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STATEMENT REGARDING SERVICE

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This rebuttal statement is served through the United States mail, first class, certified, return receipt requested as follows:

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Dr. David L. Hetrick

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Attorney Colleen P. Woodhead

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NUCLEAR REGULATORY COMMISSION

Docket No. 55-6075 Official Exh. No. 2
In the matter of Alfred Morabito
Staff ____ IDENTIFIED X
Applicant X RECEIVED ____
Intervenor ____ REJECTED ____
Cont'g Off'r ____
Contractor HR DATE 2/21/88
Other ____ Witness ____
Reporter Andrew Emerson

Alfred J. Morabito

Alfred J. Morabito

Case No.
55-6075 Morabito Exh 2
Disposition ✓
Rejected ✓
IN THE Morabito
Reporter:
Date: EMEA
2/21/88
No. Pages:

Morabito
Exh 2
EMEA
2/21/88
NRC

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PDR

BEFORE THE ADMINISTRATIVE JUDGE:

In the Matter of Alfred J. Morabito Senior Operator License for Beaver Valley Power Station, Unit 1	Docket No. 55-60755 ASLBP No. 87-551-02-SP November 7, 1987

INTRODUCTION:

This response is submitted to correct various fallacies presented by the examiners in their affidavit supporting the NRC Staff response to my Specification of Claims.

ARGUMENT

1. The Written Examination, Section 6

Question 6.03b: In their grading of this question, the examiners exhibit a mindset in that they assume that the thermal barrier will only rupture as the result of an overpressure condition. In fact, if a thermal barrier rupture is possible, then it must be considered possible at reactor coolant conditions of low pressure/low temperature as well as at high pressure/high temperature. The reactor coolant pumps are operated when the reactor coolant is at ambient temperature and atmospheric pressure.

Under those conditions, a rupture of the thermal barrier will allow chromated water to leak into the reactor coolant. An operator might observe this occurrence by observing a start of the backup cooling water pump due to decreasing pressure in the cooling water system. The operator could then determine that a problem existed with a thermal barrier by observing that the cooling water flow indication for one of the thermal barriers was significantly different from the others. An outside operator could then be dispatched to containment, which might be open and easily accessible at that time, to isolate the thermal barrier using the manual isolation valves thus mitigating the consequence of having chromated water leak into the reactor coolant.

Conclusion: As a test candidate, I had to consider all possible rupture conditions. All of my answers are correct from an operator's point of view whether or not they are the design conditions specified by the design engineers. There was no "shotgunning" of the answer to this question. I should receive full credit for the question. Pages 1 and 2 of the Appendix to this rebuttal describe preparations for a "bump" start of the reactor coolant pumps. Note that the thermal barrier is in service prior to such a start.

Question 6.06a: The pressurizer power operated relief valves (PORVs) are often referred to as pressure control components. See the last paragraph on Appendix page 4. Additionally, there are 3 PORVs and all 3 are controlled from the 2 pressurizer pressure control channels as differentiated from the 3 pressurizer pressure protection channels. See the last 3 items on Appendix page 6. The alarms associated with PORV operation are referred to as pressure control alarms. See 2335 psig setpoint on Appendix page 7. One of the PORVs is controlled by the pressurizer pressure controller. See Appendix page 8. Failure of the PORVs to function is a symptom for AOP 13, "Malfunction of Pressurizer Pressure Control". See item A. 4. on Appendix page 9. The operator is directed to manually operate a PORV to reduce increasing pressure. Such manual operation is a control action. See Manual Action 4. on Appendix page 10.

Conclusion: The distinction between control and protection regarding the PORVs is not so clear as the examiners might believe. The ambiguity of the word "what" justifies my answer. The preponderance of published literature leans heavily toward the definition of the PORVs as pressure control components.

Question 6.06b: The examiners response to my claims regarding this question makes me doubt that they understand the very purpose of this particular interlock. As discussed on Appemdix page 11, the 475° vapor space temperature setpoint measures the hottest temperature in the system. The interlock ensures that the inlet valve to the RHR system cannot be opened unless the temperature is less than 475°. My answer, 470°, is certainly indicative of the fact that I would not have exceeded the temperature capability of the RHR system. Moreover, 475° saturation temperature corresponds to 539 psia which is above the allowable pressure interlock of 430 psig so in reallity, pressurizer vapor space temperature would be less than 455° before the RHR inlet valves could be opened. That temperature is 15° less than my stated setpoint and 20° less than the setpoint listed in the manual. In addition, as shown in Precaution and Limitation A.5. on Appendix page 12 , the operator must ensure that reactor coolant system pressure and temperature are less than 430 psig and 350°F before placing the RHR system into service.

