station to restrict the motion of the 6-in. low-flow line to mitigate the consequences of potential future vibrations.
2. New 4- by 6-in. reducers were installed on both sides of the low-flow regulating valve to replace the damaged reducers. The lower carbon content of the new reducers (0.23% actual), compared to that of the old reducers (0.32% actual), should provide greater ductility with less susceptibility to cracking.
3. The cracks in the low-flow piping at the connection to the main feedwater line were repaired by welding. The header pipe was sleeved with 8-in. schedule-160 pipe to eliminate mechanical stresses from line vibration.
4. All new welds were blended into the base metal to reduce stresses and were magnetic particle inspected and radiographed.

A future corrective action will include the installation of a "drag valve" to replace one of the main feedwater regulating valves. This valve should provide more adequate flow control over a wider range of flow conditions and reduce flow-induced vibrations at the regulating station. The low-flow control valve line is to be repiped to provide a less rigorous path as another measure to reduce the flow-induced vibrations. These modifications are scheduled to be made during refueling outages in 1976.

The floor drains that conduct water to the storm-sewer system have been capped to prevent any future flows of contaminated water to the oil separators.

REFERENCES

1. Letter from W. D. Parker, Jr., Vice-President. Steam Production, Duke Power Company, to N. C. Moseley, Director, Region II of the Office of Inspection and Enforcement, Nuclear Regulatory Commission, Docket 50-287, June 27, 1975, enclosing Abnormal Occurrence Report No. 50-287/75-7, available at NRC Public Document Room.
2. Letter from W. D. Parker, Jr., Vice-President, Duke Power Company, to N. C. Moseley, Director, Region II of the Office of Inspection and Enforcement, Nuclear Regulatory Commission, Docket 50-287. Aug. 8, 1975, available at NRC Public Document Room.
3. Letter from J. S. Bitel, Superintendent, Zion Station, Commonwealth Edison Company, to J. G. Keppler, Regional Director of Regulatory Operations, Docket 50-295, Aug. 29, 1975, enclosing Abnormal Occurrence Report 50-287/75-20, available at NRC Public Document Room.
4. Letter from N. J. Kalivianakis, Station Superintendent, Commonwealth Edison Company, to Director of Nuclear Reactor Regulation, Docket 50-265, Aug. 27, 1975, enclosing Abnormal Occurrence Report No. 50-265/75-31, available at NRC Public Document Room.

ANEXO 6

Selected Safety-Related Occurrences Reported in November and December 1975

Compiled by William R. Casto

Of the occurrences reported during November and December 1975, only two seemed unique enough to be reviewed: (1) ice-condenser doors froze at the Donald C. Cook nuclear plant, Benton Harbor, Mich.; and (2) a hydrogen explosion injured two men at the Cooper nuclear power station, Brownville, Nebr.

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6.1 ICE-CONDENSER DOORS FREEZE

A force greater than 675 in.-lb, the technical specifications limit, was required to open 10 of the 48 lower-inlet ice-condenser doors at the Donald C. Cook nuclear power plant.[1] This pressurized-water-reactor plant is operated by the Indiana and Michigan Electric Company and is located at Benton Harbor, Mich. At the time this surveillance test was being conducted, the reactor was down. Ice had formed from condensation on the outside and at the bottom of the door frames in 20 of 24 inlet bays. After the ice was removed and the doors were opened manually, the opening torque for all doors was found to be in tolerance.

The problem probably developed during the summer months when the lake water temperature was comparatively high. Since lake water is used in the cooling of the containment atmosphere, this resulted in a higher ambient temperature. As vapor from the atmosphere condensed on the cold door frame, the resultant water seeped into the insulation, which became soaked and subsequently froze. To forestall future problems, the floor cooling-system controls have been adjusted to increase the floor temperature to about 15°F; the soaked insulation was replaced; the inseepage areas were caulked; rubber insulating strips were added to the lower inlet-door metal frames; and periodic inspections of the doors for ice were instituted.

6.2 HYDROGEN EXPLOSION INJURES TWO

On Nov. 5, 1975, an explosion occurred at the Cooper nuclear power station, a boiling-water-reactor plant operated by the Nebraska Public Power District[2] and located at Brownville, Nebr. The explosion was in a sump that had become pressurized. The explosion occurred when a manhole cover was being removed and a health physicist turned on an air sampler to check for air contamination. One man sustained major injuries and became contaminated enough to have a reading of 3 mr/hr at contact. Another man, who was working adjacent to this injured man, received a minor burn. Both men were rushed to the hospital, where a reading of only 1 mr/hr could be found on the contaminated man. After the man's clothing was removed and the burned areas were cleaned, there was no contamination. The second man was released from the hospital without treatment. Six persons in the vicinity of the explosion were exposed to less than 15 mrems during the day of the accident. The appropriate areas were roped off as determined by surveys for contamination and hydrogen, and the reactor was shut down until the source of the hydrogen and the cause of explosion could be determined and evaluated.

An isolation valve in the off-gas system was found to be closed instead of open. This forced off-gas from the steam jet air ejector through a loop-seal drain line from the 48-in.-diameter holdup line to this sump and back to the dilution fans prior to being discharged up the Elevated Release Point.

The valve was found to be closed even though the control-room valve position indicating lights and the control switch showed the valve to be open. Changes had been made on the electric wiring to this valve during the previous outage. Approval had been given to red-line drawings of the valve and some associated valves that are part of the additional off-gas treatment equipment that will be put in service later this year. But authorization had not been given to change any wiring associated with the valve. Personnel involved in making the wiring change thought they had verified the proper position of the valve by observing the position of the slotted notch at the top of the stem. The butterfly valve gate, however, was not parallel to the slot as they had believed.

An explosive meter was not used to sample the gases flowing from the sump, because no indication of hydrogen had been found in the past when this sump had been opened.

Wiring for the position indicating lights and for actuating the valve was corrected. Also the top of the metal lining for the sump had been separated by the explosion from the sidewall liner. This too was repaired. The personnel responsible for the unauthorized wiring change were reminded of the procedures that require appropriate review and approval of such changes before they are made.

REFERENCES

1. Letter from R. W. Jurgensen, Plant Manager, Donald C. Cook Nuclear Plant, to J. G. Keppler, Director, Region III, Office of Inspection and Enforcement, Nuclear Regulatory Commission, Docket No. 50-315, Nov. 17, 1975, enclosing Abnormal Occurrence Report No. 50-315/75-69.
2. Letter from L. C. Lessor, Station Superintendent, Cooper Nuclear Station, to E. Morris Howard, Director, Region IV, Office of Inspection and Enforcement, Nuclear Regulatory Commission, Docket No. 50-298, Nov. 17, 1975.

ANEXO 7

Selected Safety-Related Occurrences Reported in January and February 1976

Compiled by William R. Casto

Of the incidents reported in January and February 1976, two are reviewed here because of their interest to nuclear operations: (1) a unique fuel-assembly failure at Point Beach 1 and (2) an H_2 explosion in the stack filter house at the Brunswick steam electric plant.

7.1 FUEL ASSEMBLY FAILS

On Dec. 17, 1975, during the refueling of Point Beach 1, the core loading supervisor noted a protrusion from the side of a fuel assembly as it was being lowered into the fuel-assembly "upender."[1] This pressurized-water reactor, located in Manitowoc County, Wis., is jointly owned by the Wisconsin–Michigan Power Company and the Wisconsin Electric Power Company. The top 0.28 m of one of the fuel rods was missing, and adjacent fuel rods had suffered various cladding failures, with the end of one bent horizontally about 0.05 m. This failed fuel assembly had received a burnup of 23,377 MWd/mg of uranium in two core positions, and there had been no difficulty in handling the fuel assembly during the last refueling. Westinghouse stated that the failure was probably caused by water impingement through the baffle plate while the assembly was in a position on the edge of the core. Experience at two foreign plants indicated that water flow through the stitch weld joint in the baffle plate, or bolted baffle plates as may be the case at Point Beach, has occurred at similar core locations. This can result in water impingement on the corner or near-corner fuel rods of the assembly at this core position, thus inducing vibration and fretting wear of one or more fuel rods.

The rate of power increase at the beginning of the previous fuel cycle was higher than presently recommended. Also, during the increase from 40 to 50% of full power, a sharp increase in reactor coolant activity was experienced. It is now presumed that the fuel rods containing holes in the cladding, caused by the fretting, became waterlogged during the shutdown and burst owing to steam pressure.

Fuel assemblies that are, or have been, in the suspected core position will be inspected at the end of the next fuel cycle. Also, the reactor coolant will be carefully monitored for unexplained activity during startups.

No known loose fuel pellets were left in the reactor vessel, and it is not known whether any pellets below the lower core support plate would stay in place or be lifted by the coolant flow. If they are lifted, they are small enough to pass through the bottom nozzle but would be caught by the fuel-assembly bottom grid. This might cause some local flow blockage, but this is tolerable at this axial core location.

If pellets remaining in the system retain their integrity, there should be no significant increase in reactor coolant activity because the pellets will not be exposed to core neutron flux and hence cannot generate new fission products. Should the pellets disintegrate, it is expected that temporary minor increases in reactor coolant activity would be detected. The chemical and volume control-system purification demineralizers and filters would remove particulate and dissolved material from this source. It is not expected that operation will result in reactor coolant activity levels higher than those experienced during the last fuel cycle.

Therefore, based on the safety evaluation given above, operation of the Unit 1, Cycle 4 core, is not considered to pose a hazard to the health and safety of the public. Investigation as to the exact cause of the fuel failure will continue. Present plans are to remove all fuel and the lower core barrel of the Unit 1 reactor vessel during the next refueling as part of the in-service inspection program. This will permit a thorough fuel inspection and an investigation of baffle plate joints to determine if water flow through the joints was the cause of the failed fuel rods.

7.2 EXPLOSION IN STACK FILTER HOUSE

On Jan. 19, 1976, the Brunswick steam electric plant was operating at 84.7% of full power.[2] This boiling-water reactor, located in Brunswick, N. C., is owned and operated by Carolina Power & Light Company. At 12:30 a.m., an auxiliary operator completed a routine inspection of the filter-house area and found all to be well. Shortly thereafter (1:00 a.m.) he was notified by control-room personnel to return to the filter house and attempt to blow down the stack monitor sample line. Over a period of about 45 min, these monitors had apparently detected activity increases from 20 to 200 and 150 to 350 counts/sec. Because of this anomaly, the shift foreman stopped further power increases. As the auxiliary operator entered the filter house, he found the local area radiation monitor sounding its alarm (the alarm point is 1 mR/hr) and noticed water on the floor and a heavy mist overhead. By 1:30 a.m., when the shift foreman checked the filter house, the radiation reading had increased from 4 mR/hr to 6 mR/hr. After his inspection, both he and the auxiliary operator were contaminated over their entire bodies. The fact that off-gas monitors had not increased as stack monitors tended upward was noted at 3:15 a.m. At 3:30 a.m. the operations supervisor was notified of the stack-gas abnormalities. At 4:00 a.m. an auxiliary operator, outfitted with proper protective equipment and clothing, entered the area and filled the loop seals with "large amounts of water." He was unable to determine if the seals had been blown. A few hours later, at 7:58 a.m., control-room annunciators signaled trouble at the off-gas discharge header and in the process off-gas sample flow. At about the same time, a security guard informed the control-room personnel that an explosion had occurred in the filter house. Reactor power reduction was started 2 min later, and the fire alarm sounded. By 8:28 a.m. the reactor pressure was 6.44×10^6 Pa (920 psig), and there was no longer a fire nor radiological danger.

The incident was initiated by an improperly installed demister that permitted water to reach the filter. Also, the freezing weather increased the moisture problem. The moisture increased the pressure drop across the filter and caused back pressure in the system to be high enough to blow the off-gas loop seals. Unfortunately the vent line from the seal sump in the filter house to the stack had been blocked with tape, and instrument air was discharging from the Unit 2 auxiliary off-gas supply-line drain into the sump. The explosion was ignited when the back pressure became high enough to actuate the relay in the filter house and to initiate isolation of the loop seals. This conclusion is substantiated by the fact that a light that was broken in the explosion was bent away from the relay, which operated to effect isolation.

The following corrective actions have been taken. A blank was installed to separate the auxiliary off-gas system from the process system. Consideration is also being given to installing a 0.61-m loop seal on this drain line. It was found that loop seals on the process system were set at 0.51 m of water instead of the specified 0.61 m and isolation was set for initiation at 0.53 m. The loop seals were set to 0.61 m, and the isolation set point was changed to 0.41 m. An annunciator was installed to signal high off-gas pressure, and the tape was removed from the vent line for the sump. Hereafter, the filter house will be entered only after checking for an explosive atmosphere. A manometer for indicating filter pressure drop was installed, and procedures were established for readings to be taken once per shift. Increased surveillance of off-gas flow, stack radiation, and radiation at the filter house has been instituted, and a "No Smoking" sign has been posted.

It should be noted that the operating group had no warning of the occurrence. Excess differential pressure on the filter was not annunciated, and the fact that the loop seal or seals had blown was determined by the increases on the stack monitor and on the filter-house-area radiation monitor.

REFERENCES

1. Letter from Sol Burstein, Executive Vice-President, Wisconsin Electric Power Company, to B. C. Rusche, Director, Office of Nuclear Reactor Regulation, Nuclear Regulatory Commission, Docket 50-266/75-18, Dec. 30, 1975.
2. Letter from E. E. Utley, Vice-President, Carolina Power & Light Company, to N. C. Moseley, Director, Region II of the Office of Inspection and Enforcement, Nuclear Regulatory Commission, Docket 50-324, Feb. 2, 1976.

Selected Safety-Related Occurrences Reported in March and April 1976

Compiled by William R. Casto

Of the occurrences reported during March and April 1976, only three seemed unique enough to be reviewed: (1) the off-gas building was demolished by an explosion at the Cooper Nuclear Station, Brownville, Nebr.; (2) a tube failed in the isolation condenser at Millstone 1, Waterford, Conn.; (3) at Isomedix, Inc., Parsippany, N. J., a hot-cell operator received an exposure estimated at 400 rads.

8.1 OFF-GAS BUILDING DEMOLISHED BY EXPLOSION

The Cooper Nuclear Station at Brownville, Nebr., was operating at 83% of rated power, 659 MW(e), on Jan. 7, 1976, when a hydrogen explosion demolished the off-gas building.[1] This boiling-water reactor (BWR) is owned and operated by Nebraska Public Power District. The first indication of a problem came in the early morning hours when the control-room alarm indicated a low flow at the discharge of the off-gas dilution fan. Because of low flow, the instrumentation automatically started the other fan and the operators then shut down the first one. Previous to the alarm the flow records for the elevated release point of the diluted off-gas had penned a flow decrease from about 1.5 m^3/sec (2800 cfm) to about 1 m^3/sec (2200 cfm) over a period of several hours. However, no flow increase occurred after the second fan started, and a few minutes later a low-flow alarm sounded once again. The standby off-gas treatment fan was then started, but there was still no increase in flow on the recorder for the elevated release point, and the flow indication from the standby off-gas treatment fan was also low. The shift supervisor and an operator went to the off-gas building to investigate and noticed that the building did not seem to be at its normal negative pressure and that the building air monitor indicated an increase in activity. The two went next to the area of the elevated release point but saw no indication of the problem. They returned to the off-gas building; however, the building air monitor was then reading full scale, so they left immediately. Not too long thereafter the building was destroyed by an explosion. The reactor was immediately scrammed manually, the air ejectors were secured, and the off-gas isolation valve was closed. Later it was necessary to purge the condenser to remove radiolytic gases. Calculated activity levels for the incident were found to be less than the maximum permissible concentrations at the site boundary. Soil samples from downwind points at or near the site boundary indicated only background activity.

