AEOD ACTIONS CONCERNING THE

CRYSTAL RIVER 3

LOSS OF NONNUCLEAR INSTRUMENTATION AND INTEGRATED CONTROL SYSTEM POWER

ON FEBRUARY 26, 1980

BY THE

OFFICE FOR ANALYSIS AND EVALUATION

OF OPERATIONAL DATA

NOV 2 4 1980

PREPARED BY: H. L. ORNSTEIN

NOTE: This report documents results of studies completed to date by the Office for Analysis and Evaluation of Operational Data with regard to a particular operating event. The findings and recommendations contained in this report are provided in support of other ongoing NRC activities concerning this event. Since the studies are ongoing, the report is not necessarily final, and the findings and recommendations do not represent the position or requirements of the responsible program office of the Nuclear Regulatory Commission.

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AEOD ACTIONS CONCERNING THE CRYSTAL RIVER 3 LOSS OF NONNUCLEAR INSTRUMENTATION AND INTEGRATED CONTROL SYSTEM POWER ON FEBRUARY 26, 1980

1. INTRODUCTION

On February 26, 1980, Crystal River 3 experienced a plant transient which was initiated by a loss of instrument power. During that event, power to the Non-Nuclear Instrumentation and Integrated Control System was lost, a small loss of coolant was created, and almost all of the control room instrumentation was lost for a period of about 20 minutes.

During the first 48 hours after the event, AEOD had received only scant information about the event (primarily from the Phillips Building PA system on the day of the incident, from a Commission briefing held the next day, and from brief discussions with NRR and IE personnel).

Since the information being received by AEOD was neither consistent nor complete, and the AEOD staff believed that the event was highly significant, it was decided that one of the AEOD's two permanently assigned members for the new office should go to the plant to acquire accurate information about the event, help assure that no significant aspects of the event were overlooked, and later determine that adequate follow-up actions are taken to prevent recurrence of similar events. It was agreed among the Directors of AEOD, IE, and NRR that, above all, AEOD's presence at the plant was primarily an information gathering mission which was not to perturb the plant personnel and the IE staff who were still in the process of assisting the licensee who was trying to bring the plant to a safe shutdown condition.

The author left NRC headquarters on Thursday afternoon February 28, and was briefed near the plant by the Director of IE, Region II, at 7:30 a.m. the next morning. While at the plant during the next few days, the author had numerous discussions with Florida Power Corporation (FPC) personnel, IE Region II staff, NRR staff, and industry representatives (B&W and INPO/NSAC). The author returned to Washington on Sunday, March 2, 1980, and briefed the AEOD Director the following morning. Conclusions reached at that time were:

a. As suspected, the event was potentially serious and, as shown by previous LERs, there had been numerous precursor events which did not receive the requisite corrective action to prelude the transient. (At the time of this transient, FPC and the other B&W Licensees were in the process of responding to I&E Bulletin 79-27, which was issued after a similar event had occurred at Oconee 3 on November 10, 1979.)

b. During the weekend of February 29, 1980, testing of the plant instrumentation and control circuitry produced numerous surprises. Consequently, it was deemed imperative that Florida Power Corporation quickly determine that the root cause of the event. Furthermore, it was felt that the " proof testing" for system and channel dependencies and interactions should be a minimum requirement for Crystal River 3 restart, and that similar testing of the instrumentation and control systems at all other B&W plants should be required immediately.

c. Alternate safety grade instrumentation, independent of the NNI/ICS and single inverter failures, should be installed at CR-3 and all other B&W plants in order to provide information to operators in case of a repetitive event. (There had been numerous precursors, and since it appeared that total prevention could not be assured, provision to allow the plant to ride through such an event with alternate instrumentation seemed to be the way to go.)

d. Contrary to the belief of the onsite IE team, the author believed that the loss of the NNI-X power was caused directly by the newly installed T-Sat meter and the NNI-Y circuitry. This contention was based upon a discussion with the electrical technician who was at the NNI-Y cabinet trouble shooting the T-Sat meter at the time of the event (see Appendix A).

This opinion was conveyed to the IE response team leader (R. Wessman) on March 1, 1980 with the additional thought that a generic problem exists, and that unless the root cause of the transient was found quickly, it might be necessary to have all B&W plants "show cause" to allow continued operation.

e. There were questions about the meaning of the self powered neutron detector readings which might be associated with localized boiling in the core.

f. There were questions raised regarding the maintenance and lubrication associated with the CR-3 plant's decay heat removal system and design capability of DHR systems in general.

2. EVENT DESCRIPTION

On February 26, 1980, the Crystal River Unit 3 nuclear generating plant located in Citrus County, Florida, experienced an incident involving an electrical malfunction in an instrumentation and control system. This resulted in a reactor and turbine trip; the opening of the pressurizer power operated relief valve (PORV), the pressurizer spray valve, and a code safety valve; decreased feedwater flow to the steam generators; actuation of the engineered safety feactures (ESF) systems; and discharge of approximately 43,000 gallons of primary coolant into the containment building. The pressurized water reactor was designed by the Babcock & Wilcox Company (B&W).

A portion of the non-nuclear instrumentation (NNI) +24 volt power supply was lost due to a short to ground. This loss affected automatic plant control systems and about 70% of NNI control board indicators (such as reactor coolant system temperature, pressure, and flow; steam generator pressure and level; and pressurizer level). It caused the pressurizer PORV and the pressurizer spray valve to open. The failure also caused false control signals to be sent to the Integrated Control System (ICS), the most significant of which caused a reduction in feedwater flow to the steam generators. Also, the false T_{ave} signal caused the ICS to withdraw the control rods to increase power.

The reduction in feedwater flow reduced the reactor heat removal rate to below the reactor heat generation rate, which caused reactor coolant system temperature and pressure to increase in spite of the open PORV and spray valve. As

a result, the reactor tripped on high pressure and then was subsequently partially depressurized. The operators secured the reactor coolant pumps as required by emergency procedures. High Pressure Injection (HPI) automatically initiated as a result of Reactor Coolant System (RCS) depressurization due to loss of coolant inventory through the open PORV and the cooling effects associated with the reactor trip. Shortly after receipt of a high reactor coolant drain tank level alarm, the PORV block valve was closed and, with approximately 70% of NNI inoperable or inaccurate, the operator correctly decided that there was insufficient information available to justify terminating HPI. Therefore, the RCS and pressurizer were filled solid, causing RCS pressure to increase to the point where one safety valve lifted, and flow through the safety valve spilled water into the containment through the Reactor Coolant Drain Tank rupture disk.

Power was restored to the NNI about 20 minutes after the start of the transient. Plant conditions that then existed included the pressurizer filled solid with water, reactor coolant pressure was at 2400 psig, a reactor coolant outlet temperature of 556°F, steam generator "A" was dry, and the core was being cooled by water flow from the high pressure injection system out the open safety valve and by natural circulation through steam generator "B".

Three minutes after the transient began, an operator specifically assigned to purge containment to the atmosphere terminated the purge. Then, because water was still being discharged from the RCS into the reactor building, the reactor building pressure increased to the point (4 psig) where automatic building isolation occurred.