There is an additional note that I must make. The tolerance for the accuracy of the gauge and calibration

of the detector is at least ± 1% of full scale. The full scale reading of this particular instrument is 100°F to 700°F which allows for an inaccuracy of ± 6°. That tolerance easily covers my stated 470°F setpoint.

One final point should be considered. As stated in Initial Condition 3 on Appendix page 13, a startup checklist must be completed before placing the RHR system into service. As shown on that checklist, Appendix page 14, the operator must verify the temperature and pressure of the reactor coolant system. Both of the limits verified are more restrictive than the 475°F pressurizer vapor space temperature permissive.

Conclusion: These preceeding statements were mot meant to justify an incorrect setpoint. They are provided to support my claim that the point deduction made on this question during the regrade was retaliatory.

Question 6.07a: The examiners trip over their own logic in their response to my claims regarding this question. The movement of control rods in response to an increasing T average is a control function not a protection function. It requires operator action; especially since the control rod mode selector switch is never selected to "automatic" for Unit 1 operations. Operator response is generally

neglected in the safety analysis for various off-normal events. The steam generator safety valves do provide the 1st level of protection against violation of Section A of the safety limit curve up to power levels of approximately 78%. The other design protection functions, which the examiners say act before the steam generator safeties, actually perform back-up actions. The relationships of all of these design protective features are shown in Appendix page 15 with supporting explanations on pages 16 and 17.

Conclusion: My answer is a correct answer to the question. The NRC answer key for this question should be revised prior to any future use of this question.

Question 6.07b: The NRC answer key describes two conditions which could occur if the MSIVs did not close. For those conditions to be avoided, a single action has to occur, the leak must be isolated. As shown on Appendix page 18, the operability of the MSIVs ensures that the two conditions listed in the key do not occur. "Operability" implies that each of three MSIVs will close as required. All 3 are needed because one may be needed to isolate the steam generator that feeds the ruptured steam line while the other two isolate the unaffected steam generators. My answer describes two reasons why the MSIVs must close.

The NRC answer key describes conditions that may occur if the MSIVs do not close. The exam question specifically prohibited stating conditions. In addition, the NRC answer is found in the bases section of the plant technical specifications. If they had wanted to limit the answer to just those which they listed in their key, they should have asked for the basis for maintaining the operability of the MSIVs.

Conclusion: My answer describes two reasons why the MSIVs are required to close during a steam line rupture. The NRC key describes two conditions or occurrences that will be avoided if the MSIVs close. My answer is correct. The NRC answer is not correct for the question as written.

2. The Simulator Examination

A. Compliance/Use of Procedures:

1. (Refer to Examiner's Comment #1) A 10% power reduction was ordered to check the precision (agreement with each other) of the nuclear instruments as differentiated from checking the calibration (accuracy of indication) of any particular nuclear instrument. There is no procedure available to an operator for such a determination. The appropriate operating

procedure to invoke would have been AOP-10, Malfunction of Nuclear Instrumentation. But first I had to determine whether or not I had a failed instrument since I didn't have any of the symptoms listed on Appendix page 19.

Conclusion: My actions were correct and permissable. Had I subsequently been able to identify one or more malfunctioning instruments, my actions would have been conservative and in accordance with step 2.b. on Appen x page 20.

2. (Refer to Examiner's Comment #4) In light of the Staff's response that my failure to perform an immediate action step is a significant ommission, I must ask the following questions as rhetorical comment:

   a. Has every licensed operator or senior operator been examined on his ability to remember and perform all 20 immediate action steps in sequence?
   b. Has any licensed operator or senior operator ever gained his license even though he may have missed an immediate action step?
   c. Do the examiners restrict the senior reactor operators from reading the immediate

action steps out loud from the procedure after about the seventh step? If they were going to examine an operators ability to memorize and perform all immediate action steps, they would have to restrict the senior operator from reading the steps.

d. Do the reactor operator and balance of plant operator always perform only the immediate actions which affect their area or is their constant interaction among them such that one operator performs steps that the other operator forgets and do the steps which each operator performs vary from crew to crew?

B. Control Board Operations:

1. (Refer to Examiner's Comment #1) As I have stated previously, the judgement of a candidate's performance must be based on objectivity. If the candidates actions are variant from procedural direction because of an error on the candidate's part, but that error does not cause the bounds of the analyzed accidents to be exceeded, or cause equipment damage, or jeopardize the health and safety of the public then,

while the candidate's performance could be commented on and downgraded, the downgrading of that performance should not be so significant as to lead to an unsatisfactory rating in a system where one unsatisfactory rating can lead to failure of the exam. My actions in tripping the reactor coolant pumps were within the bounds of the analyzed accident. See the first paragraph on Appendix page 21.