The incident was apparently caused by an ice plug that formed at the top of 100-m (325 ft) elevated release point pipe. The area of the discharge had been reduced from 990 cm^2 (153 in.^{2}) to 80 cm^2 (12 in.^{2}). Normal flow before the ice buildup should have been around 100 m^3/min (3600 cfm) which should have included about 3 m^3/min (100 cfm) from the steam-jet air ejector, about 84 m^3/min (2900 cfm) of dilution flow, and about 18 m^3/min (635 cfm) of gland exhauster flow. The flow resistance from the ice caused backpressure in the off-gas system, thereby causing a reduction in the dilution fan flow. Starting the standby off-gas treatment fan made matters worse since, when the dilution fans were shut down, the steam-jet air ejectors continued to remove the hydrogen-laden radioactively contaminated off-gas from the condensers and to force it undiluted into the dilution fan plenum. The plenum and dampers were not built to contain pressure, and so the off-gas leaked out into the off-gas building where some electrical device supplied the spark for the explosion.

The flow reduction progressed gradually as the ice built up and went undetected because the observed reduction, as indicated by the instrumentation, was well within normal variations caused by the temperature changes. This flow instrumentation evidently had a history of unreliability. In fact, after the complete loss of flow caused by the explosion, the recorder still indicated a flow of 54 m^3/min (2000 cfm).

The following corrective actions were taken:

1. The upper 3 m (10 ft) of the elevated release point stack was heat traced and insulated. A 3-m (10 ft) section of the stack around the flow monitor and the sensor flange was also heat traced and

insulated. This will prevent ice plugging and improve flow-monitoring reliability.

2. The dilution fans were taken out of the direct path of the process flow stream, and the off-gas line was piped to the diluted discharge line. The dilution fans now take suction from the building air only. A positive isolation valve and a check valve were added to each fan discharge to provide positive isolation when a fan is off. The off-gas enters the dilution fan flow stream at a "T" section downstream of an orifice which provides a reduced pressure area. Since the piping in the off-gas building that can be subjected to an explosive mixture is now designed to withstand an explosion, the rupture disk downstream of the isolation valve was replaced with heavy plate.

3. The automatic control system was changed to close the off-gas system isolation valves following a short time delay after loss of dilution-flow indication.

4. A modification was made to the flow sensor in accordance with the manufacturer's suggestion. This, in conjunction with the heat tracing and insulation, is intended to improve flow-monitoring reliability.

5. Off-gas filter drain and loop seal modifications were made to minimize the possibility of blowing loop seals to the off-gas building and emitting hydrogen to that building.

6. Modifications were made in and around the off-gas sump to minimize the need for access into the sump during plant operation and to improve the draining of the loop seal.

The reactor was started up on Jan. 18, 1976, and the generator synchronized at 1535 hours on Jan. 19, 1976.

8.2 ISOLATION CONDENSER TUBE FAILURE

At the Millstone Nuclear Power Station, there was a release of radioactive contamination from the isolation condenser serving Millstone 1 (Ref. 2). This is a BWR which is owned by the Northeast Nuclear Energy Company with offices in Hartford, Conn. The incident occurred on Feb. 12, 1976, shortly after a reactor scram from full power. Because the reactor mode switch was in the "Run" position after the scram, normal postshutdown pressure transients caused the main-steam isolation valves to close. At about this time an operator noticed that the lights, indicating the position of the condensate return valve for the isolation condenser, flickered. As a result of this, an operator was directed to go and deenergize the valve breaker so that the valve could not open and to verify that it was closed. Also, the main-steam isolation valves were reopened during this interval.

At the time of the reactor trip, another operator in the area of the isolation condenser heard internal rumblings in the condenser. Other workers saw steam puffing from the atmospheric vent of the isolation condenser. As the reactor pressure reduced owing to normal procedures, the amount of effluent from the vent decreased considerably. Because both steam and water were coming from the vent, the area was secured. Temperature conditions in the isolation condenser were abnormal during this time. Minutes later, the radiation monitor at the vent sounded its alarm, giving the operators the final bit of information needed to diagnose the problem. A tube or tubes had failed in the isolation condenser, and so the operators closed the steam inlet valves to the isolation condenser.

It was estimated, using heat balance calculations, that approximately 900 kg (1990 lb) of water was expelled from the isolation condenser, contaminating about 4000 m^2 (1 acre), all inside the fenced area. Shortly after the incident, the area just below the isolation condenser was found to be contaminated, 400,000 dpm/cm^2, and the access road, about 90 m (100 yards) from the rear of the reactor building, had a contamination level of 5000 dpm/cm^2. Calculations and analysis show that the radioactive noble-gas release was less than 0.002% of the daily allowable from the 115-m (375 ft) stack and that the majority of the radioactive halogens and particles fell on the ground inside the site boundary. No reportable exposures of personnel resulted from the release of contaminants. By the next day all areas had been cleaned up except for the moat around the condensate storage tank, which is inaccessible.

Preliminary examination of randomly selected tubes, as well as one particular tube that had obviously failed [it had a 25-mm (1 in.) by 50-mm (2 in.) hole], disclosed the following:

1. The cracks originated only on the inside surface (primary water) of the type 304 stainless-steel tubes. The cracking was transgranular and branching, characteristic of stress-corrosion cracking. Many secondary cracks, some penetrating up to 90% of the wall thickness, were found in both the bend and straight sections (near support plate) of one tube.

2. Low-power microscopic examination of the portion of the failed tube that was intact showed no indication of stress-corrosion cracks on either tube surface along the entire sample length.

3. The fracture surfaces were covered with rust, and most cracks were filled with corrosion products.

These corrosion products had the brick red color normally associated with Fe_2O_3. The crack appearance suggested that these cracks had not occurred recently but that they had been present for some time. No indication of "active" cracks was noted.

4. The cracks followed both longitudinal and circumferential paths, indicating triaxial stresses during the initiation and propagation stages.

5. Electron probe and nondispersive X-ray studies did not reveal the presence of chlorides either in the cracks or in adjacent corrosion deposits. One slight indication of fluoride was found. The cracks, on the other hand, contained significant amounts of sulfur, calcium, and aluminum. None of these elements would be expected in the primary water. Their presence suggested $CaSO_4$ precipitation, possibly during the past seawater intrusion of the primary cooling system.

Since eddy-current checks of the remaining tubes showed numerous discontinuities ranging from 10 to 90% through the tube walls and since a metallographic analysis of a representative tube agreed with the eddy-current checks, it was decided to retube the isolation condenser. The following additional problems were discovered and corrected before the condenser was returned to service:

1. The majority of the inlet end ferrules, which were designed to minimize the thermal stress on the tube to tube-sheet welds, had collapsed. In the outlet end, only a few of these ferrules had collapsed.

2. Mounting studs for the north-side heat shield were bent, and the heat shield and tube sheet were misaligned.

3. On the south side the mounting studs for the heat shield were broken, and the shield had pulled away from the tube sheet. Because the heat shield also serves as the baffle plate, some flow diversion and reduced capacity could have occurred.

These failures were attributed to thermal stress.

The following corrective actions were taken to prevent recurrence:

1. The entire isolation condenser was retubed with 0.065-in.-wall Inconel 600 tube material.

2. Equipment for continuously monitoring the temperature of the shell side of the condenser was installed, and an alarm was provided. Also, action procedures were written.

3. The alarm set point for the radiation monitor at the isolation-condenser vent was lowered to just above steady-state background.

4. The advisability of providing an isolation signal from the vent radiation monitor to close the isolation condenser steam and condensate valves will be evaluated.

5. The shell-side water will be sampled and checked for activity more frequently.

6. Radiochemically clean water will be provided for the shell-side makeup.

8.3 HOT-CELL OPERATOR RECEIVED AN ESTIMATED 400-RAD DOSE

This incident is reported here because it illustrates some of the concerns with hot-cell operation even though it occurred 2 years ago. On June 13, 1974, between 5:30 and 6:00 p.m., a hot-cell operator employed at Isomedix, Inc., Parsippany, N. J., entered hot cell No. 2, which contained an unshielded ^{60}Co source of 120,000 Ci (4440 teradis/sec).[3] The source had been irradiating a group of 30-gal fiber drums of Teflon for 12 hr. The scheduled irradiation time was 24 hr, and the purpose of the hot-cell entry was to rotate the barrels 180° to provide uniform irradiation.

At the time of the incident, the hot-cell operator was also occupied by a second operation involving irradiation studies being performed in the adjacent hot cell No. 1. This work was done with a smaller, 50,000-Ci source (1850 teradis/sec) which is shuttled into hot cell No. 2 through a port for storage when entry is required into cell No. 1. According to procedures, this operation required two men, but on this day it was performed by one hot-cell operator.

The hot-cell operator transferred the smaller source from cell No. 2 to cell No. 1 and then entered cell No. 2 thinking that he had lowered the larger source into the storage pool. Unfortunately, he did not use a survey meter. When he opened the hot-cell door, there staring him in the face was the source. His approximate time in the cell was estimated to be 3 to 6 sec. After a hasty retreat, he closed the hot-cell door, returned to the operating face, and reset the alarms. One of the alarms that had tripped was the service-area monitor, which he had not heard. The operator lowered the source into the storage pool, reentered hot cell No. 2, rotated the drums, closed and locked the cell door, raised the source, and placed it in its "irradiate" position. He then transferred the smaller source back to cell No. 2, changed clothes, and washed up. When he checked his pocket dosimeter, it was off-scale over 200 mR. He remarked to a fellow employee that he thought he had received a radiation exposure. This employee called an ambulance and the hospital. The ambulance with the operator arrived at the hospital at about 6:30 p.m., but the operator was not admitted until 7:40 p.m. because of hospital fears that he was contaminated. Within about 1 hr after the exposure, the operator became nauseous and vomited. He was successfully treated, primarily with antibiotics and transfusions, and was released from the hospital in good condition 6 weeks later.[4] His dose, based on chromosomal aberration studies, was estimated to be about 400 rads (4 J/kg). A medical consultant is monitoring his medical progress.

Normal procedures for entering this hot cell required the operator to lower the source into the storage pool via a chute in the hot-cell floor, to observe the source descent, and to visually check that the source was in the full storage position. Procedures also required that the operator survey for radiation when opening the cell door. In addition, two radiation monitors were required to be in the service area near the cell doors, and it was also required that they be equipped with alarms.

The remote alarm for the service area did not function because a microtoggle switch controlling it had been turned to the "off" position. Both the hot-cell operator and the radiation protection officer stated that they were unaware of the function of this switch. The operator stated he had tried this switch in both positions and stated he thought the down position was normal. This turned the remote alarms off. According to plant records of tests, this remote alarm was functioning a month earlier (on May 7). The test was conducted by the radiation protection officer and the exposed operator.

The operator did wear a film badge; however, a staple was inadvertently driven through the film while the film was being attached to a letter to the film supplier, even though the film had a flap that could have been used for that purpose. The film was therefore subjected to some light leaks. The vendor's best estimate of the film's radiation exposure, after accounting for the contribution of light leaks, was 1500 ± 700 R.

The exposed operator normally worked 10 to 12 hr per day for 4 days to permit 3-day weekends. This exposure occurred in the 12th hour of this 4th day.

The investigation showed the exposure resulted from a combination of causes as follows:

1. The operator's failure to use a survey meter when opening the hot-cell door.
2. The defeat of the remote alarm in the service area and lack of a second, redundant required alarm in the same general area.
3. The operator's apparent state of fatigue resulting from working four straight days of 10 to 12 hr each.
4. The lack of knowledge of key personnel, including the exposed operator, of the function of the remote alarm-defeat switch.

It was also observed that the only means of determining if a source is in a hot cell is by visual inspection through the hot-cell window. There was no external indication, in the service area where the cell doors are, of the presence of an exposed source in a hot cell.

All uses of licensed by-product material were suspended, and Isomedix was not permitted to resume operations until appropriate corrective action had been taken, including the installation of interlocking systems that prevent the cell doors from opening while the source is exposed, and of remote area alarms that cannot be defeated.

REFERENCES

1. Letter from L. C. Lessor, Cooper Nuclear Station, Nebraska Public Power District, to E. Morris Howard, Director, Office of Inspection and Enforcement, Nuclear Regulatory Commission, Docket 50-298, Jan. 21, 1976.
2. Letter from F. W. Hartley, Millstone Nuclear Power Station, Northeast Nuclear Energy Company, to James P. O'Reilly, Director, Region 1, Office of Inspection and Enforcement, Nuclear Regulatory Commission, Docket 50-245, Mar. 5, 1976.
3. Letter from Paul R. Nelson, Directorate of Regulatory Operations, Region 1, U. S. Atomic Energy Commission, to George Dretz, President, Isomedix, Inc., License No. 29-15364-01, Oct. 23, 1974.
4. Barbara G. Brooks, Seventh Annual Occupational Exposure Report 1974, Radiation Protection Section, Radiological Assessment Branch, Division of Technical Review, Office of Nuclear Reactor Regulation, Nuclear Regulatory Commission.

ANEXO 9

Selected Safety-Related Occurrences Reported in July and August 1976

Compiled by William R. Casto

Of the occurrences reported in July and August, three are reviewed here because of their interest to nuclear operations: (1) an operator's error, while he was moving control rods, caused an increase in off-gas activity at Dresden 1; (2) a supervisor received an estimated exposure of 8 R while making an inspection at Zion 1; and (3) an operator entered a 600 R/hr field at Indian Point 2.

9.1 OPERATOR ERROR CAUSES INCREASED OFF-GAS ACTIVITY

In the early morning on Mar. 29, 1976, the off-gas activity at Dresden 1 suddenly increased. Dresden 1 is a 700-MW(t) reactor located in Grundy County, Ill., and is owned by the Commonwealth Edison Company. A sample of the off-gas activity taken that morning showed about 45,000 μCi/sec; normally, samples are between 8000 and 10,000 μCi/sec (Ref. 1). At the time of the increase, the reactor was running at 170 MW(e) and had been for a number of days. By the end of the week, the activity had decreased and was between 16,000 and 20,000 μCi/sec. On March 28, the day before the high off-gas activity occurred, a routine surveillance test had been run to verify that the control rods were attached to their drive rods. During this testing the operator had mistakenly moved 24 control-rod tips past one another. Experience has shown that fuel damage can occur when these tips pass each other because of the high flux peak which this causes. The mistaken control-rod movements were made because the operator selected the wrong level of in-core neutron-flux monitors to verify control-rod movement. One level of monitors is used for observing movement of fully withdrawn control rods, and a second level is used to monitor movement of fully inserted control rods. The procedure for this operation appears to be somewhat deficient in that it does not give instruction for movement of face-adjustment control rods. It does, however, specify that the operator inspect the control-rod movement pattern to ensure that no diagonally adjacent rods come within one notch of each other. The operator made another error in that he should have consulted the appropriate nuclear engineer when he saw no response on the in-core nuclear-flux monitors. This instruction is in the procedure.

Neither the reactor operator nor the senior reactor operator who was on duty during this surveillance test was aware of the problems associated with passing control-rod tips even though each operator had been trained in the effect of control-rod movements and in core physics.

