D O N A L D   C.   C O O K   N U C L E A R   P L A N T

ANNUAL OPERATING REPORT

1983

Compiled By: J.F. Stietzel
QC Superintendent

Reviewed By: B.A. Svensson
Assistant Plant Manager

Reviewed By: E.L. Townley
Assistant Plant Manager

Approved By: W.G. Smith, ~~Jr.~~
Plant Manager

IE01
V1

TABLE OF CONTENTS

INTRODUCTION

The Donald C. Cook Nuclear Plant, owned by the Indiana and Michigan Electric Company and located five miles north of Bridgman, Michigan, consists of two 1100 MWe pressurized water reactors. The Nuclear Steam Supply Systems for both units are supplied by Westinghouse with a General Electric turbine-generator on Unit 1 and a Brown-Boveri turbine-generator on Unit 2. The condenser cooling method is open cycle, using Lake Michigan water as the condenser cooling source. The Donald C. Cook Nuclear Plant was the first nuclear facility to use the ice condenser reactor containment system, which utilizes a heat sink of borated ice in a cold storage compartment located inside the containment. The architect/engineer and constructor was the American Electric Power Service Corporation.

This report was compiled by Mr. J.F. Stietzel, with information contributed by the following individuals:

D.C. Palmer	-	Personnel Exposure Summary
R.L. Otte	-	Inservice Inspection
E.A. Abshagen	-	Changes to Facility

1.16 REPORT - WORK FUNCTION CATAGORIES

Reactor Operations and Surveillance

Those activities involved with operating the plant or monitoring it's operation, including chemistry, performance testing, surveillance testing, etc. The plant may be at any power level, including zero, and still have work falling into this area. Many STP's run during shutdown or refueling may still fall into this catagory.

Routine Maintenance

All equipment or system maintenance, whether preventative or restorative, which does not involve significant modifications to equipment or systems. Included is C&I repair work, as well as work to adjust operable equipment to improve performance (adjusting fan blade pitch, for example).

Inservice Inspection

Inspections of equipment and systems to monitor changes that would be detrimental to function or integrity. Also included is all work required to permit such inspections, such as building required scaffolding, removing or replacing supports or insulation, or disassembly of valves, pumps, etc. Not included are inspections to assess or monitor normal wear, etc. For example, dissembly of a charging pump to inspect bearing wear would not be Inservice Inspection, but dissembly to inspect for rotor cracking or casing damage would be. Inspection of a weld on a newly added line is Special Maintenance, or inspection of a weld repair at a leaking fitting is Routine Maintenance.

Special Maintenance

All work on equipment or systems performed to make significant modifications. Installation of new systems or equipment, replacement or addition of supports or hangers, addition of new lines or instruments, removal of existing equipment, replacement of existing equipment with significantly different equipment are all Special Maintenance. For example, replacement of a properly functioning, original equipment pressure transmitter with a different model with improved characteristics or certification would be Special Maintenance, but replacement of a malfunctioning pressure transmitter with a newer or improved model would probably be Routine Maintenance.

Waste Processing

All work associated with decontamination of equipment, areas, systems, etc. (if not an integral part of another job, such as pump repair), collection and processing of waste, whether solid, liquid, or gas. Operations in support of waste handling are also included. For example, draining a filter to permit changing it, or venting it after changing are part of Waste Processing, but valving a clean filter into the system is Reactor Operations. Repair of the Baler or drumming room crane is Routine Maintenance.

<u>REFUELING</u>

All work directly concerned with refueling the reactor, including all support operations, is classified as Refueling. Testing the polar crane or installing the cavity filter rig is part of Refueling, as is cavity decon before or after flood-up. Changing the cavity filter, however, is Waste Processing and fixing the manipulator crane is Routine Maintenance.

ANNUAL OPERATING REPORT - RG 1.16 FOR 1983

	# PERSONNEL >100 mR			TOTAL MAN-REM		
	STAT.	UTIL.	CONT.	STATION	UTILITY	CONTRACT
Reactor Operations & Surveillance						
Maintenance personnel	2	0	0	0.868	0.000	0.000
Operations Personnel	76	0	0	22.901	0.000	0.000
Health Physics Personnel	20	0	48	3.595	0.000	14.832
Supervisory Personnel	3	0	0	0.584	0.000	0.000
Engineering Personnel	0	0	0	0.000	0.000	0.000
Routine Maintenance						
Maintenance Personnel	100	4	124	76.467	1.199	44.952
Operations Personnel	17	0	6	6.936	0.000	1.055
Health Physics Personnel	8	0	14	1.052	0.000	3.102
Supervisory Personnel	5	0	3	2.623	0.000	0.607
Engineering Personnel	7	2	9	2.054	0.342	6.542
In-Service Inspection						
Maintenance Personnel	29	3	126	7.324	2.575	72.819
Operations Personnel	7	0	7	1.532	0.000	7.255
Health Physics Personnel	19	0	36	4.048	0.000	10.620
Supervisory Personnel	1	0	3	0.141	0.000	1.010
Engineering Personnel	5	4	5	1.354	0.939	0.760
Special Maintenance						
Maintenance Personnel	19	2	236	6.191	2.826	146.601
Operations Personnel	1	0	21	0.203	0.000	11.374
Health Physics Personnel	0	0	13	0.000	0.000	2.899
Supervisory Personnel	1	1	7	0.111	0.518	5.913
Engineering Personnel	5	4	5	0.854	0.690	1.647
Waste Processing						
Maintenance Personnel	21	1	60	4.660	0.151	34.128
Operations Personnel	1	0	0	0.142	0.000	0.000
Health Physics Personnel	7	0	18	1.973	0.000	9.817
Supervisory Personnel	3	0	0	3.248	0.000	0.000
Engineering Personnel	1	0	0	0.508	0.000	0.000
Refueling						
Maintenance Personnel	6	2	37	2.644	1.174	20.950
Operations Personnel	4	0	8	1.212	0.000	4.182
Health Physics Personnel	0	0	3	0.000	0.000	0.536
Supervisory Personnel	2	0	1	0.678	0.000	0.147
Engineering Personnel	0	0	0	0.000	0.000	0.000
Totals						
Maintenance Personnel	114	6	439	98.154	7.925	319.450
Operations Personnel	94	0	34	32.926	0.000	23.866
Health Physics Personnel	26	0	74	10.668	0.000	41.806
Supervisory Personnel	12	1	7	7.385	0.518	7.677
Engineering Personnel	12	7	19	4.770	1.971	8.949
Grand Totals	258	14	373	153.903	10.414	401.748

STEAM GENERATOR INSPECTIONS

The attached report delineates the complete results of Steam Generator Tube Inservice Inspections and any resulting plugging performed during calendar year 1983. As a result of these inspections, 18 tubes were plugged in Unit 1 and 9 tubes were plugged in Unit 2.

