December 3, 1980

MEMORANDUM FOR: File

FROM: Roger A. Fortuna, A/D for Investigations
Office of Inspector and Auditor

SUBJECT:

I spoke with Robert Marsh, Investigator, Region IV, on November 28, 1980. Marsh gave me a brief overview of the Brunswick matter discussed in William Ward's December 2, 1980 memorandum. In short, there now appears to be a potential for criminality. In view of IE's limited effort to date and their continuing interest in the matter from a public health and safety perspective, it is appropriate for the Region to continue pursuing the matter and when the issues and facts are more clearly developed (i.e., in writing) that the matter be submitted to OIA for our review and possible referral to Justice.

Of course, I advised Marsh that if there were any significant developments pointing more clearly to criminality, that OIA be immediately advised.

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

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Docket No. 50-261

MEMORANDUM FOR: E. L. Jordan, Deputy Director
Division of Resident and
Regional Reactor Inspection, IE

THRU: W. R. Mills, Acting Section Chief, Events Evaluation Section, Reactor Engineering Branch, DRRRI, IE

FROM: H. W. Woods, Reactor Systems Specialist, Events Evaluation Section, Reactor Engineering Branch, DRRRI, IE

SUBJECT: H. B. ROBINSON EVENT ON JANUARY 29, 1981

I. Description of Event

Early on January 29, 1981, the plant was having problems with the hydraulic pumps on the turbine Electro-Hydraulic Control (EHC) system. One pump had significant vibrations when in service, and the other had a significant oil leak through the shaft seal. The operators were shifting back and forth between use of these two pumps while decreasing plant power as rapidly as possible so that the plant could be taken off-line and the EHC pumps fixed.

At 0624 with turbine load at about 6%, the operators were shifting the EHC between those pumps when the second (last) generator output breaker was opened to separate the plant from the grid. This combination of transients produced a very quick oscillation of the governor valves which admitted a quick pulse of steam into the steamline, producing two momentary high steam flow signals. Since the primary system had already been cooled below the "low T average" setpoint, this produced a Safety Injection (SI) on coincidence of two out of three high steam flow - low T average signals. The plant tripped on "P7," i.e., first stage pressure instantaneously indicated power greater than 10%, which will trip the plant unless the output breakers are closed. wrong

The SI signal existed long enough to pick up "B" train SI relays but not the corresponding "A" train relays. Observing the "B" pumps running but not "A" pumps, the operators manually initiated the "A" train SI. (NOTE: no actual injection occurred at this time since reactor pressure was around 2200 psig and shutoff head for the SI pumps at H. B. Robinson is about 1500 psig). 1470

At 0628, noting that pressurizer level was at 18% and increasing and primary system pressure was at 2200 psig and steady, the operators reset the SI. No reactor coolant pumps were tripped. 2100

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CF

Continuing to recover from the plant trip and SI, at 0637 the plant operators restored letdown (which is isolated on an SI) and stopped one charging pump. It is noted here that apparently no written procedure exists for recovery from an inadvertent SI; lacking such a procedure, the operator tried to restore letdown without resetting the air system that operates the let down isolation valves. Noting that letdown had not been restored, the operators realized the problem, went to a different panel and reset the air system, and then restored letdown.

Following restoration of letdown, the pressurizer level continued to increase but primary system pressure was decreasing, containment dewpoint increased from 85°F to 90°F, count rate in the containment went from 300 to 400 cpm, containment pressure increased from 0.12 psig to a maximum of 0.25 psig, and Heating-Ventilating and Air Conditioning (HVAC) condensate alarms were received (all indicitive of a primary system leak into containment).

At 0645, the operators re-isolated letdown but primary system pressure continued to decrease, reaching 1715 psig at 0701 at which time a low pressure, automatic SI was initiated (but no water was injected since SI pump shutoff head is 1500 psig). At 0715, unsure what was causing the continued depressurization with the letdown isolated (where the leak was suspected as all parameters except Pressurizer pressure indicated the leak had been isolated) the operators isolated the charging line, stopped the "B" and "C" RCPs, and turned on the pressurizer backup heaters (previously only 900 KW of heaters had been on). These actions arrested the pressure decrease, and the reactor was restored in an orderly manner to normal hot shutdown pressure and temperature. Minimum subcooling during the event was 60 to 70°F, and minimum pressure was 1620 psig, above the SI pump shutoff head. No flow was ever indicated from the SI.

At 0730, the 12" water level alarm in the keyway sump was received, indicating about 3000 gallons of water in containment. Sometime before 1400 the same day, the 15" alarm (∿ 6000 gallons) was received. These estimates of the water amounts are extremely rough because the curve showing water volume vs. level in the keyway ("incore" area) covers 600,000 gallons, Sump 65,000 and these measurements therefore are assuming less than 1% error in the curve.

Later investigation revealed that there were several contributors to the above sequence of events.

(1) Leakage from the primary system into containment was from a header in the letdown system just downstream of the regenerative heat exchanger and the letdown orifices. This header had two leakage paths to the containment atmosphere. First, the 600-psig-setpoint relief valve on that header (which discharges to the pressurizer relief tank) had a failed bellows such that leakage past the stem went directly into containment. This was a minor leak compared to Wrong

the second leak, which was from a 3/4" drain-line from the header with a manual valve (#204-C, normally closed) leading to a capped pipe nipple. The valve was found to have a very loose packing so that it could easily be turned, and it was open "four or five turns." The cap was missing, there was a "dimple" in the concrete floor beneath the drain, and the last turn of threads on the drain nipple was stripped. wrong

The possibility of a pressure pulse or water hammer causing these failures was investigated, but no evidence (strip chart data, failed pipe hangers, abnormal valve line up due to lack of a SI reset procedure, etc.) has been found. The most likely explanation is that vibrations from the positive displacement charging pump worked the #204-C valve open and the cap loose, and the transient of isolating and re-initiating letdown finally caused the cap to come off. The cause of the relief-valve bellows failure (a much smaller leak) is still being investigated by the licensee.

The relief valve bellows has been replaced, the #204-C valve packing has been tightened, the valve closed and locked, other similar valves in the vicinity have been verified closed and their packings have been tightened, and the valve handwheels locked. The cap down-stream of the #204-C valve has been replaced and properly tightened.

(2) Water collected in the keyway reached the 12" alarm level (~ 3000 gal) at 0715 January 29, 1981, and the 15" (~ 6000 gal) alarm level sometime before 1400. Flow calculations for the open 3/4" drain line predicted 100 to 120 gpm under pressure conditions present in the letdown system. Since the letdown system was only un-isolated from 0637 to 0645, this would account for only around 960 gallons of the initial 3000. However, sump level at the start of the leak is not known, it is not known how much leakage came from the failed bellows (rate and time period both are unknown), the "3000" gallons associated with the 6" alarm is not an exact number, and in addition between 0645 (when letdown was isolated) and 0715 (when the 6" alarm was received) there was leakage past the air operated letdown isolation valve in the letdown system and out the drain, and there was an unknown amount of drainage from other parts of the letdown system. In summary, it cannot be concluded with certainty how much water leaked into the containment. It can be concluded that all sources of leakage into the containment have been found based on RCS leakage determination and visual inspections in containment. (The additional ~ 3000 gallons collected* between 0715 and ~ 1400 are attributed to leakage past the isolation valve).

*The 6000 gallons (total) were not pumped out during this time period because post-TMI requirements required containment isolation, including sump flow, upon receipt of an SI signal, so the pumps were not operating during the time the ~ 6000 gallons were accumulating.

Before the licensee resumed power operation but after he had put the systems into their normal status, he was required to enter containment to verify the lack of other leakage sources (there were none). He also repaired the letdown isolation valve and verified its integrity, and pumped out the keyway.

(3) Reactor depressurization during the event was caused by a stuck-open pressurizer spray valve, as determined by subsequent testing following the event ("B" valve stuck during such testing). The valve has been repaired and verified operable.

(4) The EHC pumps and EHC system have been repaired and tested satisfactorily. The system will be carefully observed to further verify its proper operation upon restart.

(5) After this event, for three to six hours there was indication that "B" Steam Generator had a 0.3 gpm primary to secondary leak (based on secondary side radioactivity of $10^{-4}\mu$ Ci/cc). The indication then went away. Either there was a small leak which subsequently closed, or the transient stirred "crud" in the secondary system which caused the indication. Upon restart, the plant will monitor carefully for SG leaks (none have been detected following plant startup).

(6) A 3% level increase in the reactor drain tank occurred early in this event. This is believed to be due to lifting of the letdown system relief valve while the letdown system was isolated, due to the leakage of the letdown system isolation valve previously mentioned. NR

II. Cause of Event

There appear to have been multiple contributors to this event, as described in Section I.

III. Corrective Action

(a) Short Term

Detailed in Section I.

(b) Long Term

The possibility of a pressure pulse in the letdown system will be further investigated by the licensee, for example, be examination of the failed bellows for failure mode, further pipe hanger examinations, etc. The bellows failure is being investigated as a generic item by W with Crosby Valve Co., the valve vendor.

The need for an SI recovery procedure will be evaluated. The licensee has evaluated this need, and is actively preparing such a procedure.

IV. Evaluation

Based on the corrective actions detailed in Section I, we concluded that continued operation was acceptable.

H. W. Woods

Hugh W. Woods, Reactor Systems Specialist
Events Evaluation Section
Reactor Engineering Branch, DRRRI, IE

cc: J. H. Sniezek, IE
N. C. Moseley, IE
S. E. Bryan, IE
RONS Branch Chiefs
W. R. Mills, IE
C. J. DeBevec, IE
G. A. Schwenk, IE
T. Novak, NRR
R. Tedesco, NRR
G. Lainas, NRR
R. Vollmer, NRR
C. Berlinger, NRR
S. Varga, NRR
D. Neighbors, NRR
C. Michelson, AEOD

CP&L
Carolina Power & Light Company

March 10, 1981

FILE: NG-3514(R) SERIAL NO.: NO-81-444

Office of Nuclear Reactor Regulation
ATTENTION: Mr. Steven A. Varga, Chief
Operating Reactors Branch No. 1
United States Nuclear Regulatory Commission
Washington, D.C. 20555

RECEIVED
MAR 12 1981
U.S. NUCLEAR REGULATORY COMMISSION

H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2
DOCKET NO. 50-261
LICENSE NO. DPR-23
IN-SERVICE INSPECTION AND TEST PROGRAM

Dear Mr. Varga:

Carolina Power & Light Company (CP&L) is herewith transmitting to NRC three (3) copies of the revised In-Service inspection and Test Program (ISI Program) for the H. B. Robinson Steam Electric Plant, Unit No. 2 (HBR-2). This submittal is made in compliance with 10CFR50.55a(g). The program is being updated to ASME Boiler and Pressure Vessel Code, Section XI, 1977 Edition with addenda through the summer, 1978, addenda.

The updated ISI Program will be applicable for the second 120-month interval beginning March 7, 1981. CP&L intends to implement the new program effective April 1, 1981 which is the beginning of the second quarter of 1981. Requirements for the second quarter will be met by July 1, 1981. Plant technical specification requirements which are more conservative than the ISI Program will be followed in lieu of the ISI Program requirements.

The requirements of the component inspection portion of the ISI Program for the first interval will be completed at the next refueling outage currently scheduled for the fall of 1981. The component inspection program to be conducted during the second interval will be developed and submitted prior to January 1, 1982.

Yours very truly,

M A McDuffie

for E. E. Utley
Executive Vice President
Power Supply and
Engineering & Construction

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CAROLINA POWER & LIGHT COMPANY

H. B. ROBINSON STEAM ELECTRIC PLANT UNIT 2

IN-SERVICE INSPECTION PROGRAM

INTERVAL 2

MARCH 7, 1981 TO MARCH 7, 1991

8103130517 PDR/LPDR

TABLE OF CONTENTS

ABSTRACT

H. B. ROBINSON STEAM ELECTRIC PLANT UNIT 2
IN-SERVICE INSPECTION PROGRAM
INTERVAL 2 - MARCH 7, 1981 TO MARCH 7, 1991

In accordance with 10CFR 50.55a(g)(4)(ii) the H. B. Robinson Unit 2 ISI Program is being updated to ASME Section XI, 1977 Edition with addenda through the summer, 1978, addenda. Steam generator inspections will continue to be inspected under Plant Technical Specifications. Specific reliefs are requested in accordance with 10CFR 50.55a(g)(5)(iii).

The interval for which this program is applicable will commence on March 7, 1981, and end on March 7, 1991. Class 1, 2, and 3 inspections required to be completed during the first interval will be completed at the next refueling outage currently scheduled for the fall of 1981.

The ISI Program was developed employing the classification guidelines contained in 10CFR 50.2(v) for Quality Group A. Regulatory Guide 1.26, Revision 2 was used for classification of items in Quality Groups B and C, along with ANSI N18.2, 1973 and ANSI N18.2a, 1975. Quality Groups A, B, and C are the same as ASME classes 1, 2 and 3 respectively.

The List of Drawings identifies the drawings used in developing the program.

Attachment A describes the Class 1, 2, and 3 component inspection program developed in accordance with Subsections IWB, IWC, and IWD of ASME Section XI.

Attachment B describes the Class 1, 2, and 3 pump and valve inspection program developed in accordance with Subsections IWP and IWV of ASME Section XI.

H. B. ROBINSON STEAM ELECTRIC PLANT UNIT 2
IN-SERVICE INSPECTION PROGRAM
LIST OF DRAWINGS

Drawing #	Sheets	Title
ISI-5379-353		Sampling System
ISI-5379-376	1 of 3	Component Cooling System
	2 of 3	
	3 of 3	
ISI-5379-684		Chemical and Volume Control System
ISI-5379-685	1 of 3	Chemical and Volume Control System
	2 of 3	
	3 of 3	
ISI-5379-686	1 of 2	Chemical and Volume Control System
	2 of 2	
ISI-5379-920	1 of 4	(Liquid) Waste Disposal System
ISI-5379-921	1 of 2	(Gaseous) Waste Disposal System
	2 of 2	
ISI-5379-1082	1 of 2	Safety Injection System
	2 of 2	
ISI-5379-1484		Residual Heat Removal System
ISI-5379-1485		Spend Fuel Pit Coolant System
ISI-5379-1971	1 of 2	Reactor Coolant System
	2 of 2	
ISI-G-190196	1 of 3	Main, Extraction and Aux. Steam Sys.
ISI-G-190197	2 of 3	Feedwater, Condensate and Air Evacuation Sys.
ISI-G-190199	1 of 7	Service & Cooling Water System
	2 of 7	
	3 of 7	
ISI-G-190234	1 of 2	Steam Generator Blow-Down System
ISI-G-190261	3 of 8	Penetration Pressurization System
	7 of 8	
	8 of 8	
ISI-G-190262		Isolation Valve Seal Water
ISI-G-190304	1 of 2	HVAC - Turb, Fuel, Aux, and Reactor Buildings
ISI-HBR2-6490		Post Accident Sampling System
ISI-HBR2-6933		Post Accident Containment Venting System
ISI-HBR2-7063		Flow Diagram Legend
ISI-SK-1		Fire Protection System
ISI-SK-2		Fuel Transfer Tube

Attachment A

ASME SECTION XI COMPONENT INSPECTION PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2

The component inspection program to be conducted in accordance with Subsections IWB, IWC, and IWD of ASME Section XI will be developed and submitted prior to January 1, 1982.

Attachment B

ASME SECTION XI PUMP & VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2

The pump and valve testing program shall be conducted in accordance with Subsections IWP and IWV of Section XI of the 1977 Edition of the ASME Boiler and Pressure Vessel Code through the Summer, 1978 Addenda, except for specific relief requested in accordance with 10CFR50.55a(g) (5)(iii), which is identified in Tables 2 and 3 for pumps and valves respectively.

The interval for which this pump and valve testing program is applicable commences on March 7, 1981, and expires on March 7, 1991.

The pump and valve testing program was developed employing the classification guidelines contained in 10CFR50.2(v) for Quality Group A and Regulatory Guide 1.26, Revision 2 for Quality Groups B and C along with ANSI N18.2, 1973, and N18.2a, 1975. Quality Groups A, B, and C are the same as ASME Class 1, 2, and 3, respectively.

The List of Drawings identifies the drawings used to develop the pump and valve testing program.

Table 1 lists the codes and symbols used throughout the program.

Table 2 lists all safety related Class 1, 2, and 3 pumps included in the testing program. The test parameters measured and the testing frequency are also listed.

Table 3 lists all safety related Class 1, 2, and 3 valves included in the program. Specifically excluded per IWV-1200 are valves used for operating convenience only, such as manual vent, drain, instrument, test maintenance, pressure regulating, thermal relief, and system control valves. Test methods and frequencies are also listed. Valve maximum stroke times are listed. Valves which cannot be tested during normal operation have the next acceptable frequency listed as allowed by IWV-3412(a), IWV-3415 and IWV-3416.

Cold shutdown testing, when required, will commence 48 hours after initiation of cold shutdown conditions as defined in Technical Specifications, except for refueling outages. Testing will continue until completed or until the plant is ready to return to operation. Completion of all testing will not be a prerequisite to returning to operation. Testing not completed at one shutdown will be continued during subsequent shutdowns within the required frequencies.

TABLE 1

H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

CODES AND SYMBOLS

Valve Types

BF	Butterfly
CK	Check
DA	Diaphragm
GA	Gate
GL	Globe
ND	Needle
REG	Regulator
RV	Relief/Safety
3W	3-Way
VB	Vacuum Breaker

Actuator Types

AO	Air
M	Manual
MO	Motor
SA	Self Actuate
SO	Solenoid

Valve Position

CL	Closed
O	Open
LC	Locked Closed
LO	Locked Open

Valve Test Methods

F	Observe Failure Mode
FF	Normally closed check valves are given a forward flow test to verify that disc opens.
J	Category A containment isolation valve tested in accordance with 10CFR50 App. J.
LT	Leak Test
RF	Normally open check valves are given a reverse flow test to show that disc seats.
RV	Relief Valve (Test per IWV-3510)
S	Full Stroke
T	Measure Time
VI	Verify Remote Indication

Test Intervals

M	Monthly
Q	Quarterly
C	Cold Shutdown
R	Refueling
A	Annual
X	Frequency Determined from Table IWV-3510-1
J	Frequency Determined by 10CFR50 App. J.

Misc. Symbols

NA	Not Applicable
NR	Not Required

TABLE 2
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2
PUMP TEST PROGRAM

Pump Name & Drawing Number	Pump No.	Test Parameter Measured							Relief Request
		Speed n	Inlet Pressure P_i	Differential Pressure ΔP	Flow Rate Q	Vibration Amplitude V	Lubricant Level or Pressure	Bearing Temperature T_b	
Auxiliary Feedwater G-190197	AFW-A*	NR	Q	Q	NR	Q	Q	NR	1,2,4
	AFW-B*	NR	Q	Q	NR	Q	Q	NR	1,2,4
	AFW-SD	Q	Q	Q	NR	Q	Q	NR	1,2,4
Safety Injection 5379-1082	SI-A*	NR	Q	Q	NR	Q	Q	NR	1,2,4
	SI-B*	NR	Q	Q	NR	Q	Q	NR	1,2,4
	SI-C*	NR	Q	Q	NR	Q	Q	NR	1,2,4
Residual Heat Removal 5379-1484	RHR-A*	NR	Q	Q	NR	Q	Q	NR	1,2,4
	RHR-B*	NR	Q	Q	NR	Q	Q	NR	1,2,4
Containment Spray 5379-1082	CS-A*	NR	Q	Q	NR	Q	Q	NR	1,2,4
	CS-B*	NR	Q	Q	NR	Q	Q	NR	1,2,4
Service Water G-190199 Sh. 1	SW-A*	NR	Q	R	NR	Q	Q	NR	1,2,3
	SW-B*	NR	Q	R	NR	Q	Q	NR	1,2,3
	SW-C*	NR	Q	R	NR	Q	Q	NR	1,2,3
	SW-D*	NR	Q	R	NR	Q	Q	NR	1,2,3
Component Cooling 5379-376 Sh. 1	CCW-B*	NR	Q	Q	NR	Q	Q	NR	1,2,4
	CCW-C*	NR	Q	Q	NR	Q	Q	NR	1,2,4
Service Water Booster G-190199 Sh. 2	SWBP-A*	NR	Q	Q	Q	Q	Q	NR	1,2
	SWBP-B*	NR	Q	Q	Q	Q	Q	NR	1,2

*Synchronous or induction motors do not require speed check (IWP-4400).

TABLE 2
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2
PUMP TEST PROGRAM

Pump Name & Drawing Number	Pump No.	Test Parameter Measured							Relief Request
		Speed n	Inlet Pressure P_i	Differential Pressure ΔP	Flow Rate Q	Vibration Amplitude V	Lubricant Level or Pressure	Bearing Temperature T_b	
Charging 5379-685 Sh. 2	CVC-B	Q	Q	Q	Q	Q	Q	NR	1,2
	CVC-C	Q	Q	Q	Q	Q	Q	NR	1,2
Boric Acid Transfer 5379-685 Sh. 3	A*	NR	Q	Q	NR	Q	Q	NR	1,2,4
	B*	NR	Q	Q	NR	Q	Q	NR	1,2,4

*Synchronous or induction motors do not require speed check (IWP-4400).

TABLE 2

H. B. ROBINSON UNIT 2
SPECIFIC REQUESTS FOR RELIEF

This section provides justification for the specific relief requested from Code test requirements as provided for in 10CFR50.55a(g)(5)(iii). Each request is identified by a unique number and identifies the pump(s) for which the request is being made. The specific Code test requirement found to be impractical is defined and the basis for exclusion from Code requirements is presented. Any testing performed in lieu of Code requirements is specified.

1. Specific Relief Request:

Monthly In service Test

Applicable To:

All pumps

Basis for Relief Request:

Monthly Section XI operability testing has been a plant requirement for most of these pumps since operation began. An analysis of the results of these tests and comparable data from other operating plants has shown no significant changes in performance. Based on this analysis, the continuation of Section XI monthly testing would not significantly increase plant safety.

Monthly pump testing requires a total of at least 250 hours per year of pump operation, at least 575 man-hours per year, for data acquisition, and at least 50 man-hours per year for data reduction, analysis, and record keeping. This amounts to a total of 525 man-hours per year. At a conservative total cost of $20 per man-hour, this amounts to $12,500 per year. Based upon the average exposure rates in the pump access areas, the total man-rem exposure per year for pump testing is approximately 1.0 man-rem. At the present conservatively estimated cost of $10,000 per man-rem to plant personnel, this exposure costs an additional $10,000 per year. Total cost to our customers is approximately $25,200 per year, for no significant increase in safety.