The following are the corrective actions taken:

1. The selector switch for in-core levels located on the reactor console was labeled to indicate the relation of in-core levels to control-rod positions in the core.

2. The requalification program for licensed operators encompasses instructions concerning the movement of control rods. This training in the past was included with the technical or theoretical aspects of core physics. The importance of this training has now been further reinforced by the initiation of special training that addresses the practical everyday movement of control rods and the "do's and don't's" of control-rod movement.

3. A representative number of licensed operators were quizzed to determine the effectiveness of the control-rod movement training and to determine further training needs.

4. The procedure was revised to further reduce the possibility of a recurrence.

9.2 SUPERVISOR RECEIVED ESTIMATED 8-rem EXPOSURE

On March 18, while making an inspection under the reactor during a shutdown, a Commonwealth Edison employee received an estimated 8-rem exposure.[2] The incident occurred at Zion 1, which is a pressurized-water reactor (PWR) located at Zion, Ill. Shortly before the incident, the refueling cavity had been partially flooded in preparation for the first refueling of this nuclear power station, and considerable water was leaking from the refueling cavity into the reactor cavity. In an attempt to discover the leakage pathway, inspection personnel entered the reactor cavity three times, each time accompanied by a radiation chemistry technician as required by procedures. During these entries, dose rates up to 10 R/hr were measured. However, the inspectors did not go far into the area, and, since their inspections failed to locate the leak, a supervisor decided to go into the cavity for an additional inspection.

Before entering the cavity, the supervisor telephoned the station radiation and chemistry department and requested that the laboratory foreman assign a radiation chemistry technician to accompany him. However, because of the high dose rates, the laboratory foreman refused and further recommended that the supervisor not enter the area. After further discussion, the supervisor decided to go ahead, assuming the responsibility for the exposure he would receive. The laboratory foreman, with the station health physicist, then outlined the following procedure for the supervisor:

1. The exposure limit for the entry would be 500 mrems.

2. The supervisor would take an exposure integrator with him and have the instrument on the 500-mR scale.

3. The supervisor would provide a safety man outside the area to assist his exit in case of injury.

The entry was then made on the basis of those requirements. A maintenance staff engineer served as the safety man. The supervisor began the inspection, but the pathway of leak could not be easily determined because of echoes and because the only light was from a sealed beam lantern.

After remaining at an intermediate point for 1 to 1½ min, the supervisor noted that he had accumulated a probable exposure of 200 to 500 mrems. He then decided that he could make a rapid inspection further into the area and still maintain his exposure under the 500-mrem limit. With this in mind, he began an inspection of the annulus between the reactor vessel and the concrete shield wall. During this inspection he noticed that the integrator had pegged full scale, and so he reported to the radiation and chemistry office.

Normally the radiation under the reactor during shutdown ranged from 15 to 20 mR/hr; however, because the 58 in-core detector thimbles had been withdrawn from the reactor into their guide tubes, as required for refueling, the radiation had increased to 200 R/hr.

The inspection by the supervisor under these conditions was in direct violation of the Zion radiation protection procedures. The following actions were taken to prevent a recurrence:

1. To preclude ready access to the reactor cavity during periods of cold shutdown, the Zion 1 station established administrative controls and padlocked all accesses to the cavity.

2. The importance of following station procedures was stressed to all station personnel.

9.3 OPERATOR ENTERS 600 R/hr FIELD

Between Apr. 1 and June 30, 1976, an operator at Indian Point 2 received a radiation exposure of ~10 rems, most of which occurred on April 5 while he was determining lighting requirements in the general sump area under the reactor.[3] At the time of the exposure, the reactor, a PWR owned by Consolidated Edison Company of New York, had been in cold shutdown for 5 days.

Gamma field measurements made several hours after shutdown and again on the following day showed general radiation levels in the sump area ranging from 30 to 150 mR/hr. However, between the time of the last field survey and the time the operator entered the area, the thimbles that house the fixed and movable in-core detectors had been withdrawn from the reactor vessel. Withdrawal of the thimbles is a step required in the refueling procedure and is mechanically performed at an area far removed from the reactor sump area. Unaware that the radiation field in the area had increased considerably, the operator entered the sump level. He routinely checked his self-reading pocket dosimeters (0 to 200 and 0 to 500 mrems) and, finding them off-scale, hurriedly left the area and reported to the health-physics office.

The maximum radiation field to which the man was exposed was approximately 600 R/hr. Further, on the basis of retracing his steps in identical Unit 3 (not yet critical), it was estimated that he spent approximately 100 sec in the area.

As a result of this exposure incident, the access hatch was locked and a conspicuous warning sign was posted at the entrance. Also, the thimbles were partially inserted into the reactor vessel, an action that lowered the radiation levels from 600 R/hr to 50 R/hr, and a gamma monitor was placed in the area to alert people when the radiation fields increase. In the future, personnel access to the area will be controlled.

In addition, the designs of Units 2 and 3 were reviewed for similar situations whereby an operation at one location could significantly affect radiation levels at a different location; no similar situations were found. Finally, because of the unusually high dose rate that can exist in this area and not be immediately apparent, the management and vendor of all similar units in this country have been advised of the incident to prevent a recurrence at another site.

REFERENCES

1. Letter from R. L. Bolger, Assistant Vice-President, Commonwealth Edison Company, to James C. Keppler, Region III Director, NRC Office of Inspection and Enforcement, Glen Ellyn, Ill., Docket 50-10, June 21, 1976, available at NRC Public Document Room.
2. Letter from Jack S. Bitel, Superintendent, Zion Station, Commonwealth Edison Company, to the Director, NRC Office of Inspection and Enforcement, Docket 50-295/DPR-39, Apr. 15, 1976.
3. Letter from William J. Cahill, Jr., Vice-President, Consolidated Edison Company, to Ernst Volgenau, Director, NRC Office of Inspection and Enforcement, Docket 50-247, Apr. 29, 1976.

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ANEXO 10

Selected Safety-Related Occurrences Reported in November and December 1976

Compiled by William R. Casto

Of the occurrences reported in November and December, three are reviewed here because of their uniqueness and/or general interest: a salt problem in the switchgear of Millstone 2, flooding in the turbine building of Oconee 3, and an inadvertent criticality at Millstone 1.

10.1 HURRICANE ISOLATES PLANT FROM GRID

During Hurricane Belle on Aug. 10, 1976, several failures of equipment occurred[1] in the switchyard of Millstone 2. This pressurized-water-reactor (PWR) plant is located on Long Island Sound at Waterford, Conn., and is owned by the Northeast Nuclear Energy Company. As numerous protective relays started functioning, the operators started both diesel generators and had them running when the loss of two off-site power lines tripped the reactor from 100% power. Severe salt contamination caused by salt spray blown from Long Island Sound caused the rash of failures in the switchyard. One line was restored within 24 hr by simply washing down insulators and other switchyard equipment. Because the other line suffered damaged circuit breakers that had to be repaired, 72 hr elapsed before it was back in service.

10.2 TURBINE BUILDING PARTIALLY FLOODED

On Oct. 9, 1976, the turbine building of Oconee 3 was flooded to a depth of 610 mm in the center of the area and to 406 mm at the wall.[2] Duke Power Company owns and operates this PWR at Seneca, S. C. A previously planned and installed set of curbs to a height of 533 mm prevented the water from flooding into the adjacent auxiliary building.

At the time of the incident, Units 1 and 2 were at full power while the affected unit was being refueled. All six manually operated butterfly valves for inlet circulating water and six pneumatic piston-operated valves on the outlet had been closed to facilitate maintenance on and inspection of the condenser. Furthermore, 76-mm jackscrews had been installed to hold the piston-operated valves closed. Shortly before the flooding, two status alarms announced trouble with an inverter; the operators were diagnosing this problem when news of the flooding came in. Water was rushing through the open manways on a condenser water box, but the reason for this behavior was unknown. Building sump alarms sounded as the water level increased. At 32 min after the trouble started, the 125-V a-c panel board that had experienced the inverter trouble was reenergized normally from the regulated a-c source and flooding stopped.

The flooding had started with the loss of the static inverter that supplies 125-V a-c power to a vital instrumentation panel board. This board, in turn, supplies power for the vacuum priming system for the circulating cooling water. This vacuum priming system controls the four-way solenoid valves that direct air to open or close the circulating-cooling-water discharge valves. When power was lost, these deenergized solenoids tried to open the discharge valves. The force was so great on one valve that it bent the "hold-closed" jackscrew and opened the valve so that water freely flowed from Lake Keowee through the circulating-cooling-water discharge piping into the outlet water box and out five manways into the turbine-building basement.

The two apparent causes of this occurrence are as follows: (1) The air supply to these pneumatically operated valves was not isolated, and motion was therefore not prevented. (2) The circulating-cooling-water pneumatic piston-operated discharge valves were designed to fail open upon the loss of power to the four-way solenoid control valve.

No safety systems in the turbine or auxiliary buildings were affected with the exception of the emergency feedwater pump. The emergency-feedwater-pump lube-oil pump and circulating-cooling-water pump were submerged, and their operability was questionable. However, the capability to remove at least 5% decay heat was available from the combination of hot-well pump, condensate booster pump, and main feedwater pump or through a hot-well pump and a condensate booster pump.

After this incident an investigation was performed to assess the condition of all equipment that had been submerged. The equipment was inspected and repaired as necessary. The following corrective actions were taken in order to prevent recurrence of the incident:

1. The pilot solenoids on the condenser discharge valves were replaced with dual-coil mechanically latched types. This increased reliability because:

a. Latched solenoids do not change state on loss of control power; they require electric power only when actually changing states.

b. Condenser discharge valves controlled by latching solenoids will therefore fail "as is." Power failure will not initiate spurious operation of the discharge valves.

c. Latched solenoids avoid continuous coil energization, which should increase operating life.

d. Administrative "blocks" of condenser-discharge-valve operation can be implemented by tagging out the control power.

2. The power source for circulating-cooling-water controls was changed to another power panel board. This increased reliability because:

a. Normal power is still derived from a battery-backed static inverter.

b. Automatic transfer to a backup power source (regulated power) is made on failure of the normal source. The transfer is made without interruption of power to the load and without operator action.

3. Position-indicating lights were added in the control room for the condenser discharge valves. These will help the operator monitor the operating status of the system because:

a. They will provide additional system-status information at the existing board displays.

b. Position status of all discharge valves can be determined at once without referring to a printout.

c. The lights will provide a backup to the computer documentation of valve status.

4. The local control stations for the condenser discharge valves were relocated further from the condenser and on the protected side of a column.

5. The physical layout of electrical cabling and pneumatic tubing in the vicinity of the condensers was reviewed to ensure adequate protection from damage by water force.

6. A review was conducted to determine the feasibility of raising the lube-oil pump and circulating-cooling-water pump for the emergency feedwater pump.

7. The procedures for opening the circulating-cooling-water system inside the turbine building were reviewed and revised to require:

a. Inlet and outlet circulating-cooling-water pipes to be vented if all pumps are shut down.

b. Manually operated valves at the condenser circulating-cooling water-inlets to be closed, tagged, and mechanically locked.

c. Air to pneumatic piston valves to be manually blocked and the pistons vented.

d. Jackscrews to be in place at circulating-cooling-water discharge valves to prevent the valves from drifting open.

e. The emergency condenser discharge valve to the gravity drain system to be locked closed.

10.3

INADVERTENT CRITICALITY

On Nov. 12, 1976, Millstone Unit 1, a boiling-water reactor owned and operated by Northeast Nuclear Energy Company of Hartford, Conn., inadvertently went critical during refueling.[3] The Nuclear Regulatory Commission (NRC) investigated the incident and agreed that refueling could be resumed (under NRC's surveillance) if:

1. Operators and senior operators had been retrained in the area of Technical Specifications and if procedural requirements for activities involving reactivity changes had been completed for personnel involved in refueling activities.

2. In addition to operators required by the Technicial Specifications, a licensed senior reactor operator had been stationed in the control room during refueling to directly observe the actions that change reactivity as well as the results of these actions.

3. The evaluations by the Site Nuclear Review Board of the actions leading to the inadvertent criticality, of the subsequent corrective actions, and of the actions taken to prevent recurrence had led to the conclusion that it was appropriate to continue refueling.

4. The operators on shift during the inadvertent criticality had not performed or directed licensed activities pending further discussion with NRC.

On Dec. 22, 1976, the NRC released the following information:[4]

The Nuclear Regulatory Commission's Office of Inspection and Enforcement today proposed taking the following enforcement actions against the Northeast Nuclear Energy Company and two of its employees as a result of an unplanned reactor startup that occurred on Nov. 12, 1976, during a refueling outage at the Millstone Nuclear Power Station Unit 1 near Waterford, Connecticut.

—For four alleged items of noncompliance with NRC regulations, including allegedly failing to have its personnel properly follow procedures in certain required testing of reactor systems, a civil penalty is proposed against the company in the amount of $15,000.

—For allegedly permitting and supervising the withdrawal of a control rod that led to an unplanned reactor startup, a senior reactor operator's license is immediately suspended and he is being required to show cause why his license should not be revoked.

—For allegedly performing the action that led to the unplanned startup of the reactor, a reactor operator was cited for noncompliance with NRC regulations.

The company has 20 days to either pay the proposed fine or state in writing why part or all of it should not be imposed.

In a letter to the company, Dr. Ernst Volgenau, Director of NRC's Office of Inspection and Enforcement, said that in addition to a written response indicating what the company had done or will do to avoid a repetition of these circumstances, the company should "describe in particular those actions taken or planned to strengthen management control of your licensed activities to assure the protection of your employees and the public."

In a letter to the senior reactor operator, Dr. Volgenau explained that he has 20 days to file a written answer and may request a hearing on whether his license shall be revoked.

In a letter, James P. O'Reilly, Director of NRC Region I, advised the reactor operator that he had 20 days to inform the NRC in writing of his admission or denial of the items of noncompliance and, if admitted, the reasons for the items of noncompliance.

The State of Connecticut has been informed of these proposed enforcement actions.

REFERENCES

1. Licensee Event Report No. LER 76-49/3L, Millstone 2, Docket No. 50-336, Event Date 8-10-76, Report Date 9-3-76, available at the NRC Public Document Room.
2. Letter from W. O. Parker, Jr., Duke Power Company, to N. C. Moseley, NRC, Docket No. 50-287, Oct. 25, 1976, available at the NRC Public Document Room.
3. Letter from J. P. O'Reilly, Director, NRC Region I, to Northeast Nuclear Energy Company, Attention: Mr. D. C. Switzer, President, Nov. 15, 1976, available at the NRC Public Document Room.
4. NRC Press Release No. 76-271, Dec. 22, 1976.

ANEXO 11

Selected Safety-Related Occurrences Reported in March and April 1977

Compiled by William R. Casto

Of the incidents reported during March and April, the following are reviewed because of their uniqueness and/or general interest: a series of overexposures in Agreement States, a diesel damaged during surveillance testing, a fire at a diesel generator, and a set-point change that produced unexpected results.

11.1 OVEREXPOSURES

The following items were reported to the Nuclear Regulatory Commission (NRC) by Agreement States as a part of their efforts to keep each other informed of regulatory matters of interest within their respective jurisdictions.[1] Only a small number of the many items reported are included here.

Arizona

Two radiographers were overexposed when a source capsule was not cranked all the way back into the shield. Two identical survey meters were available; one meter was in good condition but had dead batteries, and the other meter was damaged just prior to the incident but had good batteries; thus neither meter was operative. The whole-body exposure was estimated to be 6.7 rems.