After the restoration of power to the instrumentation, the operators throttled high pressure injection to reduce the flow of water through the open safety valve and into the reactor building. The operators also re-established the water level in steam generator "A".

About 1-1/2 hours after the beginning of the transient, the operators established RCS pressure control using normal makeup and letdown flows. Because RCS temperature and pressure were well under control and the core was being adequately cooled by natural circulation, high pressure coolant injection was shut off. The decision was then made to heat up the pressurizer in preparation for establishing a steam bubble in the pressurizer. About 3-3/4 hours after the incident began, the pressurizer was heated sufficiently and a steam bubble was established in the pressurizer.

About 6-3/4 hours after the beginning of the incident, forced flow in the RCS was established by starting two reactor coolant pumps.

During the incident, about 43,000 gallons of RCS water was spilled into the containment. The radiation level within containment reached 50 rems per hour early in the event and decayed rapidly. This was the result of short-lived gaseous activity (i.e., xenon-138, krypton-89) which were released from the reactor coolant. Radioactivity released to the environment was within regulatory limits, and the spilled RCS water was reprocessed for in-plant use. No core damage occurred. There was no impact on the general public or plant employees as a result of this incident.

3. LICENSEE ACTIONS

Immediately after the transient, in addition to taking action to bring the plant to a safe-shutdown condition, the licensee took the initiative to identify the cause of the transient, assess equipment deficiencies and perform an analysis of the transient to determine short and long term modifications necessary to assure safe plant operation.

At a meeting in Bethesda on March 4, 1980 the licensee informed the NRC that they had found the short that had initiated the transient, provided their sequence of events, and presented the results of their testing and inspection of the NNI-ICS circuitry (including descriptions of equipment deficiencies and a summary of operable instruments following the NNI power failure of 2/26/80). During the meeting Florida Power Corporation also presented their Corrective Action Plan (see Table I). On March 12 and March 17, 1980 Florida Power Corporation provided the information which was requested by NRR at the March 4, 1980 meeting - namely:

a. A summary of previous power upset event on NNI-ICS at CR-3.

b. Copies of information presented at the March 4, 1980 meeting.

c. A discussion of loss of NNI-ICS power:

(1) How the operator determines which information is reliable.

(2) What information is needed by the operators to bring the plant to cold shutdown (see Table II).

d. Confirmation that prior to plant restart, the licensee would verify by functional testing that information on the major plant parameters required to bring the plant to cold shutdown are available to the operator upon loss of ICS or either train of NNI.

e. An updated list of corrective actions that would be taken prior to restart (Items 1 through 12 appearing in Table I plus eleven additional items).

f. A review of the benefits of the NRC requirements imposed since the TMI-2 accident (Short Term Lessons Learned and Bulletins and Orders) - The assessment concluded that the "requirements were of benefit to plant operations," and that the requirements for improved/additional operator training provided the largest contribution for dealing with the 2/26/80 transient.

Subsequent to review of the licensee's short term corrective actions and longer term commitments, the NRC staff provided a Safety Evaluation allowing restart of the CR-3 plant. The plant completed its refueling outage on August 10, 1980, and subsequently returned to power production.

4. NRR AND I&E ACTIONS

I&E regional teams arrived at the site a few hours after the transient started. Their mission was to assess plant conditions and evaluate the significance of the event. An NRR Operator Licensing Branch member was in the CR-3 control room giving a licensing examination while the event occurred, and similarly an I&E Performance Appraisal Team was onsite while the transient occurred. NRR sent a senior instrumentation and controls engineer to the site on March 1, 1980.

NRR requested that B&W and all the B&W licensees attend a March 4, 1980 meeting to provide information on their histories of non-nuclear instrumentation problems, the susceptibility of their plant to the CR-3 event and its implication on the safe operation of their plant.

Via a March 6, 1980 letter, NRR requested each B&W licensee to provide written copies of this information and also address the feasibility of performing a test to verify that reliable information is available to the operators subsequent to NNI/ICS power upsets as well as addressing the applicability of each of CR-3's proposed corrective actions to their plant.

In addition to reviewing the aforementioned licensee submittals, a special task force (B&W Reactor Transient Response Task Force) was established by NRR on March 12, 1980, to assess the generic aspects of operating experiences of the B&W plants. The task force consisted of 12 members from NRR, I&E, RES and ORNL. The task force assessed the sensitivity of B&W plants to transients

involving overcooling and undercooling conditions, small break loss of coolant accidents, consequences of malfunctions and failures of the NNI and ICS. The task force published their report (NUREG 0667) in May 1980. The report contained 22 recommendations. It also included the Probabilistic Analysis Staff's assessment of the risk reduction potential associated with each recommendation.

In meetings held with the B&W licensees, NRR requested that each licensee take actions to assure plant operators have the capability of coping with various combinations of loss of instrumentation and control functions (these tasks included immediate design review, analysis, and testing at each facility; and immediate correction of electrical and control deficiencies, as well as the upgrading of procedures and operator training). IE representatives witnessed the NNI/ICS testing which was performed at each plant, and also reviewed the revised plant procedures.

On July 18, 1980 NRR issued a Safety Evaluation Report for restarting CR-3. It noted that the corrective actions taken by the licensee "are sufficient to permit restart of CR-3 and to ensure operation in a safe manner during the interim period until the long term requirements resulting from the Three Mile Island Unit 2 accident and those of OIE Bulletin 79-27 are all implemented."

5. AEOD ACTIONS SUBSEQUENT TO THE PLANT VISIT ON FERRUARY 29, 1980

It was clear from the actions taking place at the plant during the weekend of February 29, 1980 (including the scheduling of a meeting in Bethesda with B&W and the B&W licensees on March 4, 1980) that Florida Power Corporation, NRR,

and IE were taking appropriate follow-up action on a timely basis. The Office for Analysis and Evaluation of Operational Data participated in the March 4, 1980 meeting and in subsequent NRC meetings held with B&W, FPC, and the other B&W licensees. At the March 4, 1980 meeting, each B&W licensee addressed NNI problems at his facility, their plant's susceptibility to an event like the one that Crystal River had just experienced, and their proposed corrective actions.

At some of those meetings, AEOD raised questions about the susceptibility of once through steam generators to overfill due to the lack of safety grade instrumentation and high level trips. In an August 4, 1980 memo, AEOD recommended that this item be considered a "New Unresolved Safety Issue."

In an April 24, 1980 meeting in which Florida Power Corporation outlined their proposed actions (near-term and long-term plant modifications, improvements in operator training, etc.), AEOD expanded on the fact that many B&W plants are susceptible to overcooling transients because their atmospheric dump valves open to the half open position upon loss of NNI/ICS power. AEOD has brought this fact to NRR's attention and NRR in turn indicated that this problem will be resolved; however, the schedule for resolution has not been established (see References 1 and 2).