Alternate Testing:

Pumps will be tested in compliance with ASME Section XI and this program once per quarter. This is in agreement with changes that were implemented in Subsection IWP of the Code in the Winter, 1979, addenda.

TABLE 2

H. B. ROBINSON UNIT 2
SPECIFIC REQUESTS FOR RELIEF

2. Specific Relief Request:

Measuring pump bearing temperature annually.

Applicable to:

All pumps.

Basis for Relief Request:

The referenced Edition of the Code requires bearing temperature to be recorded annually. It has been demonstrated by experience that bearing temperature rise occurs only minutes prior to bearing failure. Therefore, the detection of possible bearing failure by a yearly temperature measurement is extremely unlikely. It requires at least an hour of pump operation to achieve stable bearing temperatures. The small probability of detection of bearing failure by temperature measurement does not justify the additional pump operating time required to obtain the measurements.

Alternate Testing:

NONE. This is in agreement with present changes that are being implemented in Subsection IWP of the Code to delete yearly bearing temperature measurement. Deletion of bearing temperature has been approved and will be included in future Addenda. See minutes of the November 28, 1979, meeting of the Operating and Maintenance Working Group - Testing of Pumps and Valves in San Jose, California, dated January 9, 1980.

3. Specific Relief Request:

A. Flow rate measurements as required by IWP-3000.

B. Differential pressure measurements as required by IWP-3000.

Applicable To:

Service Water Pumps

Basis for Relief Request:

The service water pumps are used for removing heat from certain secondary system components during normal operation. Since heat load varies and inlet temperatures vary, automatic temperature control valves will vary the flow rates through the individual components, thus varying pump resistance. The system has no installed flow measuring devices capable of measuring flow from the pumps. The piping is concrete lined which prohibits the use of ultrasonic flow measuring techniques. There is insufficient room on the outlet piping of each individual pump to allow installation of any accurate flow devices.

H. B. Robinson currently verifies service water system operation during refueling by conducting a "dead head" (zero flow) test on each pump. This test provides a point for comparison to determine the condition of the pumps since the previous tests. These tests will be used as an alternative to the monthly Section XI test. If a pump is declared inoperable and maintenance is required on that pump, the pump will be tested in the manner in which the refueling tests are performed. Vibration and normal pump parameters will be checked on a quarterly basis as per the ISI Program requirements.

Alternate Testing:

Verification of system operation during refueling by conducting "dead head" (zero flow) test on each pump.

4. Specific Relief Request:

Measure Flow Rate.

Applicable To:

Auxiliary Feedwater A, B, and SD, Safety Injection A, B, and C, Residual Heat Removal A and B, Containment Spray A and B, Component Cooling A and B, and Boric Acid Transfer A and B.

Basis for Relief Request:

Instrumentation is not installed to measure flow rate for testing.

For the first ISI interval, these pumps (except Boric Acid Transfer A and B) were tested in a fixed resistance configuration so that any change in performance would be indicated by a change in differential pressure. This method of testing has proven satisfactory and will be continued.

Alternate Testing:

NONE.

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name Sampling System P&ID No. ISI-200-5379-353 Page 1 of 2

Valve Number	Class	Drawing Coordinates	Valve Category A	B	C	D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
956A	2	B-5	X					3/8	GL	AO	CL	Y	S	Q			
													F	Q			
													T	Q		60	
													VI	Q			
													J	J	1		
956B	2	B-6	X					3/8	GL	AO	CL	Y	S	Q			
													F	Q			
													T	Q		60	
													VI	Q			
													J	J	1		
956C	2	C-5	X					3/8	GL	AO	CL	Y	S	Q			
													F	Q			
													T	Q		60	
													VI	Q			
													J	J	1		
956D	2	C-6	X					3/8	GL	AO	CL	Y	S	Q			
													F	Q			
													T	Q		60	
													VI	Q			
													J	J	1		
956E	2	E-5	X					3/8	GL	AO	CL	Y	S	Q			
													F	Q			
													T	Q		60	
													VI	Q			
													J	J	1		

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name Sampling System P&ID No. ISI-200-5379-353

Valve Number	Class	Drawing Coordinates	Valve Category A	Valve Category B	Valve Category C	Valve Category D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
956F	2	E-6	X					3/8	GL	AO	CL	Y	S F T VI J	Q Q Q Q J	 1	 60	
956G	2	G-5	X					3/8	GL	AO	CL	Y	S F T VI J	Q Q Q Q J	 1	 60	
956H	2	G-6	X					3/8	GL	AO	CL	Y	S F T VI J	Q Q Q Q J	 1	 60	
959	2	J-4		X				3/8	GL	AO	CL	N	S F T VI	Q Q Q Q		 60	

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name Auxiliary Coolant Sys. Component Cooling   P&ID No. ISI-200-5379-376, Sh. 1 of 3   Page 1 of 1

Valve Number	Class	Drawing Coordinates	Valve Category A	B	C	D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
702A	3	H-5			X			16	CK	SA	O/C	N	FF RF	Q Q			
702B	3	K-5			X			16	CK	SA	O/C	N	FF RF	Q Q			
702C	3	M-5			X			16	CK	SA	O/C	N	FF RF	Q Q			
707	3	B-4			X			3x4	RV	SA	CL	N	RV	X			

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name Auxiliary Coolant Sys. Component Cooling P&ID No. ISI-200-5379-376, Sh. 2 of 3

Valve Number	Class	Drawing Coordinates	Valve Category A	B	C	D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
FCV-626	2	K-14	X					3	GA	MO	O	Y	S T VI J	C C C J	 1	 60	Cycling valve during normal operations would interrupt CCW flow to the Reactor Coolant Pump
715	2	N-12			X			3x4	RV	SA	CL	Y	RV	X			
716A	3	J-3		X				6	GA	MO	O	Y	S T VI	C C C		 60	Cycling valve during normal operation would interrupt CCW flow to RCP's
716B	2	J-3	X					6	GA	MO	O	Y	S T J VI	C C J C	 1	 60	Cycling valve during normal operation would interrupt CCW flow to RCP's
722A	3	M-8			X			3/4x1	RV	SA	CL	Y	RV	X			
722B	3	I-8			X			3/4x1	RV	SA	CL	Y	RV	X			
722C	3	K-8			X			3/4x1	RV	SA	CL	Y	RV	X			
729	2	H-13			X			3x4	RV	SA	CL	Y	RV	X			
730	2	I-14	X					6	GA	MO	O	Y	S T J VI	C C J C	 1	 60	Cycling valve during normal operation would interrupt CCW flow to RCP's

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name Auxiliary Coolant Sys. Component Cooling P&ID No. ISI-200-5379-376, Sh. 2 of 3

Valve Number	Class	Drawing Coordinates	Valve Category A	B	C	D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
735	3	J-16	X					3	GL	MO	O	Y	S T VI J	C C C J	 1	 120	Cycling valve during normal operations would interrupt CCW flow to Reactor Coolant Pumps
737A	2	N-3		X				3	GA	M	O	Y	S	Q			
739	2	M-14		X				3	GL	AO	CL	Y	S F T VI	Q Q Q Q		 60	
749A	3	D-3		X				16	GA	MO	CL	Y	S T VI	Q Q R			
749B	3	D-6		X				16	GA	MO	CL	Y	S T VI	Q Q R			
791A	3	B-15			X			3/4x1	RV	SA	CL	Y	R	X			
791B	3	D-15			X			3/4x1	RV	SA	CL	Y	R	X			

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name Auxiliary Coolant Sys. Component Cooling   P&ID No. ISI-200-5379-376, Sh. 3 of 3

Valve Number	Class	Drawing Coordinates	Valve Category A	Valve Category B	Valve Category C	Valve Category D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
791D	3	L-10			X			3/4x1	RV	SA	CL	Y	RV	X			
791E	3	I-10			X			3/4x1	RV	SA	CL	Y	RV	X			
791J	3	C-4			X			3/4x1	RV	SA	CL	Y	RV	X			
791K	3	E-5			X			3/4x1	RV	SA	CL	Y	RV	X			

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name CVCS

P&ID No. ISI-200-5379-685, Sh. 1 of 3

Valve Number	Class	Drawing Coordinates	Valve Category				Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
			A	B	C	D											
200A	2	B-9		X				2	GL	AO	C	Y	S F T VI	Q Q Q R		10	
200B	2	B-11		X				2	GL	AO	C	Y	S F T VI	Q Q Q R		10	
200C	2	B-10		X				2	GL	AO	O	Y	S F T VI	Q Q Q R		10	
202A	2	C-15	X					3	GA	M	O	N	S J	C J			Cycling valve during normal operation would interrupt charging flow
203	2	A-9			X			2x3	RV	SA	CL	Y	RV	X			

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name CVCS P&ID No. ISI-200-5379-685, Sh. 1 of 3

Valve Number	Class	Drawing Coordinates	Valve Category A	B	C	D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
204A	2	A-13	X					2	GL	AO	O	Y	S F T VI J	C C C C J	 1	 10	Cycling valve during normal operation would interrupt letdown flow to CVCS.
204B	2	A-13	X					2	GL	AO	O	Y	S F T VI J	C C C C J	 1	 60	Cycling valve during normal operation would interrupt letdown flow to CVCS.
282	2	D-14	X					2	GL	M	O	Y	S J	C J	 1		Cycling valve during normal operation would interrupt charging flow.
292A	2	N-14	X					3/4	GL	M	O	N	S J	C J	 1		Cycling valves during normal operations would interrupt seal water flow to Reactor Coolant Pumps. (applies to 292A through 297B)
293A	2	M-14	X					2	GL	M	o/c	N	S J	C J	 1		
293C	2	L-14	X					2	GL	M	o/c	N	S J	C J	 1		
295	2	N-15	X					3	GL	M	C	N	S J	C J	 1		
297A	2	M-1	X					2	ND	M	O	N	S J	C J	 1		
297B	2	A-19	X					2	ND	M	O	N	S J	C J	 1		

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name CVCS   P&ID No. ISI-200-5379-685, Sh. 1 of 3   Page 3 of 3

Valve Number	Class	Drawing Coordinates	Valve Category A	B	C	D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
297C	2	M-10	X					2	ND	M	O	N	S J	C J	 1		Cycling valve during normal operation would interrupt seal water flow to the Reactor Coolant Pumps.
309A	2	D-15	X				X	2	GL	M	CL	N	J	J	1		
313	1	E-2			X			2	CK	SA	C	Y	FF	C			Cycling valve requires opening valve CVC-311 which could cause reactor trip on low pressurizer pressure upon failure of CVC-311 in non-conservative position.
381	2	G-14	X					3	GA	MO	O	N	S T VI J	C C C J	 1	60	Cycling valve during normal operation would interrupt seal water flow to RCP's
382	2	F-13			X			3	RV	SA	CL	Y	RV	X			

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name CVCS   P&ID No. ISI-200-5379-685, Sh. 2 of 3

Valve Number	Class	Drawing Coordinates	Valve Category A	Valve Category B	Valve Category C	Valve Category D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
FCV-113A	3	J-13		X				1	GL	AO	C	Y	S F T VI	C C C C		300	Cycling valve during normal operation would cause injection of highly borated water into Reactor Coolant loop.
LCV-115B	2	K-9		X				4	BF	AO	CL	N	S F T VI	C C C C		300	Cycling valve during normal operation could result in over-boration of the primary system
LCV-115C	2	H-7		X				4	GA	MO	O	Y	S T VI	C C C		300	Cycling valve during normal operation would interrupt flow from Volume Control Tank to charging pumps.
209	2	B-7			X			2x3	RV	SA	CL	Y	RV	X			
257	2	C-8			X			2x3	RV	SA	CL	Y	RV	X			
266	2	I-7			X			4	CK	SA	O	Y	RF	C			Back flow testing during normal operation would interrupt flow from VCT to charging pumps.
283A	2	J-3			X			3/4x2	RV	SA	CL	Y	RV	X			
283B	2	K-3			X			3/4x2	RV	SA	CL	Y	RV	X			
283C	2	M-3			X			3/4x2	RV	SA	CL	Y	RV	X			

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name CVCS P&ID No. ISI-200-5379-685, Sh. 2 of 3

Valve Number	Class	Drawing Coordinates	Valve Category				Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
			A	B	C	D											
350	2	L-13		X				2	GA	MO	CL	Y	S T VI	C C C		 60	Cycling valve during normal operation would result in injection of highly borated water into Reactor Coolant loop.
351	2	L-13			X			2	CK	SA	CL	Y	FF	C			Cycling valve requires opening CVC-350 (see above).
355	3	J-13			X			1	CK	SA	CL	Y	FF	C			Cycling valve requires opening CVC-FCV-113A.
357	2	K-10			X			4	CK	SA	CL	Y	FF	C			Must be tested with LCV-115B

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name CVCS   P&ID No. ISI-200-5379-685, Sh. 3 of 3   Page 1 of 1

Valve Number	Class	Drawing Coordinates	Valve Category A	Valve Category B	Valve Category C	Valve Category D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
397A	3	L-7			X			2	CK	SA	CL	N	FF	Q			
397B	3	L-8			X			2	CK	SA	CL	N	FF	Q			

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name Waste Disposal P&ID No. ISI-406-5379-920, Sh. 1 of 4 Page 1 of 2

Valve Number	Class	Drawing Coordinates	Valve Category A	Valve Category B	Valve Category C	Valve Category D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
1721	2	J-10	X					3	DA	AO	O	Y	S F T VI J	Q Q Q Q J	 1	60	
1722	2	J-9	X					3	DA	AO	O	Y	S F T VI J	Q Q Q Q J	 1	60	
1723	2	L-9	X					2	DA	AO	O	Y	S F T VI J	Q Q Q Q J	 1	60	
1728	2	L-10	X					2	DA	AO	O	Y	S F T VI J	Q Q Q Q J	 1	60	
1786	2	F-11	X					1	DA	AO	O	Y	S F T VI J	Q Q Q Q J	 1	60	

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name Waste Disposal P&ID No. ISI-406-5379-920, Sh. 1 of 4

Valve Number	Class	Drawing Coordinates	Valve Category A	B	C	D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
1787	2	E-11	X					1	DA	AO	O	Y	S F T VI J	Q Q Q Q J	 1	 60	
1789	2	F-10	X					3/4	DA	AO	O	Y	S F T VI J	Q Q Q Q J	 1	 60	
1793	2	E-11		X				1	DA	M		Y	S	Q		NA	
1794	2	G-11	X					3/4	DA	AO	O	Y	S F T VI J	Q Q Q Q J	 1	 60	

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name Safety Injection P&ID No. ISI-200-5379-1082, Sh. 1

Valve Number	Class	Drawing Coordinates	Valve Category A	Valve Category B	Valve Category C	Valve Category D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
RV-842	2	H-1			X			1	RV	SA	CL	N	RV	X			
841A	2	D-9		X				1	GL	AO	O	N	S F T VI	Q Q Q Q		30	
841B	2	D-9		X				1	GL	AO	O	N	S F T VI	Q Q Q Q		30	
845A	3	J-7		X				2	GL	MO	C	N	S T VI	C C C		60	Cycling these valves during normal operation would require closing valve 845C. Closing 845C would negate the containment spray system's sodium hydroxide injection function.
845B	3	J-7		X				2	GL	MO	C	N	S T VI	C C C		60	
857A	2	D-1			X			3/4x1	RV	SA	CL	Y	RV	X			
864A	2	D-16		X				16	GA	MO	O	N	S T VI	C C C			Failures of valves in closed position would result in loss of SI, RHR and C.S, Systems
864B	2	D-16		X				16	GA	MO	O	N	S T VI	C C C			

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name Safety Injection P&ID No. ISI-200-5379-1082, Sh. 1

Valve Number	Class	Drawing Coordinates	Valve Category A	Valve Category B	Valve Category C	Valve Category D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
867A	2	F-7		X				4	GA	MO	CL	Y	S T VI	Q Q R		10	
867B	2	F-7		X				4	GA	MO	CL	Y	S T VI	Q Q R		10	
869	2	B-1	X					3	GA	MO	O	N	S T VI J	C C C J	1	60	Failure in closed position would result in loss offlow path to hot legs.
870A	2	G-1	X					3	GA	MO	CL	N	S T VI J	Q Q Q J	1	10	
870B	2	G-1	X					3	GA	MO	CL	N	S T VI J	Q Q Q J	1	10	
870C	3	H-5			X			3/4	VB	SA	CL	N	S	Q			
870D	3	H-5			X			3/4	VB	SA	CL	N	S	Q			
872	3	H-6			X			3/4x1	RV	SA	CL	N	RV	X			
878A	3	F-10		X				4	GA	MO	O	N	S T VI	C C C		120	

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name Safety Injection P&ID No. ISI-200-5379-1082, Sh. 1

Valve Number	Class	Drawing Coordinates	Valve Category A	Valve Category B	Valve Category C	Valve Category D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
878B	3	D-10		X				4	GA	MO	O	N	S	C			
													T	C		120	
													VI	C			
879A	3	H-11			X			3	CK	SA	CL	N	FF	Q			
879B	2	E-11			X			3	CK	SA	CL	N	FF	Q			
879C	2	C-11			X			3	CK	SA	CL	N	FF	Q			
880A	2	M-9		X				6	GA	MO	CL	N	S	Q			
													T	Q		60	
													VI	Q			
880B	2	N-9		X				6	GA	MO	CL	N	S	Q			
													T	Q		60	
													VI	Q			
880C	2	K-9		X				6	GA	MO	CL	N	S	Q			
													T	Q		60	
													VI	Q			
880D	2	K-9		X				6	GA	MO	CL	N	S	Q			
													T	Q		60	
													VI	Q			
883L	2	H-2	X				X	1	GL	M	LC	N	J	J	1		
883W	2	G-3	X				X	1	GL	M	LC	N	J	J	1		

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name Safety Injection P&ID No. ISI-200-5379-1082, Sh. 1

Valve Number	Class	Drawing Coordinates	Valve Category A	Valve Category B	Valve Category C	Valve Category D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
889A	2	L-13			X			2	CK	SA	CL	N	FF	Q			
889B	2	L-13			X			2	CK	SA	CL	N	FF	Q			
890A	2	M-8			X			6	CK	SA	CL	N	FF	C			Testing valves during normal operation would require injecting borated water and sodium hydroxide into the containment.
890B	2	K-8			X			6	CK	SA	CL	N	FF	C			
891A	2	N-5	X					6	GA	M	O	N	S J	C J	 1		The safety positions of these valves are open which is their normal position. The only reason they would be closed is to perform the IST, therefore compromising the integrity of the system does not appear to be justified in testing the valves quarterly
891B	2	K-5	X					6	GA	M	O	N	S J	C J	 1		
894	3	F-5			X			1	CK	SA	CL	Y	FF	Q			
895V	2	A-2	X				X	3/4	GL	M	LC	N	J	J	1		
898F	2	A-2	X				X	3/4	GL	M	LC	N	J	J	1		

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name Safety Injection P&ID No. ISI-200-5379-1082, Sh. 2

Valve Number	Class	Drawing Coordinates	Valve Category				Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
			A	B	C	D											
849	2	C-2			X			3/4	CK	SA	CL	Y	FF	C			Cycling during normal operation would require opening valve 895V and 898L which are required by Tech. Spec. to be closed.
858A	2	B-11			X			2x3	RV	SA	CL	Y	RV	X			
858B	2	E-11			X			2x3	RV	SA	CL	Y	RV	X			
858C	2	H-11			X			2x3	RV	SA	CL	Y	RV	X			
859	2	C-1			X			3/4	RV	SA	CL	N	RV	X			
860A	2	N-8		X				14	GA	MO	CL	Y	S	Q			
													T	Q		120	
													VI	Q			
860B	2	N-8		X				14	GA	MO	CL	Y	S	Q			
													T	Q		120	
													VI	Q			
861A	2	N-9		X				14	GA	MO	CL	Y	S	Q			
													T	Q		120	
													VI	Q			
861B	2	N-9		X				14	GA	MO	CL	Y	S	Q			
													T	Q		120	
													VI	Q			

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name Safety Injection P&ID No. ISI-200-5379-1082, Sh. 2

Valve Number	Class	Drawing Coordinates	Valve Category A	Valve Category B	Valve Category C	Valve Category D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
865A	2	D-9		X				10	GA	MO	O	Y	S	C			Valves are for accumulator discharge isolation. Tech. Spec. requires valves to be open with electrical breakers pulled when reactor pressure is above 1000 psig.
													T	C		120	
													VI	C			
865B	2	G-9		X				10	GA	MO	O	Y	S	C			
													T	C		120	
													VI	C			
865C	2	J-9		X				10	GA	MO	O	Y	S	C			
													T	C		120	
													VI	C			
866A	1	G-1		X				2	GA	MO	CL	Y	S	C			Valves are for high-head safety injection to hot leg isolation. Valves are required by Tech. Spec. to be closed with electrical breakers pulled when reactor is above 1000 psig.
													T	C		60	
													VI	C			
866B	1	G-2		X				2	GA	MO	CL	Y	S	C			
													T	C		60	
													VI	C			
873A	2	H-2			X			2	CK	SA	CL	Y	FF	R			These valves are in safety injection high-head flow path to RCS cold leg. Valves are kept closed during normal operation by Reactor Coolant pressure. Verifying opening of these valves would require injection of highly concentrate(Cont'd on page 3 of 3)
873B	2	G-2			X			2	CK	SA	CL	Y	FF	R			
873C	2	G-3			X			2	CK	SA	CL	Y	FF	R			
873D	2	L-2			X			2	CK	SA	CL	Y	FF	R			

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name Safety Injection   P&ID No. ISI-200-5379-1082, Sh. 2