A fire in a building housing well-logging sources and some magnesium metal resulted in destruction of the building, loss of lead and paraffin source shields, and melted/deformed source holders. The 316-mCi ^{241}Am source was placed in a barrel of water, and the 120-mCi ^{127}Cs source was placed in a barrel filled with dirt, after which negligible readings were obtained around both barrels. No contamination occurred. The affected tools and sources were subsequently packaged for transportation to a hot-cell facility.

California

Two radiographers working for different companies received whole-body exposures of 6 and 7.3 rems. A subsequent investigation did not establish causes.

Colorado

A truck with a 125-mCi ^{137}Cs source disappeared in Wyoming. The truck and source were found 3 months later.

Maryland

A hospital reported an incident involving two 20-mg radium sources that resulted in skin exposure of 73 rads (0.73 J/kg) to an individual. An investigation revealed that hospital personnel failed to follow standard procedures and that certain procedures were deficient. The agency required retraining of personnel and revision of procedures to prevent recurrence.

Oregon

A radiographer failed to return a source all the way into its shield and entered the pipe to reposition the source. Although he was carrying an operable survey instrument, he failed to properly survey the camera to determine the source position. A reconstruction of the incident indicated that the radiographer received a whole-body exposure of just over 3 rems. He was removed from the job for the balance of that quarter.

Texas

Two radiographers received overexposures of 71 and 92 rems. The incident was discovered after 4 hr of shooting and up to 5 hr of transporting the camera by truck. Simulation yielded a whole-body exposure estimate of 76 rems. Estimates of exposure based on medical evaluation were less than 100 rems whole body and 500 to 750 rems to the hands.

In another incident an overexposure occurred when a 90-Ci ^{60}Co source capsule broke away from its pigtail, and two workers involved failed to use their survey meter properly. Only after making three exposures and obtaining black film did these men call their Radiation Safety Officer. Exposure calculations produced values of 22 and 24 rems for the extremities and 5.5 and 6.0 rems for the whole body.

Another overexposure of a radiographer resulted when the individual attempted to return the source to its shielded position on three separate occasions. The licensee was informed when the individual complained of a swollen hand and was sent to a doctor. His film badge indicated a whole-body exposure of 14.50 rems, and the doctor estimated an approximate dose of 1800 rems to the hands.

An industrial radiographer, who does 90% of his work in-house, received a 3.3-rem exposure. It was found that, on entering and leaving his "shooting pit," he was receiving exposure from the doorway of the other "shooting pit." The corrective measure will be the placement of a portable shield in the doorway.

11.2 DIESEL DAMAGED DURING SURVEILLANCE TESTING

Serious damage occurred in December 1976 to a diesel undergoing surveillance testing at Millstone Point 2 (Ref. 2). This pressurized-water reactor (PWR) is owned by the Northeast Nuclear Energy Company of Hartford, Conn. The damage occurred when a connecting rod burst through the upper crankcase cover when the cap screws for the rod bearing sheared off. The failure occurred because of a series of unlubricated, or dry, engine starts. When diesels receive a signal for an emergency start, they do so without prelubrication. Until August 1976, the diesels at Millstone Point 2 had undergone emergency starts a number of times unnecessarily. These repeated dry starts caused excessive bearing wear, which permitted enough movement of the upper-connecting-rod cap screws so that the rod slipped off the crankshaft and broke through the case. The following corrective actions have been taken:

1. The four main bearings and one rod bearing of the other diesel were inspected, and evidence of wear from dry starts was found, but no more than one would expect. No indication of pending failure was found, and so the bearings and journals were deemed acceptable.

2. For nonemergency starts, the prelubrication time has been increased from 1 to 3 min to ensure more than adequate lubrication.

3. A study of a method for, and of the need for, rapid lubrication during emergency starts was initiated. More frequent filter changes for possible detection of bearing damage were a part of the study.

11.3 HUMAN ERROR CAUSES DIESEL-GENERATOR FIRE

At the beginning of the midnight shift on Sept. 18, 1976, a fire occurred in the diesel generator at Zion 2 in Zion, Ill.[3,4] This four-loop PWR is owned and operated by Commonwealth Edison Company.

The sequence of intertwining events was as follows: An equipment operator (unlicensed) remembered that when he was on the previous shift, he had placed a 125-V direct-current (d-c) battery for Unit 2 on a monthly equalizing charge, and, since he was on the Unit 1 side of the plant, he decided to open the tie breaker between a 125-V d-c bus on Unit 2 and a similar bus on Unit 1, which had been supplying the 125-V d-c control power. After this action, the operator had planned to proceed directly to the Unit 2 auxiliary electrical room to complete the switching. Unfortunately, as a consequence of the operator's actions, which left the Unit 2 d-c bus without power, the incident was already started and was proceeding through the plant with unrelenting speed. Control power was no longer available to any of the generator and transformer meters and relays nor to any of the main control-board annunciators, windows, and horns, and other loads. Underfrequency relays on two reactor coolant pumps dropped out, sent a trip signal to all four reactor coolant pumps, and tripped the reactor. However, because of the loss of d-c power to their breaker trip coils, two of the pumps did not trip.

The turbine tripped as required, but, because of the loss of d-c control power, the generator output breaker did not open, and so the grid motorized the turbine. Because the generator did not trip, the main feedwater pump that was on line did not shut down, nor could it be tripped from the control room. This resulted in drastic overfeeding of the two steam generators whose bypass valves were partly open. Overcooling occurred, and pressure reduction in the primary system resulted, followed relentlessly by safety injection. In turn, safety injection increased the pressure and caused the safety valves to lift at 17.6 kPa (2550 psig). They continued to do so sporadically for some time. Approximately 9.46 m^3 (2500 gal) of water was blown into the containment when the rupture disk of the pressurizer relief tank, which receives fluid from the safety valves, ruptured.

When this sequence of events began, one of the diesel generators was under test, loaded to about 3300 kW and tied to the system through a 4-kV bus. As the main-generator breakers were opened manually from the control board, the two 4-kV buses on the unit auxiliary transformer did not transfer automatically to the system auxiliary transformer, because d-c control power was unavailable. The diesel that had been running under test attempted to carry the loads of the two 4-kV buses that did not automatically transfer to the system auxiliary transformer, and a fire started in the generator when the field windings overloaded.

When the fire started, the feedwater pump was tripped manually, the CO_2 Cardox system was initiated, the 125-V d-c control bus was energized, and the safety-injection circuitry was reset. From this point on, recovery was rapid, except for repairs to the diesel and its generator. All safeguards equipment started upon initiation of the safety-injection signal, except that which was controlled by the d-c bus that had been isolated by the operator. The equipment operator had performed this type of switching many times and had always used the established procedure. This was the first instance in which he had not referred to the procedure before switching equipment. Because he had performed the switching operation often in the past, he said "I felt sure I knew what I was doing." He made no excuse and stated "I don't know what I was thinking about." There were no indicating lights at the location of the switch to show switching errors.

On the basis of the investigation of the special investigative committee and on the station review, the following recommendations were made to prevent a recurrence:

1. Investigate the possibility of providing a key interlock system for the d-c bus breakers.

2. Review any benefits to be obtained from charging batteries without isolating the battery from the bus. Although this method avoids operator switching, it has disadvantages in that it could result in overvoltage conditions that damage the instrument inverters or electrical relays used at the station.

3. Relabel battery and d-c bus breakers to clarify their function.

4. Revise the procedure for aligning the 4-kV buses on the two auxiliary power transformers. Buses should be aligned such that any two buses with the same source of d-c control power for breaker operation are connected to different transformers. Also, buses that can be supplied by a diesel generator should be connected to the system transformer (except for the swing diesel generator). This realignment will prevent more than one 4-kV bus from being deenergized on a loss of d-c bus. It will also prevent overloading a diesel generator that is paralleled to the system during a loss of a d-c bus. A separate procedure should be developed to similarly protect the swing diesel generator during the periodic testing of this unit.

5. The possibility of eliminating the matrix logic trip circuit for tripping all reactor coolant pumps on a two-out-of-four underfrequency condition should be reviewed with Westinghouse Electric Corporation. Elimination of this circuit will prevent placing the unit in a natural-circulation condition unless an actual system underfrequency exists.

6. Investigate an automatic throw-over to a backup power supply for the plant computers. Although the majority of alarm inputs into the computer were lost during the incident because of the loss of d-c power, the computer was also inoperable when its power supply was cut off because of fuses blowing out. This loss made the reconstruction of the sequence of events

difficult since all this information is supplied through the computer.

7. Check the fire stop used in the vertical bus risers from the diesel generator to the 4-kV emergency safeguard system bus. The present fire stop allowed smoke to enter and fill the emergency safeguard system bus room.

8. The circuit for tripping the main generator should be reviewed. Included in this review should be a system for redundant trip capability in the event that the normal d-c control power is lost.

9. Revision of the main control-board annunciators to provide a reliable alarm system to annunciate the loss of any d-c bus should be reviewed. This type of alarm will enable the operator to quickly identify any d-c bus that has been deenergized and immediately take steps to reenergize it. All of the present alarms that were provided for this function were rendered inoperable by the loss of the d-c bus.

10. Provide on-the-job training for the equipment operator until he demonstrates satisfactory performance of his duties. Sufficient criteria already exist to measure satisfactory performance. Apply these criteria to all operators in this classification.

11. Review this event with operating personnel, and emphasize the necessity for, and the importance of, following procedures properly. This requirement for procedural compliance should include notice that operations of this nature must be checked off as performed, using the new system or the general operating procedures.

12. A timely audit of compliance to the new procedures plus a follow-up audit should be performed.

13. Weekend and backshift inspections should be made by upper-level management to emphasize procedural compliance.

14. Restate the responsibility of the nuclear station operator to take action when system operating parameters exceed normal set points or values, as in the case of allowing pressurizer level to increase to 80% without resetting and terminating the safety injection. This responsibility is procedurally recorded and allows the reactor operator to take independent action if direct communication with the shift engineer is not possible.

11.4 SET-POINT CHANGE PRODUCES UNEXPECTED RESULTS

Following a trip of Millstone Unit 2 on July 5, 1976, several motors powered from 480-V motor control centers failed to start because of blown control-power fuses on the individual motor controllers.[5] The Northeast Nuclear Energy Company of Hartford, Conn., owns and operates this PWR. These controllers receive control power through 480 V–120 V transformers within the controller.

As a result of the plant trip, the grid voltage dropped from 352 to 333 kV, which, in conjunction with additional voltage drops associated with the transformers involved, reduced the control power and voltage within individual 480-V controllers to a voltage that was insufficient to actuate the main-line-controller contactors. As a result, when the motors were signaled to start, the control-power fuses blew out. Subsequent testing by the utility showed that the contactors required at least 410 V to function properly.

The immediate corrective action taken was to raise the set point of the engineered safeguards actuation system (ESAS) loss-of-power undervoltage relays to ensure that the plant would be separated from the grid and that emergency power system operation would be initiated before the control voltage fell below that required for contactor operation. A trip of the undervoltage relays causes the following sequence of events to occur: (1) the emergency buses are deenergized; (2) load shedding, which strips the emergency buses, is initiated; (3) the diesel generators are started and, in turn, power the emergency buses; and (4) the required safety-related loads are started in sequence.

The earlier corrective action yielded unexpected results 16 days later. During the starting of a circulating-water pump, the voltage dropped below the new ESAS undervoltage relay setting, which deenergized the emergency buses, initiated load shedding, started the diesel generators, and began sequencing loads onto the emergency buses. However, during the sequencing, the voltage again dropped below the undervoltage relay setting and caused the load-shed signal to strip the buses. The result was energized emergency buses with no loads supplied.

To protect plant equipment against all credible undervoltage conditions and to ensure the correct operation of all safeguard equipment, the utility personnel made design modifications[6] to the undervoltage trip logic. These modifications (1) prevent the emergency buses from load shedding after the diesels have started; (2) replace the single undervoltage trip set point with a dual set-point logic, one of which has an 8-sec delay; and (3) change the plant transformer taps to optimize the in-plant voltage. The second design change allows for grid transients while preventing sustained reactor operation under a degraded voltage condition.

The NRC has held meetings with representatives of various licensees to discuss the potential generic implications of this incident. Solutions to prevent this type of problem from recurring are being worked out on a plant-by-plant basis.

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6. Nuclear Regulatory Commission, *Current Events—Power Reactors, July–September 1976*, Dec. 13, 1976.

Selected Safety-Related Occurrences Reported in May and June 1977

Compiled by William R. Casto

Of the occurrences reported in May and June, the following are reviewed here because of their uniqueness and/or general interest: (1) short reactor periods have occurred at Quad Cities 1 during shutdown margin tests; (2) loss of instrument air caused damage to reactor coolant-pump seals at a pressurized-water reactor (PWR); (3) a power-distribution anomaly occurred because of a failure of burnable poison rods at St. Lucie 1; (4) short reactor periods have occurred at some boiling-water reactors (BWRs) during startups at peak xenon; and (5) surging in the feedwater flow caused pipe vibrations at Beaver Valley 1.

12.1 UNANTICIPATED SHORT PERIODS DURING SHUTDOWN MARGIN TESTS

During two shutdown margin tests on May 4 and 6, unexpectedly short periods occurred at Unit 1 of the Quad Cities Nuclear Power Station.[1] Commonwealth Edison Company owns this BWR, which is located in Rock Island, Ill. Two nuclear engineers were present during the first test involving four rods, and there was a written procedure (QTS 1104-5), but it was not rigorously followed in withdrawing control rod H-9 from position 06 to 08, and control rods F-8, H-8, and K-8 were all at position 48 (position 00 is all the way in, and position 48 is all the way out). This action caused a period too short to be properly indicated by the period meter. All that could be said with certainty at the time was that the period was possibly shorter than 30 sec. The operator immediately returned control rod H-9 to the 06 position.

During an investigation later the same day, it was decided that the procedure had not been followed; however, it was also decided that criticality had not occurred. This opinion was based on a close inspection of the recorder chart of the startup-range recorder, which was the only available data. Because of the very short duration of the incident (less than 1 sec for control rod H-9 to move from position 06 to 08 then back to position 06), it was impossible to see anything more than the normal "prompt jump"; there was no sustained, stable period indicating criticality. Also, just prior to the test under discussion, another test had shown subcriticality with control rod H-8 at position 48 and control rod H-9 at position 08. The only difference between the two tests was that, in the latter test, control rods F-8 and K-8 were at position 48, and each of these two control rods is one control cell away from control rods H-8 and H-9. This difference was not considered significant enough to cause criticality.

Two days later, control-rod maneuver sheets were prepared and approved for another shutdown margin test using the same control rods as before, and a step-by-step procedure was written for the control-room operator. A nuclear engineer was present. Again, a short period occurred as the operator withdrew control rod H-8 continuously from position 08 to 22, with control rod H-9 at position 08 and control rods F-8 and K-8 at position 48. Once more the operator quickly inserted control rod H-8, this time from position 22 to 14, and the reactor period decreased to 75 sec. The reactor was maintained at a critical level while the desired data for this test were taken, and then the test was terminated.

Because of the experience with the second test, the station personnel reevaluated both tests and concluded that periods of less than 5 sec occurred in both instances. Failure of the nuclear engineers to follow approved procedures caused the first incident. Although failure to follow the approved procedure did not contribute to the second occurrence, the nuclear engineer exercised poor judgment in allowing the operator to continuously withdraw a control rod during the approach to criticality.