The preceeding comments also are pertinent to the last paragraph on page 16 of the Staff Response and to the comments and summary stated on page 17 of the Staff Response.

C. Supervisory Ability:

1. (Refer to Examiner's Comment #1) The Staff and Staff Counsel seem to have things a bit mixed up. I was first to notice the open indication on the valve but this was not until many minutes later during the performance of Emergency Operating Procedure actions. The balance of plant operator had moved from in front of the valve position indicators by that time and I observed the open indication on the valve. As I have stated before, many things were happening during this scenario. Of

necessity, I had to prioritize the problems that would receive my attention. A prompt in the scenario (alarm) did not occur due to a deficiency in the scenario. That prompt, if it had occurred, would have caused me to reprioritize the situation. Candidates do not have time to look for ghosts when a testing scenario is in progress.

2. (Refer to Examiner's Comment #2) My 21 years of demonstrated proficiency on a pressurized water reactor having two radically different cores during its lifetime should have great significance in determining my supervisory capabilities. Those attributes are independent of the specific reactor or even the specific type of Nuclear Plant.

D. <u>Communications/Crew Interactions</u>:

1. (Refer to Examiner's Comment #2) The hand signal was proper. The meters that the operator had checked read out in logarithmic units. If the operator had attempted to extract a numerical reading, several potential errors could have occurred:

   1) Choosing incorrect integer

   2) Choosing incorrect exponent of 10

   3) Parralax

I then would have had to picture in my mind how far above background the reading that was communicated to me was, which would have introduced another opportunity for error. Instead, the operator drew a picture for me and I immediately understood the communication.

SUMMARY

My failure to address any comment in the Staff Response in this rebuttal does not indicate my acceptance of them. There is simply no additional argument to be made. I will rely on the astuteness of the Administrative Judges for determining the accuracy of my claims. It should be noted in my Specification of Claims, on page 12, that I did ask for consideration of all of my comments; those in the Specification, and those in my appeal letters of September 11, 1986 and December 16, 1986.

I also call attention to the fact that in at least two other written exams that I have reviewed, the creative grading applied to my answer for question 6.03b was not applied. There may be other such cases also. Consistency does not appear to be a hallmark of the license examination process.

Respectfully submitted this 9th day of November, 1987.

Alfred J. Morabito

Alfred J. Morabito

jlm/AJM

APPENDIX

TO

REBUTTAL STATEMENT

A. STARTUP (continued)

CAUTION: Operating the charging pump only on recirculation for periods exceeding one hour will exponentially accelerate wear on pump internals due to increased temperature and pressure caused by flow restrictions in the recirculation path.

6. To use aux. spray for pressure control once a steam bubble has been established:

   a. Close [FCV-1CH-160], [MOV-1CH-310] and [FCV-1CH-122].

   b. Open [MOV-1CH-311] (aux. spray valve).

   c. Control spray flow by using [FCV-1CH-122].

7. To remove aux. spray from service in order to charge into the RCS:

   a. Close [FCV-1CH-122] and [MOV-1CH-311].

   b. Open [MOV-1CH-310].

   c. Control charging flow by using [FCV-1CH-122].

8. Check open the following CVCS valves, to ensure approximately 8 gpm reactor coolant pump seal injection water flow:

   a. RCP 1A, 1B & 1C #1 seal leakoff isolation [MOV-1CH-303A, B & C];

   b. Seal injection isolation valves [MOV-1CH-308A, B & C];

   c. Seal water return containment isolation valves [MOV-1CH-378 and 381].

9. To ensure adequate Reactor Coolant Pump Cooling:

   a. Check open the following Reactor Plant Component Cooling Water System valves:

      1) RCP CCR inlet header isolation [TV-1CC-103A, B and C] and [TV-1CC-103A1, B1 and C1];

      2) RCP CCR inlet isolation [TV-1CC-103A, B and C].

      3) RCP Thermal Barrier CCR outlet isolation [TV-1CC-107A, B and C].

      4) RCP motor CCR outlet header isolation [TV-1CC-105E1 and E2] and [TV-1CC-105D1 and D2].

      5) RCP Thermal Barrier CCR outlet header isolation [TV-1CC-107E1 and E2] and [TV-1CC-107D1 and D2].