Valve Number	Class	Drawing Coordinates	Valve Category A	B	C	D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
873E	2	K-3			X			2	CK	SA	CL	Y	FF	R			(Cont'd from page 2 of 3) boric acid into the RCS. Testing during cold shutdown is also not practical for the same reason and because the RCS must be vented in order to perform the test.
873F	2	I-4			X			2	CK	SA	CL	Y	FF	R			
874A	1	H-1			X			2	CK	SA	CL	Y	FF	C			Valves are in series with 866A & B.
874B	1	H-2			X			2	CK	SA	CL	Y	FF	C			
875A	1	J-3			X			10	CK	SA	CL	Y	FF	C			Valves are in Safety Injection cold leg flow path. Valves are kept closed during normal operation by Reactor Coolant pressure.
875B	1	K-3			X			10	CK	SA	CL	Y	FF	C			
875C	1	M-2			X			10	CK	SA	CL	Y	FF	C			
875D	1	D-7			X			10	CK	SA	CL	Y	FF	C			
875E	1	G-7			X			10	CK	SA	CL	Y	FF	C			
875F	1	J-7			X			10	CK	SA	CL	Y	FF	C			
876A	1	D-6			X			8	CK	SA	CL	Y	FF	C			
876B	1	G-6			X			8	CK	SA	CL	Y	FF	C			
876C	1	J-6			X			8	CK	SA	CL	Y	FF	C			

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name Residual Heat Removal P&ID No. ISI-200-5379-1484

Valve Number	Class	Drawing Coordinates	Valve Category				Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
			A	B	C	D											
706	2	L-1			X			2x3	RV	SA	CL	Y	RV	X			
744A	2	M-1		X				10	GA	MO	CL	Y	S T VI	Q Q Q		 15	
744B	2	M-3		X				10	GA	MO	CL	Y	S T VI	Q Q Q		 15	
750	1	N-16		X				14	GA	MO	CL	Y	S T VI	C C C		 300	Valves interlocked with SI-862A & B such that they cannot be opened unless the SI valves are closed. 862A & B must be open during normal operation or RHR suction is lost.
751	1	M-16		X				14	GA	MO	CL	Y	S T VI	C C C		 300	
753A	2	G-10			X			10	CK	SA	CL	Y	FF	Q			
753B	2	G-10			X			10	CK	SA	CL	Y	FF	Q			
759A	2	G-5		X				10	GA	MO	O	Y	S T VI	Q Q R		 120	
759B	2	D-5		X				10	GA	MO		Y	S T VI	Q Q R		 120	

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name Reactor Coolant P&ID No. ISI-100-5379-1971, Sh. 2

Valve Number	Class	Drawing Coordinates	Valve Category A	B	C	D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
DWC-1	2	F-18	X				X		GA	M	CL	Y	LT	R			
DWC-2	2	F-19	X				X		GA	M	CL	Y	LT	R			
PCV-455C	1	E-17		X				3	GL	AO	CL	Y	S F T VI	Q Q Q R			
PCV-456	1	D-17		X				3	GL	AO	CL	Y	S F T VI	Q Q Q R			
PCV-473	2	E-1		X				3/4	GL	AO	O	Y	S F T	C C C		 120	Failure in open position could result in overpressurization of relief tank. Test at cold shutdown with tank vented.
516	2	C-1	X					3/8	GL	AO	CL	Y	S F T VI J	Q Q Q Q J	 1	 60	
519A	2	F-1	X					3	DA	AO	CL	Y	S F T VI J	Q Q Q Q J	 1	 60	

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name Reactor Coolant P&ID No. ISI-100-5379-1971, Sh. 2

Valve Number	Class	Drawing Coordinates	Valve Category A	Valve Category B	Valve Category C	Valve Category D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
519B	2	F-2	X					3	DA	AO	CL	Y	S	Q			
													F	Q			
													T	Q		60	
													VI	Q			
													J	J	1		
535	1	D-17		X				3	GA	MO	O	Y	S	Q			
													T	Q			
													VI	R			
536	1	E-17		X				3	GA	MO	O	Y	S	Q			
													T	Q			
													VI	R			
550	2	E-2		X				3/4	DA	AO	O	Y	S	C			
													F	C			
													T	C			
551A	1	B-11			X			4x6	RV	SA	CL	Y	RV	X			
551B	1	B-13			X			4x6	RV	SA	CL	Y	RV	X			
551C	1	B-15			X			4x6	RV	SA	CL	Y	RV	X			
553	2	C-2	X					3/8	GL	AO	C	Y	S	Q			
													F	Q			
													T	Q		60	
													VI	Q			
													J	J	1		

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name Main Extraction & Auxiliary Steam P&ID No. ISI-G-190196, Sh. 1

Valve Number	Class	Drawing Coordinates	Valve Category A	B	C	D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
MS-V1-3A	2	J-16			X			26	CK	SA	O	N			2		
MS-V1-3B	2	E-16			X			26	CK	SA	O	N			2		
MS-V1-3C	2	A-16			X			26	CK	SA	O	N			2		
MS-V1-3A Isol.	2	J-15		X				26	GA	AO	O	N	S F T VI	C C C C		5	
MS-V1-3B Isol.	2	E-15		X				26	GA	AO	O	N	S F T VI	C C C C		5	
MS-V1-3C Isol.	2	A-15		X				26	GA	AO	O	N	S F T VI	C C C C		5	
MS-V1-8A	2	K-15		X				2	GL	MO	C	N	S T VI	Q Q Q		120	
MS-V1-8B	2	G-15		X				2	GL	MO	C	N	S T VI	Q Q Q		120	

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name Main Extraction & Auxiliary Steam P&ID No. ISI-G-190196, Sh. 1

Valve Number	Class	Drawing Coordinates	Valve Category A	Valve Category B	Valve Category C	Valve Category D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
MS-V1-8C	2	C-15		X				2	GL	MO	C	N	S T VI	Q Q Q		 120	
MS-V1-9A	3	K-15			X			2	CK	SA	CL	N	FF	Q			
MS-V1-9B	3	G-16			X			2	CK	SA	CL	N	FF	Q			
MS-V1-9C	3	C-16			X			2	CK	SA	CL	N	FF	Q			
SV1-1A	2	J-10			X			6	RV	SA	C	N	RV	X			
SV1-2A	2	J-11			X			6	RV	SA	C	N	RV	X			
SV1-3A	2	J-12			X			6	RV	SA	C	N	RV	X			
SV1-4A	2	J-13			X			6	RV	SA	C	N	RV	X			
SV1-1B	2	F-10			X			6	RV	SA	C	N	RV	X			
SV1-2B	2	F-11			X			6	RV	SA	C	N	RV	X			
SV1-3B	2	F-12			X			6	RV	SA	C	N	RV	X			
SV1-4B	2	F-13			X			6	RV	SA	C	N	RV	X			
SV1-1C	2	B-10			X			6	RV	SA	C	N	RV	X			
SV1-2C	2	B-11			X			6	RV	SA	C	N	RV	X			

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name Main Extraction & Auxiliary Steam P&ID No. ISI-G-190196, Sh. 1

Valve Number	Class	Drawing Coordinates	Valve Category A	Valve Category B	Valve Category C	Valve Category D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
SV1-3C	2	B-12			X			6	RV	SA	C	N	RV	X			
SV1-4C	2	B-13			X			6	RV	SA	C	N	RV	X			

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name Feedwater Condensate & Air Evacuation P&ID No. ISI-G-190197, Sh. 2

Valve Number	Class	Drawing Coordinates	Valve Category A	Valve Category B	Valve Category C	Valve Category D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
AFW-2	3	I-17			X			6	CK	SA	CL	N	FF	Q			Verified open during testing of Motor driven aux. feed pump.
AFW-19	3	H-11			X			6	CK	SA	CL	N	FF	Q			
AFW-20A	3	L-8		X				4	GA	MO	O	N	S T VI	Q Q Q		60	
AFW-20B	3	M-8		X				4	GA	MO	O	N	S T VI	Q Q Q		60	
AFW-24	3	L-14		X				6	GA	M	LC	N	S	Q		NA	
AFW-40	3	L-10			X			4	CK	SA	CL	N	FF	Q			
AFW-41	3	N-10			X			4	CK	SA	CL	N	FF	Q			
AFW-68	2	M-5			X			4	CK	SA	CL	Y	FF	C			Normal feedwater pressure on back side of valves prevents cycling during normal operation.
AFW-69	2	L-5			X			4	CK	SA	CL	Y	FF	C			
AFW-70	2	N-5			X			4	CK	SA	CL	Y	FF	C			
AFW-V2-14A	2	C-10		X				4	GA	MO	CL	Y	S T VI	Q Q Q		60	
AFW-V2-14B	2	E-10		X				4	GA	MO	CL	Y	S T VI	Q Q Q		60	

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name Feedwater Condensate & Air Evacuation P&ID No. ISI-G-190197, Sh. 2

Valve Number	Class	Drawing Coordinates	Valve Category A	Valve Category B	Valve Category C	Valve Category D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
AFW-V2-14C	2	G-10		X				4	GA	MO	CL	Y	S T VI	Q Q Q		60	
AFW-V2-16A	2	M-7		X				4	GA	MO	CL	N	S T VI	Q Q Q		60	
AFW-V2-16B	2	L-7		X				4	GA	MO	CL	N	S T VI	Q Q Q		60	
AFW-V2-16C	2	N-7		X				4	GA	MO	CL	N	S T VI	Q Q Q		60	
DW-19	3	K-17		X				6	GA	M	LC	N	S	Q		NA	
DW-21	3	K-16		X				6	GA	M	LC	N	S	Q		NA	
FCV-479	2	B-11		X				4	GL	AO	CL	Y	S F T VI	C C C C		60	Cycling during normal operations could result in steam flow/feed flow mismatch and plant trip.
FCV-489	2	D-11		X				4	GA	AO	CL	Y	S F T VI	C C C C		60	Cycling during normal operations could result in steam flow/feed flow mismatch and plant trip.

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name Feedwater Condensate & Air Evacuation P&ID No. ISI-G-190197, Sh. 2

Valve Number	Class	Drawing Coordinates	Valve Category A	Valve Category B	Valve Category C	Valve Category D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
FCV-499	2	F-11		X				4	GL	AO	CL	Y	S F T VI	C C C C		60	Cycling during normal operation could result in steam flow/ feed flow mismatch and plant trip
FW-V2-6A	2	B-12		X				16	GA	MO	O	N	S T VI	C C C		120	
FW-V2-6B	2	D-12		X				16	GA	MO	O	N	S T VI	C C C		120	Cycling during normal operations could result in steam flow/ feed flow mismatch and plant trip.
FW-V2-6C	2	F-12		X				16	GA	MO	O	N	S T VI	C C C		120	

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name Service and Cooling Water P&ID No. ISI-G-190199, Sh. 1 Page 1 of 1

Valve Number	Class	Drawing Coordinates	Valve Category A	Valve Category B	Valve Category C	Valve Category D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
374	3	K-2			X			18	CK	SA	O/C	N	FF RF	Q Q			
375	3	K-5			X			18	CK	SA	O/C	N	FF RF	Q Q			
376	3	K-3			X			18	CK	SA	O/C	N	FF RF	Q Q			
377	3	K-6			X			18	CK	SA	O/C	N	FF RF	Q Q			

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name Service and Cooling Water P&ID No. ISI-G-190199, Sh. 2

Valve Number	Class	Drawing Coordinates	Valve Category A	B	C	D	Passive	Size (Inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
V6-33A	2	H-8		X				6	BF	MO	O	N	S T VI	Q Q Q		300	
V6-33B	2	H-7		X				6	BF	MO	O	N	S T VI	Q Q Q		300	
V6-33C	2	H-7		X				6	BF	MO	O	N	S T VI	Q Q Q		300	
V6-33D	2	H-6		X				6	BF	MO	O	N	S T VI	Q Q Q		300	
V6-33E	2	H-8		X				6	BF	MO	O	N	S T VI	Q Q Q		300	
V6-33F	2	J-7		X				6	BF	MO	O	N	S T VI	Q Q Q		300	
V6-34A	2	D-16		X				6	BF	MO	O	N	S T VI	Q Q Q		300	

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name Service and Cooling Water   P&ID No. ISI-G-190199, Sh. 2

Valve Number	Class	Drawing Coordinates	Valve Category A	Valve Category B	Valve Category C	Valve Category D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
V6-34B	2	C-16		X				6	BF	MO	O	N	S T VI	Q Q Q		300	
V6-34C	2	C-16		X				6	BF	MO	O	N	S T VI	Q Q Q		300	
V6-34D	2	B-16		X				6	BF	MO	O	N	S T VI	Q Q Q		300	
V6-35A	2	B-12		X				1	GL	MO	O	N	S T VI	Q Q Q		300	
V6-35B	2	B-11		X				1	GL	MO	O	N	S T VI	Q Q Q		300	
V6-35C	2	B-11		X				1	GL	MO	O	N	S T VI	Q Q Q		300	
V6-35D	2	B-10		X				1	GL	MO	O	N	S T VI	Q Q Q		300	

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name Service and Cooling Water   P&ID No. ISI-G-190199, Sh. 2

Valve Number	Class	Drawing Coordinates	Valve Category A	B	C	D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
560	3	J-7			X			12	CK	SA	O/C	N	FF	Q			
561	3	J-8			X			12	CK	SA	O/C	N	FF	Q			
580	3	M-12		X				1	GT	SO	O	N	S	Q			
581	3	I-12		X				1	GT	SO	O	N	S	Q			

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name Service and Cooling Water P&ID No. ISI-G-190199, Sh. 3 Page 1 of 1

Valve Number	Class	Drawing Coordinates	Valve Category A	B	C	D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
V6-16A	3	N-20		X				16	GA	MO	O	N	S	Q			
													T	Q		300	
V6-16B	3	M-20		X				16	GA	MO	O	N	S	Q			
													T	Q		300	
118	3	M-20		X				6	GA	M	LC	N	S	Q		NA	
530	3	L-25			X			1	CK	SA	CL	N	FF	Q			
541	3	I-19			X			30	CK	SA	O/C	N	FF	Q			
542	3	M-19			X			1	CK	SA	CL	N	FF	Q			
543	3	M-19			X			1	CK	SA	CL	N	FF	Q			
544	3	M-20			X			6	CK	SA	CL	N	FF	Q			
545	3	M-20			X			30	CK	SA	O/C	N	FF	Q			

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name Steam Generator Blowdown P&ID No. ISI-G-190234

Valve Number	Class	Drawing Coordinates	Valve Category A	B	C	D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
FCV-1930A	2	B-5		X				3/4	GA	AO	O	N	S	Q			
													F	Q			
													T	Q		10	
													VI	Q			
FCV-1930B	2	B-5		X				3/4	GA	AO	O	N	S	Q			
													F	Q			
													T	Q		10	
													VI	Q			
FCV-1931A	2	F-5		X				3/4	GA	AO	O	N	S	Q			
													F	Q			
													T	Q		10	
													VI	Q			
FCV-1931B	2	F-5		X				3/4	GA	AO	O	N	S	Q			
													F	Q			
													T	Q		10	
													VI	Q			
FCV-1932A	2	K-5		X				3/4	GA	AO	O	N	S	Q			
													F	Q			
													T	Q		10	
													VI	Q			
FCV-1932B	2	K-5		X				3/4	GA	AO	O	N	S	Q			
													F	Q			
													T	Q		10	
													VI	Q			

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name Steam Generator Blowdown P&ID No. ISI-G-190234

Valve Number	Class	Drawing Coordinates	Valve Category A	B	C	D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
FCV-1933A	2	C-4		X				3/4	GA	AO	O	N	S F T VI	Q Q Q Q		10	
FCV-1933B	2	D-4		X				3/4	GA	AO	O	N	S F T VI	Q Q Q Q		10	
FCV-1934A	2	G-4		X				3/4	GA	AO	O	N	S F T VI	Q Q Q Q		10	
FCV-1934B	2	H-4		X				3/4	GA	AO	O	N	S F T VI	Q Q Q Q		10	
FCV-1935A	2	K-4		X				3/4	GA	AO	O	N	S F T VI	Q Q Q Q		10	
FCV-1935B	2	L-4		X				3/4	GA	AO	O	N	S F T VI	Q Q Q Q		10	

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name Penetration Pressurization (PPS)   P&ID No. ISI-G-190261, Sh. 7 of 8   Page 1 of 2

Valve Number	Class	Drawing Coordinates	Valve Category A	B	C	D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
EV-H2A	2	E-2	X					1	3W	SO	-	N	S F VI J	Q Q Q J	 1		
EV-H2B	2	E-5	X					3/8	3W	SO	-	N	S F VI J	Q Q Q J	 1		
EV-1722	2	E-9	X					1	3W	SO	-	N	S F VI J	Q Q Q J	 1		
EV-1727	2	D-5	X					3/8	3W	SO	-	N	S F VI J	Q Q Q J	 1		
EV-1728	2	A-5	X					3/8	3W	SO	-	N	S F VI J	Q Q Q J	 1		
225C	2	A-5	X					3/8	GA	M	CL	N	J	J	1		
226C	2	C-5	X				X	3/8	GA	M	CL	N	J	J	1		

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name PPS

P&ID No. ISI-G-190261, Sh. 7 of 8

Valve Number	Class	Drawing Coordinates	Valve Category A	B	C	D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
235C	2	E-5	X				X	3/8	GA	M	CL	N	J	J	1		
245A	2	E-9	X				X	3/8	GA	M	CL	N	J	J	1		
251C	2	E-2	X				X	3/8	GA	M	CL	N	J	J	1		

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name Penetration Pressurization (PPS) P&ID No. ISI-G-190261, Sh. 8 of 8

Valve Number	Class	Drawing Coordinates	Valve Category A	Valve Category B	Valve Category C	Valve Category D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
EV-1723	2	A-12	X					1	3W	SO	-	N	S F VI J	Q Q Q J	 1		
EV-1724	2	A-16	X					1	3W	SO	-	N	S F VI J	Q Q Q J	 1		
241C	2	A-16	X				X	3/8	GA	M	CL	M	J	J	1		
248A	2	A-12	X				X	3/8	GA	M	CL	N	J	J	1		
274C	2	G-12	X		X			3/8	CK	SA	-	N	J	J	1		

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name Isolation Valve Seal Water P&ID No. ISI-G-190262

Valve Number	Class	Drawing Coordinates	Valve Category				Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
			A	B	C	D											
Check valves at class boundaries	2		X						CK	SA	O/CL	Y	J	J			

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name HVAC P&ID No. ISI-G-190304, Sh. 1 of 2

Valve Number	Class	Drawing Coordinates	Valve Category A	Valve Category B	Valve Category C	Valve Category D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
RMS-1	2	I-19	X					1	GA	AO	O	N	S F T VI J	Q Q Q Q J	 1	60	
RMS-2	2	I-19	X					1	GA	AO	O	N	S F T VI J	Q Q Q Q J	 1	60	
RMS-3	2	I-19	X					1	GA	AO	O	N	S F T VI J	Q Q Q Q J	 1	60	
RMS-4	2	I-19	X					1	GA	AO	O	N	S F T VI J	Q Q Q Q J	 1	60	
V12-6	2	F-10	X					42	BF	AO	O	N	S F T VI J	Q Q Q Q J	 1	60	

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name HVAC P&ID No. ISI-G-190304, Sh. 1 of 2

Valve Number	Class	Drawing Coordinates	Valve Category				Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
			A	B	C	D											
V12-7	2	F-11	X					42	BF	AO	O	N	S	Q			
													F	Q			
													T	Q		60	
													VI	Q			
													J	J	1		
V12-8	2	G-18	X					42	BF	AO	O	N	S	Q			
													F	Q			
													T	Q		60	
													VI	Q			
													J	J	1		
V12-9	2	G-17	X					42	BF	AO	O	N	S	Q			
													F	Q			
													T	Q		60	
													VI	Q			
													J	J	1		
V12-10	2	H-18	X					6	BF	AO	C	Y	S	Q			
													F	Q			
													T	Q		60	
													VI	Q			
													J	J	1		
V12-11	2	H-17	X					6	BF	AO	C	Y	S	Q			
													F	Q			
													T	Q		60	
													VI	Q			
													J	J	1		

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name HVAC

P&ID No. ISI-G-190304, Sh. 1 of 2

Valve Number	Class	Drawing Coordinates	Valve Category A	Valve Category B	Valve Category C	Valve Category D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
V12-12	2	G-10	X					6	BF	AO	O	N	S F T VI J	Q Q Q Q J	 1	 60	
V12-13	2	G-11	X					6	BF	AO	O	N	S F T VI J	Q Q Q Q J	 1	 60	

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name Post Accident Sampling   P&ID No. ISI-HBR2-6490   Page 1 of 1

Valve Number	Class	Drawing Coordinates	Valve Category A	Valve Category B	Valve Category C	Valve Category D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
PAS-1	2	C-5	X				X		GL	M	CL	N	LT	R			
PAS-2	2	D-5	X				X		GL	M	CL	N	LT	R			
PAS-3	2	C-5	X				X		GL	M	CL	N	LT	R			
PAS-4	2	D-5	X				X		GL	M	CL	N	LT	R			
PAS-5	2	D-5	X				X		GL	M	CL	N	LT	R			
PAS-6	2	D-5	X				X		GL	M	CL	N	LT	R			

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name Post Accident Cont. Vent & Ins. Gas P&ID No. ISI-HBR2-6933

Valve Number	Class	Drawing Coordinates	Valve Category A	Valve Category B	Valve Category C	Valve Category D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
PCV-1716	2	G-4		X				2	GA	AO	O	N	F VI	C C			Cycling would result in loss of instrument air. Valve can only be tested by failing air supply. Operability is further verified during SI Tests during refueling outages.
SA-43	2	G-4	X				X	2	DA	M	LC	N	J	J	1		
SA-44	2	G-3	X				X	2	DA	M	LC	N	J	J	1		
V8-5	2	G-3			X			2	CK	SA	O/C	N	RF	Q			
V12-14	2	B-1	X					3	DA	AO	C	N	S F T VI J	C C C C J	 1	 60	No testing during normal operations due to potential violation of containment integrity.
V12-15	2	B-3	X					3	DA	AO	C	N	S F T VI J	C C C C J	 1	 60	

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name Post Accident Cont. Vent & Ins. Gas P&ID No. ISI-HBR2-6933

Valve Number	Class	Drawing Coordinates	Valve Category A	B	C	D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
12-18	2	D-2	X					3	DA	AO	C	Y	S	C			No testing during normal operation due to potential violation of containment integrity.
													F	C			
													T	C		60	
													VI	C			
													J	J	1		
12-19	2	D-4	X					3	DA	AO	C	N	S	C			
													F	C			
													T	C		60	
													VI	C			
													J	J	1		

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name Fire Protection P&ID No. ISI-SK-1

Valve Number	Class	Drawing Coordinates	Valve Category A	B	C	D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
FP-248	2	-	X					4	GA	MO	O	Y	S T VI LT	Q Q Q R		60	Valves installed by Plant Modification 445 0.
FP-249	2	-	X					4	GA	MO	O	Y	S T VI LT	Q Q Q R		60	
FP-256	2	-	X					4	GA	MO	O	Y	S T VI LT	Q Q Q R		60	
FP-258	2	-	X					4	GA	MO	O	Y	S T VI LT	Q Q Q R		60	

TABLE 3 VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

System Name Fuel Transfer Tube P&ID No. ISI-SK-2

Valve Number	Class	Drawing Coordinates	Valve Category A	Valve Category B	Valve Category C	Valve Category D	Passive	Size (inches)	Valve Type	Actuator Type	Normal Position	High Radiation Area	Test Method	Test Frequency	Relief Request	Max. Stroke Time (sec.)	Remarks
FP GATE	2	-	X				X		GA	M	CL	Y	J	J			

TABLE 3 - VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT 2
SPECIFIC REQUESTS FOR RELIEF

This section provides justification for specific requests for relief from code requirements as provided for in 10CFR50.55a(g)(5)(iii). Each relief requested is identified by a unique number and identifies the valve(s) for which the relief request is being made. The code test requirement found to be impractical is defined and the basis for exclusion from code requirements is presented. Any alternate testing is specified.