While at the Crystal River 3 plant, AEOD probed the circumstances behind the fact that there was a three day gap between the NNI-ICS power loss, and the cooldown of the plant to the level where the RHR system could be used. The problem stemmed from inadequate lubrication of a decay heat

removal pump (DCP 1-A - one of two redundant pumps). In a March 20, 1980 memo, AEOD documented this information and copies were forwarded to NRR and IE along with some preliminary recommendations (see Appendix B). Subsequently, AEOD also searched the LER and NPRDS files to determine how widespread the problem of inadequate pump bearing lubrication might be. Initial results indicated that the problem was not widespread and that the bearing lubrication problem at Crystal River 3 may have just been an isolated incident. Pump and motor bearing lubrication will be watched by AEOD.

In the course of examining the decay heat removal system for Crystal River 3, AEOD noted that the Nuclear Services Closed Cycle Cooling System (NSCCCS) was subject to a single passive failure which could have significant implications. This information was conveyed to NRR by a memorandum (see Reference 3). AEOD is concerned that short-term improvements in decay heat removal systems are not a high priority item in the TMI Task Action Plan and, therefore, is not receiving the attention which is required. AEOD has begun a case study of the recent losses of decay heat removal capability at the Davis-Besse Plant during the summer 1980 refueling outage.

AEOD has reviewed the May 1980 draft of the Crystal River 3 IREP report. AEOD's review (see Reference 4) pointed out serious omissions in the study, including the fact that the operational experience associated with the loss of NNI-ICS power and inverter failures at CR-3 and other B&W plants were not considered in the IREP report (see Reference 4, Page 15). In its review, AEOD also pointed out that in addition to the dependencies noted in the IREP report, the integrity of

all of the reactor coolant pump seals, pump bearings, and motor bearings are dependent upon the NSCCCS. AEOD's review also noted a disconnect between the IREP study and operating experience in the area of procedural or operator error (see Reference 4, Pages 7, 14, and 15) and the incomplete assessment of OTSG overfill and OTSG tube rupture problems.

Subsequent to examining self powered neutron detector data from the CR-3 events recorder, AEOD questioned the possibility of localized core boiling during the event. Florida Power Corporation reviewed this aspect of the transient and concluded from comparison with earlier trip data that local core boiling did not take place during the event (see Appendix C).

Presently, AEOD is carefully monitoring the actions being taken by Florida Power and the other B&W licensees in the areas of NNI/ICS power, steam generator overfill, emergency feedwater control, etc., and as additional concerns appear, AEOD will bring them to the attention of the appropriate NRC office.

6. CONCLUSIONS

a. The immediate and long-term corrective actions proposed by Florida Power Corporation, as well as those required by NRC of all B&W plants regarding the major aspects of the February 26, 1980 event, appear to be appropriate. (These include immediate confirmatory testing of NNI/ICS instrumentation and circuitry, provision of alternate sources of information required by the operators to bring the plant to a safe shutdown subsequent to another similar power loss, and improved or additional operator training).

b. Some items which NRR or IE did not focus attention on immediately after the transient have ben raised by AEOD, and NRR or IE are now addressing them, e.g.,

- o Steam generator overfill
- o Opening of atmospheric dump valves upon loss of ICS power
- o Improved decay heat removal reliability

It is too early to determine how these issues will be resolved; however, AEOD is following efforts on these subjects closely.

c. AEOD has reviewed the pilot IREP study of the Crystal River 3 Plant. AEOD noted that in addition to other deficiencies, the report, omitted significant operating data (especially that acquired from the February 26, 1980 event). AEOD has conveyed this information to RES/Probabilistic Assessment Staff, who in turn has requested

the contractor who performed the study to provide schedule and cost information associated with correcting the deficiencies noted by AEOD and other reviewers.

d. Even though the February 26, 1980 event at Crystal River 3 resulted in a long (and costly) power outage, it resulted in enhancing reactor safety, with minimal impact upon the public, the environment and industry. For example, the subject transient succeeded in focusing Commission and industry attention on a previously known problem, and sped up the schedule for its resolution. (Similar events had occurred at other B&W plants, but none had resulted in spillage of primary coolant into containment.) The transient undoubtedly resulted in speeding up the pace of implementing plant improvements that appeared to be necessary at B&W plants subsequent to previous NNI/ICS power failures.

Table I

FLORIDA POWER CORPORATION'S CORRECTIVE ACTION PLAN (MARCH 4, 1980)

Short Term

1. Thorough testing of the NNI system to determine cause of failure.
2. Modify PORV so that NNI failure closes valve.
3. Modify pressurizer spray valve so that valve doesn't open on NNI failure.
4. Provide positive indication of position of all three relief or safety valves.
5. Establish procedural control of NNI selector switches.
6. Train all operators in response to NNI failures.
7. Move 120V ICS "X" power to vital bus.
8. Initiate more extensive program for events recorder system.
9. Provide operator with redundant indication of main plant parameters.
10. Install indication lights on all panels to know if power is on.
11. Quick access fuses to be designed into cabinets.
12. Modify EFW pump circuit to start pumps on any low steam generator level signal.

Long Term

1. Investigate upgrade of NNI capabilities - total loss of NNI.
2. Remote shutdown panel to be designed.
3. Provide backup AC sources to inverters with automatic transfer.

Table II

FLORIDA POWER CORPORATION'S LISTING OF MAJOR PLANT PARAMETERS NEEDED TO BRING PLANT TO COLD SHUTDOWN (March 12, 1980)

Pressurizer Level
Pressurizer Temperature
Reactor Coolant Loop A Wide Range Cold Leg Temperature
Reactor Coolant Loop B Wide Range Cold Leg Temperature
Reactor Coolant Loop A Wide Range Hot Leg Temperature
Reactor Coolant Loop B Wide Range Hot Leg Temperature
Emergency Feedwater Flow A and B
Reactor Coolant System Wide Range Pressure
OTSG A Startup Level
OTSG B Startup Level
OTSG A Operating Level
OTSG B Operating Level
OTSG A Pressure
OTSG B Pressure
Decay Heat Removal Flow (Both Trains)
Core Flood Tank A Level
Core Flood Tank B Level
Core Flood Tank A Pressure
Core Flood Tank B Pressure
High Pressure Injection Flow (Both Trains)
Makeup Tank Level
BWST A Level
BWST B Level
Tsat Meters
Letdown Flow
Decay Heat Suction Temperature
Low Range RC Pressure
Core Exit T/C Indication
Makeup flow

REFERENCES

1. Memo: C. Michelson to H. Denton, "Lessons Learned from the Crystal River Transient of February 26, 1980 - Correcting Atmospheric Dump Valve Opening Upon Loss of ICS Power," (May 23, 1980).

2. Memo: H. Denton to C. Michelson, "Lessons Learned from the Crystal River Transient of February 26, 1980 - Correcting Atmospheric Dump Valve Opening Upon Loss of Integrated Control System Power," (July 21, 1980).