1983 ANNUAL INSERVICE INSPECTION REPORT OF UNIT NO.1 STEAM GENERATORS

During the Unit 1 Refueling Outage which commenced on July 15, 1983, Westinghouse Corporation performed an eddy current examination of all four steam generators.

The performance of eddy current testing in the steam generators was not required during this outage by ASME Code Section XI, 1974 Edition, 1975 Addenda, Regulatory Guide 1.83 or the Unit 1 Technical Specifications. However, Plant Management and Senior American Electric Power Corporation Management had planned an eddy current inspection program for the Unit 1 steam generators.

The scheduled steam generator (S/G) eddy current testing (ECT) on Cook Unit 1 started July 23 and was completed August 8. Two thousand seven hundred and forty (2740) tubes in each S/G were inspected. Indications of imperfections (20% through-wall damage), degradation (20-39% through-wall damage), and defects (40% through-wall damage) were found in the hot legs of all four S/G's. The indications can be divided into two groups: 1) the tube bundle, and 2) those occurring on top of the tube sheet. In addition to these indications, tube denting at the top of the tube sheet, primarily in the sludge pile region, was reported. Totals for each of the four S/G's and the remedial action taken when necessary are identified in the following data summarization.

	Hot Leg Indications				Dents
	20%	20-39%	40%	Total	
S/G No. 11	31	1	2	34	127
S/G No. 12	43	8	2	53	153
S/G No. 13	22	32	5	59	233
S/G No. 14	34	8	2	44	132

Breakdown Of Hot Leg Indications (AVB/TTS*)

	20%	20-39%	40%
S/G No. 11	1/30	0/1	0/2
S/G No. 12	2/41	3/5	0/2
S/G No. 13	2/20	32/0	5/0
S/G No. 14	4/30	3/5	0/2

*Top of Tubesheet

Designated Tubes Plugged

S/G No. 11

	Indication
Row 18, Column 56	44% H/L - Mechanical Plug - C/L - Mechanical Plug
Row 2, Column 84	68% H/L - Mechanical Plug - C/L - Mechanical Plug

S/G No. 12

	Indication
Row 14, Column 83	80% H/L - Mechanical Plug - C/L - Mechanical Plug
Row 13, Column 85	64% H/L - Mechanical Plug - C/L - Mechanical Plug
Row 14, Column 82*	20% H/L - Mechanical Plug - C/L - Mechanical Plug

*Plugged by mistake.

S/G No. 13

Row 1, Column 19[1]	N/A H/L - Mechanical Plug - C/L - Mechanical Plug
Row 1, Column 60[1]	N/A H/L - Mechanical Plug - C/L - Mechanical Plug
Row 1, Column 63[1]	N/A H/L - Mechanical Plug - C/L - Mechanical Plug
Row 1, Column 66[2]	N/A H/L - Mechanical Plug - C/L - Mechanical Plug
Row 36, Column 38	42% H/L - Mechanical Plug - C/L - Mechanical Plug
Row 36, Column 45	51% H/L - Mechanical Plug - C/L - Mechanical Plug
Row 41, Column 55	41% H/L - Mechanical Plug - C/L - Mechanical Plug
Row 36, Column 62	80% H/L - Mechanical Plug - C/L - Mechanical Plug
Row 36, Column 63	54% H/L - Mechanical Plug - C/L - Mechanical Plug

[1] Plugged because of unmeasurable indications on inside of tubes

[2] Plugged because of partial restriction

S/G No. 14

Row 12, Column 17	70% H/L - Mechanical Plug - C/L - Mechanical Plug
Row 21, Column 31*	84% H/L - Welded Plug - C/L - Mechanical Plug [1]
Row 17, Column 33*	N/A H/L - Welded Plug - C/L - Mechanical Plug
Row 18, Column 33*	N/A H/L - Welded Plug - C/L - Mechanical Plug

* 116 inches of tube removed from H/L side

[1] This tube was initially plugged with a mechanical plug and subsequently with a welded plug after tube removal.

The 11 tubes having through-wall defects greater than 40% were plugged. Additionally, four row 1 tubes in S/G No. 13 were plugged, 3 due to unmeasurable indications of cracking on the inside of the tube at the U-bend hot leg tangent point and one because of a partial restriction

(probably due to ovaling) at the U-bend cold leg tangent point. Also, an additional tube was mistakenly plugged by Westinghouse in S/G No. 12.

A meeting was held with Westinghouse on August 8 to discuss the results of this eddy current inspection, particularly the unexpected damage found at the top of the tube sheet. In order to evaluate the severity of this potential problem we removed three tubes from the hot leg side of S/G No. 14 on September 9, 1983.

The three tubes were designated as Row 21 Column 31, Row 17 Column 33 and Row 18 Column 33. The tube designated Row 21 Column 31 was previously plugged because of a 84% tubesheet indiction. The plug on the hot leg side required removal prior to pulling this tube and the plug in the cold leg side remained in place. The tube removal required the mechanical plugging of the the additional two tubes on the cold leg side of the steam generator.

All three tubes were cut just below the second support plate and then were pulled through the tubesheet opening by means of an integral gripper attached to a hydraulic ram system.

Once the tubes were removed the tube sheet holes were prepared, and a semi-automatic welding tool was installed in the channel head. The welding tool was remotely controlled from an area away from the steam generator platform. The weld plugs were installed in the prepared tube sheet holes and welded into place.

The equipment and procedures were qualified by Indiana and Michigan Electric Company Maintenance personnel and the welding was performed by our Maintenance personnel with direction being provided by Westinghouse personnel.

The final step in the process was a visual inspection of the welds by a Westinghouse Quality Assurance Engineer who indicated that the welds were acceptable. In addition, the steam generator was filled with water to 45 feet above the tubesheet and a leak test was performed around the welded plugs with no evidence of leakage noted.

1983 ANNUAL INSERVICE INSPECTION REPORT OF UNIT NO.2
STEAM GENERATORS
June 1983 Outage (Unscheduled)

On June 23, 1983, Unit 2 was taken out of service due to an indicated primary to secondary leak in Steam Generator No. 23 of .06 GPM. A defective tube Row 1 Column 72 was identified by helium leak testing. All tubes in Rows 1 and 2 were individually tested by the helium method and a scan was made of the rest of the tubes. Only the one tube was found to be defective, and it was verified by eddy current testing and mechanically plugged. The tubes surrounding Row 1 Column 72 were also eddy current tested with no defects found. The unit was parallel July 9, 1983 at 2130 hours.

October 1983 Outage (Unscheduled)

On October 15, 1983, Unit 2 was taken out of service due to an indicated primary to secondary leak occurring in Steam Generator No's. 21, 22 and 23.