1. Specific Relief Request:

   Seat leak testing and Category A valves as required by IWV-3420.

   Applicable to:

   All Category A valves for which test method is designated as J.

   Basis for Relief Request:

   10CFR50 Appendix J requires periodic leak testing of Containment Isolation Valves. All Section XI Category A valves for this plant are containment isolation valves and require Section XI leak testing. In order to preclude redundant test requirements on these valves, the Appendix J requirements will be met in lieu of the Section XI requirements.

   The H. B. Robinson containment has two features in its design that assure adequate integrity during and following a loss of Coolant Accident. These are the Isolation Valve Seal Water System and the Penetration Pressurization System. These two systems are conservatively designed, seismically qualified, and required to be operable by the Unit Technical Specifications. Additionally, they satisfy the requirements of 10CFR50 Appendix J for seal systems that can be used in lieu of local Type C valve testing.

   Alternate Testing:

   The PPS and IVSW systems will be tested as required by 10CFR50 Appendix J.

2. Specific Relief Request:

   Exercising of valves as required by IWV-3520.

TABLE 3 - VALVE TEST PROGRAM
H. B. ROBINSON STEAM ELECTRIC PLANT UNIT 2
SPECIFIC REQUESTS FOR RELIEF

Applicable to:

MS-V1-3A-C

Basis for Relief Request:

These valves are the Main Steam check valves downstream of the MSIV's. Normal steam flow verifies the proper opening of the valves. Section XI requires reverse flow seating of the valves. Due to the design of the system, no meaningful test can be performed to prove this seating at any operating condition.

Alternate test:

NONE

ENGINEERING EVALUATION OF THE H. B. ROBINSON

REACTOR COOLANT SYSTEM LEAK ON JANUARY 29, 1981

by the

Office for Analysis and Evaluation
of Operational Data

March 23, 1981

Prepared by: Wayne D. Lanning
Lead Reactor Systems
Engineer

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.

TABLE OF CONTENTS

1. EVENT DESCRIPTION

A sequence of events is contained in Table 1. Problems with both oil pumps in the turbine electro-hydraulic (E-H) system forced the plant to initiate a plant shutdown. During the process a safety injection signal was generated by a high steam flow coincident with low RCS average temperature. The high steam flow signal was generated by the governor valves spiking open, believed to be caused by the erratic operation of the turbine E-H system. The low average temperature was the result of overcooling the RCS by excessive injection of boric acid solution. The safety injection (SI) signal tripped the reactor. The reactor power had been reduced from 100% to approximately 6% at the time of trip. The duration of the high steam flow/low average temperature signal was apparently not of sufficient duration to latch the "A" train nor close the main steam line isolation valves. Both were manually actuated. A containment fire alarm was received shortly after the SI.

After having determined that a spurious SI had occurred, the operators initiated actions (e.g., reset SI, feedwater isolation, restore letdown) to continue to hot standby condition. During the automatic isolation of the CVCS letdown line due to the spurious SI, it is believed that the outermost isolation valves (see Figure 1, valves 204A&B) closed faster than the two open orifice isolation valves (CVC-200B and C), or that leakage past the orifice isolation valves resulted in the opening of the relief valve and the rupturing of the bellows on the relief valve (CVC-RV-203). In addition, a pressure surge due to the isolation valves closing caused a drain cap to be blown off. Unaware of these two failures, letdown flow was reestablished. Subsequently, containment pressure and dew point increased. The containment pressure and humidity increases attached additional significance to the already decreasing

RCS pressure. Letdown was secured (valves closed and sequence unknown) about 15 minutes after letdown was reestablished. A containment entry was made. A leak was identified in the letdown system area but no fire existed. The heat sensitive fire alarm detected the steam from the leak in the letdown system, which implies that this leak occurred in the CVCS during the first SI. Approximately 3,000 gallons was estimated to be in the containment sump based on level indication in the control room.

After the letdown was thought to be isolated, the pressurizer pressure continued to decrease and the level to increase. A second safety injection occurred on low pressurizer pressure. Both trains of safeguards equipment actuated. The level increase was the result of continued charging flow and heatup of the primary system (the MSIVs had been closed to recover average temperature earlier). The cause for the depressurization could not be identified positively.

Four hours after the first entry, a second containment entry was made and the leak was identified to be from a drain line which was still leaking. The drain line is located upstream of the orifice isolation valves (see Figure 1). The cap on the drain pipe was missing and valve (CVC-200E) was manually closed. Water in the containment sump had now increased to approximately 4,500-6,000 gallons. Evidently, the two level control valves (CVC-LCV-460A&B) were leaking at five to seven gallons per minute between 0650 and 1120. After the drain valve was closed during the second containment entry, the RCS pressure continued to decrease.

Many steps were taken to determine the cause of the decreasing RCS pressure after letdown had been isolated; e.g., isolating charging line auxiliary spray, checking pressurizer relief and safety valve leakage, and increasing pressurizer heater output. The cause was identified when the operators stopped two of the three reactor coolant pumps in the loops with the pressurizer spray scoops and the pressure began to increase. One of the two pressurizer spray valves was not fully closed. Positive identification of spray valve RC-455B as the leaking valve was made later. The spray valve position is indicated by demand, not stem position, which delayed identification of the cause for depressurization.

During this event, steam generator samples indicated a primary-to-secondary leak of approximately 0.5 gpm based on activity of 10^{-4} μC/ml. Steam generator "B" was isolated on the secondary side. Subsequent samples indicated decreasing activity and no leak. The licensee has concluded that the increased activity was the result of "crud" being agitated during isolation of the steam generators during the event.

Repairs were made to the spray valve and the relief valve bellows. The cap was replaced on the drain line and all drain valves were verified closed. The unit was back online on February 1, 1981.

2. EVALUATION OF THE EVENT

2.1 Operator Actions

Operators responded to the events in a systematic and timely fashion. Data entered into the logs were detailed and accurate. After the plant was stabilized, the license contacted Westinghouse to ensure that their diagnoses were correct and no other unforeseen problems existed.

One shortcoming identified was the lack of a procedure for recovery from a spurious safety injection actuation. Guidelines should be available to the operators to differentiate between a real and spurious SI actuation. The licensee indicated that a procedure will be written for recovery from a spurious SI (identification criteria not included). For this event, resetting the SI had no consequences. However, pressurizer pressure, level and average temperature had all been decreasing prior to the SI and had "stablized" for only about two minutes before resetting SI. In retrospect, there was still a small reactor coolant leak and the spray valve was open. However, SI had been initiated on signals indicative of a steam line break and since secondary system conditions were stable and the governor valve position recorder indicated spurious valve opening, the operators correctly diagnosed the SI signal as spurious for this event.

An area of improvement would have been to test the safety injection actuation and main streamline isolation signals since one train of SI failed to latch and the MSIVs failed to close. Both were manually actuated. Although both SI trains actuated on the second safety injection signal, this was not adequate verification of operability on high steam flow/low average temperature actuation before returning to power. These tests could have helped substantiate that the signal was not of sufficient duration to latch the SI relay and close the MSIVs.

2.2 Charging Flow Termination

Although SI actuation occurred twice, no boric acid was injected into the RCS based on samples of the boric acid injection tank. This was because the RCS system pressure exceeded the shutoff head (1,500 psig) of the SI pumps at the times of actuation. Hence, the charging pumps were making up lost RCS inventory during the event.

During the attempts to identify the cause for the depressurization and recognizing that pressurizer spray could cause the depressurization, the charging flow was isolated (closed valve CVC-HCV-121) to terminate a possible leak from the auxiliary spray valve (Figure 1). This operator action did not terminate all makeup flow to the RCS. The flow path was maintained to the RCP seals which would provide makeup flow (approximately 60 gpm). RCS conditions (approximately) at this time were: Pressure = 1,600 psig; Tavg = 548°F; pressurizer level = 56% and increasing; normal steam generator level for the condition; and margin to saturation was approximately 50-55°F.

The charging line was isolated from 0726 to sometime after 1932 (shift foreman's log). No consequences resulted from isolating the normal charging flow for this event although SI flow was not available due to the pump head limits. However, it is suggested that NRR determine whether isolating the charging flow is advisable for small loss-of-coolant accidents or when the system pressure is above the shutoff head of the SI pumps. Westinghouse has indicated that no credit was taken for charging flow for the ECCS analyses. The emergency procedure for depressurization (EI-1) does not include criteria for terminating charging flow. The charging pumps are a part of the CVCS and not considered a part of the safety injection system at Robinson. However, the charging pumps provide high pressure makeup flow when the RCS pressure exceeds the shutoff head of the SI pumps. Ensuring that charging flow is not interrupted for the systems employing low/medium heat SI pumps may be desirable to enhance safety.

2.3 Safety Injection Actuation

The first safety injection actuation occurred on a "high steam line flow/low Tavg" signal. The licensee's review of the event indicated that the momentary spike-opening of the turbine governor valves caused the steam flow, in at least two steam lines, to exceed the steam flow set point for a period of about 25 msec. The combination of high steam flow in 2/3 steam lines and the existing low average temperature of the reactor coolant generated a main steam isolation valve (MSIV) closure signal and a SI actuation signal.

However, only train B of safeguards equipment responded - the other train of safeguards equipment and all the MSIVs did not actuate. Licensee's observations are that the MSIVs require a signal duration of one second to close and that the SI actuation relays, including SI logic train latching relay, require a signal duration greater than 25 msec to actuate. Since the SI signal was of less than 25 msec duration, only the train B latching relay actuated. Reactor trip, emergency diesel start, feedwater isolation and other safeguards equipment actuations for train B occurred as a consequence of SI train B actuation.

Reviewing the logic diagram of Robinson's Safeguard Actuation Signals (Dwg CP 300-5379-2759 sh 8, rev 6) it is seen that the reactor trip signal is initiated on SI actuation along with emergency diesel start, feedwater isolation and safeguards sequence actuation. A review of a later Westinghouse logic diagram (typical) shows that the reactor trip signal is derived separately from the SI actuation signal; i.e., the reactor trip signal is taken off "upstream" of the SI actuation signal, similar to the MSIV closure signal on Robinson. This could mean that on certain spurious SI actuation events of short signal duration, SI, feedwater isolation and auxiliary feedwater system actuations may occur with no simultaneous reactor trip occurring. The comparison of logic diagrams also shows that the P-4 interlock (reactor trip breaker position) in the the Reset/Block feature of SI logic of later Westinghouse units is not provided in the Robinson design. Additional analyses would be needed to ascertain the significance of different reactor trip logics for Westinghouse plants. The need to provide a direct reactor trip on spurious safety injection actuation is referred to NRR for review.

2.4 Pressurizer Spray

The open spray valve could not be identified due to lack of spray flow indication or actual spray valve position. The failure of the valve to close evidently did not affect the capability of the valve to open as evidenced by subsequent testing. The Licensee is evaluating the possibility of relocating and replacing the spray valves during the next refueling outage. Previous problems have been experienced with the spray valves and their location in containment reduces their accessibility for maintenance.

2.5 Relief Valve Bellows Failure

The licensee has experienced previous failures of this Crosby relief valve (number JB-36, Type B, shop drawing number H51380). Basic information about the valve and the discharge piping configuration were obtained from CP&L and Crosby Valve Company and are as follows:

Relief Valve

- 2" diameter inlet, 3" diameter outlet
- Set pressure, 600 psig
- System pressure, 300 psig (approximate)
- Dynamic backpressure, 25 psig (specified)
- Bellows tested to 150 psig

Piping

- A horizontal run exits from the relief valve before turning vertically up for at least 12 feet to the pressurizer relief tank.

CP&L indicated that the bellows fails every time the relief valve lifts. Since the bellows has been tested to 150 psig, it would appear that the system is operating quite differently from the anticipated mode. The dynamic backpressure probably exceeds 150 psig (six times the specified 25 psig). A mechanism that could cause the high pressure might be stagnate water from either steam condensation or valve leakage in the line from the relief valve to the pressurizer relief tank. Boric acid crystal formations may also be a possibility. When the valve opens, water or other debris in this line could restrict steam flow and cause a high dynamic backpressure until the line is cleared. Also, if the line is filled with stagnate borated water, the bellows may be susceptible to corrosion attack, but corrosion has not been identified from previous failures and replacements. From an operational viewpoint, the failure mode for the bellows should be identified and changes necessary to prevent additional failures should be implemented. The operation of the CVCS isolation valves may be a major contributor to the bellows failures and is discussed in Section 2.6.

2.6 Letdown Isolation Valves

The isolation valves played a dominant role in the sequence of events at Robinson. The failure of the bellows on the relief valve was attributed to the closing of the out board valves (CVC-204A&B) before the closing of the orifice isolation valves (CVC 200B&C) upstream of the relief valve. Consequently, the set point (600 psig) of the relief valve was reached since this part of the CVCS was pressurized by the reactor coolant system which was at approximately 1,800 psi. The design pressure downstream of the valves (CVC-200 series) is 600 psig. The sequential operation of the isolation valves is evidently causing this part of the CVCS to be pressurized to at least the setpoint of the relief valve, as evidenced by the opening of the relief valve whenever the CVCS is isolated.

In addition to the isolation valves, valves LCV-460 A and B (Figure 1) were closed in an attempt to isolate the leaking drain valve/pipe. Both of these valves leaked which permitted an additional 3,000 gallons (approximately) to leak into the containment after the letdown system was thought to be isolated. The licensee did not perform any maintenance on these valves to ensure their operation before returning to power since these are not containment isolation valves. These valves are part of the reactor coolant pressure boundary and are designed to close on low pressurizer level to conserve RCS inventory.

The design and operation of this part of the CVCS raises two concerns: first, the potential for overpressurizing the system to 2,200 psig assuming the downstream isolation valves (CVC-204A&B) are closed; and secondly, the capability to isolate a potential break downstream of valves LCV-460A&B. The licensee has indicated that the relief valve is designed to prevent overpressurization of the CVCS. The failure of the bellows does not appear to affect the pressure relieving function of the relief valve. In addition, the flow control valves (CVC-LCV-460A&B) have been designed to isolate a break downstream of these valves for the maximum size break and RCS conditions.

The functional and testing requirements for the flow control valves are not clear. These valves should be ASME Class 1 since there are no valves upstream and the valves downstream are classified as ASME Class 2. However, these flow control valves are not identified in the Robinson Inservice Inspection and Testing Program (Reference 4). Since these valves are on the RCS pressure boundary and are designed to isolate the RCS on low pressurizer level, it is not clear why maintenance on the valves was not required after they were known to leak and before returning to power.

Both of these concerns could lead to a small loss-of-coolant event inside containment. This postulated event is within the scope of an analyzed small break loss-of-coolant accident and not a new safety concern. However, from an operational consideration, overpressurizing the CVCS could be prevented, provided the orifice isolation valves were closed before the outboard isolation valves. Correcting the valve closing sequence for isolation would also reduce the challenge to the relief valve.

2.7 Leakage Inside Containment

The licensee has acknowledged that the quantity of water that leaked into containment can only be approximated. The estimated 6,000 gallons (corresponding to approximately 15" in the sump) is a small fraction of the range of indication in a 65,000-gallon capacity sump (See Figure 2). A mass balance was not possible since neither charging flow nor volume control tank level are recorded. The major leak was after letdown flow had been reestablished between 0635 and 0650. This could account for approximately one half of the 3,000 gallons indicated at 0650. The drain valve could have also been leaking at an unknown reduced rate from the initial SI until letdown was restored (approximately ten minutes). The ruptured bellows on the relief valve also contributed some amount to the inventory in the sump. These sources in combination with the inaccuracy of the sump measurements can lead to the conclusion that all the leak sources had been identified.

2.8 Drain Valve and Pipe Cap

The leaking valve was CVC-200E (see Figure 1) not CVC-204C as reported by IE (Reference 1). This helps to understand the leak rates and quantity of water reported in the LER (Reference 2) and the IE evaluation.

The licensee's explanation for the missing cap on the pipe was that when the orifice isolation valves closed, a pressure pulse was applied to the valve and cap. Since the valve was partially open and the cap not tightly secured, the cap was blown off. The licensee believed that vibration in the CVCS (induced by the charging pumps) caused movement of the valve and cap. The valve position was last verified on October 11, 1980 during a refueling outage. Since the drain pipe is located close to the pressure reducing orifices, the flow instabilities at these orifices could also induce vibration in the CVCS.

All drain pipes with valves have been verified closed. Most valves have been chained and locked.

2.9 Failure of Fire Protection Isolation Valve

When a Phase A isolation signal was generated by the safety injection actuation, one (FP-248) of the four containment isolation valves failed to close due to a tripped breaker. Since the other isolation valve in the line closed, containment isolation was achieved. This failure had no bearing on the leak and was a separate reportable event.

3. CONCLUSIONS

The event at H. B. Robinson involved four separate, somewhat unrelated failures: (1) pump failures in the turbine EHC system; (2) two separate leaks in the CVCS (related failures); (3) an undetected open pressurizer spray valve; and (4) leaking valves in the CVCS. The event did not appear to include any safety concerns.

The following areas of review concering this event are referred to NRR for consideration:

a. Whether a requirement should be placed upon operating plants to establish a procedure for identification and recovery from a spurious safety injection actuation (if such a procedure is not already in place).

b. Whether criteria for terminating SI should include provisions for isolating charging since charging flow could be considered high pressure safety injection for very small breaks.

c. Whether there is a need for a direct reactor trip on a spurious safety injection actuation at other Westinghouse plants which do not have a direct trip.

d. Whether operation of the isolation valves in the CVCS at Robinson is causing the system to be operated in a manner which is contrary to its design bases. The closing sequence for the isolation valves appears to cause part of the CVCS to be pressurized to the setpoint of the relief valve and may be contributing to the failure of the relief valve bellows whenever the system is isolated.

AEOD did not find any basis for a need to study this event further. A formal response from NRR is not requested.

This event and the operator's response provide a good example of an operating experience which should be disseminated to other licensees for information and training purposes.

4. REFERENCES

(1) Memorandum, H. Woods to E. Jordan, Subject: H.B. Robinson Event on January 29, 1981, dated February 12, 1981.

(2) Licensee Event Report 81-005, H.B. Robinson Steam Electric Plant, Unit 2, Docket 50-261, dated February 12, 1981.

(3) Meeting with Carolina Power and Light Company in Bethesda on February 20, 1981.

(4) Letter, E. E. Utley, CP&L to S. Varga, Subject: H. B. Robinson Steam Electric Plant Unit No. 2, Inservice Inspection and Testing Program, dated March 10, 1981.

Table 1
SEQUENCE OF EVENTS

January 29, 1981
Plant at 100%
Primary to secondary leak of approximately 0.3 gpm.

0500 "A" EHC oil pump seal leak, "B" EHC pump already out of service due to vibration.

0541 Started load reduction.

0542 Added boric acid to RCS.

0543 Started "C" charging pump, "B" charging pump running, "A" charging pump inoperable.
Opened CVC-200B orifice isolation valve, CVC-200C already open.

0549-
0609 Continued to add boric acid.

0613 Stopped "B" feedwater pump and condensate pump due to erratic FWP behavior.

0620 Tavg reached low Tavg setpoint (543°F) alarm.

0623 Generator output breaker opened.
Turbine governor valves spike open.
SI signal and MSIV closure signal on high steam flow/low Tavg.

SI train "B" automatically started.
Phase A isolation; safeguard B emergency equipment started.
Reactor trip on SI signal.
Tavg = 532°F.
Pzr pressure = 2210 psig.
Pzr level = 13%.

0625 Fire alarm in containment.
Pressurizer relief tank level alarm due to opening of CVC-RV-203 relief valve.
Bellows probably ruptured and drain cap was blown off.
MSIVs closed manually.
SI train "A" started manually. Started "A" DG, AFWP, RHR, manually.
Letdown valves CCV-460A&B manually closed (should have automatically closed on PZR level of 13%).

0627 Reset SI and feedwater isolation.

0634 Attempted to restore letdown flow but CVC-200A would not open (instrument air system isolated on Phase A isolation).
Restored letdown flow after resetting isolation signals.
Pressurizer pressure started decreasing sharply (~2000 psig).
Containment dew point and pressure started increasing.

0637 Received condensate collection alarm from the coolers.
Diesel generators A and B stopped manually.

0645 Isolated letdown flow. (Isolation valves closed from control room.)
Containment dew point and pressure decreased.
Pressurizer pressure still decreasing (1840 psig).
Tavg increasing.
Pressurizer pressure increasing.
Notified NRC by ENS.

0650 Containment sump level indicated approximately 3000 gallons.

0700 First containment entry to check for leak and fire.

0705 Second SI actuation on low pressurizer pressure.
Both trains and all equipment started.
Pressurizer pressure = 1715 psig.
Pressurizer level = 50%.

0705-
0727 Operators attempting to determine cause of depressurization.

0722 Steam dumps opened manually to control pressurizer level.

0727 Reactor coolant pumps B and C stopped and charging line isolated to eliminate possibility of leaking auxiliary spray valves.
Increased pressurizer heater output to maximum.
Pressurizer pressure started increasing.