3. Memo: C. Michelson to R. Mattson, "NRC Action Plans Developed as a Result of TMI-2 Accident - Draft 3, Task II E.3 Decay Heat Removal," (April 24, 1980)

4. Memo: H. Ornstein to R. Bernero "Review of IREP Crystal River-3 Safety Study," (June 19, 1980).

Florida Power

Logged F/C

RC APPENDIX A

WORK REQUEST

Nº 13860

J

PART I:	IDENTIFICATION AND DESCRIPTION OF CONDITION

SYSTEM: RC — DISCREPANCY: YES ☐ NO ☒

TEM / TAG NO: RC-4-TI5 (Test meter) — NCOR NO: N.A.

DESCRIBE CONDITION, CAUSE AND METHOD OF DETECTION:

Meter shows B loop Tsat margin to be 234°F
Actual Margin is Approx 100°

RELATED DOCUMENTS: MAR NO. N.A. — PROC'D. NO. N.A — WR NO. N.A.

ORIGINATOR: M.P Holmes — DATE: 2-25-90 TIME: 1031 — RESPONSIBLE SUPVR: N.A — DATE:

PART II — EVALUATION OF WORK REQUIRED

NUCLEAR SAFETY RELATED: YES ☐ QC REQ'D NO ☒

QUALITY ITEM: YES ☐ QC REQ'D NO ☒

PRIORITY CODE: ☐ 1 TECH. SPEC. OR SECURITY ITEM PERSONNEL OR EQUIPMENT SAFETY ☒ 2 SCHEDULE ☐ 3 OUTAGE

PROCEDURE REQUIRED:	POST. MAINT. TEST:	CLEARANCE:	RWP / SRWP	FPWP REQ'D	NDE REQUIRED:
YES ☐ NO ☒	YES ☒ NO ☐	YES ☐ NO ☒	YES ☐ NO ☒	YES ☐ NO ☒	YES ☐ NO ☒
LIST	LIST Functional Ck.	NO:	NO:	NO:	LIST

CHARGE ACCOUNT NO.:

WORK INSTRUCTIONS:
Trouble Shoot. Make necessary Adjustments

MANHOUR ASSESSMENT: NO. OF MEN: — NO. OF HOURS:

EVALUATED BY: B. Cunningham — DATE: 2/26/90 — WORK REQUEST TO SUPERVISOR: D. Fowles

PART III — WORK PERFORMED DESCRIPTION:

DESCRIBE WORK AS PERFORMED: — SHIFT SUPERVISOR: T Hughes — DATE: 3/26/90

MANHOUR ACCOUNTING: NO. OF MEN: — NO. OF HOURS: — TOTAL MANHOURS:

COMPLETED BY — DATE: — RESPONSIBLE SUPVR. — DATE:

PART IV — CORRECTIVE ACTION

CORRECTIVE ACTION: YES ☐ NO ☐ — DESCRIBE INVESTIGATION / ACTION TAKEN:

INITIALS/DATE

WORK REVIEW COMPLETION: (PLAN. COORD.) — DATE: — WORK VERIFIED BY: (QC INSP.) — DATE:

RESPONSIBLE SUPT.: — DATE: — QA / QC MGR. — DATE: — PLANT MANAGER: — DATE:

N10 13860

POOR ORIGINAL

APPENDIX B

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

MAR 2 0 1980

MEMORANDUM FOR: Carl Michelson, Director
Office for Analysis and Evaluation of
Operational Data

FROM: Harold L. Ornstein
Office for Analysis and Evaluation of
Operational Data

SUBJECT: CRYSTAL RIVER NUCLEAR POWER PLANT DECAY HEAT CLOSED CYCLE COOLING WATER PUMPS/DCP-1A AND DCP-1B

I have pulled together the following information:

The NRC requires surveillance testing of these pumps every 30 days. Pump DCP-1A tested satisfactorily on 2/6/80. Above and beyond the inservice inspection program required by NRC, Florida Power Corporation has an outside consultant (C&S Maintenance Consultants) conduct a plant-wide overall vibration maintenance program.

On 2/13/80, one week after DCP-1A passed the NRC required surveillance test, C&S found the pump motor vibration to have a 1.4 mil displacement (1.0 mil alert is required, 1.5 mil action is required). A C&S report, dated 2/15/80, noted the increased displacement and indicated that it was not at a point of concern, and advised FPC that the pump should be watched for increases in vibration and/or temperature.

On 2/26/80, at 8:00AM, C&S retested the motor and found it to be out of spec (4.7mil) and in need of immediate repairs. The vibration was attributed to the motor bearing closest to the coupling. A work request was written up noting the fact that this is a tech spec priority item (72-hour action status). The fact that DCP-1A was inoperable was not relayed to the control room personnel until after the incident, partially due to system inertia and the plant evacuation. (A meeting between the shift supervisor and the maintenance planners/coordinators to go over the pump repair did not take place until after reactor trip. The question of communication between operations and maintenance personnel regarding declaring vital equipment out of service needs to be addressed - is this a problem at many other plants vs. just Crystal River vs. just an isolated event at Crystal River?)

POOR ORIGINAL

The motor bearing closest to the coupling was changed on the morning of 2/27/80; however, excessive vibration was still recorded (displacement of 1.1 mil). Because of this vibration, the motor bearing on the opposite side of the motor was then changed. Changing the second bearing brought the displacement down to 0.68 mil which was within the alert range, but still outside the normal operating range of about 0.5 mil. Subsequently, FPC broke down the coupling, found that one end of the coupling was unlubricated, and that it "had bad teeth which were somewhat corroded"; most probably due to improper lubrication. The coupling was then replaced and the pump/motor were realigned. C&S ran vibration tests on the pump/motor on 3/28/80 and readings were within normal ranges (displacement was 0.3 mil).

The redundant decay heat closed cycle cooling system pump, DCP-1B, was examined, and the pump and motor were found to be out of alignment. There was grease in the coupling; however, the grease showed signs of degradation (loss of "slickness"). It was concluded that the degradation arose from misalignment which caused the heating of the grease and excessive wear.

The coupling does not have any grease cup or simple provisions for lubrication. In order to grease the coupling, it must be disassembled. FPC (G. Claar - shop supervisor) informed me that FPC was of the impression that the DCP couplings were not permanently lubricated. FPC had found that the plant equipment lubrication list (which was put together with the assistance of Gulf Atomic) had omitted the couplings on DCP-1A and 1B. As a result, FPC was planning to check the couplings during the next refueling outage for lubrication. I&E (Ashenden) was informed that, as a result of their recent experience with DCP-1A and 1B, FPC is now planning to implement a plant-wide program for alignment and coupling lubrication.