A. STARTUP (continued)

b. Ensure component cooling water heat exchanger outlet temperature is less than 105F.

c. Verify CCR flow indication to the RCPs:

1) [FI-1CC-104A, B and C] (UBLO), greater than 150 gpm.

2) [FI-1CC-105A, B and C] (Motor Stator), greater than 220 gpm.

3) [FI-1CC-106A, B and C] (LBLO), greater than 5 gpm.

4) [FI-1CC-107A, B and C] (Thermal Barrier HX), 40 - 50 gpm.

CAUTION

a. Only one RCP is to be started at any one time.

b. After any period of running or after any attempt to start an RCP where the motor has failed to achieve full speed before it is stopped, a restart should not be made until the motor has been allowed to cool by standing idle for a period of not less than 30 minutes. When three starts or attempted starts have been made within a two hour period, then a fourth start should not be made until the motor has been allowed to cool by standing idle for at least one hour.

c. The RCP should not be operated continuously until the RCS has been filled and vented.

d. If all pumps have been idle for more than 5 minutes and the reactor coolant temperature is greater than the charging and seal injection water temperature, do not start the first pump until a steam bubble has been formed in the pressurizer. (A steam bubble is not required for a bump start during performance of the filling and venting procedures).

e. A backup supply of electrical power must be available to continue the flow of component cooling water to the RCP in case the primary electric power supply is interrupted.

f. Seal injection water should be flowing at all times when the primary system is above atmospheric pressure or when the Reactor Coolant System water level is above the seals.

g. Do not start a reactor coolant pump with #1 seal leakoff flow less than 0.2 GPM and less than 200 psid differential across the No. 1 seal.

ATTACHMENT 1

Westinghouse Electric Corporation

Power Systems

Box 355
Pittsburgh Pennsylvania 15230-0355

July 9, 1987
DLW-87-589

Mr. W. S. Lacey, Plant Manager
Beaver Valley Station Unit No. 1
Duquesne Light Company
P. O. Box 4
Shippingport, Pennsylvania 15077

Dear Mr. Lacey:

Duquesne Light Company
Beaver Valley Unit No. 1
FSAR Loss of External Electrical Load/Turbine Trip Event

This letter is to notify you that the Westinghouse Safety Review Committee has reviewed an issue for potential reportability as an unreviewed safety question as defined in 10CFR50.59 concerning the FSAR Loss of External Electrical Load/Turbine Trip Analyses. The SRC determined that this issue did not constitute a substantial safety hazard.

The potential unreviewed safety question involves possible non-conservatisms in the analysis assumptions regarding the DNB analysis for the Loss of Load/Turbine Trip event. This leads to the possibility of a scenario different than that described in the FSAR and also the possibility that the DNBR design limit may not be met. The new scenario is a turbine trip event with a consequential loss of forced reactor coolant flow prior to reactor trip.

BACKGROUND

Following a turbine trip where there are no electrical faults which require tripping the generator from the grid, the generator remains connected to the grid for approximately 30 seconds (turbine-generator motoring) before attempting to transfer to an offsite power supply (see the attachment for the functional requirement and bases on the balance of plant electrical system design). A turbine trip is classified as an ANS Condition II event. The analysis must demonstrate that the DNB design basis is met and that the peak pressure reached during the event is below 110% of design. The turbine trip event is the most limiting Condition II transient with respect to overpressurization and as such, the assumptions made in the FSAR analyses are to maximize the pressure transient.

The FSAR Complete Loss of Flow event is classified as an ANS Condition III event. The Westinghouse criterion for this event is the same as the criterion for Condition II events (i.e. the analysis must demonstrate that the DNB design basis is met). The NRC currently reviews this accident as a Condition II event. The FSAR Complete Loss of Flow event is initiated from the worst

allowable steady state conditions (typically 102% power, Tavg plus 4 degrees F, Pressure minus 30 psia for plants with the standard thermal design procedure. For plants with the improved thermal design procedure, the above uncertainties are statistically combined into the DNB design limit value).

In the FSAR analysis, no credit is taken for the anticipatory reactor trip on turbine trip. Primary protection for the Loss of Load/Turbine Trip events is usually provided by the high pressurization pressure or overtemperature delta-T reactor trips. The new scenario is as follows: Should a reactor trip not occur in the first 30 seconds following the turbine trip (the period during which the generator is motored), a complete loss of forced reactor coolant flow could be assumed to occur 30 seconds into the transient due to a postulated single failure in the fast bus transfer to offsite power. This postulated loss of flow could occur at essentially full thermal power with the reactor at off-normal conditions (vessel inlet temperature approximately 15 degrees F above nominal T-inlet). The FSAR Complete Loss of Flow event is analyzed from steady state initial conditions as defined in Chapter 15.0 of the FSAR.