The unit was drained to half-loop and the primary side of the steam generators was opened on October 21 and helium leak testing was started on October 24. The following tubes were identified as leakers by helium testing:

S/G No. 21	S/G No. 22	S/G No. 23
Row 1, Column 84	Row 1, Column 73	Row 1, Column 24
Row 1, Column 88		Row 1, Column 25

As verifications of the helium testing, Westinghouse performed eddy current testing (ECT) on the leaking tubes and all tubes adjacent to the leakers. ECT confirmed inside diameter indications in the U-Bend region of each of the leakers. None of the other tubes tested showed indications. ECT results were as follows:

	Tube No.	Defect Location
S/G No. 21	Row 1, Column 84	U-Bend, Hot Leg Tangent Point
S/G No. 21	Row 1, Column 88	U-Bend, Apex
S/G No. 22	Row 1, Column 73	U-Bend, Cold Leg Tangent Point
S/G No. 23	Row 1, Column 24	U-Bend, Cold Leg Tangent Point
S/G No. 23	Row 1, Column 25	U-Bend, Cold Leg Tangent Point

The above five tubes were mechanically plugged by Westinghouse on October 26 and 27.

The Unit went critical at 0544 hours and entered Mode 1 at 0643 on November 7, 1983. Steam Generator No. 21 still showed some activity following tube plugging.

The Unit was brought out of service again, on November 7, 1983, at 2128 hours after reaching an indicated primary to secondary leak rate of approximately .293 GPM in Steam Generator No. 21.

The primary manway was reopened and a visual examination of the tubesheet was performed with the steam generator full of water. The visual examination identified a positive leaking tube on the hot leg side in Row 16, Column 40. Temporary plugs were inserted into the leaking tube, both hot and cold leg tubesheets, so that the steam generator secondary side could be pressurized with helium. Twenty-four tubes surrounding the known leaker were tested with no signs of leakage, also Row 1 and 2 tubes and a complete scan of the tubesheet was inspected with no indiction of leaking tubes. After completion of helium testing, the steam generator was degassed and temporary plugs removed.

Eddy current testing commenced on November 12, 1983, to identify the mechanism and location of the known failure. An eddy current inspection of a 5 x 5 tube grid around the leaker showed that all tubes in the test area were dented at the top of the tubesheet on the hot leg side and two of the tubes had pluggable indications just above the tubesheet (Row 14, Column 40 and Row 14, Column 41 - both 87% defects) along with the Row 16, Column 40 throughwall defect.

Although eddy current testing could not positively identify the tube degradation mechanism, stress corrosion cracking (or a similar corrosion phenomenon) is believed to be the probable cause. Since tube denting is considered a precursor to corrosion-induced tube degradation, the Eddy Current Inspection Program was expanded to include all dented tubes in the sludge pile region of Steam Generator No. 21. Additionally, when a review of Steam Generator No. 21 eddy current data from April, 1981, showed that all three of the pluggable tubes had previously exhibited a "suspect" or "unidentified" tubesheet signal similar to that now seen on other Steam Generator No. 21 tubes, a complete review of recent ECT data for Steam Generator No. 23 (1982) and No. 24 (1981) was initiated to see if similar signals were present. Eddy current testing of the pertinent areas of Steam Generator No. 22 had not been performed since 1979, so it was decided to open Steam Generator No. 22 for a limited ECT inspection.

A careful review of new and previous data by both the on-site Zetec Data Analyst and by Westinghouse Steam Generator Technology Division personnel resulted in the discovery of numerous suspect ECT signals in all four Unit 2 steam generators. However, the final conclusion was that suspect tubesheet signals cannot be definitely linked to tube degradation at this time. Westinghouse recommends performing metallographic analysis of tube samples, during the upcoming Unit 2 refueling outage tentatively scheduled during the first quarter of 1984, to properly characterize these signals and determine their importance.

On Steam Generator No. 21, a total of 728 tubes in the sludge pile region were inspected full length. Hot leg side dents were found at the top of the tubesheet in 388 tubes, but no tube degradation other than the three previously mentioned defects were found. The three defective tubes were mechanically plugged on both the hot and cold legs.

On Steam Generator No. 22, a total of 572 tubes in the sludge pile region were inspected full length. Dents were found at the top of the tubesheet on the hot leg side of 19 tubes. The only incidence of tube degradation was a 39% (non-pluggable) indication at the No. 4 anti-vibration bar intersection of Row 10, Column 31.

Additionally, all Row 1 tubes on Steam Generators No. 21 and 22 not previously plugged were eddy current tested through the U-bend region, with no indications being found.

Designated Tubes Plugged

S/G No. 21	Indication
Row 1, Column 84	100% H/L - Mechanical Plug - C/L - Mechanical Plug
Row 1, Column 88	100% H/L - Mechanical Plug - C/L - Mechanical Plug
Row 14, Column 40	87% H/L - Mechanical Plug - C/L - Mechanical Plug
Row 14, Column 41	87% H/L - Mechanical Plug - C/L - Mechanical Plug
Row 16, Column 40	100% H/L - Mechanical Plug - C/L - Mechanical Plug
S/G No. 22	
Row 1, Column 73	100% H/L - Mechanical Plug - C/L - Mechanical Plug
S/G No. 23	
Row 1, Column 24	100% H/L - Mechanical Plug - C/L - Mechanical Plug
Row 1, Column 25	100% H/L - Mechanical Plug - C/L - Mechanical Plug
Row 1, Column 72	100% H/L - Mechanical Plug - C/L - Mechanical Plug

1983 ANNUAL INSERVICE INSPECTION REPORT OF UNIT NO.1 AND UNIT 2 PORVs

The following is a list of Unit 1 and Unit 2 Pressure Operated Relief Valves challenged during the 1983 calendar year:

VALVE NO.	DATE CHALLENGED	STROKE TIME
1-NRV-151	July 16, 1983	3.94 sec.
	November 23, 1983	4.47 sec.
1-NRV-152	July 16, 1983	4.59 sec.
	November 23, 1983	3.05 sec.
1-NRV-153	July 16, 1983	3.39 sec.
	November 23, 1983	2.55 sec.
2-NRV-151	January 14, 1983	4.6 sec.
	July 3, 1983	4.7 sec.
	November 3, 1983	4.7 sec.
2-NRV-152	January 14, 1983	4.3 sec.
	July 3, 1983	4.6 sec.
	November 3, 1983	5.5 sec.
2-NRV-153	January 14, 1983	5.8 sec.
	July 3, 1983	5.7 sec.
	November 3, 1983	6.3 sec.

The valves listed above were challenged in accordance with the Inservice Inspection Valve Program and successfully passed there operational test. Documentation is maintained in the D.C. Cook Plant Information and Records Center vault.

CHANGES TO FACILITY

Brief descriptions and summary safety evaluations for design changes (RFC's) made to the facility as described in the Donald C. Cook Nuclear Plant Final Safety Analysis Report (FSAR) are presented in this section. These changes were completed pursuant to the provisions of Title 10, Code of Federal Regulations subsection 50.59(a).