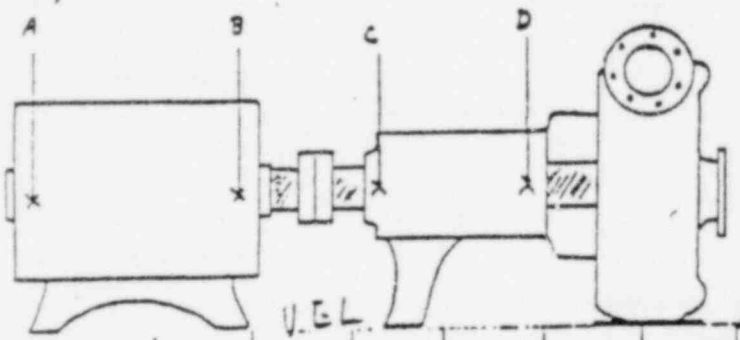
The lubrication problem on the decay heat closed cycle cooling system pumps, the unexpected failure, and the resultant delay in going to cold shutdown highlight the vulnerability of nuclear power plants to inadequate lubrication. The NRC does not appear to have adequate visibility of lubrication and maintenance on vital pumps and other critical equipment. Inadequate lubrication and alignment checks and the "impending common mode failures" of the decay heat closed cycle cooling water pumps, DCP-1A and 1B, at the time of the 2/26/80 Crystal River incident, are viewed as potential accident precursors which should be addressed immediately.

Harold L. Ornstein
Office for Analysis and Evaluation
of Operational Data

Enclosures:
1. C&S Maintenance Consultants' Data Sheet
2. Florida Power Work Request

POOR ORIGINAL

MACHINE SKETCH



MAINTENANCE CONSULTAN

plant

machine

P.M. PROGRAM

			L-13	12-12	1-2-80	2-13	2-26	2-27	2-27	2-28	2-28
			CON	Ewz	HPC	EWO	EWO	EWO	EWO	EWO	EWO
A	H		.10	.07	.04	.14	.48	.14	.04	.04	.04
	V		.07	.11	.05	.08	.18	.09	.02	.05	.05
	A		.10	.06	.06	.09	.15	.04	.02	.04	.05
B	H		.05	.06	.03	.16	.60	.14	.05	.05	.05
	V		.09	.07	.06	.09	.16	.09	.04	.05	.06
	A		.09	.05	.08	.07	.17	.05	.03	.04	.05
C	H		.10	.11	.08	.13	.17	after 1st fuse change on motor	after 2nd fuse change on motor	.11	.11
	V		.05	.05	.09	.08	.10			.06	.05
	A		.05	.05	.05	.07	.10			.07	.08
D	H		.05	.12	.06	.07	.12			.08	.10
	V		.07	.05	.06	.07	.10			.09	.10
	A		.07	.07	.06	.06	.10			.07	.06

					1-2-80	2-13	2-26	6:11 Am	16:44 Am	07:29 Am	08:20 Am
					HPC	EWO	EWO	EWO	EWO	EWO	EWO
A	H			.20	.20	1.0	3.7	.98	.46	.21	.16
	V			.15	.19	.30	1.2	.20	.29	.16	.15
	A			.20	.21	.38	.88	.14	.30	.19	.17
B	H			.22	.22	[redacted]		1.1	.68	.30	.30
	V			.25	.30	.36	1.0	.29	.45	.26	.26
	A			.15	.27	.36	.78	.55	.29	.19	.20
C	H			.15	.30	.46	1.0			.24	.30
	V			.07	.12	.19	.52			.16	.14
	A			.10	.10	.20	.32			.18	.19
D	H			.12	.30	.74	.52			.16	.16
	V			.06	.16	.14	.28			.10	.13
	A			.15	.15	.30	.74			.18	.19

COMMENTS:

POOR ORIGINAL

PART I: IDENTIFICATION AND DESCRIPTION OF CONDITION

SYSTEM: DECAY HEAT C.C. COOLING WATER | DISCREPANCY: YES ☐ NO ☑

ITEM / TAG NO: ELEC MOTOR / DCP-1A | NCOR NO:

DESCRIBE CONDITION, CAUSE AND METHOD OF DETECTION:

- OUT OF SPEC VIBRATION
- BEARINGS POSSIBLY BAD
- C+S VIBRANALYSIS READINGS; .6 IN/SEC (.1 NORMAL) VELOCITY
  4.7 MILS (.5 NORMAL) DISPLACEMENT

A.E. ...

G.E. 100 HP. ~~4160V~~ 480V DRIVE END Brg No. 6318

OPP END BRG. No. 6314

RELATED DOCUMENTS: MAR NO. | PROC'D. NO. | WR NO.

ORIGINATOR: H GROOMS, JR. | DATE: 2/26/80 TIME: 1100 | RESPONSIBLE SUPVR: R.A. Brown | DATE: 2.26.80

PART II EVALUATION OF WORK REQUIRED

NUCLEAR SAFETY RELATED: YES ☑ QC REQ'D NO ☐

QUALITY ITEM: YES ☐ QC REQ'D NO ☐

PRIORITY CODE: ☑ 1 TECH. SPEC. OR SECURITY ITEM ☐ 2 SCHEDULE ☐ 3 OUTAGE

PROCEDURE REQUIRED: YES ☐ NO ☑	POST. MAINT. TEST: YES ☑ NO ☐	CLEARANCE YES ☑ NO ☐	RWP / SEMP YES ☑ NO ☐	FPWP REQ'D YES ☐ NO ☑	MDE REQUIRED: YES ☐ NO ☑
LIST SP-~~3114~~ 2514	LIST	NO: Ø2-75	NO: 79-56	NO:	LIST
SP 3440		CHARGE ACCOUNT NO.: 530.00			

WORK INSTRUCTIONS: Repair as Required

MANHOUR ASSESSMENT: NO. OF MEN: 2 | NO. OF HOURS: 7

EVALUATED BY: [signature] DATE: 2-26-80 | WORK REQUEST TO SUPERVISOR: [signature]

PART III WORK PERFORMED DESCRIPTION:

DESCRIBE WORK AS PERFORMED: REMOVED INBOARD ENDBELL AND BEARING WITH 3 HRS. Removed outboard Endbell and replaced bearing 2 men 1.5 hr. 3 man hrs AB determ to take to ~~Westshop~~ disassemble, reassemble, ~~vibrate~~ bump for Rotation Sat 2 men 6 hrs 12 man hrs AB ~~Align Motor and load to move Coupling from motor 2 men 2 hrs = 4 hrs~~

SHIFT SUPERVISOR DATE: [signature] 2-26-80

MANHOUR ACCOUNTING: NO. OF MEN: 2 | NO. OF HOURS: 11 | TOTAL MANHOURS: 22

COMPLETED BY: [signature] DATE: 28 Feb 80 | RESPONSIBLE SUPVR. DATE:

PART IV CORRECTIVE ACTION

CORRECTIVE ACTION: YES ☐ NO ☐ | DESCRIBE INVESTIGATION / ACTION TAKEN:

INITIALS/DATE

WORK REVIEW COMPLETION: PLAN. COORD. DATE: | WORK VERIFIED BY: (QC INSP.) DATE:

RESPONSIBLE SUPT.: DATE: | COMPLIANCE ENG.: DATE: | PLANT MANAGER: DATE:

No 09516

POOR ORIGINAL

Florida Power
CORPORATION

March 14, 1980

Mr. Hal Ornstein
Office of Analysis and Evaluation of Operating (AEOD)
United States Nuclear Regulatory Commission
Washington, D. C. 20555

Subject: Incore Self-Powered Neutron Detector Information

Hal:

Sorry for the delay on getting this information to you. I am afraid the strip chart reproductions are pretty poor but this is the best we can do for now.