EVALUATION

Typically for the FSAR Loss of External Electrical Load/Turbine Trip analyses, four cases are analyzed and presented. These cases are minimum and maximum reactivity feedback, with and without pressurizer pressure control. Control systems are assumed to function in cases where the effect of their functioning provides a more limiting result. In the two cases without pressure control, a reactor trip occurs early in the event (about 5 - 10 seconds) on high pressurizer pressure. Therefore, a loss of flow 30 seconds after the turbine trip event would not have any impact on the minimum DNBR reached during the event since the reactor trips early. Thus, the conclusions in the FSAR remain valid.

Two cases are presented which take credit for pressurizer pressure control (PORV's and sprays operational), but these cases do not include other control systems (such as steam dump, feedwater control, steam generator PORV's). In the FSAR analyses, these cases trip on either high pressurizer pressure or overtemperature delta-T within about 20 seconds. For these cases, if the above three control systems function as designed, the reactor trip on either high pressurizer pressure or overtemperature delta-T would be delayed, and the reactor would remain at essentially full thermal power with the inlet temperature to the reactor increasing due to the turbine trip and resultant steam flow reduction. A loss of flow would then occur 30 seconds into the event due to a single failure of the fast bus transfer and the current FSAR Turbine Trip analysis would not be conservative with respect to DNB. In addition, the FSAR Complete Loss of Flow analysis would not bound this event with respect to the minimum DNBR since the reactor may be at or near full thermal power with an increased inlet temperature above the nominal value.

CONCLUSION

Westinghouse has performed calculations for a typical plant to determine the relative impact on the DNBR for a turbine trip event with a subsequent loss of flow prior to reactor trip. The results show a possible DNBR reduction for the FSAR Turbine Trip event with an assumed subsequent loss of flow prior to reactor trip. Furthermore, the DNBR for this event could possibly be lower than the minimum DNBR reached for the FSAR Complete Loss of Flow event. In addition, a new accident scenario has been defined which has not been previously evaluated in the FSAR.

However, should a turbine trip occur, the redundant reactor trip on turbine trip function is expected to occur if the power is above the P-7 (or P-9) permissive. For this situation, the FSAR analyses remain bounding and the DNBR design basis is met. Furthermore, on a best estimate basis where conservatisms are removed from the analysis assumptions, the minimum DNBR for this new accident scenario will be bounded by the results presented in the FSAR for the Complete Loss of Flow event. Finally, if it can be demonstrated that the reactor coolant pumps have an uninterrupted power supply for all turbine trip events (even with any single failure), then the FSAR analyses remain bounding.

This issue has been discussed with the Westinghouse Owners Group Issues Review Group and the attached letter from R. A. Newton, Chairman of the Westinghouse Owners Group, is the result of that review. If you have any questions, please contact the undersigned.

Sincerely,

S. P. Swigart

for J. N. Steinmetz, Manager
Operating Plant Projects

Attachments
HT/3043G

cc: J. J. Carey
H. M. Siegel
J. O. Crockett
J. D. Sieber
W. S. Lacey
G. S. Sovick WOG Rep.
N. R. Tonet
C. E. Ewing
K. D. Grada
R. J. Druga
BVPS-1 Nuclear Central File
R. L. Snyder - BV Site - SSM

INSTRUMENTATION AND CONTROLS (continued)

determine water temperature when the pressurizer is completely filled with water. The water phase detector, located at an elevation near the center of the heaters, is used during cooldown when the steam phase detector response is slow due to poor heat transfer.

Surge Line Temperature - [TE-1RC-450]

This detector supplies a signal for a temperature indicator and a low temperature alarm. Low temperature is an indication that the continuous spray rate is too small.

Safety and Relief Valve Discharge Temperature - [TIS-1RC-463, 465, 467, 469]

Temperatures in the pressurizer safety and relief valve discharge lines are measured and indicated. An increase in a discharge line temperature is an indication of leakage through the associated valve.

Spray Line Temperatures - [TIS-1RC-451 and 452]

Temperatures in the spray line from Loops 1A and 1C are measured and indicated. Alarms from these signals are actuated by low spray water temperature. Alarm conditions may indicate insufficient flow in these spray lines.

Pressurizer Pressure - [PT-1RC-455, 456 and 457]

These three pressure transmitters provide signals for use in initiation of low pressure reactor trip, high pressure reactor trip, and safety injection. They also provide a signal to open the safety injection accumulator discharge valves [MOV-1SI-865A, B, C] above 2000 psig, to block automatic power operated relief valve operation below 2000 psig, and to initiate a low pressure alarm. These pressures are indicated on the main control board.