0729 Continued cooldown using steam dumps.

0735 Pressurizer pressure increasing (= 1720).
Tavg constant = 540.
Pressurizer level = 50%.

0738 Stopped diesel generators A&B.

0741 Stopped "B" RHR pump.

0745 Opened breakers on containment sump pumps.

0825 Secured SI pumps.

1000 Continued plant cooldown.
Sample on "B" steam generator indicated 0.5 gpm primary to secondary leak. Isolated "B" steam generator.
Second sample showed decreased leakage (0.25 gpm).

1120 Second containment entry. Found CVC-200E open and cap missing.
Found bellows on relief valve CVC-203 ruptured.
Contacted Westinghouse.

1218 Blocked low pressure SI.

1230 Closed CVC-200E.
Isolated letdown by closing CVC-309D.
Containment sump level was 4,500-6,000 gallons.

1445 "B" charging pump out of service due to leaking relief valve

1830 Aligned "A" charging pump for operation after completing surveillance tests.

(late
entry) Tested pressurizer spray valves.

1913 Started "B" RCP.

1932 Started "C" RCP.

(Later) Placed charging line and CVCS letdown in service. Removed excess letdown line from service.

2315 Spray valve RCS-455B identified as leaking spray valve
No additional primary to secondary leak identified.

January 30, 1981 at 1700 plant on-line

APPENDIX A

INFORMATION PROVIDED BY LICENSEE AT MEETING ON FEBRUARY 20, 1981

Contents:

1. Draft Plant Operating Experience Report
2. Operators Log
3. Shift Foreman Log
4. Strip Charts
5. Figure 1 - CVCS Diagram (excerpt)
6. Figure 2 - Containment Sump Volume

PLANT OPERATING EXPERIENCE REPORT

1. Event Date

January 29, 1981

2. Identification of Occurrence

A) A spurious safety injection signal initiated by a "High Steam Line Flow/Low T_{avg}" signal.

B) Reactor Coolant System leak through letdown line drain valve CVC-2002.

C) Primary plant depressurization leading to a second safety injection signal initiated by a "Low Pressurizer Pressure" signal.

3. Conditions Prior to Occurrence

A plant shutdown to hot standby was in progress to repair a secondary plant problem. The unit had been operating at 100% reactor power (725 MWe) with normal Reactor Coolant System pressure and temperature.

4. Description of Occurrence (All Times Are Approximate)

A) At 0624 hours on January 29, 1981, a safety injection signal initiated "B" train of safeguards. "A" train equipment was manually started at 0625 hours.

B) At 0635 hours on January 29, 1981, the chemical and volume control letdown system was restored and system pressure began decreasing with an increasing containment pressure and dew point. Letdown was secured at 0650 hours.

C) At 0705 hours on January 29, 1981, a safety injection signal initiated both trains of safeguards.

5. Designation of Apparent Cause of Occurrence

At approximately 0400 hours, "A" turbine electro hydraulic (E-H) oil pump developed a seal leak. "B" E-H oil pump had been taken out of service earlier due to high vibrations. At 0541 hours, the decision was made to shut down to hot standby before receiving a trip signal due to the loss of E-H oil. Attachment No. 1 contains additional information on the failure of the E-H Oil System.

At 0624 hours, immediately following opening the generator output breakers, the reactor tripped and a safety injection was initiated by a "High Steam Line Flow/Low T_{avg}" signal. Only "B" train of the safeguards was activated. "A" train equipment was manually started at 0625 hours. It was determined that the erratic operation of the E-H Oil System and the fact that the operators were switching from "A" E-H oil pump to "B" E-H oil pump caused the governor valves to spike open. The resultant steam flow spike was high enough to cause a "High Steam Line Flow/Low T_{avg}" signal but it was of insufficient duration to fully latch the "A" safeguards train seal-in relay. The seal-in relays in the safeguard trains are latching relays that require a finite period of time in the energized mode to mechanically latch them into the closed position. Attachment No. 2 contains additional information on the partial safety injection.

The steam line isolation signal that was generated from the "High Steam Line Flow/Low T_{avg}" signal was of insufficient duration to allow the main steam isolation valves to go shut. The open signal was reinstated so quickly

5. Designation of Apparent Cause of Occurrence (Continued)

after the isolation signal that the valves were unable to travel far enough to isolate the steam flow. The main steam isolation valves were manually shut to reduce the secondary steam demand following the reactor trip, thereby promoting the return of T_{avg} to the no load setpoint.

At 0627 hours it was determined that safety injection conditions did not exist and that the initiation was spurious. The safety injection and feedwater isolation signals were reset. The chemical and volume control letdown system was restored at 0635 hours. The Reactor Coolant System pressure had been slowly decreasing, but when letdown was returned to service, the containment pressure and dew point began increasing. Another indication of abnormal containment conditions was a fire alarm from the area of the containment operating deck which was received at approximately 0624. Letdown was secured at 0650 hours with Reactor Coolant System pressure at 1850 psig. The initial containment entry made at 0700 hours to investigate the abnormal conditions confirmed that the RCS leakage was from the letdown line and that no fire existed. A subsequent containment entry at 1120 hours further identified the source of the leak as valve CVC-200E, a drain valve on the letdown line, which was found open and the pipe cap missing. The leak that resulted from the open drain valve was approximately 5 to 7 gpm with the letdown air operated valves closed and approximately 100 gpm with letdown flow established. The leak was completely stopped by shutting valve CVC-200E. The letdown flow was not restored until after the condition was found and repaired. Additional information regarding the RCS leak and containment fire alarm can be found in Attachment No. 3.

5. Designation of Apparent Cause of Occurrence (Continued)

However, even with the letdown control valves closed, the pressurizer pressure continued to decrease, leading to the second safety injection initiation at 0705 hours from a "Low Pressurizer Pressure". Both trains of the safeguards equipment functioned as designed. At 0727 hours, charging was isolated (except reactor coolant pump seal injection) to eliminate auxiliary spray and "B" and "C" reactor coolant pumps were secured to prevent the pressurizer spray valves from circulating cooler water from the Reactor Coolant System into the pressurizer through the spray valves, decreasing the pressure. It was subsequently discovered that the pressurizer spray valve from "C" reactor coolant loop had probably opened and not fully reseated. The pressurizer pressure immediately started to increase. The reactor coolant system was stabilized at approximately 2050 psig and 535^{O}F with pressure controlled by the pressurizer heaters and temperature controlled by the secondary steam dump. Attachment No. 4 contains additional information on the reactor coolant system pressure transient caused by the spray valve malfunction.

Coincidental with the decreasing pressurizer pressure, pressurizer level was increasing. This was caused by two factors. 1) The charging flow from two charging pumps was maintaining or increasing the system volume, including the system losses through CVC-200E. The slightly open pressurizer spray valve was causing the pressure to decrease. 2) The density changes in the reactor coolant due to the slowly increasing RCS temperatures and the heat up of the relatively cold water added by the charging system caused the system to expand. These factors combined to cause an increasing pressurizer level. The margin to subcooling remained

5. Designation of Apparent Cause of Occurrence (Continued)

greater than 55°F throughout the entire transient. The minimum subcooling margin occurred at 0720 hours, with reactor coolant system pressure at 1620 psig and temperature at 551°F.

The relief valve on the letdown line, CVC-RV-203, lifted following the first safety injection initiation. This was apparently due to the isolation valves, CVC-204A and CVC-204B, closing slightly faster than the orifice isolations, CVC-200A, CVC-200B and CVC-200C, or leakage past one or more of the orifice isolation valves. This caused the pressure between the valves to increase above the set pressure for CVC-RV-203 (600 psig). The valve reset after the letdown isolations closed, but the bellows had ruptured. Attachment No. 3 also contains additional information regarding valve CVC-RV-203.

6. Analysis of Occurrence

Several problems with the turbine E-H Oil System had occurred within approximately one week preceeding the reactor trip and safety injection on January 29, 1981 which could have contributed to the initiation of the event. These problems are summarized as follows:

1) The E-H oil had become contaminated with water due to a ruptured E-H oil cooler approximately one week prior to this event. However, the E-H oil had been purified (replaced) and restored to specification prior to this event. It is not felt that this contributed to the following problems.

2) On January 28, 1981 "B" E-H pump unloader developed a fatigue crack in its discharge nipple. While replacing this nipple, air was introduced into the "B" E-H oil pump portion of the system. When

6. Analysis of Occurrence (Continued)

"B" E-H oil pump was restarted, it caused excessive vibrations throughout the E-H Oil System. "A" E-H oil pump was restarted and "B" E-H oil pump was secured after a brief period of operation.

3) The seal leak which developed on "A" E-H oil pump on January 29, 1981 which necessitated the turbine shutdown is felt to have been caused by either age or the excessive system vibration.

4) As the seal leak on "A" E-H oil pump became larger during the remaining moments of the turbine shutdown, the operators decided to run "B" E-H oil pump despite the vibration problem in order to allow the leak to be isolated so a normal turbine shutdown could be completed. Coincidentally, "B" E-H oil pump was started as the generator output breakers were opened. When the generator output breakers are opened the turbine switches from load control to speed control.

One, or some combination, of the above probably caused the turbine governor valves to spike open. The exact cause cannot be determined. This caused the first safety injection initiated on a low reactor coolant system average temperature coincident with high steam line flow. The high steam flow was of a very short duration, thus only "B" safeguards train was activated and the main steam isolation valves remained open.

Letdown line drain valve CVC-200E had vibrated open since it had last been verified shut on October 11, 1980. It is postulated that the pressure transient caused by the letdown line isolation caused the pipe cap to blow off. Thus, a Reactor Coolant System leak existed.

6. Analysis of Occurrence (Continued)

The continued decrease in pressurizer pressure was caused by the failure of the pressurizer spray valve from "C" reactor coolant system loop (RCS-455B) to fully shut after opening during the transient. The event identification was complicated by the letdown relief line lifting to the pressurizer relief tank which indicated that there were two separate leaks. The Reactor Coolant System pressure decrease was stopped when "B" and "C" reactor coolant pumps were secured and the charging line was isolated to eliminate auxiliary spray. With the pressure decrease stopped, operator control of the Reactor Coolant System was re-established and normal hot shutdown conditions were established.

Following the first safety injection at 0624 hours, the fire protection containment isolation valve FP-248 did not shut automatically and had to be manually closed. Attachment No. 5 contains additional information on the performance of the fire protection containment isolation valve.

A summary of the P250 computer output for this event is provided as Attachment No. 6.

7. Corrective Action

A) The E-H oil was completely replaced with new oil.

B) "A" E-H oil pump and unloader were replaced.

C) The unloader and discharge nipple on "B" E-H oil pump were replaced.

D) The valve stem on RCS-455B was lubricated, stroked and valve positioner was adjusted to ensure the valve will fully close. RCS-455A was also checked for proper operation.

7. Corrective Action (Continued)

E) CVC-200E was locked closed and the pipe cap was replaced. Similar valves in the letdown and charging lines were also locked closed or otherwise verified to be secured.

F) The breaker over current trip setpoints on the four Fire Protection System containment isolation valves have been adjusted and checked to insure proper valve performance.

G) The event was fully analyzed by the plant staff and Westinghouse, and the results discussed with the NRC, Region II, to ensure that all safety concerns were identified and resolved prior to returning the unit to operation.

F. L. Forrey
Unit 2 Operating Supervisor

Crawford
Manager - Operations and Maintenance

M. S. ...
General Manager

SEQUENCE OF EVENTS

0541 Unit shutdown was initiated due to E-H System trouble.

0620 Tavg reached the low Tavg setpoint (543°F) during plant shutdown.

0624 Generator output breaker is opened removing unit from system.

Load on unit is ~6%.

Turbine governor valve(s) spike open (see Attachment No. 1).

High Steam Flow/Low Tavg signal generated.

MSIV's closure signal (see Attachment No. 2).

SI signal, train "B" actuates (see Attachment No. 2).

CV isolation valve FP-248 fails to close (see Attachment No. 5).

Minimum Tavg ≈ 532°F (based on incore thermocouple).

PZR pressure ≈ 2100 psig.

PZR level ≈ 13%.

0625 Fire alarm at CV operating deck (see Attachment No. 3).

Pressurizer relief tank level alarms from CVC-203 discharge (see Attachment No. 3).

0625 (Contd.) Primary pressure begins to decrease (see Attachment No. 4).

MSIVs manually closed.

SI train "A" equipment manually started.

Letdown valves 460A & B manually shut.

0627 Manually reset SI.

0635 Restored letdown.

Containment dew point and pressure begin to increase.

0650 Isolated letdown (suspected leak in letdown system).

0656 Tavg reaches maximum value of 552°F and holds steady.

PZR pressure ≈ 1750 psig.

PZR level ≈ 50%.

0700 Containment entry to check for leak and fire (see Attachment No. 3).

0705 Second SI signal due to low PZR pressure, 1715 psig.

Both "A" and "B" trains activated.

0705-0727 Operators attempt to determine cause of depressurization. The following equipment was checked:

0705-0727 (Contd.)

a) PZR safety valves flow indicators.

b) PZR PORV discharge line temperature.

c) PZR block valve position.

d) PZR relief tank level.

e) PZR relief tank pressure.

f) PZR spray valve position (the valves indicated closed but since this indication is demand indication the valve controllers were again manually closed).

0722 The RCS temperature was lowered slightly using the secondary steam dumps to help control the increasing pressurizer level.

Tavg ≈ 549°F.

PZR pressure ≈ 1620 psig.

PZR level ≈ 62%.

0727 The charging line was isolated to eliminate the possibility of auxiliary spray causing the depressurization. RCP "B" and "C" were stopped to eliminate the possibility of main spray flow causing the depressurization.
Pressurizer pressure begins to rise.

0735 Tavg ≈ 543°F.

PZR pressure ≈ 1715 psig.

PZR level ≈ 50%.

0820 PZR pressure stabilized.

Tavg = 535°F.

PZR pressure ≈ 2050 psig.

PZR level = 45%.

1120 Made second containment entry and isolated CVC-200E at 1230 hours.

1120 (1-29-81)
to 1700 (2-1-81) Review and analysis of transient with Westinghouse. Discussions of transient with NRC Region II.

2315 (1-29-81) RCS-455B positively identified as leaking spray valve.

1700 (2-1-81) Plant on-line.

ATTACHMENT NO. 1

E-H SYSTEM FAILURE

The E-H System had experienced several problems prior to the transient on 1-29-81. During the previous week the E-H fluid had become contaminated with water. (This contamination was restored to within specification.) On Wednesday morning, 1-28-81, a stainless steel nipple on the E-H System unloader on "B" pump cracked. This caused a loss of approximately 30 gallons of E-H fluid. The fluid and nipple were replaced and "B" pump restarted. However, the pump was immediately stopped due to noise and vibration. Several attempts were made to troubleshoot the problem but no definite cause was found. The system was left operating satisfactorily with one pump in service. At 0500 on 1-29-81 the second E-H pump, "A", developed a seal leak which caused E-H fluid to leak out of the system. At 0541 the operators began to take the unit off line to repair the E-H System. At 0624 while the unit was being separated from the system, the E-H System generated a pressure surge to the governor valves which resulted in the valves momentarily opening. Three factors could have contributed to the pressure surge. The turbine control was switching to speed control. The operators were trying to start "B" E-H oil pump to supply E-H oil during the final moments of the turbine shutdown. The E-H System had been contaminated by water during the previous week. This caused a momentary high steam flow to be sensed on at least 2 steam lines. The spike shows up on all three steam flow charts. The effect of this flow spike is described in Attachment No. 2.

The failure of "A" pump seal on the E-H System was due to age and transferred vibration from "B" pump. Subsequent to these pump failures, the unloader of pump "B" has been replaced and pump "A" was replaced in its entirety. The complete system was restored to service and is operating satisfactorily.

ATTACHMENT NO. 2

PARTIAL SI AT 0624 HOURS

On January 29, 1981 at 0541 a unit shutdown was commenced to do repair work on the turbine E-H System. At approximately 0620 hours Tavg dropped below the low Tavg setpoint of 543°F due to an inadvertent overshoot during plant shutdown. At 0624 with the unit at ~6% power the generator output breakers were opened disconnecting the unit from the system. At this time the turbine E-H control system switched to speed control and due to pressure instabilities in the E-H control system the turbine governor valves spiked open. A review of the event indicates that the spike caused an indicated steam flow in at least two steam lines to exceed the steam flow setpoint for a time period less than 25 msec. This indicated high steam flow in 2/3 steam lines combined with the low Tavg mentioned earlier generated a main steam isolation valve closure signal and a SI signal. The duration of this signal would be the same as the steam flow spike. It has been observed during periodic tests that the MSIVs require a signal duration of approximately 1 sec. to close and so none of the MSIVs closed on the momentary high flow/low Tavg signal. (The MSIVs were manually closed immediately by the operators in order to stabilize RCS temperature.) The SI signal is divided into 2 trains "A" and "B". Each of these trains contains several relays including a mechanical latching relay (Westinghouse Type MG6) which is used to lock in the SI train until manually reset. A signal duration greater than 25 msec. is required to insure that all relays close and the latching relays lock in. Since the SI signal was less than 25 msec. only the latching relay for train "B" fully engaged. The operators immediately noticed that train "A" had not engaged and so they manually started the train "A" equipment. Containment isolation Phase A was initiated by train "B". No SI water was injected into the system since RCS pressure was ~2100 psig and the

ATTACHMENT NO. 2 (Continued)

shut off head of the SI pumps is 1500 psig. SI was manually reset at 0627 since the SI initiation was identified as spurious.

Once train "A" was manually initiated the SI System performed as expected, with the exception of CV isolation valve FP-248 (see Attachment No. 5). The actuation of the SI System did not effect the physical course of events during the transient, however it did obscure the cause of the RCS depressurization (stuck pressurizer spray valve). No repairs to the SI logic or components are considered necessary.

at 0624 it apparently caused a heat sensitive fire detector to go off in containment. The detector was located above the drain valve on the operating deck. Since the operators had indication of RCS leakage and a fire in the containment, an individual using respiratory protection was sent into the containment to investigate. This individual confirmed the leakage and identified the source as the letdown line but was unable to identify the exact leak point because his air supply was low. During the inspection no evidence of fire was found.

To prevent future occurrences the CVC-200E pipe threads were dressed and a new end cap installed. CVC-200E and several other valve/pipe cap arrangements which could be exposed to the same condition were inspected and physically locked or verified secured in the closed position.

ATTACHMENT NO. 4

PRIMARY SYSTEM DEPRESSURIZATION

The main concern during the transient of 1-29-81 was an unexplained decrease in RCS pressure. The pressure dropped from 2200 psig to 1620 psig in approximately one hour. Many steps were taken during the first hour of the transient to determine what was causing the depressurization. The pressurizer (Pzr) safety valves were checked by looking at the accoustic flow indicators downstream of the valves. No flow was indicated. The Pzr PORVs were checked by looking at the pipe temperature downstream of the valves. Again, no flow was indicated. The Pzr block valves were checked to verify that they were shut. The Pzr relief tank level and pressure were also checked to verify that they were not increasing. The main Pzr spray valves were then switched to manual control and closed by the operator. The indication on the RTGB showed the valve to be closed, however, since this indication is only of demand position, the operator tried to insure that the valves had closed by manually closing them. The charging line was then isolated to see if the auxiliary spray valve, CVC-311, was leaking. Additionally, RCP "B" and "C" were stopped so that flow through the main spray valves 455A & B was not possible. Pzr pressure began increasing. Later that night (2315 hours) spray valve 455B was positively identified as the leaking valve.

An inspection of the valve showed that the stem was binding on the valve packing. One reason the binding problem was not identified earlier is that the spray valves do not move much during power operation. RCS pressure control is accomplished by varying the Pzr heaters with the spray valve partially opened. The valve was repaired by lubricating the stem. The valve was then tested four times to insure proper operation. In addition, the electro-mechanical positioner zero setpoint was discovered to be slightly off and therefore was reset.

ATTACHMENT NO. 5

CONTAINMENT ISOLATION VALVE FAILURE (FP-248)

At 0624 on 1-29-81 a SI signal generated a Phase A containment isolation. As part of this isolation the newly installed fire protection containment isolation valves FP-248, FP-249, FP-256, FP-258 were signaled to shut. FP-248 did not shut. The valve was then manually shut. The cause of failure was a tripped breaker which would not allow power to the motor operator. Subsequent review indicated that the trip point on the magnetic overload breaker was not set high enough to insure proper operation.

The breakers had been tested successfully upon installation, however, the current demand of the valve motors can change with time and so if the trip point is not set with enough margin the breaker can pass a test and yet fail at a later time.

The setpoints on all four valves have been readjusted to compensate for the above problem and tested. This should correct any future problems with these valves.