For any additional information on this subject please contact myself or Bill Cross (1-904--795-6486, ext. 101).

Sincerely,

W. E. Kemper

W. E. Kemper
Plant Training Manager

WEK:ub

General Office 3201 Thirty-fourth Street South • P.O. Box 14042, St. Petersburg, Florida 33733 • 813 866-5151

PROFESSIONAL SYSTEMS

★ TO PERSON RECEIVING THIS COMMUNICATION, WRITE REPLY IN LOWER SECTION PROVIDED. ZIP IT GIFT. RETURN ORIGINAL TO SENDER AND KEEP COPY.

906 212 (s)

INTER-OFFICE COMMUNICATION

TO: Bill Cross DATE 3/6/80

SUBJECT Incore Alarms following Rx Trips of 2/26/80 + 12/21/79

I have completed a review of the incore computer alarm data for the 2/26/80 Reactor Trip. As a comparison I have also reviewed incore computer alarm data for the Reactor Trip of 12/21/79 — Also ~~from~~ from 100% FP. In both instances the incores have gone into alarm after 6-7 minutes into the trips. Similar alarms exist for both trips (Please see attached) I regret that from the 12/21 trip there is no more data than shown; This would have been beneficial. Note also that RC pressure for the trip of 12/21/79 is ~2100 PSIG whereas RC pressure for the 2/26/80 trip ≃ 1350 PSIG. From the computer larms on 12/21 the system was 99° subcooled and on 2/26 it was 21° subcooled. Based on the data we have available I cannot definitely state that the incore alarms are not a common occurrance following a Rx trip.

SIGNED Mike Collins 3/6/80

RETURN TO: → DATE

POOR ORIGINAL

12/2/79

		CONT	T0[illegible]	[illegible] LIFT OIL PUMP		
		NORM	[illegible]	2[illegible] MAIN STEAM TO TURB PRESS		
		NORM	S[illegible]	STEAM GEN 6 INLET FW TEMP		
		CONT	T006	GLAND STEAM CDSR VACUUM		
		BAD	[illegible]	HEATER 6 3B DRAIN DP		
	13702702	NORM	S886	HEATER 6A DRAIN DP		.6
	13702702	BAD	S879	REHEATER C HP DRAIN FLOW		[illegible]
4	13702702	NORM	S886	HEATER 6A DRAIN FLOW	-	0
5	13702705	BAD	T312	HP TURB BEARING NO 1 VIBR (MILS)		-??.??
6	13702706	CONT	T006	GLAND STEAM CDSR VACUUM		LOW
7	13702707	BAD	R722	RC OUTLET A PRESS (NARROW)		1998.
8	13702707	NORM	R239	RC LOOP B FLOW (CH C) (MLB/HR)		71.66
9	13702709	CONT	T006	GLAND STEAM CDSR VACUUM		OK
10	13702711	CONT	T006	GLAND STEAM CDSR VACUUM		LOW
11	13702714	CONT	T006	GLAND STEAM CDSR VACUUM		OK
12	13702719	HIGH	T234	2B MAIN STEAM TO TURB PRESS		937.
13	13702720	CONT	A035	GLAND STEAM CDSR COND FLOW		OK
14	13702722	NORM	R722	RC OUTLET A PRESS (NARROW)		2006.
15	13702727	NORM	R222	RC OUTLET A PRESS (NARROW)		2067.
16	13702735	NORM	T312	HP TURB BEARING NO 1 VIBR (MILS)		.02
17	13702736	NORM	R223	RC OUTLET A PRESS (NARROW)		2100.
18	13702736	NORM	R224	RC OUTLET B PRESS (NARROW)		2099.
19	13702737	BAD	R722	RC OUTLET A PRESS (NARROW)		2100.
20	13702737	NORM	R225	RC OUTLET B PRESS (NARROW)		2102.
21	13702738	HIGH	R252	RC PUMPS TOTAL SEAL FLOW (GPM)		53.05
22	13702742	HIGH	S308	STEAM GEN OUTLET 1B PRESS		966.
23	13702747	BAD	S386	*HEATER 6A DRAIN DP		-??.?
24	13702747	BAD	S886	HEATER 6A DRAIN FLOW		-??.
25	13702752	NORM	R722	RC OUTLET A PRESS (NARROW)		2109.
26	13703700	BAD	S324	*RHTR C TO FWPT A DP		-??.?
27	13703701	BAD	N230	FLUX 8-5 LEVEL 7 (NANOAMPS)		-???.
	13703701	BAD	S824	REHEATER C TO FWPT A FLOW		-???.?
29	13703702	NORM	S379	*REHEATER C HP DRAIN DP		.007
30	13703702	NORM	S386	*HEATER 6A DRAIN DP	-	.6
31	13:33:41	VATR	N791	CORE THERMAL POWER (MW)		0
32	13703702	NORM	S879	REHEATER C HP DRAIN FLOW		5.7
33	13703702	NORM	S886	HEATER 6A DRAIN FLOW	-	0
34	13703711	CONT	P052	MAKE UP PUMP C		OFF
35	13703713	BAD	S231	*HEATER 3B DRAIN DP		-??.??
36	13703716	BAD	S731	HEATER 3B DRAIN FLOW		-???.?
37	13703717	CONT	T005	HP TURB STEAM SEAL PRESS		LOW
38	13703728	NORM	S231	*HEATER 3B DRAIN DP		.20
39	13703731	NORM	S731	HEATER 3B DRAIN FLOW		[illegible]
40	13703732	BAD	S386	*HEATER 6A DRAIN DP		[illegible]
41	13703732	BAD	S886	HEATER 6A DRAIN FLOW		[illegible]
42	13703734	CONT	A035	GLAND STEAM CDSR COND FLOW		LOW
43	13703736	LOW	A211	FWP B SPEED (RPM)		99.
44	13703742	NORM	S308	STEAM GEN OUTLET 1B PRESS		947.
45	13703742	HIGH	S212	HEATER 1B INLET COND TEMP		141.0
46	13704702	NORM	S386	*HEATER 6A DRAIN DP	-	.8
47	13704702	BAD	N672	ROD 4-5 NO.33 LOC.16-F POSITION		-???.?
48	13704702	NORM	S886	HEATER 6A DRAIN FLOW	-	0
49	13704707	BAD	R722	RC OUTLET A PRESS (NARROW)		2109.
50	13704709	HIGH	T315	LP TURB BEARING NO 4 VIBR (MILS)		7.18
51	13:05:12	NORM	R770	RC SUBCOOLING (DEG F)		95.
	13:05:16	NORM	T315	LP TURB BEARING NO 4 VIBR (MILS)		6.16
	13105118	BAD	N534	FLUX 5-0 LEVEL 7 (NANOAMPS)		-????.
	[illegible]	NORM	N672	ROD 4-5 NO.33 LOC.16-F POSITION		.0
	[illegible]	NORM	T231	2B MAIN STEAM TO TURB TEMP		[illegible]
	[illegible]	NORM	T234	2B MAIN STEAM TO TURB PRESS		[illegible]
	13109123	BAD	N582	FLUX 12-0 LEVEL 7 (NANOAMPS)		-????.
	[illegible]	NORM	R722	RC OUTLET A PRESS (NARROW)		[illegible]
	13110120	BAD	N406	FLUX 14-0 LEVEL 2 (NANOAMPS)		-????.