DC-12-1614 (Unit #2 Only)

The 3-way modulating glycol valves on the Ice Condenser Air Handling Units were replaced on Unit #2 of the Donald C. Cook Nuclear Plant. These valves were replaced with a 2-way (on-off) solenoid valve. The valves were replaced for two reasons: 1) Replacement 3-way valves are no longer available, and 2) As described in our response to Question 022.11 in the Unit #2 Appendix Q to the FSAR (prior to submittal of the Updated FSAR) the 3-way valves were being operated as 2-way valves because of the problems associated with the valve actuators.

The AHU's are categorized as Seismic Class II components and are required for the proper operation and maintenance of the ice condenser system. The ice condenser is a very important design safeguard relied upon to mitigate the consequences of several design base accidents. Operability of the ice bed, mandated by the Technical Specifications, requires implicitly the function of the AHU's to keep the temperature of the ice bed at or below 27°F. Thus, this RFC is considered safety related.

The change is not considered to be an unreviewed safety question in accordance with 10CFR50.59 (a) 2; and, in fact, will improve the overall reliability and operability of the AHU's.

This RFC will not adversely affect the health and safety of the public nor create a substantial safety hazard.

DC-12-1742 (Unit #1 Only)

An air operated containment isolation valve (PCR-40) and a check valve were installed on the containment penetration for the Plant Air System of

Unit #1 of the Donald C. Cook Nuclear Plant. The air operated valve which is located outside containment and the check valve which is located inside containment fulfill the requirements for double isolation for containment penetrations. The air operated valve can be operated from the Control Room and is designed to close upon a containment Phase A isolation signal.

Prior to the modification, the system was required to be isolated by the installation of a blind flange prior to the Reactor Coolant System entering Mode 4 (Hot Shutdown). This modification will allow remaining maintenance activities requiring the use of the Plant Air System to continue during primary system heatup following a cold shutdown or refueling outage.

This RFC is considered safety-related because it involves modification of a containment penetration and its corresponding isolation system. The plant service air line is presently a Class E containment isolation system which includes a closed manual valve and a membrane barrier (such as a blind flange). The proposed system which is comprised of a check valve and an automatic valve will be a Class A containment isolation system as defined in FSAR Chapter 5, Section 5.4. This is consistent with the licensing basis of the Cook Plant which differs somewhat from current NRC criteria such as GDC-56. We are not required at the present time to comply with GDC-56 and as such this RFC is acceptable.

This safety review is conducted on the RFC compliance of containment integrity under various plant conditions and it indicates that the proposed changes do not create substantial safety hazard nor involve an unreviewed safety question as defined in 10CFR50.59.

DC-12-1765 (Unit #1 Only)

An intermediate low load trip circuit was installed on the Manipulator Crane in Unit #1 Containment. This modification allows the setting of a weight-loss trip limit on the manipulator crane to prevent fuel assembly damage during core alterations. The circuitry will prevent travel of the hoist when a loss of weight (approximately 300 lbs.) occurs in any position other than the down-direction of the gripper tube in the core and transfer areas.

The manipulator crane is a Class III system. This RFC is safety-interface, however since it must be assured that this modification will not result in any adverse interactions with the fuel.

RFC DC-12-1765 does not constitute an unreviewed safety question as defined in 10CFR50.59, nor does it compromise the health and safety of the general public.

DC-12-1874 (Unit #1 Only)

The interlock system on the Unit #1 Containment personnel airlocks was replaced with a new quick acting interlock system to eliminate frequent problems with the latch operated interlock system.

The new system consists of a new cam and cam follower that replaces the latch operated interlock. The cam is attached to the opening turning gear and the follower interlocks the opposite door by means of a ratchet and pawl. During the door opening cycle, the door latching pins actually extend slightly before they begin to retract. It is during this period of slight extension and retraction to the original closed position that the mechanical interlocking of the opposite door takes place. Therefore complete interlocking of the opposite door is assured well in advance of the parting door seals.

This RFC is classified as safety interface as its function is to help maintain containment integrity. The doors can only be opened manually and failure of this mechanism is always in the safe mode in that it would not open the personnel airlocks.

This new interlock system improves the performance of the airlock system and reduces the possibility of breaking containment integrity. Implementation of RFC DC-12-1874 does not create any safety hazards nor constitute an unreviewed safety question as defined in 10CFR50.59.

DC-01-1940

A third source range channel consisting of a spare source range detector, preamp and instrumentation drawer was installed in Unit #1 of the Donald C. Cook Nuclear Plant. This modification was required because the placement of irradiated sources on the core periphery for Cycle 8 was expected to produce non-conservative $^1/M$ plots. The "shine" from the irradiated sources

was expected to mask core neutrons and as a result the existing source range detectors might not provide the accurate $^1/M$ plots necessary to monitor the core during startup. Installation of an extra source range detector in a spare detector well located 90° from the current detector locations was required to remove this source "shine" effect and to produce the type of $^1/M$ plots presently seen during startups. This third source range channel was installed for indication purposes only and provides no protective functions.

The detector was installed in the spare detector well located at the 270° position of the reactor. The preamp is located in the reactor cable tunnel. The source range drawer was seismically mounted in the Nuclear Instrumentation Cabinet III located in the Control Room. Existing spare cabling was used to connect the detector to the preamp and the preamp to the instrumentation drawer.

In order to be bounded by an FSAR analysis, the worst possible reactivity addition rate due to operator inability to assess criticality during Unit #1 Cycle 8 initial criticality must be less than or equal to 75 pcm/sec. (Section 14.1.1 of the FSAR analyzes the consequences of an accident with a reactivity insertion rate of $75 \times 10^{-5} \frac{\Delta K}{K}$ /sec, or 75 pcm/sec.)

Assuming criticality is approached by deboration, and assuming a conservative boron reactivity worth of 15 pcm/ppm, the boron dilution rate of 5 ppm/sec, is set as the maximum allowable rate.

Review of the FSAR shows an RCS total inventory of 11,780 ft^3, and a maximum CVCS charging rate of 300 gpm = .0668 ft^3/sec. Assuming RCS boron of 3,000 ppm, and charging of unborated water, the maximum physically possible boron dilution rate is .21 ppm/sec.

Therefore, the worst uncontrolled reactivity addition rate due to operator unability to assess criticality is easily bounded by the FSAR uncontrolled rod withdrawal analysis.

Based on the above, it is believed that the initial approach to criticality, as planned, will not create any substantial safety hazard, nor will it constitute an unreviewed safety question as defined by 10CFR50.59 or adversely affect the health and safety of the public.