Pressurizer Pressure - [PT-1RC-444]

This pressure transmitter furnishes a source signal for high and low pressure deviation alarms, backup heaters, pressurizer heater control, pressurizer spray valve [PCV-1RC-455A and B], and power relief valve [PCV-1RC-455C] control.

Pressurizer Pressure - [PT-1RC-445]

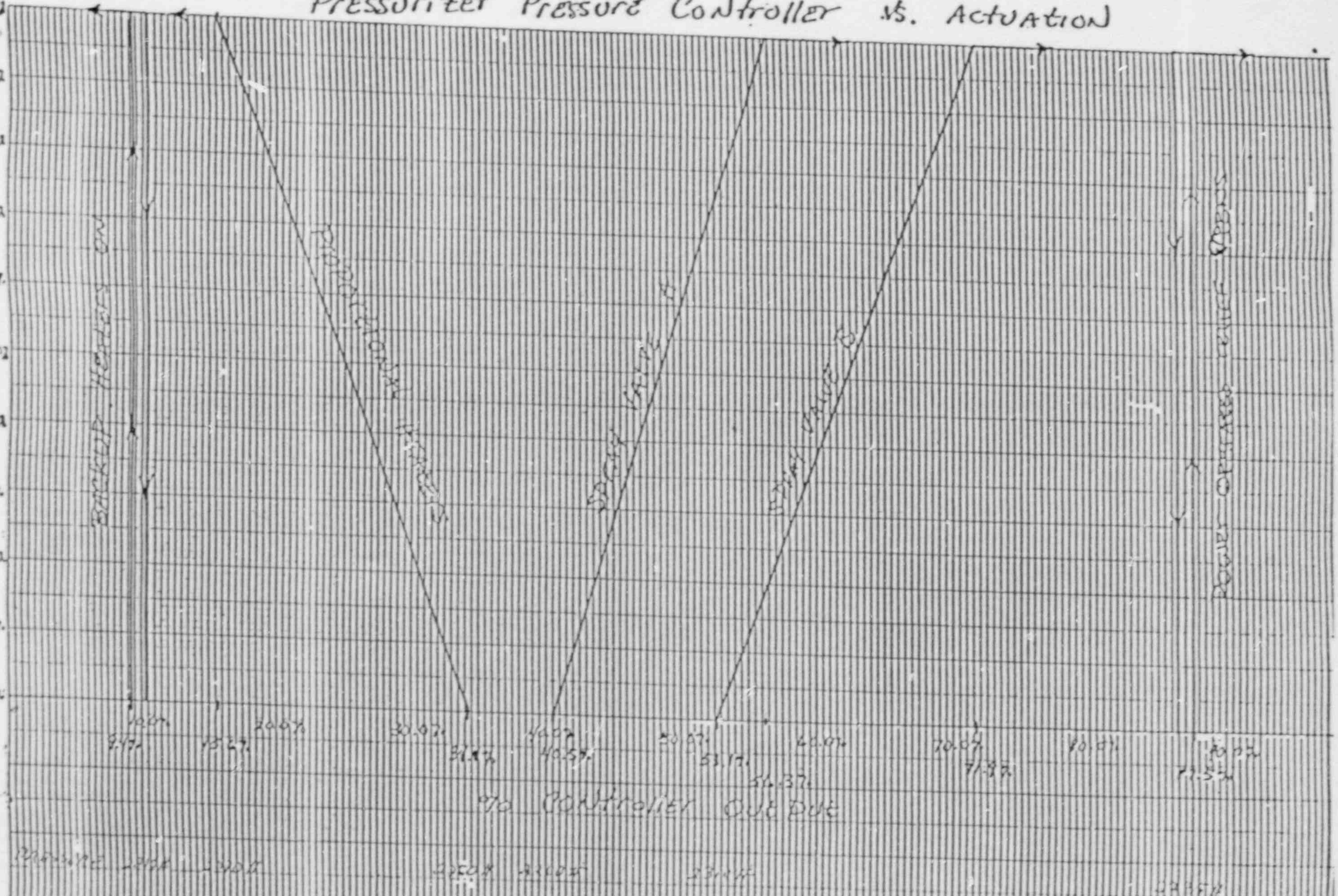
This transmitter will provide high-high, high and low pressure alarms and will open power operated relief valves [PCV-1RC-456 and 455D] on high-high pressure.