-DRAFT-

ATTACHMENT NO. 6

SUMMARY OF P250 COMPUTER OUTPUT

Time	Event
0620	Alarm - Low Tavg Permissive Set
0620	Alarm - Low Tavg 541.2 (setpoint is 543.0)
0623	ORR - Control Rod Bank C Inserted (reactor trip)
0624	Alarm - RHR Pump "B" BKR Closed (SI signal)
0624	Alarm - Low Tavg 532.7 (minimum Tavg)
0625	INCR - Hi PZR Relief Tank 75.2% (Valve CVC-203 lifts)
0627	RETRN - RHR Pump "B" BKR Open (SI reset)
0705	Alarm - PZR Low P & L SI (Second SI signal)
0705	Alarm - RHR Pump "B" BKR Closed
0705	Alarm - RHR Pump "A" BKR Closed
0726	Alarm - RCLB Lo Flow (RCP "B" stopped)
0727	Alarm - RCLC Lo Flow (RCP "C" stopped)

Operators Log

234

00-08 Thursday JAN 29 1981

Reviewed previous shift logs, status lights indicate All vital valves in proper position for plant Condition, RC-535 & 536 are shut Due to Porv's leakage, Rod L-11 on Temp power supply per mw #568 Loop #3 ΔT & Tavg Control Defeated, Gen Exciter Temp being Control on Bypass, LwCH 94 & 85 on B & C 5/6 in progress, OWP's CVC-1 & 25 are in effect, SG leak Rate in progress, Stm Driven feedwtr pump OOS, CUPR # 81-15 in progress

0118 Completed PT 12.1

0145 Rod to Manual Due to Rods step out for No Reason

0154 Completed PT 8.0 .3171 GPM

0218 Started "A" SW pump

0221 ADDed 30 Gals PW to RCS

0230 Completed CUPR # 81-15

0232 Reset R-14 from 12.5K to 17.5K

0541 Started load Decrease Due to EH oil pump Seal leakage

0542 ADDED 10 Gals BA & 20 Gals PW

0543 Started "C" Chg pump and 200B orifice

0547 Shift plant Aux's

0549 ADDED 20 Gals BA 15 PW

0551 " " " " " "

0556 " " " " " "

0601 " " " " " "

0604 " " " " " "

0606 "C" MFW RV Acting very erratic @ 55% Valve position

0609 ADDED 20 Gals BA & 15 Gals PW

0613 Stopped "B" FWP and "B" Cond pump

0616 ADDED 10 Gals BA & 15 Gals PW

0624 Open North and South OCBs

0624 Recieved SI from Hi stm flow/Lo Tavg/Lo stm P

0625 Manually initiated "A" & "B" Train (SI), also Started A & B SI pumps, started "A" & "B" D/G, "A" & "B" AFW, "A" RHR

0625 Recieved Fire Alarm in CV, No Fire was found on operating Deck

20-08 Thursday JAN 29 1981

0627 Reset SI and FW Isol

0625 Started "B" MFW pump

H. B. Robinson Plant Unit # 2

Critical Configuration

Date 1-29-81 Time 0541 Oper. [signature]

Bank Position (Steps)

A 228 B 228 C 228 D 214/214

Tave 575 °F Pressure 2235 PSIG

Boron Concentration 668 PPM

Reactor Power Level 3 10^-3 Amps 100 %

0

0634 Stopped HUH 4 Due to Hi vibs. CVC-200A will not open

0637 Cond Collection Alm, Stripped A+B DCs

0650 Started "A" MFW pump 3 Isol LtDN and PZR press started increasing

0705 Received Lo press SI, verified Safe/Guard Equipment Started

0706 investigating CV for leakage

Late Entry Late 0653 Stopped "B" RHR pump

0635 Restored LtDN RCS press Started Decreasing

0727 Stopped B & C RCPs and PZR press Started increasing

0729 Started cooling down

0731 Stopped A "B" RHR

Late entry 0624 Stopped LWL'S A 84 + 85 on B & C S/G's ~~in Rx~~

Unit S/D, Aux's on S/U X-formers Source Range @ 2000 CPS, Cool Down in progress. All 230 KV OCB's are Closed except 52/8 & 52/9

[signatures]

100

05-16

THURSDAY 1-29-81

REVIEWED PREVIOUS SHIFTS LOGS. STATUS LIGHTS INDICATE ALL VITAL VALVES IN PROPER POSITION FOR PLANT CONDITIONS EXCEPT THOSE VALVES WITH BKRS OPEN IAW TECH. SPECS. RC 535 + 536 SHUT DUE PORV LEAKAGE. RED C-11 CR TEMP POWER PER HOD 569. LOOP B AT + Tavg CONTROL BYPASSED. ~~RHR'S A + B ON B+C S/G'S IN PROGRESS.~~ CMP'S CLC-1 + SUC-25 ARE IN EFFECT. STM DRIVEN FEEDWATER PUMP OOS. UNIT OFF LINE SI IN PROGRESS, PZR LEVEL + PRESS INCREASING. SI HAS BEEN RESET ALONG WITH FW ISOL. HIGH HEAD INJECTION RUNNING (NOT FEEDING). INVESTIGATING LEAK IN CV. "B" RHR PUMP RUNNING. "A" RCP RUNNING

0730 STOPPED SEC. LEAK RATE TEST. (110.64 GPM)

0730 RCC BORON 522 PPM

0738 STOPPED A + B DIESELS

0741 STOPPED "B" RHR PUMP

0745 OPENED BKR ON CV SUMP PUMPS

0745 FILLED B RCP STANDPIPE TO CLEAR LO ALARM

0815 FILLED B RCP STANDPIPE

0822 STARTED R-11 + R-12 VAC PUMP

0825 STOPPED SI PUMPS

0830 HOLDING RCS PRESS @ 2100#

0839 STARTED HVE-4 FOR ADDITIONAL ACT. REMOVAL

0846 STARTED RCS BORATION

0847 ALL S/G BLOWDOWN ISOLATED

0852 STOPPED HVH-4 + HVH-1

0900 RCS boron 1026 ppm

0910 STARTED LINE #56 ON "B" MT

0916 PT 7.3 + 20.1 COMPLETED

0918 STOPPED BORATING RCS

0932 FILLED "B" RCP STANDPIPE

0933 SIT TEMP 156 / 155 (SAME AS DAYS SHIFT)

0957 RESET RX TRIP BKR'S + ROD CONTROL

1002 "A" SHUT DOWN BANK PULLED OUT. N2 ON VCT

1007 "B" S/D BANK PULLED OUT

1008 BLOCKED LO PRESS SI

1012 STARTED RCS C/D @ 570°

(CONT)

CATE

1600

0844 (CONT'D) THURSDAY 1-28-81

1022 SHUT BYPASS ON "B" MSIV

1025 OPENED BKR ON "B" 4KV SUPPLY TO STM DRIVEN FEED PUMP

1030 RCS BORON 1074 PPM

1035 DROPPED BATCH TO "B" BAST (21214 PPM)

1038 CLOSED SAMPLE LINES ON "B" S/G & CHECKED ABOVE & BELOW "B" SEAT DRAINS CLOSED ON "B" S/G

1041 UNIT DISCONNECTS OPEN

1107 TURBINE ON GEAR

1145 CLOSED CVC 309 D TO ISOLATE LEAK IN CV

1148 FILLED "B" REF STANDPIPE

LATE ENTRY 0730 IODINE DOSE EQIV. 7.08 E-4

1218 BLOCKED LOW PRESSURE SI

1250 DROPPED BATCH TO 'B' BAST BATCH 22,950

1445 'B' CHARGING PUMP OOS AS PER OWP CVC-2

1500 PUMPED BATCH FROM 'A' B.A. EVAP - 21,300 PPM, CI-.45

1510 HOLDING RCS TEMP @ 480 °F

UNIT SHUTDOWN, AUX'S ON STARTUP TRANSFORMER, ALL 230 KV OCB'S ARE CLOSED EXCEPT FOR 52/8 & 52/9, RCS AT 482 °F AND 1800 PSIG, TURBINE ON TURNING GEAR, N-31 @ 900 CPS, N-32 @ 3300 CPS.

RELIEVED BY [illegible]

[illegible signature]

THURSDAY 1-28-81

1600-2400 REVIEWED PREVIOUS SHIFTS LOGS. STATUS LIGHTS INDICATE ALL VITAL VALVES ARE IN PROPER POSITION FOR PLANT CONDITIONS WITH EXCEPTION OF THOSE VALVES WITH [illegible] WITH [illegible] RC 535 & 536 ARE SHUT DUE TO PORV LEAKAGE. VALVE [illegible] IS CLOSED TO ISOLATE LEAK ON LETDOWN DRAIN LINE. [illegible] AS PER [illegible]. [illegible] AND [illegible] CONTROL [illegible] @ 480 °F AND 1800 PSIG. [illegible] CONTROLLING [illegible] WITH STEAMDUMP. CONTROLLING LETDOWN ON EXCESS LETDOWN LINE. [illegible] ARE IN EFFECT. [illegible] IS IN EFFECT. [illegible] IN PROGRESS. HOLDING PRESSURE AND TEMP.

[illegible]

Shift Foreman log

H. B. ROBINSON
UNIT 2

№ 7631

DATE TIME	
	1600 - 2400 Continued Wednesday. 1/28/81
	Conditions: Reactor at 100% Power, Unit load at 724 MWe Net.
D.S.	Relieved By David Seagle. / C. Lee
	00 - 0800 Thursday 1/29/81
	1) Reviewed previous shifts logs : DS
	2) Conditions as found: RC-535 + 536 are closed. Rod L-4, Steam driven auxiliary feedwater pump, Recharging pump, HVH 15 + 16A, "A" CWP discharge valve motor, "B" EH oil pump are inoperable. Danger Tags number 661, 662 + 683 + 664 are installed on "A" circulating water pump. Secondary leak rate in progress. LWR's # 84 + 85 on B + C steam generator in progress
	3) Completed CVPR # 81-15
	4) Reset R-14 alarm to 17.5K on completion of release
	5) Completed PT-8 leakage = .3171 gpm
	6) Completed PT-12.1
	7) @ 0530 "A" EH oil pump developed a leak around pump shaft
	8) @ 0541 started taking unit off line due to losing EH oil
	9) @ 0624 separated unit from system & received SI signal from Hi STM line flow with low Tavg. Received "B" Train only.
	10) @ 0627 Reset SI due to Przr Press above 2000 psig + level back in Przr + level in S/G is normal for conditions
	11) @ 0635 Restored letdown + Przr Press started decreasing, Dew points increased + C.V. press started increasing.
	12) @ 0650 isolated letdown, Dew point started down + C.V. press went down, Przr Press still decreasing.
	13) @ 0705 Received second SI signal from low press. All equipment started. Przr press still decreasing.
	14) @ 0727 stopped "B + C" RCP's. Przr Press started increasing continued recovery procedures.
D.S.	Conditions: Recovery from SI in progress, Unit shutdown. N 31 = 1000 CPS N 32 = 2000 CPS
	Relieved by D Nelson / DK Seagle

H. B. ROBINSON
UNIT 2

№ 7632

08-16 Thursday Jan 29 1981

1) Reviewed Previous Shifts Logs & [illegible]
2) Conditions as Found: RC-535 & 536 are closed. Rod C-11, S/D AFW Pump, A Charging Pump HVE 15 & 15A, A CWP Discharge Valve Motor and B EH oil Pump are Inoperable. Jumper tags #661 662 663 & 664 are installed on A Circ Water Pump; Secondary leak rate in Progress. LWR #84 & 85 in Progress on B&C S/G. SI in Progress with B&C RCP's Stopped. Pressurizer Press increasing slowly. Fire Water Valve VA 102F failed to Close on SI Signal and was Closed Manually.
3) [illegible] Releases #84 & 85 were terminated on First S/I actuation at 0624 hrs and SI Equipment Returned to Normal.
4) Terminated Secondary leakrate test at 0735 hrs leakage 110.64 GPM.
5) Completed PT 9.0B
6) At 1000 hrs B S/G Sample shows ≈ 10^{-4} uc/ml activity and ≈ .5 gpm leak. Isolated B S/G on Secondary side.
7) BIT Sample From the Bottom of tank analysis results of 21776 ppm. Thus no flow thru BIT on the SI actuation.
8) Second Sample of B S/G Shows activity of approx 7×10^{-5} uc/ml and Pri-Sec leakage of .25 GPM.
9) Made C.V. Entry @ 1120 hrs and found ~~[illegible]~~ CVC-200E Drain Valve open and Cap Missing. Isolated Letdown with CVC-309A and closed CVC-200E Drain Valve @ 1230 hrs.
10) I^{131} Dose Equil Sample Result of 0930 hrs was 7.08×10^{-4} uci/gm
11) Cooled RCS down to 500 °F at 1012 hrs
12) B Charging Pump Inoperable at 1445 hrs due to Discharge Relief Valve leaking Thru
13) Started LWR #86 on B Mon Tank
14) Performed PT 1.7 Exception

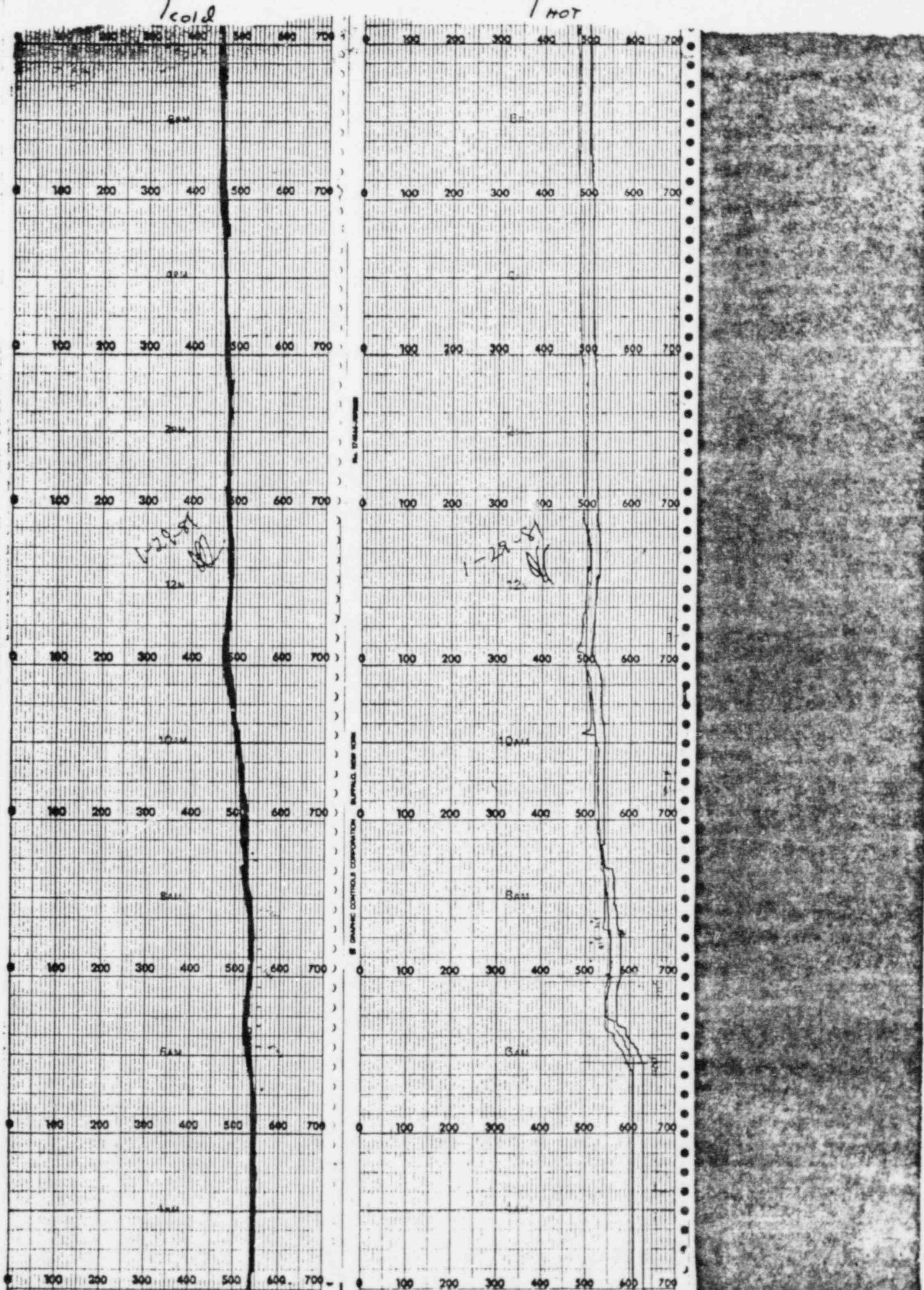
Conditions @ RCS at 479 °F and 1800 psig with B&C RCP's Stopped waiting on B S/G Sample Results

N-31 @ 800 cps N-32 @ 3001 cps

Relieved by [illegible]

H. B. ROBINSON
UNIT 2 № 7633

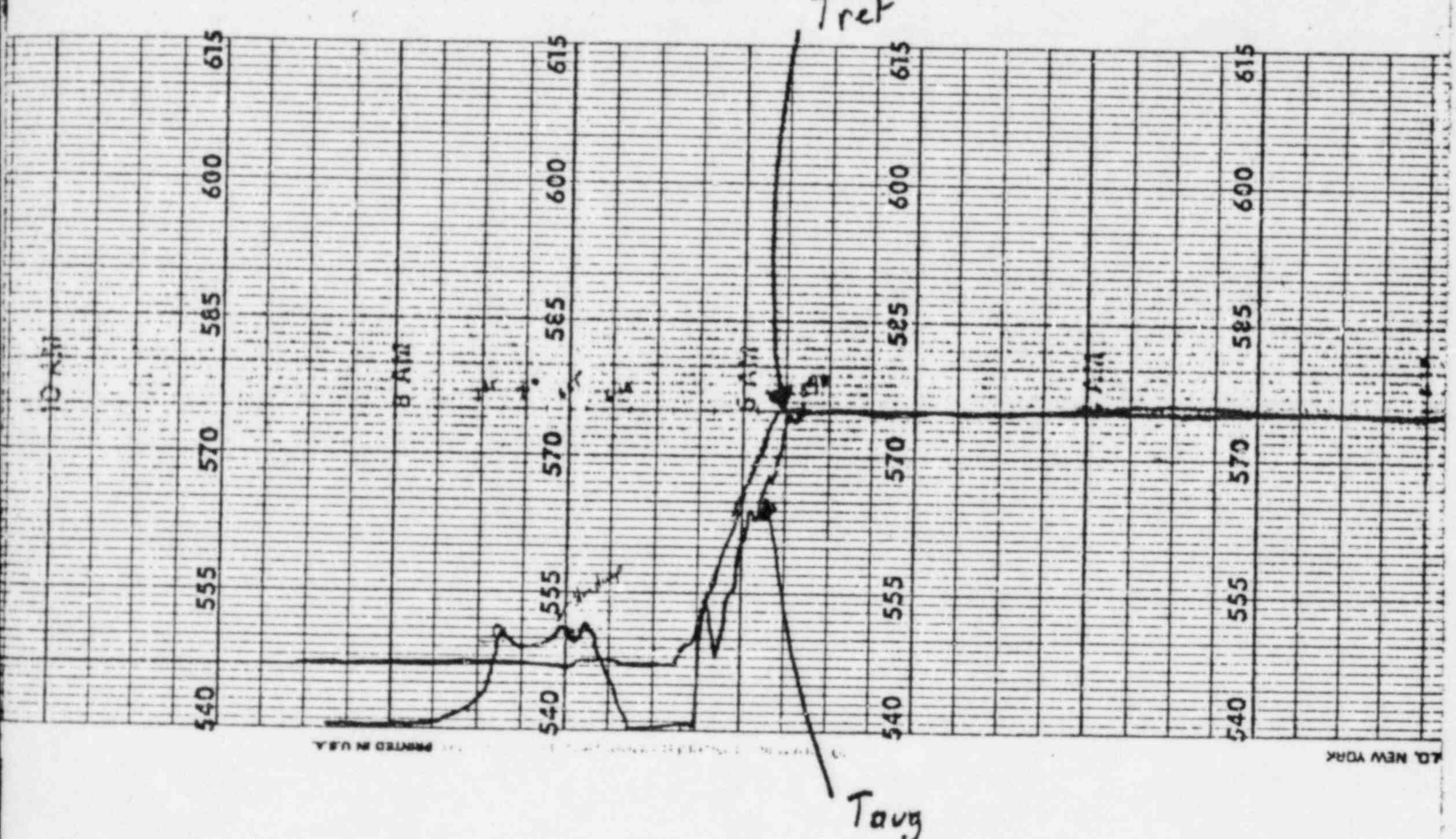
UNIT	TIME	1600 - 2400 Thursday 1/29/81
		1) Reviewed previous shifts logs. Ex-f
		2) Conditions as found: RCS-535 & 536 are closed; Rod 6-11, SD aux. feedwater pump, A & B charging pumps, HVE-15 & 15A, 'A' CWP Discharge valve are inoperable. Jumper tags #661, 662, 663, 664 are installed on 'A' circulating water pump; Fire water valve 1020A (FP-248) failed to close on SI & is under maintenance; A RCP running; RCS at 479°F & 1800 psi; LWR # 86 on 'B' monitor tank is in progress;
		3) Opened breaker for valve 1020B (FP-249) while maintenance is to be performed on valve 1020A (FP-248).
		4) Completed PT-8.0, RCS leakrate .2134 gpm.
		5) 1830 hours lined up 'A' charging pump for operation. PT-15.2 not performed due to non-normal lineups & RCS pressure & pressurizer level flow & unstable respectively.
		6) 1913 hours started 'B' RCP as per special procedure and OP-29B.
		7) 1932 hours started 'C' RCP as per special procedure and OP-29B.
		8) Received load of liquid nitrogen
		9) Isolated generator hydrogen.
		10) Transferred 2 batches of boric acid to 'B' Boric acid storage tank. 'B' BAST 21,322 ppm
		11) Placed charging line and RCS letdown line in service; ~~isolated excess~~ Ex-f Removed excess letdown from service.
		12) Completed LWR# 86 on 'B' monitor tank. Late entry - Tested pressurizer spray valves open and closed, observed them locally during operation and left them in the closed position; This ~~test~~ OG was completed prior to starting 'B' or 'C' RCP's.
		13) Completed PT-21.2
		Conditions: Unit retired for maintenance. RCS at 468 °F & 1700 psig; N1-31 840 cpm N1-32 3500 cpm
		Relieved by [illegible]