DC-12-2448 (Partial)

This RFC was initiated to upgrade the Radiation Monitoring System in order to comply with the requirements of NUREG-0578 and 0737. The following paragraphs identify the changes that have been completed:

1) Two (2) Victoreen Post Accident High Range Containment Area Monitors were installed in each containment. The upper volume monitors are designated VRA-1310 (Unit #1) and VRA-2310 (Unit #2). They are located near the 180° mark in the containment at an elevation of 559'-7½". The lower containment monitors are designated VRA-1410 (Unit #1) and VRA-2410 (Unit #2). They are located near the 0° mark in the containment at an elevation of 618'. The upper volume monitors are powered from a Train A source and the lower volume monitors are powered from a Train B source. The monitors have a range of 10^{0} to 10^{7} R/Hr (gamma) which meets the requirements of Table II.F.1-3 of NUREG-0737.

2) An Eberline Model SPING-3 high range noble gas monitor was installed on the common discharge header from the Steam Jet Air Ejectors. The monitors SRA-1900 (Unit #1) and SRA-2900 (Unit #2) have a range of 10^{-7} to 10^{+3} μci/cc noble gases to cover normal operation and post accident conditions.

3) An Eberline Model SPING-3 high range noble gas monitor was installed on the Turbine Gland Steam Condenser Vent Line. The monitors SRA-1800 (Unit #1) and SRA-2800 (Unit #2) have a range of 10^{-7} to 10^{+3} μci/cc noble gases to cover normal operation and post accident conditions. The design basis maximum range of the monitor is acceptable based on the belief that the gland steam exhaust is somewhat analogous to the "PWR steam safety valve discharge" which has a design basis maximum range to 10^{3} μci/cc noble gas.

4) Eberline Noble Gas monitors were installed upstream of the Safety Valves and Power Operated Relief Valves on each steam generator. The detectors for these monitors are located in the Main Steam Enclosures and are identified as follows:

	Unit #1	Unit #2
S/G #1	MRA-1601	MRA-2601
S/G #2	MRA-1701	MRA-2701
S/G #3	MRA-1702	MRA-2702
S/G #4	MRA-1602	MRA-2602

These monitors have a range of 10^{-4} to 10R/Hr gross gamma. In accordance with clarification (3) of Item II.F.1, Attachment 1, externally mounted monitors viewing the main steam line upstream of the SV/PORV's are acceptable with procedures to correct for the low energy gammas that the external monitors would not detect.

5) An Eberline model SPING-4 high-range noble gas, particulate and iodine monitor was installed in the unit vent. The monitors VRS-1500 (Unit #1) and VRS-2500 (Unit #2) utilize several overlapping detectors in order to cover normal operation and post accident conditions. The design basis maximum range of the monitor, up to 10^{+5} µci/cc noble gas, meets the requirements of Table II.F.1-1 for monitoring "diluted containment exhaust gases" and auxiliary building ventilation system discharge.

The incorporation of extended range particulate and radioiodine sampling capability into VRS-1500 and VRS-2500 fulfills the requirements of Item II.F.1, Attachment 2 and Table II.F.1-2 regarding the ability to obtain a sample of plant gaseous effluents for analysis of post accident releases of radioactive iodines and particulates.

The following is an overview of the Radiation Monitoring System:

GENERAL

All radiation measurements are made with a standard Eberline detector combination which is served by a local processor (field unit). The local processor performs background subtraction, applies conversion factors, and retains the data from each detector channel in history files consisting of the last 4 hours of ten-minute averages, the last 24 hours of one-hour averages and the last 24 days of one-day averages. Each local processor is AC operated with 8 hours of battery backup. Bi-directional communication is provided between all local processors and two central control terminals. Provisions exist to access each local processor with a portable control terminal to conduct calibration and service functions at the local processor's location.

Each local processor with its detectors is optically isolated from the rest of the system. Failure of a local processor or its detector(s) will have no effect on any other portion of the system. Each local processor communicates with two (redundant) control terminals via two (redundant) communication interfaces. Because the local processors are completely self-supporting for the performance of their tasks, even simultaneous power failures at both control terminals do not result in any loss of data accumulation or storage in the local processor.

LOCAL PROCESSOR

The local processor performs the tasks of data acquisition, history management operational status and alarm determinations and communications with the Control Room Control Terminals. A microcomputer supports up to nine detector channels which are present in the local processor.

History files are maintained on each channel (detector) in three time details. These files are (a) 23 each 10-minute intervals, (b) 24 each 1-hour intervals and (c) 24 each 1-day intervals. The data presented for any interval are the average of the data accumulated during that interval. Trend, alert and high alarm data are included in the averages. Any of the history files may be requested for printout from the Control Terminal.

AIRBORNE MONITORS

These radiation monitors collect and measure particulates and Iodine 131, and measure the amount of noble gas in the passing airstream. The particulate channel uses a fixed collection filter, monitored by a beta scintillation detector from one side and a solid state alpha detector (for background subtract purposes) on the other side. The Iodine 131 channel uses a charcoal cartridge for collection and is monitored by a gain-stabilized (to minimize the effects of drift caused by fluctuations in temperature and/or aging) 2-inch x 2-inch NaI(Tl) gamma scintillation detector. The effects of a fluctuating noble gas measurement is performed by several detectors viewing a sample volume. Low and medium range noble gas detectors view the same sample volume. A high range noble gas detector utilizes a section of one-inch stainless steel tubing as the sample volume. Ranges of the three noble gas detectors are: Low range, 1E-7 μCi/cc to 4E-2 μCi/cc; Medium range, 2.5E-2 μCi/cc to 1E3 μCi/cc; High range, 1 μCi/cc to 1E5 μCi/cc.

BACKGROUND SUBTRACTION

Each detector channel has the capability to compensate for background contributions by subtracting signals which are related to background interferences as determined by any two of the other detector channels in the local processor. For example, the beta particulate monitor response could be affected by a combination of ambient gamma radiation and radon-thoron daughter beta decay products. All background subtraction must be performed by detectors in the local processor. No background subtraction input can be accepted by one local processor from another local processor.

Similar capabilities exist for any monitoring channel. In addition to variable contributions, the count rate of a channel can be affected by non-time dependent factors such as fixed contamination in the sample shield. Each channel, therefore, has the ability to reduce its count rate by a fixed number. The end result of background subtraction is to produce a net count which is as close to the actual desired response as is possible.

SPING SAMPLE SYSTEM DESCRIPTION

The sample enters the front tube and is drawn through the particulate filter. The filter is held in position by the RDS-1 alpha radon detector and is in a fixed geometry between the RDS-1 and the RDA-3A beta scintillator.

The sample exits the particulate filter and is drawn into the iodine sampling station. There, it passes through a charcoal cartridge which is viewed by a RDA-2A gamma scintillation detector. The cartridge is held in place by a removable cartridge holder and is in a fixed geometry with the RDA-2A.