3107 psig	Hydrostatic Test Pressure of Reactor Coolant System
2735 psig	Reactor Coolant Pressure Safety Limit (110% of design pressure - 2500 psia)
2485 psig	Design Pressure of Reactor Coolant System Safety Valves Lift
2385 psig	High Pressure Reactor Trip PRESSURIZER PRESSURE HIGH Alarm
2335 psig	Power Operated Relief Valves Lift PRESSURIZER CONTROL HIGH PRESSURE DEVIATION Alarm PRESSURIZER CONTROL HIGH POWER RELIEF ACTIVATION Alarm
2310 psig	PRESSURIZER CONTROL PRESSURE HIGH Alarm Pressurizer Spray Valves Full Open
2260 psig	Pressurizer Spray Valves Begin to Open
2250 psig	Proportional Heaters Minimum Output
2235 psig	Normal Operating Pressure
2220 psig	Proportional Heaters Maximum Output Backup Heaters Off
2210 psig	Backup Heaters On PRESSURIZER CONTROL LOW PRESSURE DEVIATION Alarm
2185 psig	PRESSURIZER CONTROL PRESSURE LOW Alarm
2000 psig	Power-operated Relief Valve Interlock Safety Injection Accumulator Discharge Valve Auto Open Signal SAFETY INJECTOR ACCUMULATOR #1(2)(3) DISCH. VALVE NOT FULLY OPEN Alarms, if applicable Safety Injection Block Permissive* and Auto Reset PRESSURIZER 2/3 PRESS. RELIEF BLOCK Alarm LOW HEAD INJECT TO COLD LEGS ISOL MOV-SI-890C NOT FULLY OPEN alarm if applicable.
1945 psig	Pressurizer Low Pressure Reactor Trip PRESSURIZER PRESSURE LOW Alarm
1845 psig	Pressurizer Pressure Low Safety Injection Setpoint PRESSURIZER LOW PRESSURE SAFETY INJECTION SETPOINT Alarm

* Block also changes the steamline isolation signal from 2/3 pressure transmitters at 510 psig on any steamline to 2/3 pressure transmitters sensing a drop of 99 psi per 50 seconds.

14

Pressurizer Pressure Controller vs. Actuation



AOP-13 MALFUNCTION OF PRESSURIZER PRESSURE CONTROL

The malfunction may be maintained by an increasing (or high) pressure transient or a decreasing (or low) pressure transient.

A. INCREASING PRESSURE OR HIGH PRESSURE TRANSIENT

Symptoms

1. The following alarms and trip annunciators can be initiated on a high pressure condition:

   a. PRESSURIZER CONTROL PRESS HIGH Annunciator Window No. A4-9

   b. PRESSURIZER CONTROL HIGH PRESS DEVIATION Annunciator Window No. A4-10

   c. PRESSURIZER CONTROL PRESS HIGH PWR RELIEF ACT Annunciator Window A4-13

   d. PRESSURIZER PRESS HIGH Annunciator Window No. A4-19

   e. PRESSURIZER HIGH PRESS RX TRIP Primary Plant Status Panel Window No. A-4

   f. PRESSURIZER HIGH PRESS RX TRIP Primary Plant Status Panel Window No. B-4

   g. PRESSURIZER HIGH PRESS RX TRIP Priamry Plant Status Panel Window No. C-4

2. The pressurizer spray valves [PCV-1RC-455A and 455B] controllers' output meters have not indicated the controllers have started to modulate the valves open (with system pressure above 2260 psig*) Auto/Manual stations, BB-B.

3. Back-up pressurizer heaters are energized as indicated by red light on BB-B without pressure High Level Deviation Alarm present.

4. None of the pressurizer power-operated relief valves [PCV-1RC-455C, PCV-1RC-455D or PCV-1RC-456] opened as indicated by their respective position lights and/or a normal ambient temperature on the pressurizer power relief valve discharge temperature indicator [TI-RC-463] on VB-B.

* Setpoint is derived from compensated pressure signal and may not correspond to indicated pressurizer pressure.

AOP-13 MALFUNCTION OF PRESSURIZER PRESSURE CONTROL (Continued)

Automatic Actions

1. Controlling group pressurizer heaters cease cycling and turn off at 2250 psig*.

2. Pressurizer spray valves [PCV-1RC-455A and PCV-1RC-455B] start to modulate open at 2260 psig*.

3. PRESSURIZER CONTROL PRESS HIGH alarm is received at 2310* psig.

4. PRESSURIZER CONTROL HIGH PRESS DEVIATION alarm is received at 2335* psig and power-operated relief valve [PCV-1RC-455C] opens.