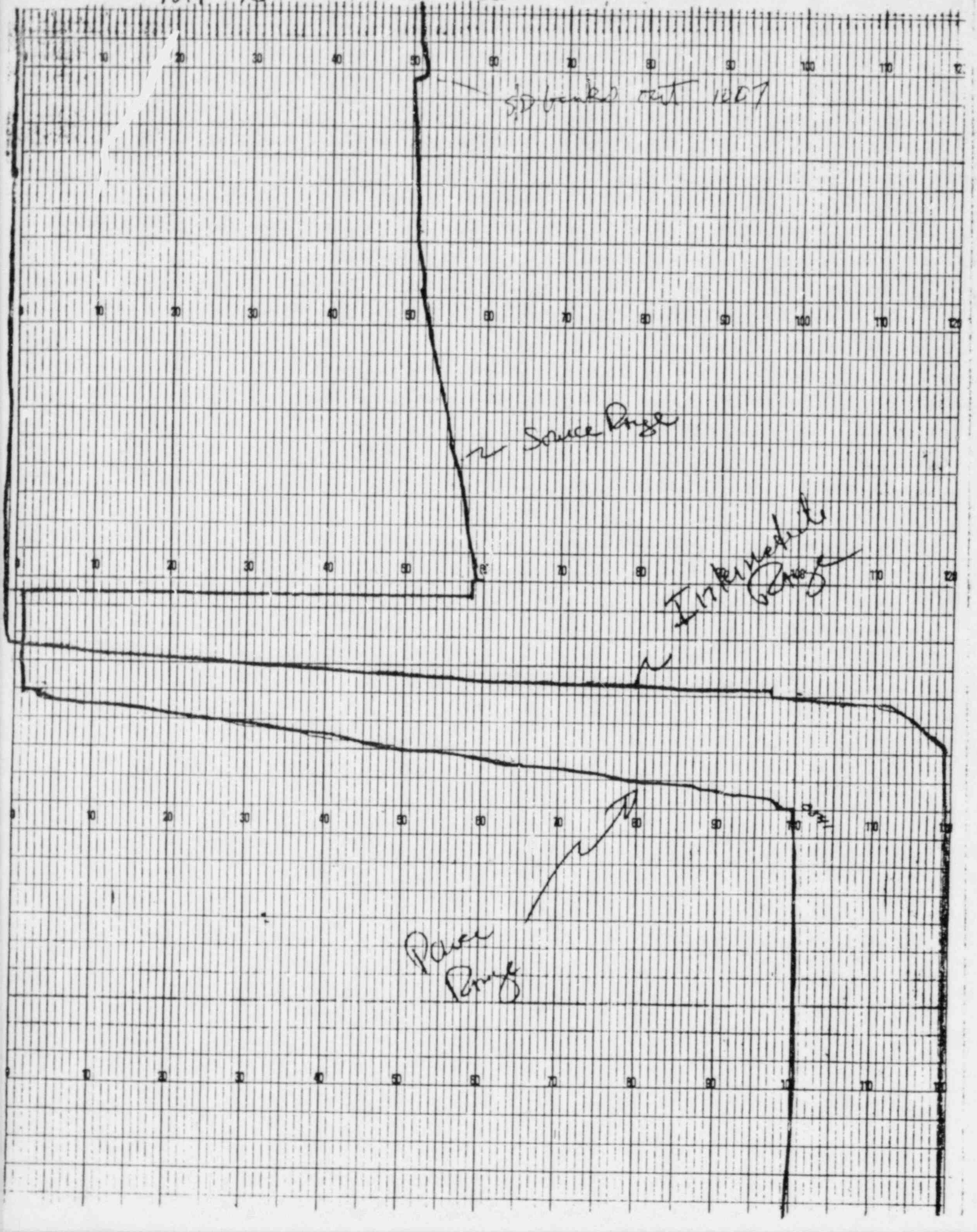
T_{cold}
T_{HOT}
0 100 200 300 400 500 600 700
6AM
8AM
10AM
12N
2PM
4PM
6PM
1-28-81
GRAPHIC CONTROLS CORPORATION BUFFALO, NEW YORK

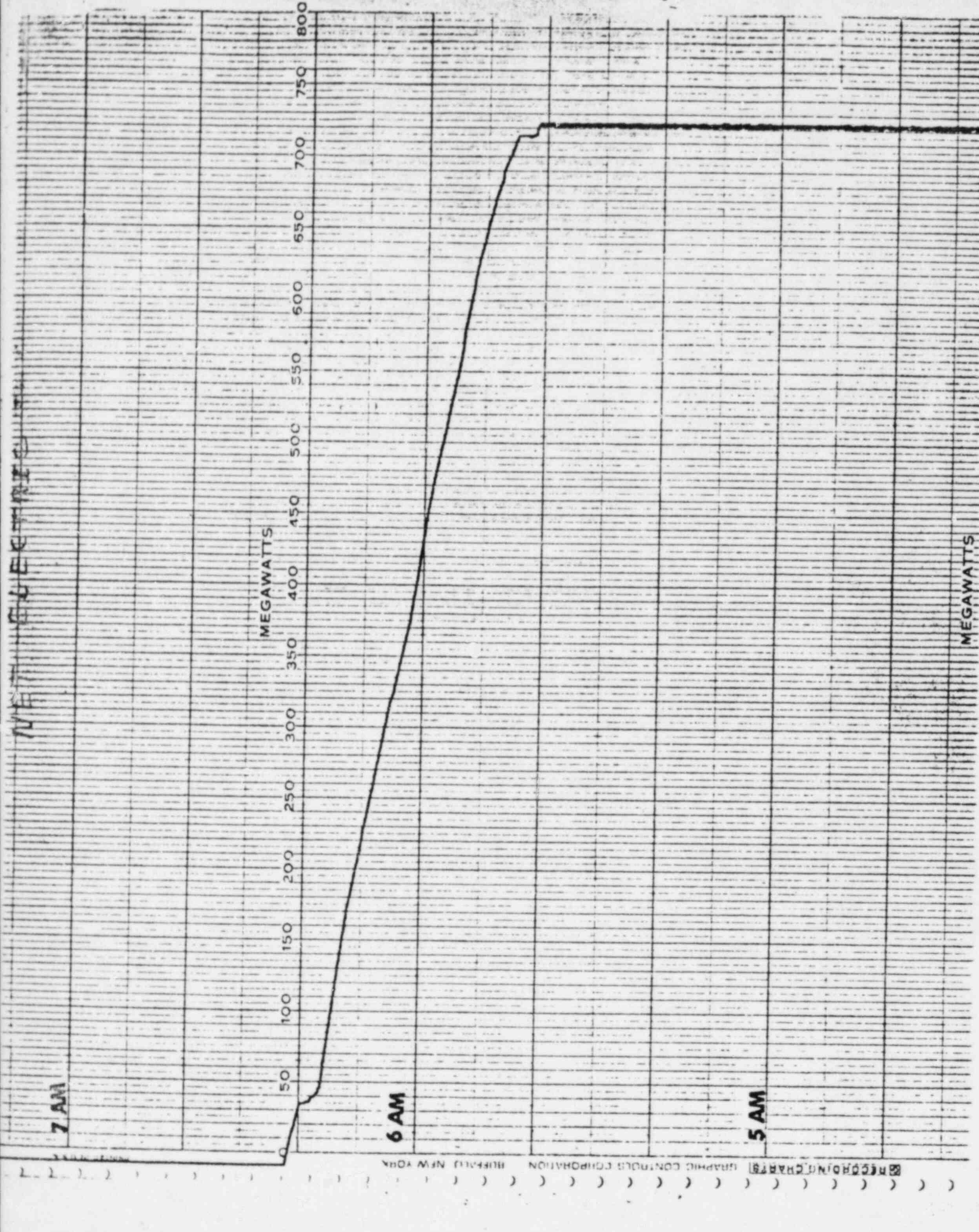
TR-408

Tavg/Tref



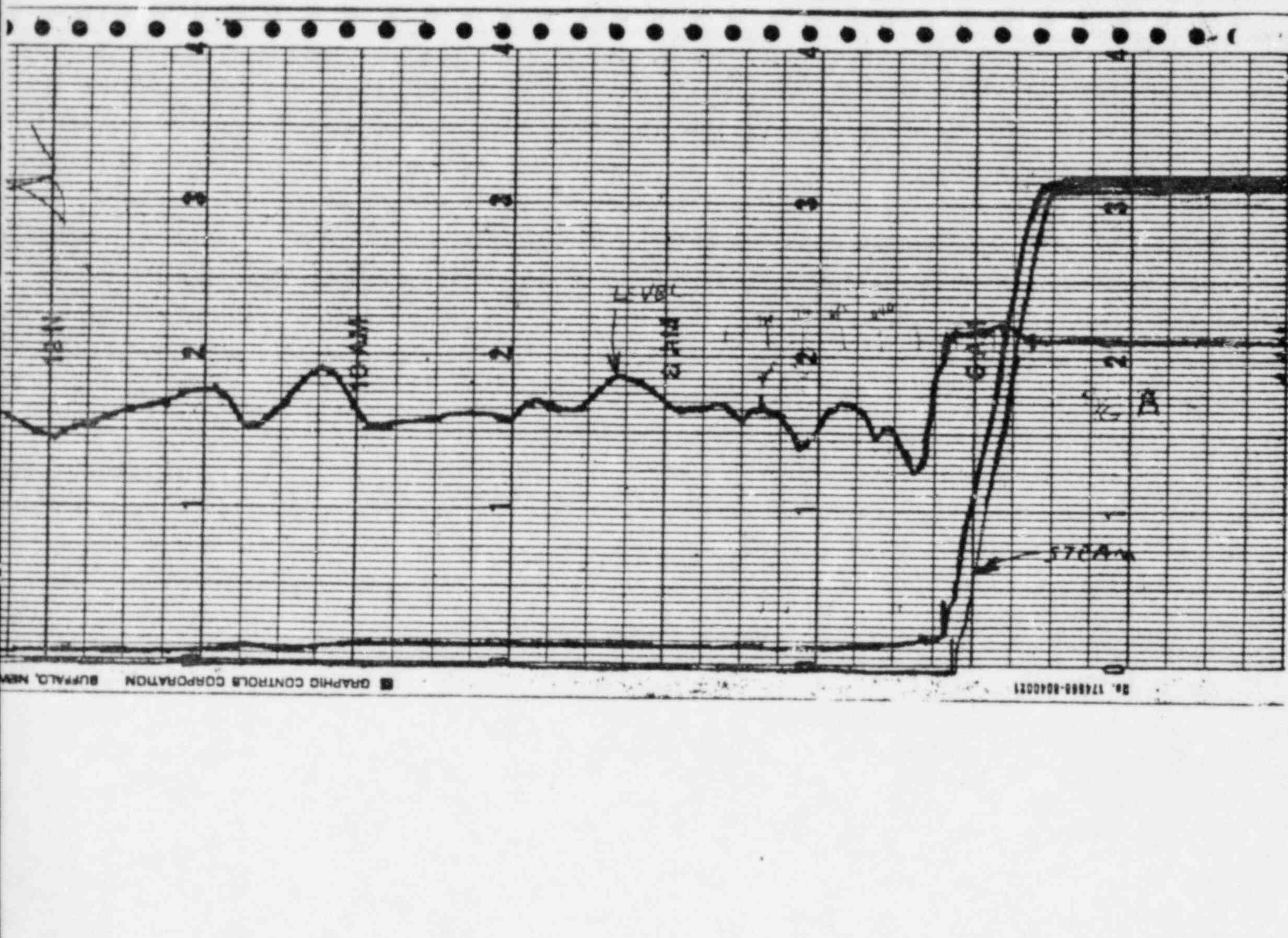
NR 45 Nuclear Power



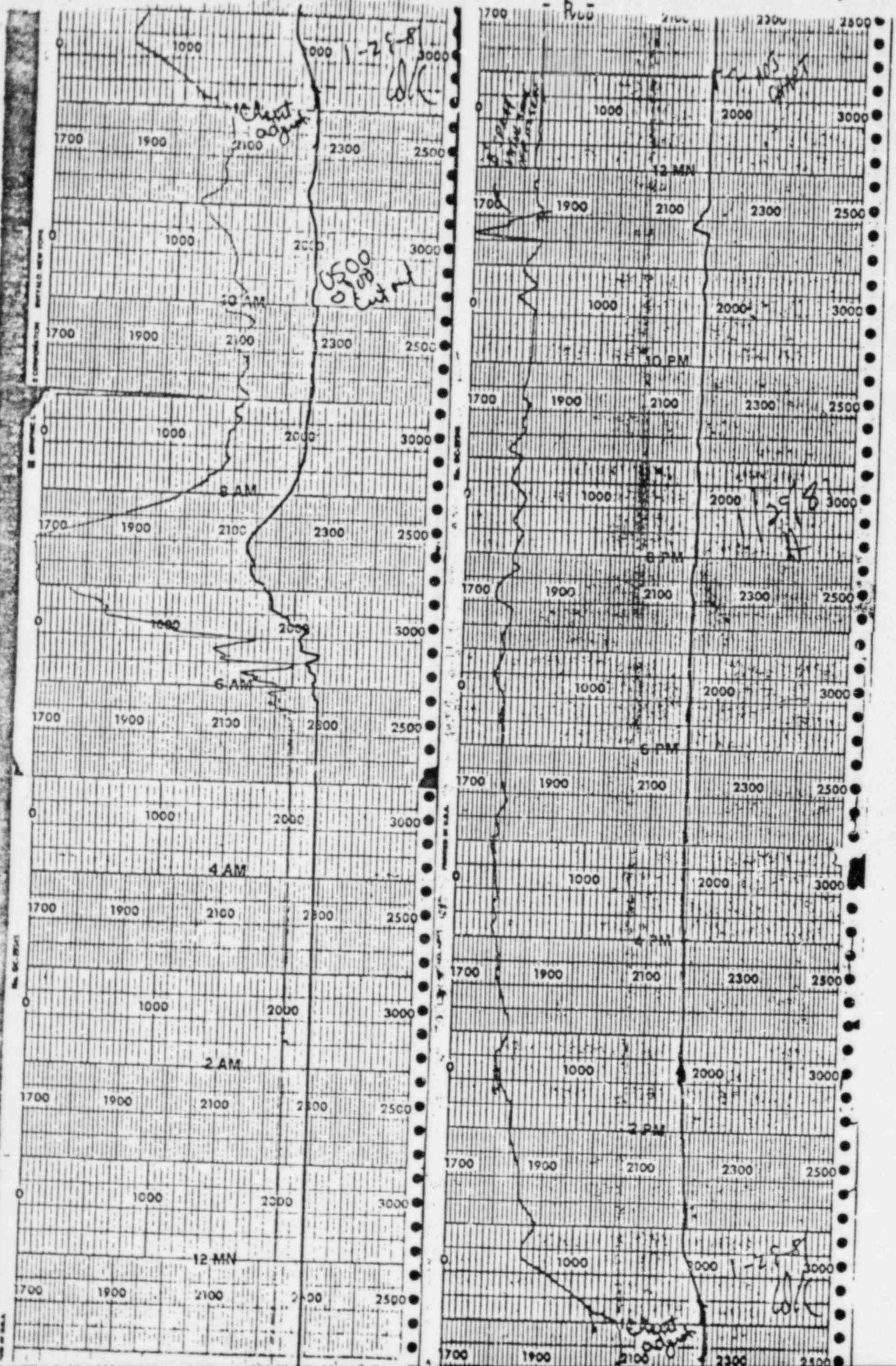

MEGAWATTS
0
50
100
150
200
250
300
350
400
450
500
550
600
650
700
750
800
7 AM
6 AM
5 AM
MEGAWATTS
RECORDING CHARTS
GRAPHIC CONTROLS CORPORATION
BUFFALO, NEW YORK

LEVEL
FEED
STEAM

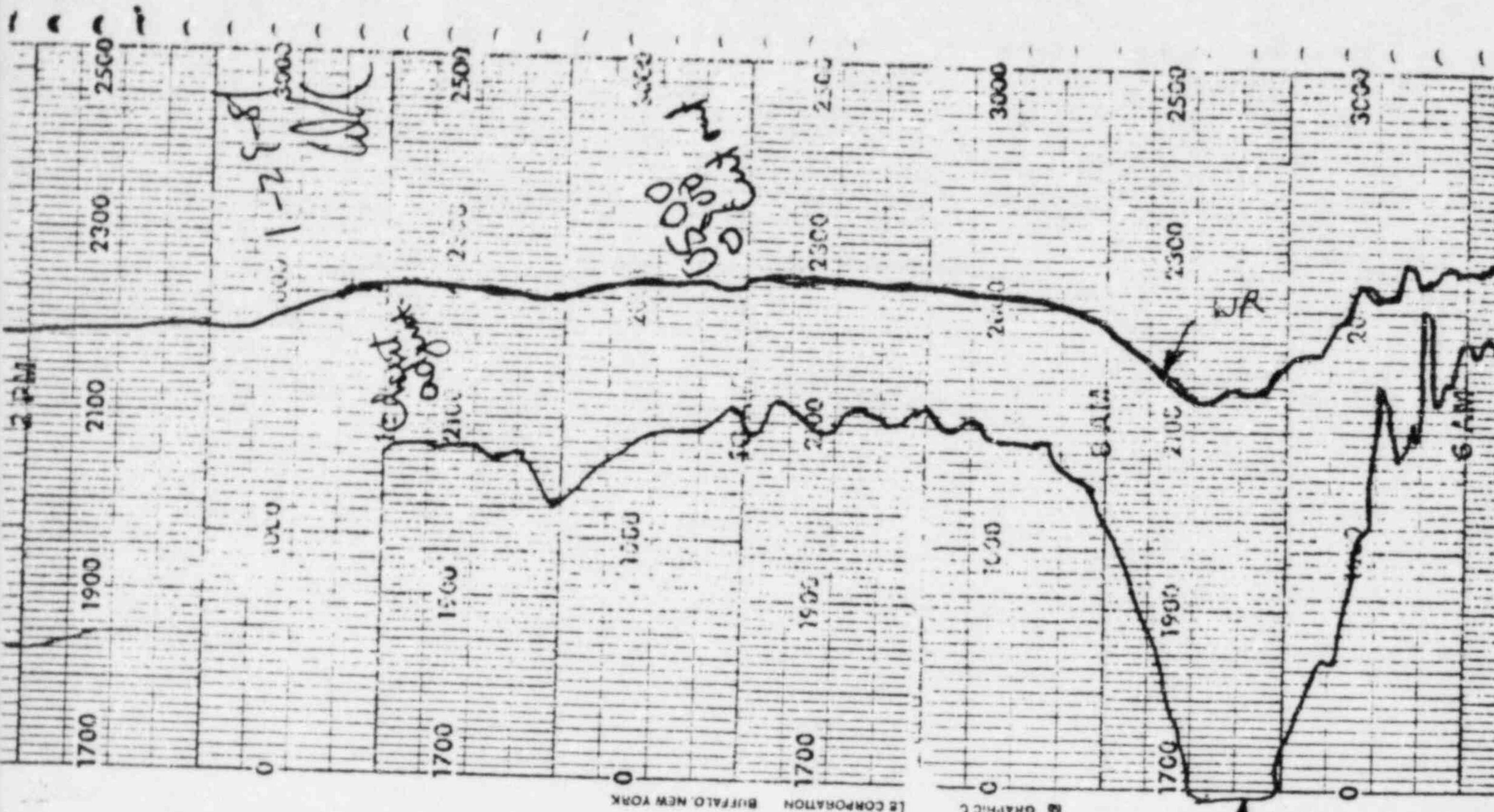
STEAM GENERATOR A Level
FEEDWATER FLOW/STEAM FLOW



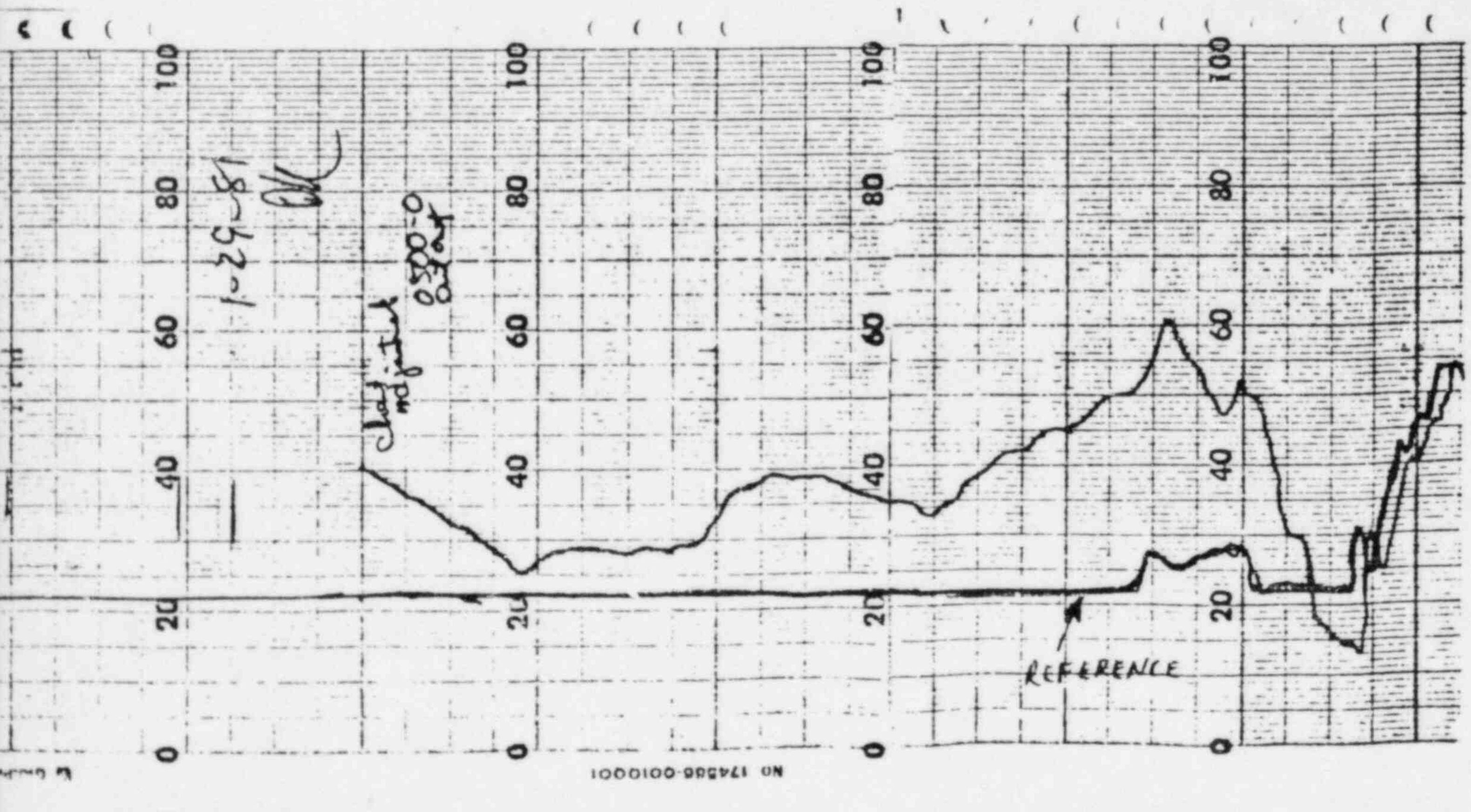
Pressurizer Pressure (NR + WR)