The sample exits the iodine charcoal cartridge and is drawn into the noble gas sampling station. This is a fixed, cylinder-shaped volume viewed at one end by a RDA-3A beta scintillation detector. The other end of the

cylinder is a lead plug which supports the mid-range noble gas detector. This detector is located on the center-line of the gas volume cylinder and is surrounded by the sample.

The sample then exits the low and mid-range noble gas chamber. It continues to a flow metering orifice, pressure gauge, high range noble gas monitor, sample pump, and returns to the process flow.

The subject RFC calls for extensive modifications of and additions to the Radiation Monitoring System (RMS). These modifications are intended to assure compliance with the requirements of NUREG-0737 Item II.F.1 - Attachments 1, 2, and 3 and fulfillment of our commitments made to the NRC in this area. Portions of this RFC involve Electrical Class 1E equipment and components required to perform post-accident monitoring functions. These functions are considered to be safety related as per the provisions of Procedure No. NSL/7.

The following items were considered during the safety review of this RFC:

(a) No aluminum or mercury is being introduced into the containment under this RFC.

(b) The number of cabling runs made for installation is apprxoimately 400 which are routed both in the cable tray and conduits. This item pertains to Fire Protection concerns and we find it acceptable that it be addressed as part of the Appendix "R" review.

(c) Verification of Seismic acceptability of the Victoreen high-range area monitors can be found in Victoreen Qualification Test Report No. 950.301.

(d) The RMS contract C5252 shows compliance with the overall intent of the separation criteria for Class 1E circuits on the non-class 1E portions of the RMS. The Hi-range in-containment area monitor is the only portion of the RMS which is required by NUREG-0737 to be Class 1E. This monitor was designed to meet these requirements.

(e) The heat tracing provided under this RFC is of the appropriate classification to ensure proper operation of the detectors.

(f) The classification of the alarms, annunciators, and the CRT as safety-related by Nuclear Safety & Licensing does not constitute imposition of any design requirements such as the requirements for Class 1E cir-

cuits. (e.g. IEEE-279, IEE-344, etc.) Rather, the classification of these items as 'safety-related' reflects Nuclear Safety & Licensing's belief that these devices would provide important information to the operator following an accident. The digital display provided in the control room for the Victoreen area monitors is the sole Class 1E display device provided under this RFC.

Nuclear Safety & Licensing has concluded that implementation of this RFC does not constitute an unreviewed safety question as defined in 10CFR50.59 and will not adversely affect the health and safety of the general public.

DC-12-2524

An Uninterruptible Power Supply was installed to provide the Technical Support Center (described in Chapter 12.3 of the FSAR) with the transient free, quality power source necessary for computer based loads. NUREG-0696 states, "circuit transients or power-supply failures and fluctuations shall not cause a loss of stored data vital to the Technical Support Center functions. Sufficient alternate or backup power sources shall be provided to maintain continuity of Technical Support Center functions and to immediately resume data acquisition, storage, and display of Technical Support Center data if loss of the primary Technical Support Center power source occurs." The Uninterruptible Power Supply provides a continuous source of power with a sufficient level of reliability to meet this requirement.

The Interruptible Power Supply consists of a battery, two battery chargers (one in service, one installed spare), static inverters and their associated static transfer switches. The 125V battery is rated at 725 amps for a 30-minute period and consists of 60 lead calcium cells. The battery chargers provide 125V 700 amp DC output from a 575V, 3-phase AC input. Two (2) 40KVA and one (1) 60KVA (installed spare) single phase inverters provide 120V AC output from a 125V DC input. All inverters are equipped with zero-break static transfer switches and make-before-break manual bypass switches.

The normal source of AC power to the Uninterruptible Power Supply and Technical Support Center is the 600 volt balance of plant bus through a 80KVA, 600V primary, 120V secondary single phase regulating transformer. If the normal AC source is lost, the automatic transfer switch aligns the in-service and reserve battery chargers to the 600 volt security bus, which is energized by the security diesel. If this energy source is subsequently lost, the battery will supply the inverters for a minimum of 30 minutes. If after 30 minutes the normal and backup sources are still unavailable, the static transfer switch will automatically align their respective Technical Support Center loads to the 600 volt safety bus fed from the Unit #1 CD Emergency Diesel Generator. A cross-tie between the Uninterruptible Power Supply room and the Security Uninterruptible Power Supply room enables the spare 60 KVA inverter to service both Uninterruptible Power Supply rooms.

The Uninterruptible Power Supply Room is located on the Auxiliary Building roof above the Unit #1 Control Room. The Uninterruptible Power Supply Room is designed to withstand all environmental conditions including earthquakes. Anchoring of the room is designed to meet Seismic Class I criteria even though it is not required.

RFC DC-12-2524 is safety interface since the Uninterruptible Power Supply will insure the continuous availability of technical data to aid Technical Support Center personnel in handling emergency conditions and since it is connected to a backup source of power from a 600 volt safety bus.

Electrical Engineering has determined that the addition of this non-safety related load will not overload the Emergency Diesel Generator. The 225A Motor Control Center Breakers and the 600/120 transformer provides adequate protection against the possibility of a failure propagating from the Uninterruptible Power Supply system to the Emergency Diesel Generator.

The Design Division has re-analyzed the seismic response of the auxiliary building roof with the additional loads introduced by Uninterruptible Power Supply Room and concludes that the Uninterruptible Power Supply Room will not degrade the function of the auxiliary building roof nor will the method of attachment.

RFC DC-12-2524 does not constitute an unreviewed safety question as defined in 10CFR50.59 and will not adversely affect the health and safety of the public.

DC-12-25258

The Control Room Ventilation Systems for both units of the Donald C. Cook Nuclear Plant were modified to fulfill the requirements for Control Room Habitability specified in Item III.D.3.4 of NUREG-0737. The following items were included in this modification:

1) Weatherstripping was added to the Control Room doors, the door to the Control Room Machine Room and the hatches between the Control Rooms and the Control Room Cable Vaults. This weatherstripping was added to seal the doors and hatches against an internal control room pressure differential of up to ¼" water.

2) Isolation dampers ACRDA-2 and ACRDA-3 were reset to limit makeup air flow through ACRDA-2 to less than 80 CFM following a control room isolation signal resulting from a LOCA. This makeup air is sufficient to pressurize the Control Room to 1/16" water differential between the Control Room and out-of-doors when one of the filter system fans is running.

3) The fresh air supply (via the normal air conditioning system) was balanced to 570 CFM.

4) The logic for Control Room isolation was modified to automatically start the lead fan on each unit upon receipt of a Phase A signal.

5) The control switches for isolation dampers ACRDA-1, -2, -3 and -4 (Unit #1) and ACRDA-1, -2 and -3 (Unit #2) were relocated from the ACRA-1 and ACRA-2 air conditioning subpanels in the Control Room Machine Room to the "VS" panels in the Control Room.