A contributing cause of these occurrences was the inadequacy of procedure QTS 1104-5 and its corresponding data sheet QTS 1104-S3. The data sheet calls for readings from the source-range monitoring instrumentation and the control-room operator's initials at specific control-rod configurations. However, the control-rod movements performed in attaining those specific configurations are governed by procedure QTS 1104-5. Using only the data sheet was misleading owing to the required control-rod maneuvers between specified rod configurations. A previously successful demonstration of a two-rod face adjacent shutdown margin was performed using procedure QTS 1104-1 and checklist QTS 1104-S4, both of which specify exact control-rod maneuvers. The inconsistency involved in going from QTS 1104-1 to QTS 1104-5 was unnecessarily misleading.

The final contributing factor was a misunderstanding between the nuclear engineers and the control-room operators. The control-room operators, who were performing shutdown margin demonstrations for the first time, should have been made aware by the nuclear engineers of the potentially high notch worths of the control-rod maneuvers they were performing. The uniqueness of shutdown margin criticals should have been discussed and the operator cautioned in each case. Failure to do so, along with the successful previously completed two-rod face adjacent shutdown margin demonstrations, lulled the operators into a false sense of security when they performed the other shutdown margin demonstration tests.

The nuclear group of the technical staff was given additional specific training in the performance of shutdown margin demonstrations, and emphasis was placed on interacting with the control-room operator and on technical specification implications when the tests were being performed.

The procedures and checklists used to perform shutdown margin testing were revised to be consistent and to include a complete step-by-step sequence of control-rod maneuvers for the control-room operator. Furthermore, the procedures were generally reviewed for safety and current applicability.

12.2

LOSS OF INSTRUMENT AIR CAUSES DAMAGE TO REACTOR COOLANT-PUMP SEALS

The St. Lucie 1 reactor was scrammed on April 15 when a loss of cooling water for the reactor coolant-pump seals became evident.[2] St. Lucie 1 is owned by the Florida Power & Light Company and is located at Hutchinsons Island, Fla. As usual, one failure led to another. The trouble with the coolant-pump seals started with a seal problem in the containment instrument-air compressor during normal plant operation. As designed, the backup air compressor started, but, because a check valve on the discharge line of the first air compressor stuck in the open position, pressure could not be maintained. Without compressed air, control of all air-operated valves in the containment was lost, including those on the seals for the reactor coolant pumps. Air pressure was restored within an hour, but the instrumentation records and a visual inspection revealed that the loss of instrument air had caused possible damage to the reactor coolant-pump seals. The plant was placed in cold shutdown for further inspection and repairs. Naturally the two compressors were completely checked out, and new check valves were installed. For additional backup, the compressed-air system was modified so that compressed air for the turbine-building instrument-air system would automatically be available if the instrument air for the containment were lost.

12.3

POWER-DISTRIBUTION ANOMALY

In July 1976 the 2560-MW(t) Combustion Engineering reactor in Unit 1 of the St. Lucie Nuclear Power Plant was at 80% power.[3] The reactor core exhibited an azimuthal power tilt (a measure of deviation from uniform core power distribution) of about 3%; the expected tilt would be no more than 2%. A review of the test data showed that three core characteristics (axial power shape, radial power distribution, and gross core reactivity) had begun to show anomalous behavior in June, and the magnitude of the anomalies had increased in a slow and uniform manner.

On July 9, 1976, the following measurements of core parameters led to a decision to shut the plant down for testing and inspection: (1) azimuthal power tilt had increased to about 4%; (2) the average axial peak, which had been expected to grow to 1.35, had grown to 1.53 and was centered at the core midplane; and (3) the core was about 0.4% more reactive than expected. Visual inspection of the vessel internals showed some minor debris in the lower plenum, but the debris that was removed appeared to have no relationship to the observed anomalous behavior of the core characteristics. However, a borescopic examination of the fuel bundles revealed extensive blistering and breaches of the lumped burnable poison (LBP) rods. An LBP rod consists of a stack of alumina pellets (containing uniformly dispersed boron carbide particles) clad with a Zircaloy tube. The rods are used to absorb the excess neutrons produced in the fissioning process and to help shape the power distribution in the core. Burnable poison rods were incorporated in nearly one-half of the fuel assemblies of the St. Lucie core.

Breaks in the cladding allowed the reactor coolant to diffuse throughout the affected rods, and the boron carbide oxidized and leached out. Since the process is dependent on neutron flux and temperature, the rate of removal was greatest near the midplane of the core and accounted for the increase in core reactivity and for the axial peaking. Since the poison-rod failures and subsequent leaching process possibly were not azimuthally uniform, the observed flux tilt could also have resulted from this same cause.

Because a large number of LBP rods were known to be defective, it was decided to unload the entire reactor core and replace all the LBP rods.

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

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

A preliminary visual examination of 11 fuel assemblies in the Combustion Engineering reactor at Calvert Cliffs 1 also revealed blisters on some of the poison rods. The blisters appeared to have been caused by hydriding, and some of the rods appeared to be perforated.

At other plants with Combustion Engineering reactors, the management was requested by the Nuclear Regulatory Commission (NRC) to increase in-core surveillance to ensure that a similar problem did not exist. In all plants except two, the burnup of the LBP rods had proceeded far enough so that the burnable poison no longer had a significant effect on the reactivity and power distribution. The exceptions were Millstone 2 and Calvert Cliffs 2. At Millstone 2, over one-half of the reactivity effect of the LBP rods has been burned out. A review of the plant's power distribution revealed no anomalous behavior similar to that which occurred at St. Lucie 1. At Calvert Cliffs 2, which had not yet gone to power, the poison rods were removed, dried to lower moisture specifications, and returned to the core.

12.4

SHORT PERIODS DURING REACTOR STARTUPS

In April 1977 the NRC circulated information to all licensees of operating BWRs concerning short periods that had been experienced in the startup of two BWRs, Dresden and Monticello. At Dresden 2 on Dec. 28, 1976, during a reactor startup, following a scram from unrelated causes about 9 hr earlier, a rod withdrawal of one notch resulted in a rapid power rise within a period of about 1 sec.[4] Commonwealth Edison Company owns this BWR, which is located in Grundy County, Ill. On its most sensitive scale, the intermediate-range monitor scrammed the reactor. At the time of the startup, the moderator was essentially without voids and at a temperature of 170°C (338°F). A similar event occurred at Dresden on Aug. 17, 1972.

Similarly, at the Monticello Nuclear Power Station on Feb. 23, 1977, following a reactor scram about 10 hr earlier, again from unrelated causes, a reactor period of about 1 sec occurred during startup when a single rod was pulled one notch. Northern States Power Company owns this BWR, which is located at Monticello, Minn. In this instance also, the intermediate-range monitor was on its most sensitive scale and terminated the power rise. Few voids existed in the moderator, where the temperature was 249°C (480°F).

The two most recent events were similar in the following respects:

1. Prior to the earlier, unrelated scram, both plants had been operating at or near full power, with axial flux peaking in the bottom portion of the core.
2. The time from the earlier scrams to the subsequent startups maximized the xenon concentrations in the core.
3. High-worth rod locations were similar, and both plants were using the same generic control-rod pattern (identified as B1).
4. Prior to the intermediate-range-monitoring scram at both facilities, dramatic indications of high notch worth had been seen with rod withdrawals resulting in periods ranging from 10 to 30 sec, which were terminated by reinsertion of the rod.

All the systems, including the reactor protection system, functioned as required. The combination of essentially no voids in the moderator and high xenon concentration accounted for the conditions that resulted in the control-rod notch acquiring an unusually high differential reactivity worth, which approximated 50% $\Delta k/k$ at Monticello. This excessive worth of rod-notch was the result of essentially no voids in the moderator and peak xenon conditions, which necessitated the withdrawal of significantly more control rods than are normally required to reach criticality. The resultant flux distribution at criticality magnified the normal axial peaking at the top of the core because of the heavy xenon concentrations at the bottom. In addition, the radial contribution to flux peaking was enhanced owing to the withdrawal of peripheral rods.

NRC records show that, after the earlier event at Dresden 2 on Aug. 17, 1972, corrective measures were taken for the subsequent startup, consisting of notchwise withdrawal of the group of rods. This corrective action was taken only for that operating cycle.

An evaluation of these events indicates that essentially trouble-free startups can be accomplished by avoiding peak xenon with no moderator voids or possibly by the use of a rod pattern developed for these particular conditions.

These events indicate a need for all licensees of operating BWRs to review their startup procedures and practices to ensure that their operating staff has adequate information to perform reactor startups avoiding such short periods. Operators should be made aware that extremely high rod notch worths can be encountered under these conditions. The procedures should include requirements for a thorough assessment following the occurrence of a short period before any further rod withdrawals are made. The considerations should be included in the operator training and requalification training programs.

12.5 RECURRENT WATER-PRESSURE SURGES

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

Approximately 2 min later, a second but louder rumbling was heard. At that time, even though the steam-generator-level control was in automatic, the operator noted large variations in feed flow and level indication. Also, operators at the main feed-pump suction valve reported that the feedwater line shook from the main feed pump to the feed heater.

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

An investigation revealed that a 20-mm drain line connected to the auxiliary feedwater system had failed. Since the line was welded to the drain header (a condition not considered in the piping design), it resulted in a permanent anchor point and prevented pipe movement. As part of the repair, similar lines were disconnected from the A, B, and C auxiliary feedwater lines and replaced with removable spool pieces.

To ascertain the cause of the feedwater instability, the licensee instrumented the main feedwater and auxiliary feedwater systems. The plant was returned to operation to conduct tests at 5% increments in the power level to duplicate the event under controlled conditions in order to determine the exact cause of the vibrations. In the test the licensee proposed to induce flow fluctuations by momentarily removing a steam-generator water-level signal and a feedwater-flow signal. The instability testing was performed on Dec. 22 and 23, 1976, but no pipe motion or flow instability occurred.

On Dec. 27, 1976, the plant again experienced a feedwater-line vibration approximately 5 min after a plant transient. The vibration resulted in a reactor trip from a low-water-level signal from the steam-generator coincident with a steam flow/feed flow mismatch signal.

The feedwater regulating valves were presumed to be a major contributor to the feedwater-flow instabilities. Investigation revealed that the valves' trim was not characteristic of a typical feedwater valve. This particular type of valve trim was oversized and capable of opening quickly. Very small changes in the valve opening would result in large flow variations; in other words, the trim lacked fine control. It was planned to install hydraulic dampers to smooth the incoming hydraulic signal and to order a new valve trim with more linear characteristics. A modification was made to the feedwater regulating valves to prohibit them from closing beyond the 5% open position, except in the tripped mode, to preclude operation of the valve in a known unstable region.

Before these changes could be effected, power operation of the reactor was resumed, although the cause of the flow instability had not been completely determined.

On Jan. 5, 1977, Beaver Valley 1 experienced its third feedwater-line vibration. The reactor was at 75%

power when a feedwater heater drain pump tripped; this caused the main feed pumps to trip on low suction pressure, resulting in a low feed flow. Turbine load reduction was commenced immediately at a rate of 2% per minute. The drain and feed pumps were returned to service, and the plant operated at 54% power for approximately 3 min, when a loud rumbling noise was heard, followed by a reactor trip initiated by a signal indicating a low water level in the steam-generator coincident with a steam flow/feed flow mismatch signal. The vibration lasted about 15 sec.

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

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

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

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2. Letter from A. D. Schmidt, Vice-President, Power Resources, Florida Power & Light Company, to N. C. Moseley, Director, Region II of the NRC Office of Inspection and Enforcement, May 13, 1977; Subject: Reportable Occurrence 335-77-23, St. Lucie 1, Date of Occurrence—Apr. 15, 1977.
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ANEXO 13

Selected Safety-Related Events Reported in March and April 1978

Compiled by William R. Casto

Of the incidents reported during March and April 1978, two are reviewed here because of their uniqueness and general interest: (1) two hydrogen explosions occurred in one day at Millstone 1, a boiling-water reactor (BWR) plant and (2) power oscillations were observed at Oconee 3, a pressurized-water reactor (PWR) plant. The explosions at Millstone reflect a generic problem, and the Nuclear Regulatory Commission (NRC) has subsequently issued an Inspection and Enforcement Bulletin to all BWR licensees.[1]

13.1 HYDROGEN EXPLOSIONS AT MILLSTONE 1

On Dec. 13, 1977, two hydrogen explosions occurred at the Millstone Nuclear Power Station, Unit 1 (Ref. 1). This BWR is operated by the Northeast Nuclear Energy Company and is located at Waterford, Conn. The first explosion occurred at 9:30 a.m. and was mostly confined to the off-gas system. Damage was relatively minor: the glass faces on the off-gas system flow-differential pressure gauges broke; a rupture disk blew out; and the loop seals between the off-gas-system drain lines and stack-base sump blew. This incident had no safety significance for the reactor, which was allowed to continue operating while the damage was being repaired.

The second explosion occurred at 1:00 p.m. outside the off-gas system in the two-level room at the base of the plant stack. The explosion propelled the door of the room into a warehouse about 60 m away, breached the reinforced-concrete ceiling of the room at the base of the stack, extensively damaged the ceiling beams, dislodged the 2-Mg concrete plugs in the floor above the off-gas-system particulate filters, damaged the probe supports for the isokinetic radiation monitor for the stack, and cracked the stack. The cracks were vertical, with a maximum separation of 2 mm at the surface; however, they did not impair the strength of the stack. In any event the control room was alerted by the second detonation, and the operators immediately tripped the reactor manually, thus terminating the generation of hydrogen in the reactor core.

One man was injured as a consequence of the second explosion. He received a concussion, skin abrasions, and bodily contamination and was hospitalized for 4 days.

Millstone personnel concluded that the attempt to restore water to the loop seals after the first explosion had not been successful. Without these seals, gases from the off-gas system accumulated and caused an explosion, which was probably ignited by a spark from the liquid-level switch in the stack-base sump. Inadequate ventilation of the room at the base of the stack and the lack of equipment for monitoring explosive gas concentrations within the enclosed area were also contributing factors.

Since this is a generic problem, the accumulation of explosive hydrogen mixtures had been considered in the design of BWR off-gas systems. As a result, major releases of airborne radioactivity have been prevented in the approximately 25 known hydrogen explosions that have occurred. However, there was extensive mechanical damage to equipment and structures, in addition to uncontrolled releases of radioactive material, in five of these explosions, including the last Millstone event. In each of these incidents, hydrogen accumulated outside the off-gas system. In view of this situation, the NRC has directed BWR licensees to take the following steps:

1. Review the operations and maintenance procedures related to the off-gas system to ensure proper operation in accordance with all design parameters. Include measures taken or to be taken to prevent inadvertent actions (such as arc strikes) that might cause ignition of the mixture of gases contained in the off-gas piping.
2. Review the adequacy of the ventilation of spaces and areas where there is piping containing explosive mixtures of gases. The review should consider ventilation losses and off-normal operation of the off-gas system, such as lack of dilution steam, lost loop seals, blown rupture disks, bypassing recombiners, and leakage of off-gas into isolated portions of various systems.
3. For those spaces and areas identified, describe what action has been taken or will be taken to ensure that explosive mixtures cannot accumulate, that

monitoring equipment would warn of such an accumulation should it occur, and that disposal of such mixtures would be controlled without explosion.