PRESSURIZER PRESSURE

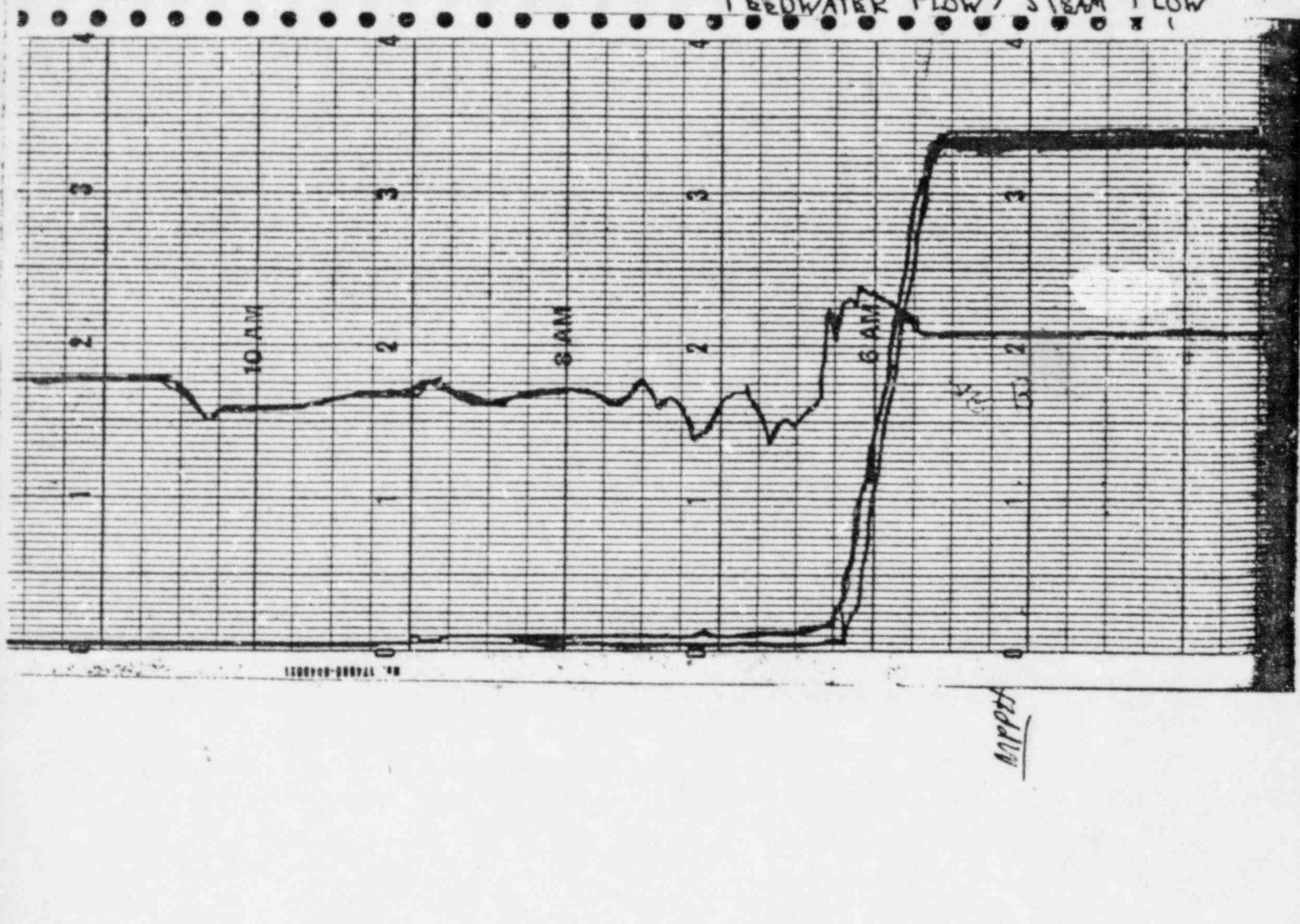


PZR LEVEL



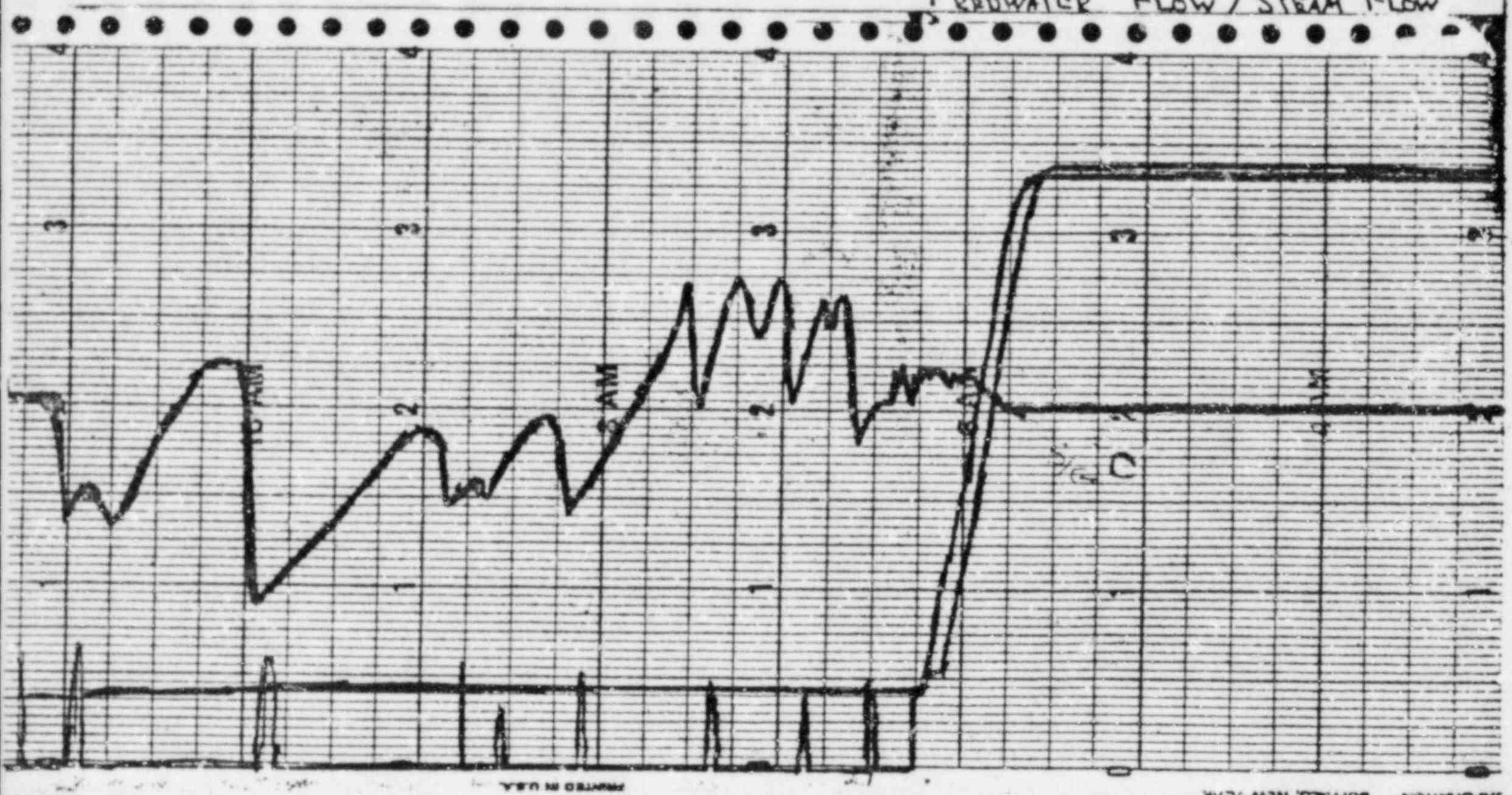
LEVEL
FEED
STEAM

STEAM GENERATOR B LEVEL
FEEDWATER FLOW/STEAM FLOW

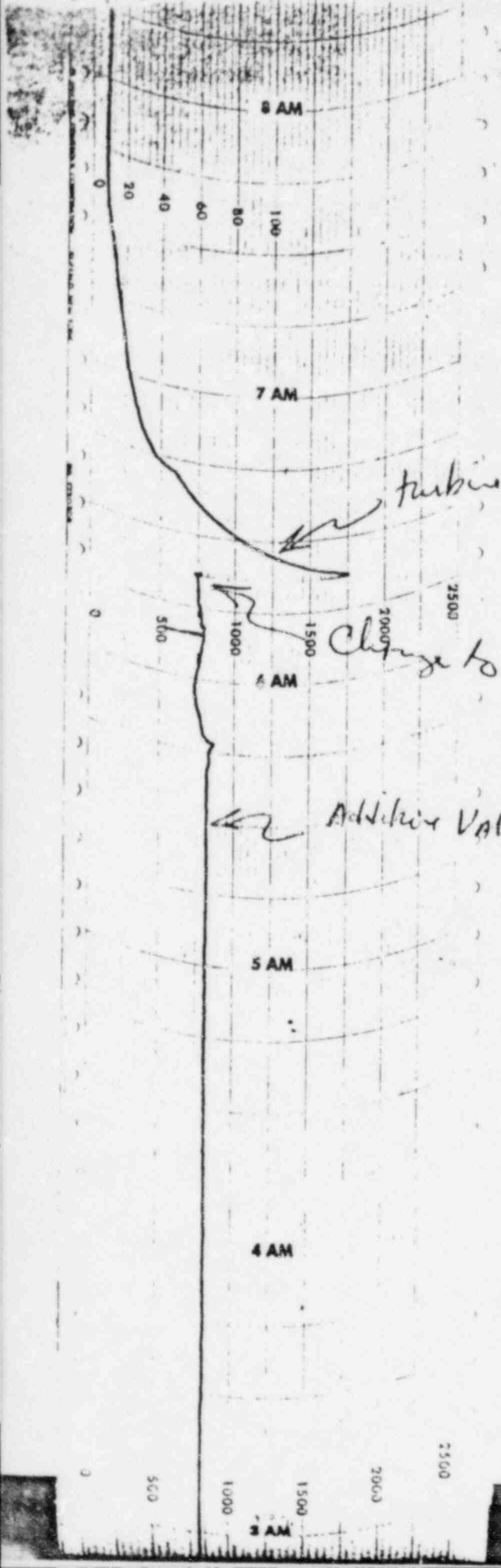


Level
Feed
Steam

Steam Generator C Level
Feedwater Flow/Steam Flow



Turbine Governor Valve Position

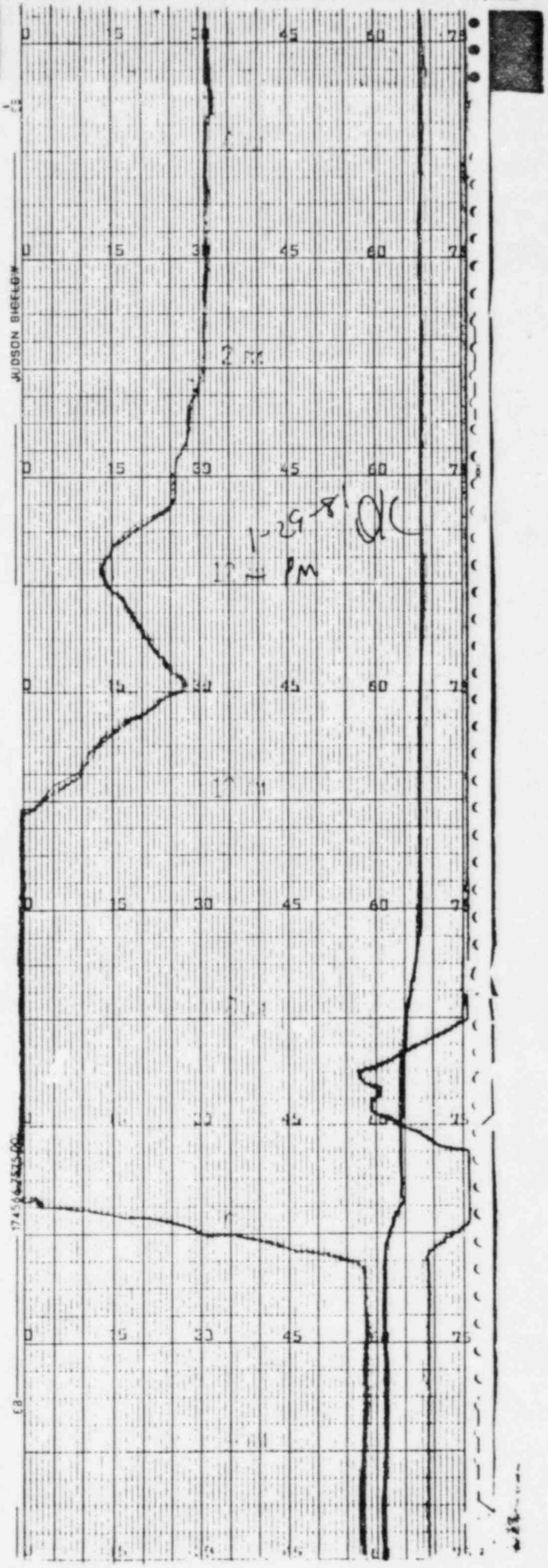


ΔT

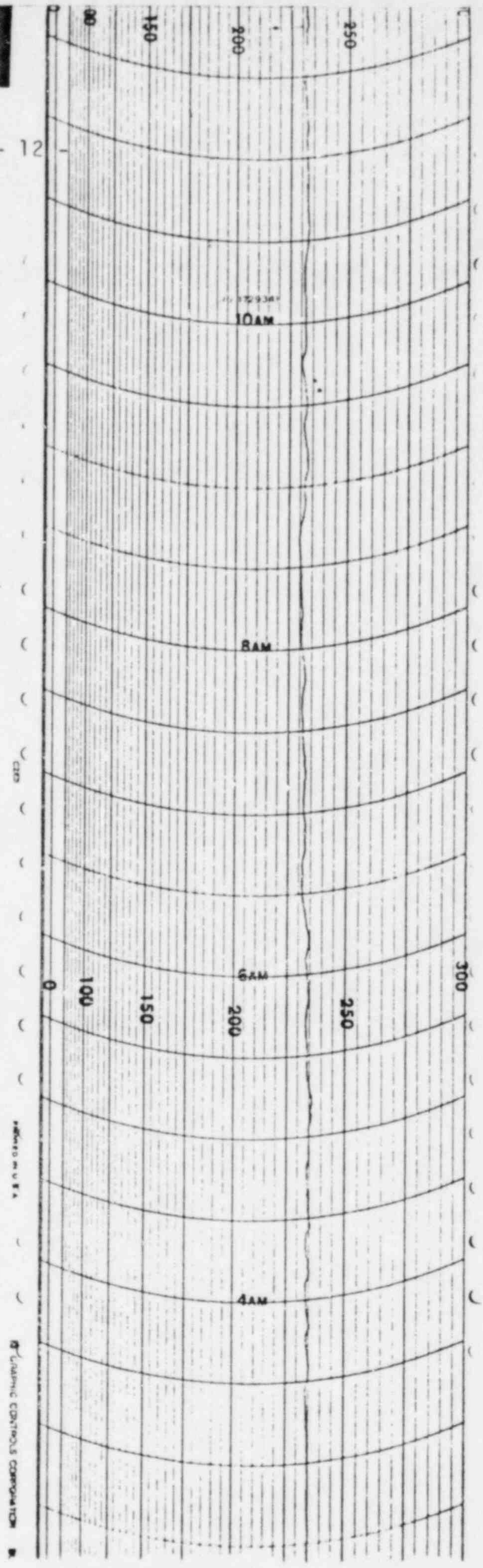
Loop A ΔT

OVER Temp ΔT

OVER Power ΔT setpoint



[illegible] #11 VOLTAGE


- 12
150
200
250
10AM
8AM
6AM
0
100
150
200
250
300
4AM
GRAPHIC CONTROLS CORPORATION

RCP Seal Leak (NR).

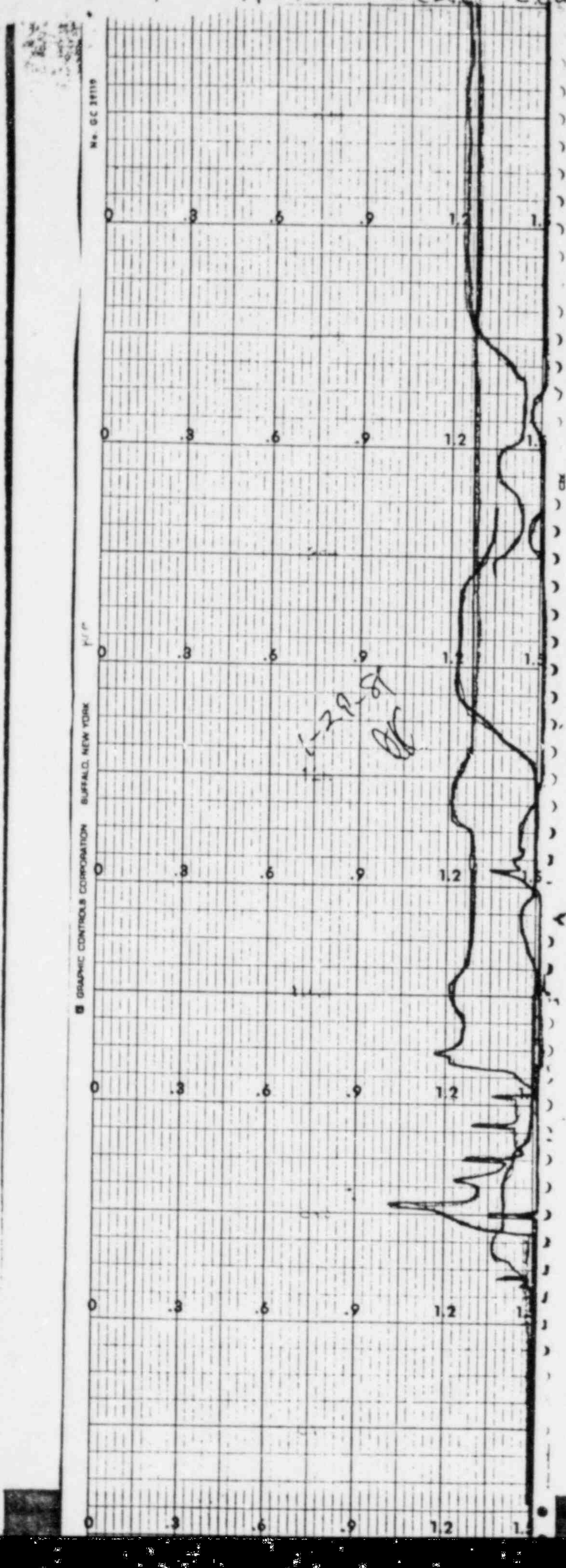
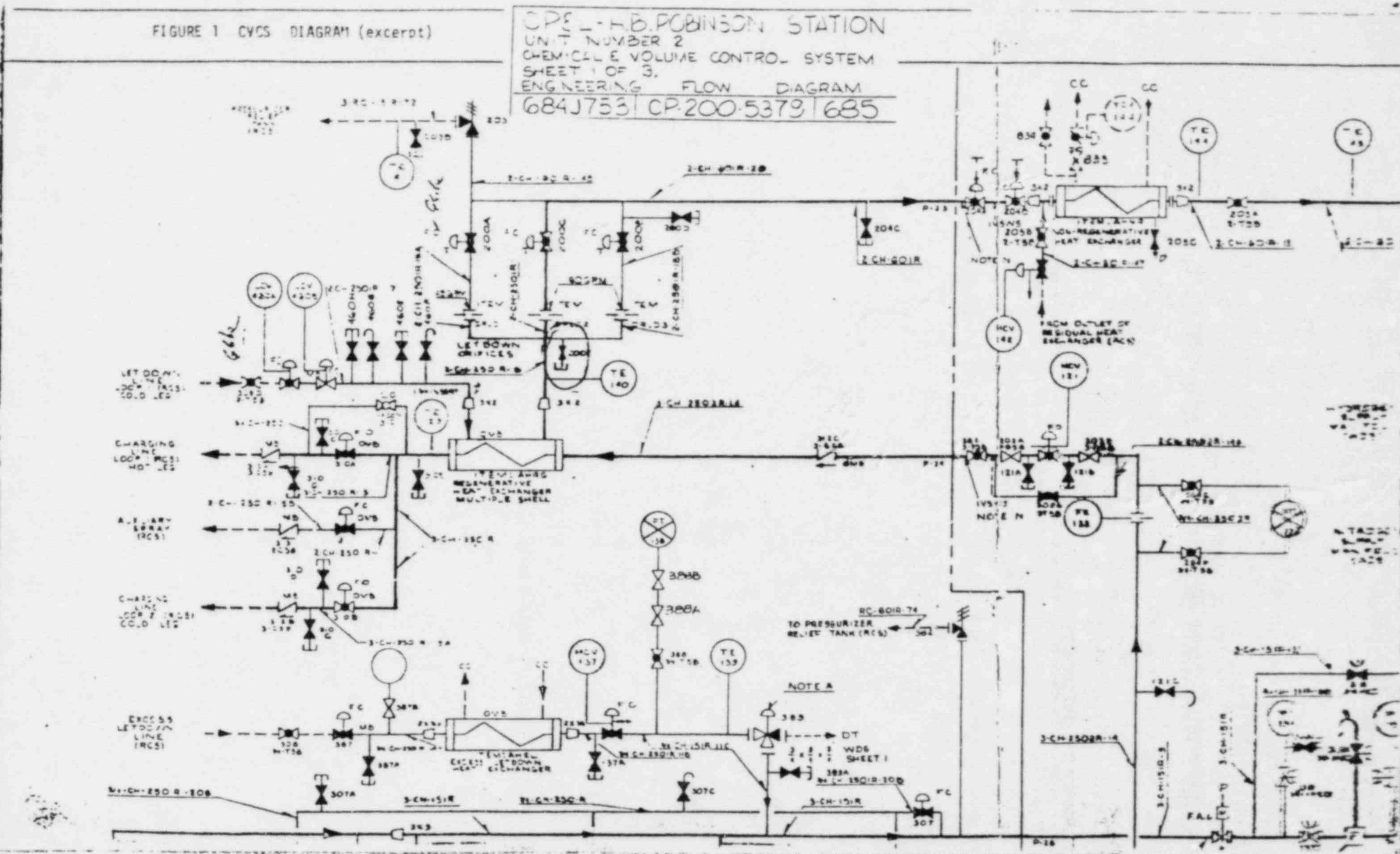


FIGURE 1 CVCS DIAGRAM (excerpt)



MODIFICATION NO. 525
REVISION 3

FIGURE 2 CONTAINMENT SUMP VOLUME