6) A chlorine detection alarm system was installed to alarm in the Control Room upon sensing 5 ppm chlorine at the fresh air intake of the Control Room Pressurization system.

RFC DC-12-2528 proposes certain modifications to the Control Rooms to meet the habitability requirements derived from our review of NUREG-0737, Item III.D.3.4. The modifications involve safety systems (Item 4 in particular) and, therefore, this RFC is considered safety related.

These proposed modifications have been reviewed conceptually by the NRC and found to be acceptable. After the installation of the modifications, they must be thoroughly tested to ensure that the operability requirements for air flow and pressure predicated in AEP:NRC:0398C are met.

The subject RFC has been reviewed and found to be acceptable. It does not constitute an unreviewed safety question as defined in 10CFR50.59 and will improve the occupational safety for the plant operators.

<u>DC-12-2578 (Unit #2 Only)</u>

The Westinghouse Upper Containment Area Radiation Monitor VCR-302 (R-2) was replaced with two independent Eberline Area Monitor Channels (VRS-2101 and VRS-2201). The range of these channels is the same as before: $0.1\text{mR}/_{\text{hr}}$ to $10\text{R}/_{\text{hr}}$.

Each area monitor channel is electrically Train oriented and is capable of automatically isolating seven of the following containment ventilation valves through the Containment Ventilation Isolation circuit.

1) VCR-101, -201 Instrument Room Purge Supply
2) VCR-102, -202 Instrument Room Purge Exhaust
3) VCR-103, -203 Lower Containment Purge Supply
4) VCR-104, -204 Lower Containment Purge Exhaust
5) VCR-105, -205 Upper Containment Purge Supply
6) VCR-106, -206 Upper Containment Purge Exhaust
7) VCR-107, -207 Containment Pressure Relief

The Train A device (VRS-2101) is capable of isolating the seven valves located inside containment (VCR-101, 102, 103, 104, 105, 106 and 107). It is located on the 650' elevation near the refueling upender console. The Train B device (VRS-2201) is capable of isolating the seven valves located outside containment (VCR-201, 202, 203, 204, 205, 206 and 207). It is located approximately 35 feet above VRS-2101 and is mounted on the crane wall.

A meter, lights and annunciator horn are mounted locally near each detector. The meter indicates the current radiation level at that location. The blue light indicates a detector or cable failure. The red light and horn indicate that the High Alarm setpoint has been reached or exceeded.

This RFC is considered to be safety related as per the provisions of Procedure No. NSL/7.

The equipment installed as part of the permanent modification will be seismically and environmentally qualified in accordance with IEEE-344-1975 and IEEE-323-1974 and the new "system" will be installed in accordance with IE standards. This permanent revision will fulfill our commitment made to the NRC in our letter No. AEP:NRC:0295B dated March 25, 1980.

Nuclear Safety & Licensing has reviewed the information contained in the RFC Packet, the documents listed on Form 7-1 (The "NS&L Checklist"), and the Indiana and Michigan Electric Company drawing numbers 1-98816-0, 1-98304-6, 2-98816-0 and 2-98304-3 and has discussed the proposed modification several times with the RFC Lead Engineer and other involved parties. As a result of these reviews and discussions, Nuclear Safety & Licensing has concluded that implementation of this RFC does not constitute an unreviewed safety question as defined in 10CFR50.59 and will not endanger the health and safety of the general public. Implementation of the proposed modifications will fulfill the commitment made in our AEP:NRC:00642 letter dated December 7, 1981.

DC-12-2605

Debris screens were installed over the return air duct outlets of the Ice Condenser panels in each unit of the Donald C. Cook Nuclear Plant. The screens were fabricated from .063 inch diameter galvanized carbon steel wire

mesh with .5624 inch openings. This wire mesh has an approximate free area of 80.9%. The screens are installed on the top of the supply headers along the containment and crane walls and under the subway grating at the end walls. The screens were required to prevent debris from falling into the return duct and interfering with the air flow through the Ice Condenser Panels.

This change involves a modification to a Class I structure, and because there is the possibility of the screens falling off and prohibiting normal air flow through the ice condenser panels, the change is considered safety interface. Normal air flow is necessary to maintain the proper ice weight in the ice condenser required by Technical Specification 3.6.5.1.

The Nuclear Safety & Licensing Section requires that the proper engineering judgment be used when anchoring the screens to make sure that they will not loosen during normal operations, during an accident conditions (LOCA), nor during a design basis earthquake (DBE).

This RFC does not create any substantial safety hazards, nor does it constitute an unreviewed safety question as defined in 10CFR50.59, nor will it adversely affect the health and safety of the public.

DC-12-2637 (Unit #1 Only)

A redundant gripper tube full-up safety circuit in the form of a geared limit switch was added to the Manipulator Crane in Unit #1 Containment. The existing proximity switch for gripper tube full-up light was replaced with a geared limit switch. Activation of both the geared limit switches are now required for lateral movement of the bridge and trolley.

Prior to these modifications the activation of the gripper tube full-up light was all that was required for crane movement. These modifications assure that fuel assemblies are fully retracted into the gripper tube by preventing bridge or trolley movement of the crane if the inner mast is below the full-up position.

The manipulator crane system is Class III equipment. This RFC is safety-interface, however, since it must be assured that the proposed modifications will not result in any adverse fuel interactions.

Conversations with the Lead Engineer have indicated that these modifications should prevent fuel assembly damage, such as that which occurred during the 1981 Unit #1 Refueling Outage, since two different geared limit switches must now be actuated. While we can not obtain a guarantee of this from Stearns-Rogers, the new safety circuit will decrease the possibility of this type event from occurring. It must be assured that the installation

and attachment of this equipment to the Manipulator Crane system will not result in the generation of any loose parts during normal operation or during the Design Basis Earthquake (DBE).

RFC DC-12-2637 does not constitute an unreviewed safety question as defined in 10CFR50.59 nor does it compromise the health and safety of the general public.

DC-12-2662

This modification involved draining the water seal from the loop seals upstream of the Pressurizer Safety Valves (SV-45A, -45B, -45C) on both units of the Donald C. Cook Nuclear Plant. A drain was provided at the bottom of the U-bend of the loop seal to remove possible water accumulation due to condensation inside the loops. The drains (½-inch tubing) from the individual loop seals are connected to a common header (3/4-inch pipe) which in turn is connected to the lower connection of pressurizer level instrument NLI-151.

Prior to the modification the loop seals contained comparatively cold water ($150^{\circ}F \pm$). A thermal-hydraulic analysis performed in compliance with NUREG-0737, Item II.D.1 indicated potential overstressing of the Safety Valve piping system caused by the slug of cold water as it passes through the piping system. It was decided to drain the loop seals to eliminate the cold water and allow only steam to pass through the system.