POOR ORIGINAL

2/26/80

14:27:33	NORM	T028	1A MAIN STEAM TO TURB PRESS	938.	
14:27:37	CONT	A128	CRD SYSTEM SEQUENCE FAULT	YES	
14:27:37	CONT	E032	120VAC REG INST BUS 3B(VBDP-2)	DEAD	
14:27:38	CONT	X029	RC MOTOR B1 LOWER OIL POT LVL LO	YES	
14:49:59	DATA	R205	PRESS RELIEF VLV RCV-10 OUT TEMP	280.4	
14:50:04	DATA	R206	PRESS RELIEF VALV RCV-9 OUT TEMP	154.8	
14:27:38	CONT	A128	CRD SYSTEM SEQUENCE FAULT	NO	
14:50:14	DATA	R207	PRESS RELIEF VALV RCV-8 OUT TEMP	356.2	
14:27:39	CONT	E032	120VAC REG INST BUS 3B(VBDP-2)	ENRG	
14:27:46	BAD	S370	*REHEATER B COMB DRAIN DP	-?.???	
14:27:47	BAD	S870	REHEATER B COMB DRAIN FLOW	-???.?	
14:27:52	CONT	T006	GLAND STEAM CDSR VACUUM	OK	
14:27:54	HIGH	T315	LP TURB BEARING NO 4 VIBR (MILS)	7.11	
14:27:54	CONT	X040	RC MOTOR A2 LOWER OIL POT LVL LO	YES	
14:27:56	CONT	T006	GLAND STEAM CDSR VACUUM	LOW	
14:28:09	NORM	S293	STEAM GENERATOR B LEVEL(STARTUP)	29.0	
14:28:13	CONT	T006	GLAND STEAM CDSR VACUUM	OK	
14:28:16	NORM	S379	*REHEATER C HP DRAIN DP	.045	
14:28:17	NORM	S879	REHEATER C HP DRAIN FLOW	13.9	
14:28:17	FLAG	X182	RC PUMP A1 SUCTION TEMP (R214)	GOOD	
14:28:17	FLAG	X184	RC PUMP B1 SUCTION TEMP (R216)	GOOD	
14:28:36	VATR	N791	CORE THERMAL POWER (MW)	2437.	
14:28:17	FLAG	X185	RC PUMP B2 SUCTION TEMP (R217)	GOOD	
14:29:44	NORM	T315	LP TURB BEARING NO 4 VIBR (MILS)	6.42	
14:28:47	FLAG	X185	RC PUMP B2 SUCTION TEMP (R217)	BAD	
14:28:48	CONT	X040	RC MOTOR A2 LOWER OIL POT LVL LO	NO	
14:29:03	LOW	T028	1A MAIN STEAM TO TURB PRESS	834.	
14:29:18	NORM	T029	2A MAIN STEAM TO TURB TEMP	588.6	
14:29:29	CONT	T005	HP TURB STEAM SEAL PRESS	LOW	
14:29:29	HIGH	S328	DEAERATOR (B SIDE) TEMP	310.1	
14:29:46	NORM	S370	*REHEATER B COMB DRAIN DP	.087	
14:29:46	NORM	S870	REHEATER B COMB DRAIN FLOW	56.1	
14:29:54	CONT	X029	RC MOTOR B1 LOWER OIL POT LVL LO	NO	
14:30:0.	BAD	S370	*REHEATER B COMB DRAIN DP	-?.???	
14:30:02	BAD	S870	REHEATER B COMB DRAIN FLOW	-???.?	
14:30:31	**BAD**	**N230**	**FLUX 8-P LEVEL 7 (NANOAMPS)**	**-????.**	
14:30:46	NORM	S370	*REHEATER B COMB DRAIN DP	.082	
14:30:47	NORM	S870	REHEATER B COMB DRAIN FLOW	156.8	
14:30:52	BAD	S9A6	STEAM GEN A UPPER DOWNCOMER TEMP	559.7	
14:30:54	CONT	X030	RC MOTOR A2 UPPER OIL POT LVL LO	YES	
14:31:04	BAD	N358	FLUX 7-R LEVEL 7 (NANOAMPS)	-????.	
14:30:34	VATR	N791	CORE THERMAL POWER (MW)	2437.	
14:31:10	NORM	R770	RC SUBCOOLING (DEG F)	21.	
14:31:25	CONT	P058	CRD WITHDRAWN INHIBIT	ALRM	
14:31:32	BAD	P204	STARTUP RATE (SOURCE RANGE)CH NI1	-??.??	
14:31:32	BAD	P205	STARTUP RATE (SOURCE RANGE)CH NI2	-??.??	
14:31:46	BAD	N382	FLUX 13-F LEVEL 7 (NANOAMPS)	-????.	
14:31:47	BAD	N390	FLUX 12-F LEVEL 7 (NANOAMPS)	-????.	
14:31:59	CONT	A029	FWP A SUCTION VALVE OPEN	NO	
14:32:01	**BAD**	**N534**	**FLUX 5-O LEVEL 7 (NANOAMPS)**	**-????.**	
14:32:02	NORM	P204	STARTUP RATE (SOURCE RANGE)CH NI1	1.59	
14:32:02	NORM	P205	STARTUP RATE (SOURCE RANGE)CH NI2	1.54	
14:32:06	**BAD**	**N582**	**FLUX 12-O LEVEL 7 (NANOAMPS)**	**-????.**	
14:32:09	**BAD**	**N606**	**FLUX 14-D LEVEL 7 (NANOAMPS)**	**-????.**	
14:32:09	CONT	P058	CRD WITHDRAWN INHIBIT	OK	
14:32:11	NORM	S308	STEAM GEN OUTLET 1B PRESS	944.	
14:32:13	BAD	S261	FWPT A FIRST STAGE PRESS	-???.?	
14:32:18	BAD	T028	1A MAIN STEAM TO TURB PRESS	-????.	
14:32:18	LOW	T029	2A MAIN STEAM TO TURB TEMP	564.7	
14:32:39	VATR	N791	CORE THERMAL POWER (MW)	2437.	
14:32:06	LOW	R102	RC OUTLET A PRESS (NARROW)	1720.	
14:32:31	BAD	S370	*REHEATER B COMB DRAIN DP	-?.???	
14:32:32	BAD	S870	REHEATER B COMB DRAIN FLOW	-???.?	
14:32:1A	LOW	R10A	RC OUTLET A PRESS (NARROW)	1669.	
14:32:1A	LOW	R10A	RC OUTLET B PRESS (NARROW)	1671.	
14:32:16	BAD	R202	RC OUTLET A PRESS (NARROW)	1669.	