4. Loop seals are potential off-gas leakage paths following a pressure transient in off-gas systems. Describe the design features that minimize and detect the loss of liquid from loop seals, and describe operating procedures that ensure prompt detection and resealing of blown loop seals.

5. Review operating and emergency procedures to ensure that the operating staff has adequate guidance to respond properly to off-gas system explosions.

6. Within 45 calendar days of this date, report in writing to the director of the appropriate NRC Regional Office the results of the review and the plan of action with regard to Items 1 through 5. A copy of the report should be sent to the U. S. Nuclear Regulatory Commission, Office of Inspection and Enforcement, Division of Reactor Operations Inspection, Washington, D. C. 20555.

13.2 POWER OSCILLATIONS OBSERVED AT OCONEE 3

During an examination of an applicant for a license to operate Oconee Nuclear Station, Unit 3, an NRC examiner noticed oscillations on the nuclear power-range instrumentation and notified Region II personnel. This PWR, located at Seneca, S. C., was purchased from The Babcock & Wilcox Company by Duke Power Company of Charlotte, N. C. Later, on July 8, 1977, an NRC inspector, who was witnessing a shutdown of the reactor, observed power oscillations of from 3 to 6% as the power was decreased slowly from 85 to 50% of full power.[2] Oconee personnel had first noticed this increase in the magnitude of oscillations in April 1977. Previously, at power levels of about 50 to 60% of full power, the oscillations had been only 1 to 2%. However, Babcock & Wilcox had predicted such oscillations with a frequency of 0.25 Hz. The Oconee staff theorized that instability in relative water levels between the feedwater heating and tube-nest regions of the once-through steam generator might have caused the oscillations. They believe that the final control elements, such as control rods, feedwater valves and pumps, and turbine control valves, did not move in response to the oscillations due to long time constants. Tests were conducted by placing various equipment controllers in the manual mode to determine if the oscillations could be caused by the automatic control systems, but the results were inconclusive. While the plant was being shut down in late August to early September, the NRC inspector observed the oscillations once more and noted little or no change from those which occurred during the July 8 shutdown.[3]

In December, after the unit had been refueled, no oscillations occurred when the power was increased to 75% of full power.[4] When the plant was down for refueling, the steam-generator feedwater orifice assemblies were examined and found to be 25% open. Maintenance personnel attempted, unsuccessfully, to adjust the orifice. Because the special tool for making these adjustments was inadequate, a new one is being considered as work on resolving the problem of oscillations continues.

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3. NRC Inspection and Enforcement Report No. 50-287/77-20, Region 2, Aug. 30–Sept. 2, 1978.
4. NRC Inspection and Enforcement Report No. 50-287/77-31, Region 2, Dec. 14–16, 1978.

ANEXO 14

Selected Safety-Related Events Reported in July and August 1978

Compiled by William R. Casto

Of the incidents reported during July and August 1978, four are reviewed here because of their uniqueness and general interest: (1) a small light bulb that was dropped into a switch assembly caused a series of failures at Rancho Seco, (2) cracks were found in nozzle safe ends on the pressure vessel at Duane Arnold, (3) radiation exposures were reduced during special maintenance at Monticello, and (4) welds on Mark I containment toruses are being examined for cracks.

14.1 COMMON-CAUSE INCIDENT INVOLVING NONNUCLEAR INSTRUMENTATION

On Mar. 20, 1977, a short to ground in nonnuclear instrumentation at Rancho Seco resulted in a reactor trip and a subsequent reactor-cooling-system (RCS) cooldown rate that exceeded the technical specifications limit.[1] This pressurized-water reactor (PWR) is owned by the Sacramento Municipal Utility District, Sacramento, Calif.

Before the cooldown transient the plant was operating at a power level of 70%, with all four reactor coolant pumps operating and an average RCS temperature of 306°C. Shortly before 4:25 a.m., a control-room operator began replacing a burned-out light bulb in a back-lighted push-button switch assembly on one of the control consoles. The d-c power for this switch is provided from the "Y" portion of the nonnuclear instrumentation (NNI-Y). During replacement of the light bulb, the assembly was pulled from the panel and flipped down, exposing the bulbs. A bulb was dropped into the open light assembly cavity, creating a short to ground, whereupon the current-limiting and undervoltage protection for the NNI-Y d-c power supplies was actuated, cutting off the a-c power to all NNI-Y d-c power supplies. Preliminary investigations have shown that approximately two-thirds of the NNI signals (pressure, temperature, level, flow, etc.) were affected. The inevitable erroneous signals gave faulty information to both the control room and the integrated control system (ICS). Attempting to match equipment output with plant requirements, the ICS reduced main feedwater flow to zero, which caused the RCS pressure to increase. A reactor trip from high pressure followed.

After the reactor trip the operators were still hampered by the lack of instrumentation and by equipment responding to inaccurate signals. For approximately 9 min following the trip, pressure slowly decayed to about 13.8 MPa (2000 psig) in the RCS. It has been postulated that the pressure remained fairly adequate during this period owing to the cooling provided by makeup flow into the RCS and to the lifting of a pressurizer code safety valve below its set point of 17.5 MPa (2500 psig). On the loss of feedwater flow, an auxiliary feedwater pump had started; however, the auxiliary feedwater valves remained closed in response to erroneous level signals from the once-through steam generators—another effect of the NNI-Y d-c power failure. The "A" steam-generator level signal drifted to zero over a 9-min period, whereas that from the "B" steam-generator level drifted full scale. In reality, both steam generators boiled dry during this period. When the start-up level for the "A" steam generator drifted below the low-level set point, the ICS opened the auxiliary feedwater valve, admitting water to the shell side. This inflow of water created a heat sink for the RCS, causing a rapid pressure drop. The operators also may have increased the main-feed-pump flow at this time and thus provided another source of water for the "A" steam generator. The RCS pressure dropped rapidly to 11.1 MPa (1600 psig), at which point both auxiliary feedwater bypass valves automatically opened and began filling both steam generators with water.

Until power was restored to NNI-Y, approximately 1 hr and 10 min after the reactor trip, the operators continued the injection of auxiliary feedwater that was started automatically. Since it did not appear that the RCS temperature indication was reliable, the operators maintained RCS pressure as well as possible, using the pressurizer level indication and the RCS pressure indication that was available. These two parameters were controlled by adjusting the high-pressure injection flow. Unfortunately, the pressurizer heaters were not available for pressure control because of the NNI power loss. As injection of auxiliary feedwater continued, both steam generators were completely filled and water began to enter the steam lines. This large heat sink continued to rapidly cool the RCS, unknown to the operators who had no information on the temperature.

When the power to the NNI-Y d-c power supplies was finally restored, the operators realized that the RCS temperature had dropped to ~141°C and that the technical specifications had been violated. Immediate action was taken to return to the permissible operating region: spraying the pressurizer to reduce pressure, keeping three reactor cooling pumps (RCPs) operating (pump combinations were changed) to increase temperature, shutting off auxiliary feedwater flow, and draining the steam generators.

The short caused by the light bulb drew excessive current through the 24-V d-c power supplies that service components in NNI cabinets 5, 6, and 7. The power for these cabinets is designated NNI-Y, with the power for cabinets 1, 2, 3, and 4 designated as NNI-X. The four power supplies for NNI-Y are operated current-limited with a set point of 7.5 A. The subsequent reduction in voltage caused an undervoltage monitor to operate, opening the two shunt breakers through which a-c power from inverter D and inverter J is supplied to the d-c power supplies. Loss of these power supplies meant that every component in cabinets 5, 6, and 7 operating on d-c power was not functioning properly. An NNI signal could have been affected two ways between its source and the receiving component. The signal could be interrupted completely owing to a contact's opening when it was deenergized. Because most of the signals are −10 V to +10 V, this would have resulted in a midscale reading or, in some cases, a reading anywhere between −10 V and +10 V being transmitted to the indicator or sent to the ICS as an actual plant parameter. If a signal-conditioning component (buffer amplifier, square root extractor) was affected, this would have meant that the desired conditioning would not have been performed on the signal or that the component might not pass the true signal so that erroneous values were sent to the indicator or to the ICS. Since signal paths in the NNI are not restricted to either the X or the Y cabinets, about two-thirds of the signals passed through at least one component in cabinets 5, 6, or 7 and therefore were invalid.

Practically no permanent records of the plant parameters during the transient were kept. A major source of information was the posttrip transient review, which prints out selected data periodically following a reactor trip. It was not possible to extensively analyze this and the other data available (recorder outputs, hourly logger typer, etc.) during the transient. Over a period of several days following the incident, the plant engineers were able to trace which signals were valid, determine what equipment operated at which times, and then interpolate a temperature trace which indicated that the RCS temperature fell from about 312 to 141°C in slightly more than 1 hr. This cooldown rate of approximately 150°C/hr is well above the permitted rate of 40°C/hr.

To ensure that all components of the plant were in satisfactory condition, Babcock & Wilcox (B&W) personnel evaluated the effects of the transient on the reactor vessel, the reactor coolant piping, the pressurizer, the once-through steam generators, the fuel assemblies, the RCPs and seals, and the control-rod-drive mechanisms. The B&W team recommended to the Nuclear Regulatory Commission (NRC) that Rancho Seco be permitted to return to power under certain specified conditions.

The Plant Review Committee reviewed the B&W recommendations and requested that a special test procedure and a casualty procedure be written to ensure compliance. At the Committee's request, the following tasks were also completed prior to start-up:

1. Because of possible damage to steam lines from the injection of water, they were checked for any deformations.

2. A 15.5-MPa (2255-psig) leak test was performed on the reactor cooling system.

3. The overvoltage trip set points on the NNI d-c power supplies were increased from 27 V to 29 V to prevent spurious trips.

The special test procedure addressed conditions such as reactor maneuvering limits for the first start-up, increased surveillance of the loose-parts monitors for a week, an operability check of on-line and redundant NNI instrumentation, and daily surveillance of the primary and secondary radiochemistry for a week to check for leaking components. The casualty procedure was written to provide required operator actions for restoration of NNI power following a trip similar to the one experienced. The Plant Review Committee also required that a procedure be written giving operator instructions if NNI power cannot be restored.

On Friday, May 24, the reactor was taken critical, and the initial power ascension began.

14.2

CRACKS FOUND IN NOZZLE SAFE ENDS

On June 17 after a reactor scram at the Duane Arnold Energy Center, the dry well was inspected to locate a previously unidentified leak[2] of 11.4 liters/min. The Iowa Electric Light and Power Company owns this boiling-water reactor (BWR), which is located in Cedar Rapids, Iowa. A through-the-wall crack was found in one of the inlet nozzles of the recirculation system; it measured about 127 mm and was circumferential. All the remaining seven nozzle safe ends were examined by ultrasonic and radiographic methods. Five of these had suspicious indications, although there was no indication of additional through-the-wall cracks. All eight safe ends will be replaced, and laboratory investigations will be conducted to determine the cause of the cracks.

14.3

RADIATION EXPOSURE REDUCED DURING MAINTENANCE

The feedwater nozzles of essentially all operating BWRs in the United States which have been inspected have shown some degree of cracking. In the past, repair has required long exposure time of workers in high-radiation fields. During the fall 1977 outage, Northern States Power Company greatly reduced the exposures received by workers inside the reactor vessel at their Monticello facility[3] by extensive training, decontamination, shielding, and the use of special tools.

The Monticello facility was the first BWR to undergo feedwater nozzle cladding removal using the General Electric Company cladding-removal machine. Previously the cladding had been removed from the feedwater nozzles at Oyster Creek and Nine Mile Point with different equipment.

Most of the work was done by contractor personnel who had received training on a full-scale mock-up of the reactor vessel, using the actual tool that was used to remove the cladding. Any local personnel who worked on the job were required to view a videotape of the training session before entering the work area. Daily meetings were held to plan the day's activities to keep working time in high-radiation areas as short as possible.

The pressure-vessel work areas, such as reactor-vessel walls and nozzle openings, were decontaminated using a hydrolasing (high-pressure water) technique. Radiation surveys indicated dose-rate-reduction factors of 2 to 5 when this method was used.

Since the core was not removed during the performance of the work, extensive shielding was used to reduce the radiation levels. The shield platform placed over the core region weighed about 23 Mg (50,000 lb) and consisted of an 840-mm-thick concrete slab with a 25-mm steel plate on the top and bottom. It was supported by the core shroud. This placed the top of the plug 1.9 m above the top of the active fuel. The core spray line was shielded by setting vertical steel shields in front of the line, by placing a steel plate horizontally so that it rested on the vertical shield and the line, and by covering the plate with lead blankets. Nozzle areas, including the feedwater spargers, were shielded by hanging steel shields from support lugs around the circumference of the vessel. These shields were raised only when necessary in the area of the nozzle that was being worked on. Waist-level dose rate on the shield plug was 500 mR/hr after shielding but before sparger removal; before shielding and after hydrolasing, the level had been in excess of 4 R/hr. After removal of the sparger, the level dropped to 300 mR/hr.

The milling tool used to remove the cladding was developed by General Electric Company specifically for this job. Past repairs had been made by manual grinding, which required long exposure times and caused high airborne particulate activity due to the small size particles generated by the grinding. Using the milling tool required a minimum of manual grinding to smooth the nozzle surface. The milling machine operated at 5 to 10 rpm, with the material being removed as chips about 0.25 mm thick and collected in a basket located under the nozzle. Since all machining was remotely controlled, it was necessary for people to work in the high-radiation area only to set up the machine and to change cutting heads. In addition, a continuous water spray impinged on the nozzle, washing out any small grinding residue. The area was ventilated by a portable air hose that drew 100 m^3 (4000 cfm) of air from the work area and exhausted it to the containment after passing it through a high-efficiency particulate air filter and a charcoal filter. All workers in the radiation area were carefully monitored for exposure and occupancy time.

The work areas on the refueling floor and inside the reactor vessel were also continuously monitored for radioactivity. The floor was monitored by the normal installed instrumentation and the vessel work area by an area radiation monitor located inside the vessel with a readout on the refueling floor. A continuous air monitor operated in the vessel work area near the nozzle at approximately head level. During the milling operation the area monitor read 150 to 200 mR/hr. However, manual grinding increased airborne activity in the vessel to about 90 times the maximum permissible concentration (MPC) and to 1½ times the MPC on the refueling floor. During most of the repair effort, airborne activity was significantly less.

The 1977 maintenance, which included control-rod-drive return-line nozzle work, ultrasonic inspection of the core spray piping, as well as the feedwater nozzle work, resulted in a total of only 380 man-rems.

14.4 EXAMINATION OF MARK I CONTAINMENT TORUS WELDS

On June 28, 1978, Vermont Yankee Power Company (VYPC) reported that five nonpenetrating surface crack indications and one 230-mm-long surface crack were found in the heat-affected zones of the weld between the overlay torus base metal during the process of performing modifications (addition of strengthening gussets) to the torus support columns at the Vermont Yankee Nuclear Facility.[4] These modifications were part of VYPC's overall program to restore the originally intended design safety margins for the Vermont Yankee Mark I containment system. The reactor is a BWR located at Vernon, Vt.

On the basis of initial indications of the depth of the cracks, VYPC personnel performed an analysis of the structural capability of the torus shells, decided it was all right, and proceeded to attempt to grind out the 230-mm crack. On June 30, 1978, the crack was still apparent after grinding to the calculated depth of 6.4 mm. The plant was then placed in cold shutdown.