DC-12-2662 proposes modifications to the existing loop seals of the Pressurizer Safety Valves. Since this modification involves a Seismic Class I system which is part of the primary pressure boundary, the subject RFC is classified as Safety-Related.

The Safety Valves at the Cook Plant are spring loaded Crosby Valves type 6M6. In the full scale tests conducted by EPRI in compliance with NUREG-0737, Item II.D.1, it was observed that the valve disc exhibits measurable lift at the setpoint pressure, oscillatory behavior (chattering) during the loop seal water bleed off, and pop-opening on steam. Following opening, the system blows down until the valve closes. The Crosby valves were not sensitive to back pressure. The chattering that was observed is attributed to two-phase "flashing" of water/steam flow through the valve. During tests conducted without the water loop seals, dry tests, the valves opened at the set pressure with steam discharge only and did not exhibit chattering. During one dry test, the Crosby 6M6 valve chattered following closing. However, the valve performed stably without chattering at blowdown pressures.

The as-built piping analysis being performed to determine the safety valve transient loads and the effect of water slug discharge through the valve and piping has shown that for Emergency Conditions the inlet and outlet piping loads are higher than allowable values. These higher loads

could overstress the discharge piping system. The hydraulic forcing functions on the piping system during a transient without the water seal were substantially lower than those with the water loop seal. Therefore it was decided to drain the water from the Safety Valve Loop seals.

In the Cook Plant, the Safety Valve setpoint pressure is 2485±1% PSIG. In some FSAR analyses the overpressure transient is mitigated by the blowdown through the safety valves and will result in steam discharge through the safety valves. Continuous water discharge through the safety valves during the Feedwater Line Break accident is not predicted for the Cook Plant with a water-solid pressurizer. If during the unlikely event of a Safety Valve transient, the discharge piping is overstressed because of the seal water discharge, this could conceivably result in a failure of the piping and a LOCA (6" diameter). Under the condition of full rupture of the 6" line, the break area will be less than 1.0ft^2 (approximately 0.2ft^2), and can be classified as a small break. Small break accidents have been analyzed for both units and the details of the most up-to-date analyses are given in FSAR Section 14.3.2.3 (Unit #2) and in Attachment E to our letter No. AEP:NRC:0745C. The worst break size is a 4-inch diameter break. For the 6-inch break, the depressurization transient and the extent to which the core is uncovered are shown in figures 14.3.2-10 and 14.3.2-12 of the FSAR, respectively. The FSAR analysis of the small break LOCA concludes that the high head portion of the Emergency Core Cooling System, together with the accumulators will provide sufficient core flooding to keep the Calculated Peak Clad Temperatures below the required limits of 10CFR50.46 and that, hence, adequate protection is afforded by the ECCS in the event of a small break LOCA. Additional concerns raised by the NRC on the small break LOCA analyses in NUREG-0611 and NUREG-0737 are presently under study by the Westinghouse Owners Group.

The subject RFC DC-12-2662 has been reviewed and found to be acceptable as not constituting an unreviewed safety question as per 10CFR50.59 and the proposed modifications will not adversely affect the health and safety of the public.

DC-01-2716

A flow reducing orifice plate was installed in the discharge piping of the Unit #1 East Centrifugal Charging Pump. The ½" thick orifice plate was installed between the pump discharge flange and the pipe flange in order to reduce the flow rate at runout conditions.

During recent flow balancing of the Centrifugal Charging Pumps through the Emergency Core Cooling System, the East pump exceeded the single pump runout flow rate of 470 GPM (excluding 80 GPM to the Reactor Coolant Pump Seals). The total flow via the Boron Injection Tank to the cold legs was measured at 499 GPM thus exceeding the maximum rate as stated in the Plant Technical Specifications.

In order to reduce the increased capacity exhibited by the East pump, it was recommended by both Pacific Pumps and Westinghouse to install an orifice plate in the pump discharge. The added resistance provided by this orifice plate reduced the flow and allowed the pump to operate at the desired value. Pacific Pumps has manufactured and successfully tested orifices for the 2½-RLIJ Model pump in question to meet the design runout flow rate for other companies.

The RFC has been classified as Safety-Related because the modification involves the discharge line of the Centrifugal Charging Pump which is a Seismic Class I System. The fundamental safety issue with regard to this change is that it brought the flow of both pumps within the required technical specification limits. This in fact has been accomplished.

Nuclear Safety and Licensing has reviewed the modification performed as per the review criteria in NS&L Procedure No. 7. As a result of the review, the modifications performed were found to be acceptable. As part of our review process we looked in some detail at the orifice plate procurement and installation. Although this activity performed under normal company procedures, this was a routine independent review to assure the effectiveness of the procedures with regard to safety related components. As a result of that review we found the orifice plate is made up of SA-182-316 stainless steel and has been procured and installed as per the procedures applicable to the safety related systems. The required seismic review has been performed and found to be acceptable.

The purpose of this review is for procurement, design, and installation. With this in mind, it is concluded that this RFC does not constitute an unreviewed safety question as defined in 10CFR50.59, nor does it create a substantial hazard to the health and safety of the public.

DmB

American Electric Power System
INDIANA & MICHIGAN ELECTRIC COMPANY
DONALD C. COOK NUCLEAR PLANT
P.O. Box 458, Bridgman, Michigan 49106
(616) 465-5901

PRINCIPAL STAFF			
RA		DPRP	✓
D/RA		DE	
A/RA		DRMSP	
RC		DRMA	
PAO		SCS	
SGA		ML	
ENF		File	

Orig+1

February 29, 1984

Mr. J.G. Keppler, Regional Administrator
United States Nuclear Regulatory Commission
Region III
799 Roosevelt Road
Glen Ellyn, IL 60137

Donald C. Cook Nuclear Plant
Docket Nos. 50-315/50-316
License Nos. DPR-58/DPR-74

Dear Mr. Keppler:

Two copies of the 1983 Annual Operating Report for the Donald C. Cook Nuclear Plant are being transmitted to you under this cover letter. The information contained in this report covers the activities delineated in Appendix A (Section 6.9.1.5) of the Donald C. Cook Nuclear Plant Technical Specifications, and the requirements of 10 CFR 50.59.

Additional copies of this report have been transmitted to the Office of Inspection and Enforcement and the Office of Management Information and Program Control of the United States Nuclear Regulatory Commission as specified in Regulatory Guide 10.1.

Sincerely,

W.G. Smith, Jr.
W.G. Smith, Jr.
Plant Manager

/bab

Attachments

cc: John E. Dolan
M.P. Alexich
R.W. Jurgensen
R.F. Kroeger
J.G. Feinstein
G. Charnoff, Esq.
R.C. Callen, MPSC
J.M. Hennigan
R.O. Bruggee, EPRI
J.F. Stietzel
Dir., IE
Dir., MIPC

MAR 5 1984

IE01
1/1