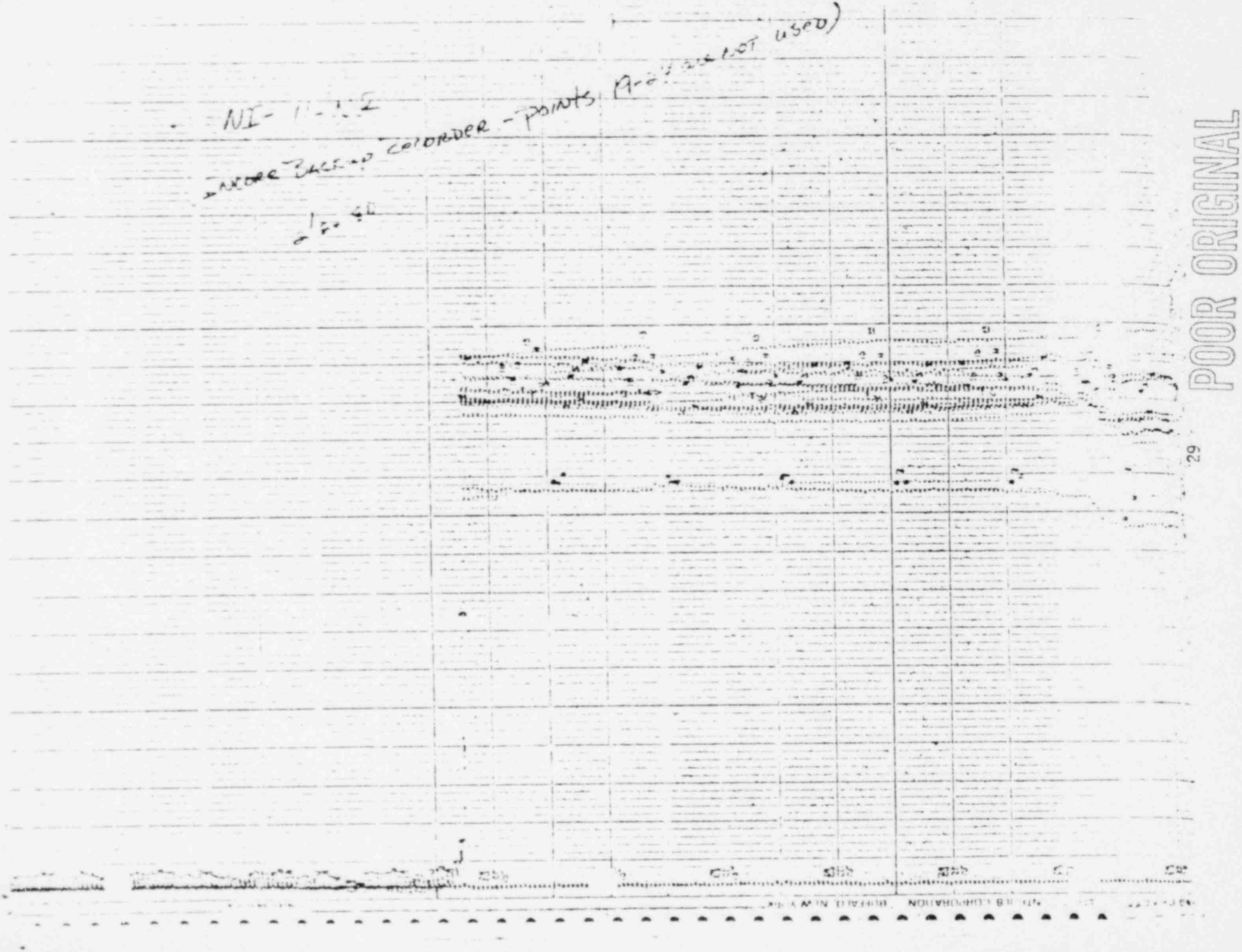
POOR ORIGINAL

NI-10=NR

(INCORE Backup Recorder - points 19-24 are NOT used)

2/26/80

POOR ORIGINAL


POOR ORIGINAL

Attachment of Incore Grids Backup Recorders

ENCLOSURE 1
(Page 1 of 1)

- DATA SHEET I -

IN-CORE NEUTRON DETECTOR SYSTEM CALIBRATION

Step 6.1 - Method "A" used. /

Method "B" used. /

EQUIPMENT REQUIRED

DVM No.

RECORDER #1 NI-10-NR

RECORDER POSITION	NPND SYSTEM NO	LEVEL NO	FULL ASSY	P	RH REQUIRED	RH ACTUAL	RH ADJUSTED	DVM REQUIRED	DVM ACTUAL	DVM ADJUSTED
1	23	6	L-13							
2	1	6	H-08							
3	35	6	F-03							
4	50	6	L-13							
5	1	4	H-08							
6	35	4	F-03							
7	39	6	L-3							
8	1	2	H-08							
9	35	2	F-03							
10	32	2	C-06							
	26	2	C-10							
12	23	2	F-13							
13	50	2	L-13							
14	42	2	O-10							
15	43	2	O-06							
16	39	2	L-03							
17	39	4	L-3							
18	23	4	F-13							

RECORDER #2 NI-11-NR

1	13	6	M-07							
2	11	6	E-05							
3	9	6	G-05							
4	7	6	E-07							
5	5	6	E-09							
6	2	6	H-09							
7	2	4	H-09							
8	2	2	H-09							
9	25	2	G-11							

POOR ORIGINAL

Definitions Con't

DATA SHEET I (Cont'd)
IN-CORE NEUTRON DETECTOR SYSTEM CALIBRATION

EQUIPMENT REQUIRED

DVM No. _____

RECORDER #2										
RECORDER POSITION	SPND STRING NO.	LEVEL NO.	FUEL ASSY.	P	RU REQUIRED	RU ACTUAL	RU ADJUSTED	DVM REQUIRED	DVM ACTUAL	DVM ADJUSTED
10	25	4	G-11							
11	25	6	G-11							
12	19	6	K-11							
13	19	4	K-11							
14	16	6	M-9							
15	9	4	G-05							
16	9	2	G-05							
17	11	2	K-05							
18	19	2	K-11							

6.12.1 a. The symmetrical in-core detector system is operable (computer calculation using at least 75% of the detectors in each core quadrant) and shall be used as the quadrant power tilt monitor.

Yes ____ No ____

b. The minimum in-core detector system for quadrant power tilt is operable. (See Section 2.0.) Notify the Shift Supervisor that the computer is inoperative as quadrant power tilt monitor and refer to STS 4.2.4.

Yes ____ No ____

6.12.2 a. The in-core detector system is operable (computer calculation) and shall be used as axial power imbalance monitor.

Yes ____ No ____

b. The minimum in-core detector system for axial power imbalance is operable. (See Section 2.0.) Notify the Shift Supervisor that the computer is inoperative as axial power imbalance monitor and refer to STS 4.2.1.

Yes ____ No ____

Performed By _____ Date _____

POOR ORIGINAL