The welding operations at Vermont Yankee were performed at locations on the torus shell that were lower than the water level in the torus. Although the underlying causes of the cracking have not yet been determined, the presence of water on the opposite side of the torus shell during the welding operations appears to have been a primary contributor. Consequently, a generic concern has arisen that the potential for cracking could exist when welding is performed on a torus containing water.

In view of the above, on July 7, 1978, the NRC Office of Inspection and Enforcement verbally requested licensees to perform close visual inspections on similarly made torus weldments at Peach Bottom Units 2 and 3, Quad Cities Units 1 and 2, Hatch Unit 1, and the Monticello facilities. These inspections revealed no apparent linear indications through the painted surface. However, Monticello reported that magnetic particle examination, together with visual inspection, revealed two relevant surface linear indications 13 and 39 mm long, which were verified by liquid penetrant tests after removal of the paint. Both indications were reportedly removed by grinding at less than 3 mm depth.

Licensees for Peach Bottom Units 2 and 3, Quad Cities Units 1 and 2, Hatch Unit 1, and Monticello were further requested to provide the following information:

Item A:

1. The welding procedures, procedure qualifications, welder qualifications, and electrode controls used in strengthening the support-column-to-torus connections (i.e., addition of gussets, saddle supports, webs, etc.).
2. The preventive measures used to ensure that condensation does not occur on surfaces to be welded before and during the welding.
3. The chronology of nondestructive examinations (NDE) performed subsequent to such welding operations. Include procedures, methods, and techniques, how long the welds had been at ambient temperature before they were nondestructively examined, and the results of these examinations.

Item B:

Where the NDE documentation (Item A3) is not sufficiently definitive to show that welding to the torus was nondestructively examined after the completed welds were at ambient temperature for a minimum period of 72 hr, the following measures should be taken:

1. Remove paint from surfaces of the overlay weld and torus base-metal heat-affected zones by rotary wire brushing or equivalent means.
2. Examine the exposed interbead fusion zone of the overlay weld and the associated base-metal heat-affected zones utilizing magnetic particle techniques in accordance with the applicable section of the ASME Code.
3. Any indications detected as a result of magnetic particle techniques are to be evaluated as to their acceptability in accordance with the applicable ASME Code. Examinations that detect relevant linear indications may be supplemented by other nondestructive methods and techniques to determine the character of the flaws (i.e., estimated size, shape, depth, orientation, etc).
4. Results of the field examination of individual weldments are to be documented.

REFERENCES

1. Letter from A. J. Mattimore, Assistant General Manager and Chief Engineer, Sacramento Municipal Utility District, to Director of Regulatory Operations, NRC Operations Office, Region V, Walnut Creek, Calif., Mar. 31, 1978; Subject: Reportable Occurrence 78-1, Docket 50-312.
2. Iowa Electric Light and Power Co., Licensee Event Report 78-030, Docket 50-331, June 30, 1978.
3. a. Memorandum, Cwalina to Grimes, Nov. 11, 1977; Subject: Monticello Trip Report.
   b. Memorandum, Snaider to Davis, Dec. 29, 1977; Subject: Summary of Dec. 15, 1977, Meeting with Northern States Power Company.
4. NRC Inspection and Enforcement Bulletin No. 78-11, July 24, 1978.

ANEXO 15

Selected Safety-Related Events Reported in January and February 1979

Compiled by Wm. R. Casto

Of the licensee event reports received during January and February 1979, three are reviewed here because of their uniqueness and general interest: One incident involved a "spill" of contaminated water which resulted in the contamination of 13 operating personnel. The other two incidents involved short periods (e.g., rapid reactivity increases), one due to an accidental increase in power demand and the other to rapid rod withdrawal during startup. All three events are summarized below.

15.1 CONTAMINATED WATER SPILL

On Oct. 24, 1978, several cubic meters of contaminated water from the chemical and volume control system of North Anna 1 were spilled onto the floor of the auxiliary building.[1] This pressurized-water reactor (PWR) is located in Louisa County, Virginia, and is operated by the Virginia Electric and Power Company (VEPCO).

During the day shift on October 24, the header for the alternate reactor-cooling-system charging pump was removed from service, and portions of the line were drained to repair a leaking packing gland on an isolation valve. Draining of the line was effected through a vent valve. In accordance with VEPCO practice, these two valves were not physically tagged, but they were listed on the Tagging Record (a form used for maintenance activities). The valves were entered as "Drains Open" by valve number on the lower half of the Tagging Record.

At shift change the status of the line was discussed by the oncoming assistant control-room operator and the person he was relieving. They had a detailed discussion of the line status, including how it had been drained and the fact that drain valves were still open. However, conversation between the oncoming and departing shift supervisors apparently established that the line was "out of service" but with no other details.

On the evening shift the assistant control-room operator asked his shift supervisor for permission to clear the tags on the header, which was granted along with instructions on how to do it. However, the lower half of the Tagging Record was covered when it was presented to the shift supervisor, and he was not aware that the line had been drained. Shortly after the assistant control-room operator had gone to the auxiliary building to clear the tags, the control-room operator noted a decreasing volume-control-tank level and a decreasing seal-injection flow to the reactor coolant pumps. When attempts to contact the assistant control-room operator (who was clearing tags) failed, other people were dispatched to find him, investigate the apparent loss of water, and increase the reactor coolant-pump seal-injection flow rate. Shortly thereafter the valves were closed, and the auxiliary building was evacuated.

Water from these valves spilled about 4 m^3 of contaminated water onto the floor of the auxiliary building and collected in drains and sumps. Some water splashed onto the controls for a component-cooling-water valve that controls the flow of cooling water to a reactor coolant-pump thermal barrier and caused it to close. Owing to increasing temperatures on the reactor coolant pump, the operators tripped the reactor and shut down the pump.

Thirteen persons were contaminated; however, they were successfully decontaminated onsite. No significant release of radioactivity to areas outside the plant occurred. Procedures for taking systems out of service and for placing them back in service will be reviewed and changed as appropriate.

15.2 SHORT PERIOD AT BWR

The Cooper Nuclear Station, a boiling-water reactor (BWR) located in Brownville, Nebr., experienced a reactivity increase that produced a reactor period of less than 5 s. The incident occurred on Nov. 24, 1978, at the BWR owned by the Nebraska Public Power District. At the time of the occurrence, the reactor was operating at about 27% of full power so that surveillance testing of the turbine stop valves and a scheduled rod exchange could be accomplished.[2] At this reduced power level, various pressure settings on the oil lubrication system for recirculation motor-generator (MG) set B were being calibrated and reset as necessary. While this was being done, the MG set B was inadvertently tripped through personnel error. After the oil lubrication-system pump was restarted, it was discovered that the MG set would not respond to an increase in speed demand. Troubleshooting led to the possibility of a blown fuse in the control circuitry. Two 1-A fuses located in the scoop-tube drive could have been the problem. When the lower fuse was pulled for testing, the scoop-tube drive jumped in and caused a sudden increase in speed of the MG set, which resulted in a rapid reactor power increase. It is thought that the rate of power increase was higher than it would have been if the speed change had been performed manually.

The exact duration of the power increase could not be determined, although it is believed the duration was not greater than 10 s. The fuse was replaced as soon as human reaction time permitted, and the MG set was tripped by an operator very shortly thereafter; one of these actions terminated the transient. During the transient the thermal power increased to about 75% of full power.

The apparent cause of the transient was personnel error coupled with poor electrical prints. Subsequently the manufacturer of the control system provided a current electrical diagram, which was reviewed by station personnel to ensure that the system is the same as the as-built condition. A tag stating "Do not remove lower fuse while RR MG Set is running" was added to each scoop-tube control unit, and an engineering evaluation of the control-system logic will be performed.

15.3 SHORT PERIOD DURING STARTUP

On Dec. 14, 1978, at the Oyster Creek Nuclear Generating Station, the reactor automatically scrammed during a startup.[3] This BWR is owned by the Jersey Central Power & Light Company in Morristown, N. J.

At the time of the scram, the operator was withdrawing control rods following a scram from full power the previous day. Because of the high xenon concentrations, an accurate estimated critical rod position was not possible. As usual, the operator was watching the count rate as indicated by the source range monitor (SRM). Since the SRM count rate had changed only slightly (425 to 450 cps) from the start of the rod withdrawal, it was thought that the reactor was still strongly subcritical; hence rods were being withdrawn in the "notch override mode." When the first rod in Group 9 was withdrawn to notch position 10, the reactor became critical on an estimated 2.8-s period. The operator attempted to insert the rod using the "emergency rod in" control switch to no avail. However, the excursion was terminated by an automatic reactor scram in the low range of the intermediate-range monitor.

Obviously the operator did not expect criticality to occur because of the low count rate on the SRM. In addition, the approach to critical procedure does not provide specific guidance for startup under peak xenon conditions. The rod did not respond to the "emergency rod in" switch because the switch failed to make contact owing to a bent mechanical switch stop.

There was no safety significance to the fast positive period since it occurred at a very low power and did not cause any measurable heating of the moderator. Furthermore, because of the time required to transfer heat from the fuel to the cladding, the cladding was not affected. Very likely, if the "emergency rod in" switch had functioned properly, the short period would have been terminated by manual control.

The associated procedures will be revised to require that specified control rods be notched out before starting withdrawal of the Group 6 rod.

The significance of this reportable event will be incorporated into the plant's training program, and emphasis will be placed on hot startups when the xenon concentration is greater than that at operating equilibrium.

REFERENCES

1. RII Reports 50-338/78-37 and 50-339/78-32, Dec. 11, 1978.
2. Letter from L. C. Lessor, Cooper Nuclear Station, Brownville, Nebr., to K. V. Seyfrit, Director, U. S. Nuclear Regulatory Commission, Office of Inspection and Enforcement, Region IV, Arlington, Tex., Dec. 8, 1978.
3. Oyster Creek Nuclear Generating Station, Forked River, N. J., Licensee Event Report, Reportable Occurrence No. 50-219/78-33/1T-1, Jan. 10, 1979.

ANEXO 16

Selected Safety-Related Events Reported in January and February 1979

Compiled by Wm. R. Casto

Of the incidents reported during March and April 1979, two are reviewed because of their uniqueness and general interest: (1) feedwater valving problems at Oconee 1 and (2) a loss of coolant inventory at Oyster Creek.

16.1 FEEDWATER VALVING PROBLEMS AT OCONEE 1

On Dec. 14, 1978, at Duke Power Company's Oconee Unit 1, problems were experienced with water-level control in the two once-through steam generators following a reactor trip. The trip occurred as a result of a sequence of events initiated by a short in the power cord for the reactor-average-temperature recorder in the integrated control system, which caused an erroneous low reading of about 7°C (Ref. 1). As designed, the integrated control system withdrew a group of control rods to restore the proper average temperature. Reactor power increased, of course, as the reactivity was added to the core, and the reactor tripped on high pressure and temperature. Shortly thereafter, both normal feedwater pumps tripped because of high discharge pressure. This started an emergency feedwater pump, which operated until the normal feedwater pumps restarted automatically. Approximately 2 min after the reactor trip, the water levels in steam generators A and B had dropped to.6 and 0 in., respectively. The normal level is 0.28 m.

An emergency feedwater pump again started flow to steam generator B. Within 5 min after the reactor trip, the water level in steam generator A returned to normal, but in steam generator B the level increased to only 900 mm before dropping again to 0. Thirteen minutes after the reactor trip, however, steam generator B had been refilled through the emergency feedwater header. High-pressure injection occurred as designed when the reactor coolant pressure dropped to 10 MPa (1500 psig). The feedwater problems apparently resulted from improper operation of the feedwater valves involved in switching from normal to emergency flow paths.

The power cord for the average-temperature recorders on Unit 1 was repaired. Similar cords on Units 2 and 3 were inspected and found to be in good condition. The feedwater valves for Units 2 and 3 will be checked during a future outage.

16.2 LOSS OF COOLANT INVENTORY AT OYSTER CREEK

The Oyster Creek Nuclear Power Plant, a boiling-water reactor (BWR) owned and operated by Jersey Central Power and Light, was operating normally on May 2, 1979, at approximately 98% power with one of its five recirculation loops (loop D) and one of its two startup transformers out of service when simultaneous reactor and recirculation pump trips occurred.[2] The cause of these trips was a momentary, spurious signal indicating high pressure in the reactor coolant system, which was occasioned by routine surveillance testing of the isolation-condenser pressure switches. The subsequent events resulted in a serious loss of water inventory before adequate cooling was restored. (It should be kept in mind while reading this description of the event that the Oyster Creek BWR does not have jet pumps in its recirculation system.)

As a result of the reactor and recirculation pump trips, reactor power, steam flow, pressure, water level, recirculation flow, and turbine generator output began decreasing. At about 13 sec into the transient, the turbine generator tripped at the low-load trip point. This subsequently caused all three reactor feedwater pumps to trip, because the backup electric power source supplied by the one available startup transformer was not capable of providing sufficient power to the condensate and feedwater pumps to retain even a partial feedwater supply to the reactor vessel. The reactor operator attempted unsuccessfully to restart a feedwater pump, and the reactor water level continued to drop since the steam flow from the reactor was being replaced by water from only a single control-rod-drive pump.

Recognizing the continued loss of water inventory from the reactor, the operator started a second control-rod-drive pump at 31 sec into the event then initiated manual reactor isolation at 43 sec. With the reactor fully isolated from the main condenser, the operator manually closed the discharge valves of recirculation loops A and E, which receive the return condensate from the two isolation condensers. The operator then manually placed one of the isolation condensers into service. It is believed that the operator also initiated the closure of the B and C loop discharge valves at about this time as a first step in starting one or both of the associated recirculation pumps that had tripped at the start of the event. In addition, as indicated previously, one loop (loop D) was already isolated and out of service, with its discharge valve closed before the event. However, all the discharge valve bypass lines were open before and throughout the event. As the discharge valves moved to the full-closed position, the water distribution in the reactor vessel continued to shift away from the core region toward the downcomer (annulus). At 172 sec, the reactor triple-low water level trip point was reached. All discharge valves were fully closed at 186 sec.

Heat was then removed from the system by manually starting and stopping flow in the isolation condenser. The increases and decreases in reactor pressure and annulus water level that were noted during this period were caused by the intermittent operation of the isolation condenser. At approximately 32 min the operator started the loop C recirculation pump. However, when the operator observed the water level in the annulus dropping rapidly, the pump was shut down and the discharge valve reclosed. At about 37 min, one feedwater pump was restarted, causing the water level in the annulus to rapidly rise to 4.2 m above the top of the core. At 39 min a recirculation pump was placed in service, and the triple-low water level in the core region was observed to be cleared. Steps were then taken to bring the plant to a cold-shutdown condition.

On the basis of calculations, it was concluded that the water level had remained above the core during the transient. There was no indication from either the primary coolant radiochemical analyses or the radioactive off-gas rates that there was any abnormal release of fission products from the fuel due to the transient, supporting the conclusion that the core was not damaged.

Following are the corrective actions that have been or will be undertaken:

1. A readout of the core water-level instrumentation (the system that provided the triple-low set point) will be installed in the control room. Also, the installation of a tap at an elevation lower than the core differential-pressure tap will be investigated. At this time, levels below the core spray sparger cannot be monitored.
2. The surveillance testing procedures were modified.
3. The triple-low alarm was made a safety limit for all modes of operation.
4. The technical specifications were changed to require that the discharge valves of more than one recirculation pump remain open.

Furthermore, both the double-low level and the maximum time delay before the isolation condenser valves open were included in the technical specifications as limiting safety-system settings.

REFERENCES

1. Letter from W. O. Parker, Jr., Duke Power Company, to J. P. O'Reilly, Nuclear Regulatory Commission, Jan. 15, 1979; Subject: Oconee Unit 1, Reportable Occurrence Report RO-269/78-27, Docket 50-269.
2. Letter from V. Stello, Jr., Director, Division of Operating Reactors, Nuclear Regulatory Commission, to I. R. Finfrock, Jr., Jersey Power and Light Company, May 30, 1979; Subject: Restart Safety Evaluation Report in the Matter of Oyster Creek Nuclear Generating Station, Docket 50-219.

ANEXO 17

Selected Safety-Related Events Reported in October and November 1979

Compiled by Wm. R. Casto

Of the incidents reported during this period, two are reviewed because of their uniqueness and general interest: (1) at Rancho Seco the reactor experienced a rapid cooldown and (2) at North Anna 1 high gaseous activity occurred in the auxiliary building.

17.1 FAST REACTOR COOLDOWN AT RANCHO SECO

At the Rancho Seco Nuclear Generating Station on Jan. 5, 1979, a reactor trip was caused by a technician making modifications to the Integrated Control System (ICS).[1] The Sacramento Municipal Utility District of Sacramento, Calif., owns and operates this 2772-MW(t) pressurized-water reactor (PWR). The trip from 100% of full power resulted in a rapid cooldown rate and in a reactor shutdown of about 13 h. However, the pressure/temperature limits for heatup/cooldown were not violated, and there was sufficient water in the pressurizer through the transient. Therefore the unit was immediately returned to full-power operation.

At the time of the transient, the plant was operating with all four reactor coolant pumps and with an average reactor coolant temperature of 306°C (582°F). A technician performing a modification to the ICS allowed a wire connected to a terminal in the

ICS panel to swing free. The resultant short circuit caused the loss of the ±25-V d-c power supplies. This system is designed so that the loss of either the positive or negative 25-V d-c supply will trip both the ICS a-c supply breakers which in turn run the feedwater valves back to the 50% position. Reduced feedwater flow caused the reactor coolant-system (RCS) pressure to increase to 16.3 MPa (2355 psig), where all four RCS channels tripped on high pressure approximately 0.16 s into the transient. Although the feedwater flow was reduced, it was still adequate to remove the decay heat. As a result, approximately 70 s into the transient, the RCS pressure dropped to 11.0 MPa (1600 psig) and started the high-pressure injection, decay-heat removal, and reactor-building isolation systems. Feedwater flow continued and was augmented by auxiliary feedwater that was automatically started. By the time the ICS power was restored, about 5 min into the transient, feedwater flow was approximately 1000 Mg/h (2.2 million lb/h). At 7 min into the transient, both main feedwater pumps were tripped, and only the auxiliary feedwater system was used to supply water to the once-through steam generators (OTSGs).

Although the water level in both OTSGs increased during the transient, the level in the A-OTSG was brought under control and remained on scale, and the B-OTSG was filled to the top of the operating range and continued at tha' level for 10 to 15 min. This filling was the single most significant cause of the excessive cooldown rate. The problem with the B-OTSG was caused by the lack of indication of the status of safety channel A in the control room. Although both channels actuated, the 24-V power-supply breaker that powers the indicating lights was in the "off" position. This did not prevent actuation of the safety but did leave the control room without indication of its status.

The design pressure/temperature requirements for heatup and cooldown had not been violated even though the maximum cooldown rate was 120°F/h, which exceeded the Technical Specifications limit of 100°F/h. However, this high cooldown rate was judged to be small when it was compared to the design factors. The lowest temperature measured during the transient was 221°C (430°F).

Rancho Seco personnel are evaluating the event and are considering the following corrective actions:

1. Placing the ICS cabinets under "key control."

2. Modifying the operating procedures to include specific instructions to ensure that the safety cabinets are properly powered before heating up the plant from a cold shutdown condition.

3. Performing an engineering evaluation to determine the necessity for automatic initiation of auxiliary feedwater on safety features actuation. The evaluation would leave the system as a safety feature system but would require operator action to admit water to the OTSGs.

17.2

GASEOUS ACTIVITY IN AUXILIARY BUILDING OF NORTH ANNA 1

A safety injection occurred[2] at North Anna 1, on Sept. 25, 1979. This 2275-MW(t) PWR located at Mineral, Va., is owned and operated by the Virginia Electric & Power Company. In the following discussion of this incident, the times are approximate and should not be considered to reflect the transient response of either the system or the operators.

North Anna 1 was at 78% power in "end-of-life coastdown." Dilution was in progress with about 44 m^3 (10,000 gal) of water being added per shift with the letdown going to the boron-recovery gas stripper for processing.

At 5:44 a.m. the drain valve on the 5B feedwater heater commenced cycling, and at 6:09 the turbine tripped on high level in 5B heater; the reactor and the turbine tripped simultaneously. Also as a result of the turbine trip, the steam-dump valves opened to the turbine condenser in order to reduce the temperature of the primary system, and the auxiliary feedwater pumps started. When the steam-dump valves should have closed, one valve failed to close, and thus cooldown of the primary-system low pressure continued. At about 6:11 low-level alarms from the pressurizer sounded.

By 6:12 a.m. the primary-system temperature had dropped to about 272°C (522°F), the pressurizer level was zero, and safety injection started on low pressure. The reactor coolant pumps were tripped, and the main-steam valves were closed to stop the cooldown.

At about 6:18 a.m. the pressurizer level had increased to 11% because of the safety injection flow, and the primary-system pressure was up to about 14.9 MPa (2160 psig). By 6:20 the primary-system pressure had recovered to about 15.9 MPa (2310 psig). The main feedwater pumps had been tripped by the safety injection signal. At 6:21 one main feedwater pump was restarted, and the auxiliary feedwater pumps were shut down at 6:25.

Continued operation of safety injection had filled the primary system and raised its pressure to the power-operated relief valve (PORV) set point by 6:27 a.m. At this time the pressurizer level had reached

50 to 60%, and letdown was restored through two orifices. The PORV continued to cycle until about 6:39, relieving gases and vapor but no solid water to the pressurizer relief tank, which was not overpressurized.

At 6:29 a.m. one reactor coolant pump was restarted, and auxiliary spray flow was established to the pressurizer for pressure control. At 6:31 the pressurizer level was 68%, and by 6:39 pressure had stabilized, safety injection had ceased, normal charging and letdown had been established, and the PORV was closed.

At about 6:45 a.m. the particulate, gaseous, and liquid monitors in the auxiliary building indicated elevated levels of activity. The operator in the area was told to leave the building, and the doors were shut. Initial grab samples indicated levels of up to 150 x MPC for ^{133}Xe and ^{135}Xe and ^{88}Kr. Later samples, at about 9:00, showed a decrease to about 6 x MPC. By 10:30 levels were less than the maximum permissible concentration. Area monitors in the auxiliary building never indicated greater than background. It was determined that indications on the gaseous, liquid, and particulate monitors were due to the "submergence effect" of the gas in the area which was removed by the building ventilation system and discharged through the stacks.

The gas release occurred just after the time when normal charging was resumed and safety injection stopped. During the entire transient, dilution flow had been going to the volume control tank (VCT). The high pressurizer level caused the charging flow controller to decrease flow to a minimum; at this time, letdown was flowing to the VCT and then to the boron-recovery system as the VCT letdown valve modulated to divert full flow in that direction. When the boron-recovery holding tank was full, the valve on the inlet closed, and the letdown low-pressure relief valve opened, sending raw gassed coolant to the VCT. Correspondingly the relief valve on the full VCT opened, sending raw coolant to the high-level liquid waste tank (HLLW). From that point, gases from the HLLW should have gone through the vent system to the process vent. However, some time previously, possibly during construction, the flange-mounted flow-limiting orifice in the HLLW vent line had been removed and an elbow placed on the open end of the line. Therefore the vent gases were dumped into the auxiliary building and released through the building's charcoal filters to the atmosphere.

The release was calculated to have been about 7 Ci, at a rate of 0.04% of Technical Specifications limits. Calculated off-site doses were on the order of less than 0.01 mrems. Off-site sampling instruments, analyzed by the Virginia Department of Health, indicated normal background.

North Anna 1 was cooled down for its scheduled refueling.

REFERENCES

1. Sacramento Municipal Utility District, Rancho Seco Nuclear Generating Station, Docket No. 50-312, LER 79-01, Jan. 5, 1979.
2. *Nucleonics Week*, 20(39): 1 (Sept. 27, 1979), and personal communication with J. R. Buchanan, Oak Ridge National Laboratory.

Selected Safety-Related Events Reported in November and December 1979

Compiled by Wm. R. Casto

Of the incidents reported during November and December 1979, two are reviewed here because of their uniqueness and general interest: (1) Oconee suffered a loss of non-safety-related instrumentation for the reactor coolant system during operation and (2) cascading events at North Anna caused a minor release of radioactivity.

18.1 NON-CLASS 1E INSTRUMENTATION AND CONTROL POWER LOST DURING OPERATION

On Nov. 10, 1979, an event occurred at the Oconee Power Station, Unit 3, that resulted in loss of power to a non-class 1E, 120-V, a-c, single-phase power panel that supplied power to the integrated control system (ICS) and the nonnuclear instrumentation (NNI) system.[1] This loss of power resulted in control-system malfunctions and a significant loss of information to the control-room operator. Duke Power Company owns this pressurized-water reactor (PWR), which is located near Seneca, S. C.

Following is a description of the circumstances: With Unit 3 operating at 100% power, the main condensate pumps tripped, apparently as a result of a technician's performing maintenance on the level-control system of the hot well. This pump trip led to reduced feedwater flow to the steam generators, followed by high pressure in the reactor coolant system, which tripped the reactor and the turbine simultaneously. Almost immediately, the non-class 1E inverter power supply to the ICS (which provides proper coordination of the reactor, steam-generator feedwater control, and turbine) and to one NNI channel tripped and failed to automatically transfer its loads from the d-c power source to the regulated a-c power source. The inverter tripped owing to blown fuses. Loss of power to the NNI rendered the control-room indicators and recorders for the reactor coolant system (RCS) inoperative (except for one wide-range RCS pressure recorder). Also, most of the secondary plant systems became inoperable, causing loss of indication for systems used for the removal of decay heat and the addition of water to the reactor vessel and steam generators. On loss of power, all valves controlled by the ICS assumed their respective failure positions. The loss of power existed for approximately 3 min, until an operator could reach the equipment room and manually switch the inverter to the regulated a-c source.

As a result of this incident, the Nuclear Regulatory Commission directed that all power-reactor facilities with an operating license and those nearing completion of construction (North Anna 2, Diablo Canyon, McGuire, Salem 2, Sequoyah, and Zimmer) take the following actions:

1. Review the class 1E and non-class 1E buses supplying power to safety-related and non-safety-related instrumentation and control systems that could affect the ability to achieve a cold-shutdown condition with existing procedures or procedures developed under item 2 below. For each bus: (a) identify and review the alarm and/or indication provided in the control room to alert the operator to the loss of power to the bus; (b) identify the instrument and control-system loads connected to the bus and evaluate the effects of loss of power to these loads, including the ability to achieve a cold-shutdown condition; and (c) describe any proposed design modifications resulting from these reviews and evaluations and your proposed schedule for implementing those modifications.

2. Prepare emergency procedures or review existing ones that will be used by control-room operators, including procedures required to achieve a cold-shutdown condition, on loss of power to each class 1E and non-class 1E bus supplying power to safety-related and non-safety-related instrument and control systems. The emergency procedures should include: (a) the diagnostics/alarms/indicators/symptoms resulting from the review and evaluation conducted per item 1 above; (b) the use of alternate indication and/or control circuits which may be powered from other non-class 1E or class 1E instrumentation and control buses; and (c) methods for restoring power to the bus.

Describe any proposed design modification or administrative controls to be implemented resulting from these procedures and your proposed schedule for implementing the changes.

3. Re-review IE Circular No. 79-02, *Failure of 120 Volt Vital AC Power Supplies,* dated Jan. 11, 1979, to include both class 1E and non-class 1E safety-related power-supply inverters. On the basis of a review of operating experience and your re-review of IE Circular No. 79-02, describe any proposed design modifications or administrative controls to be implemented as a result of the re-review.

4. Within 90 days of the date of IE Bulletin 79-27 (Ref. 1), complete the review and evaluation required and provide a written response describing your reviews and actions taken in response to each item.

18.2 CASCADING EVENTS CAUSE MINOR RELEASE OF RADIOACTIVITY

North Anna Unit 1, a PWR owned by the Virginia Electric and Power Company, was at 78% of full power on Sept. 25, 1979, when a steam-dump valve cooler began to cycle.[2] The cycling of the valve was believed to be due to a tube rupture inside a drain cooler. Since the leakage was more than the capability of the drain valves, extraction-steam condensate backed up the heater to the turbine trip set point and a trip occurred, followed by a reactor trip. At this time the steam-dump valves opened to reduce the reactor-coolant-system temperature to 286°C (547°F). When the temperature of the reactor coolant system decreased below the steam-dump set point, one of them failed to close, and it became necessary to close the main steam isolation valves.

Excessive cooldown caused by the open steam-dump valve resulted in depressurization of the reactor coolant system as well as a low-pressure signal from the pressurizer. The pressurizer level was also decreasing, and, when it reached the low-level alarm point, the operators decided to manually initiate a pressurizer low-low level signal which, combined with the low-pressurizer pressure signal, started safety injection.

The reactor coolant pumps were immediately tripped manually as required. As a result of the safety injection and the termination of the cooldown, the reactor-coolant-system pressure began increasing. One of two safety-injection charging pumps was then secured. Shortly thereafter, the power-operated relief valve on the pressurizer began to cycle, maintaining pressure at 17.48 MPa (2335 psig) until normal letdown and charging were established. When this happened, the remaining charging pump was still drawing suction from the reactor water-storage tank. This resulted in an increasing level in the volume-control tank, causing the level-control valve to divert reactor coolant letdown to the boron recovery system via the gas stripper. This high flow to the stripper resulted in closure of the inlet valve to the stripper due to high level. Then pressure in the letdown line increased to the low-pressure letdown-line relief-valve set point of 1.4 kPa (200 psig). This valve discharged directly to the volume-control tank where the pressure increased to the set point of the relief valve, 515 kPa (75 psig). The relief valve then discharged letdown water and gases directly to the high-level liquid-waste tank. Normally, the noble gases would have been released from here through a vent line connected to the plant process vents. However, in this vent line a flange had been disconnected, and the noble gases were released into the auxiliary building and were vented through the plant charcoal and the high-efficiency particulate air (HEPA) filters and then out the plant ventilation vents.

Had the flange not been open, a release of noble gases to the auxiliary building may still have occurred. The discharge rate of reactor coolant to the high-level liquid-waste tank may have been too high to pass the fluid through the normal vent line. If so, the reactor coolant gases would have vented to the low-level liquid-waste tanks and out into the auxiliary building via the overflow line of the low-level liquid-waste tanks. The disconnected flange was, of course, reconnected.

The noble gas release rate from the auxiliary building was less than 0.05% of the rate permitted by the technical specifications.

REFERENCES

1. Nuclear Regulatory Commission, Office of Inspection and Enforcement, IE Bulletin 79-27, Nov. 30, 1979.
2. Virginia Electric and Power Company, Licensee Event Report 50-338/79-128, North Anna Power Station, Unit No. 1, Oct. 9, 1979.