5. Pressurizer PORVs [PCV-1RC-455D] and PCV-1RC-456] open at 2335 psig.

6. PRESSURIZER PRESS HIGH alarm is received and high pressure reactor trip occurs at 2385 psig.

Manual Actions

1. Observe pressurizer pressure indications on BB-B and verify that the Automatic Actions (above) associated with that observed pressure have occured.

2. Secure any pressurizer heaters that may be energized.

3. Take manual control of one pressurizer spray valve and gradually modulate it open to reduce pressurizer pressure.

4. If pressurizer pressure is increasing rapidly, use a pressurizer PORVs to decrease pressurizer pressure. Ensure valve is unblocked. Only one Power Operated Relief Valve Isolation Valve [MOV-RC-535, 536, 537] may be open at one time in Operational Mode 1.

5. If a recator trip has occurred, go to Emergency Operating Procedure E-0, "Reactor Trip Or Safety Injection".

6. If pressurizer pressure reaches 2385 psig and a reactor trip has not occurred, manually trip the reactor and go to Emergency Operating Procedure E-0, "Reactor Trip Or Safety Injection".

* Setpoint is derived from compensated pressure signal and may not correspond to indicated pressurizer pressure.

3.2.2 Residual Heat Removal System Inlet Valves

Each of the inlet valves [MOV-1RH-700 and MOV-1RH-701] to the Residual Heat Removal System is interlocked with the Reactor Coolant System pressure (cannot be opened until Reactor Coolant System pressure is below 430 psig) and in addition, [MOV-1RH-701] is interlocked with the pressurizer vapor space temperature (cannot be opened until the temperature is below 475°F). These interlocks ensure the Residual Heat Removal System is not subjected to overpressure or overtemperature. Both of the valves are manually adjusted (OPEN-CLOSE) from benchboard - section A. They automatically close if Reactor Coolant System pressure exceeds 630 psig.

3.2.3 Residual Heat Removal System Outlet Valves

Manual controls (OPEN-CLOSE), located on benchboard - section A, are provided for the Residual Heat Removal System outlet valves [MOV-1RH-720A and MOV-1RH-720B]. Both of these valves are interlocked with reactor coolant pressure; they cannot be opened until Reactor Coolant System pressure is below 430 psig. They automatically close if Reactor Coolant System pressure exceeds 630 psig.

3.2.4 Residual Heat Removal System Temperature Control Valve

This remote-manual motor-operated valve [MOV-1RH-758] regulates the temperature of the return flow from the system. The reactor operator modulate the valve to provide the required cooldown rate of Reactor Coolant System.

CHAPTER 10

RESIDUAL HEAT REMOVAL SYSTEM

SECTION 2 - PRECAUTIONS, LIMITATIONS AND SETPOINTS

A. PRECAUTIONS AND LIMITATIONS

1. REACTOR COOLANT SYSTEM SHUTDOWN - (TECH. SPEC. 3.4.1.3.)

2. RESIDUAL HEAT REMOVAL SYSTEM - (TECH. SPEC. 3.9.8.1)

3. RESIDUAL HEAT REMOVAL SYSTEM - (TECH. SPEC. 3.9.8.2)

4. The Residual Heat Removal System should be placed in service within 8 hours from the beginning of a containment spray or an accident in general due to MOV qualification limitations.

5. Ensure that the reactor coolant system pressure and temperature are 430 psig and 350F or less before placing the RHS in operation. Loop isolation valves [MOV-1RH-700], [MOV-1RH-701] and [MOV-1RH-720A and B] are pressure interlocked to prevent their inadvertent opening at primary system pressures greater than 430 psig.

NOTE: Operation of the reactor coolant system at or near 400 psig avoids approaching the set pressure of the RH relief valve when the RH pumps are operating near shutoff head.

6. Before initiation of RHR operation, the reactor plant component cooling water system (CCR) supply to items not in use should be isolated to provide maximum cooling water flow to the residual heat removal system heat exchangers.

7. Flow through the RHS must be initiated slowly to avoid thermal shock. A warmup period of approximately five (5) minutes on mini-flow with [MOV-1RH-758] (heat exchanger outlet control valve) and [MOV-1RH-605] (heat exchanger bypass valve) just partial open is required before flow is increased through the heat exchanger.

8. To further reduce the thermal shock problem, it is recommended that low temperatures on the CCRS side be avoided. If the reactor plant river water temperature is low, the river water flow should be throttled back to increase the component cooling water inlet temperature to the residual heat removal heat exchangers to at least 70F.

9. A reactor coolant pump shall not be started with one or more of the RCS cold leg temperatures less than or equal to 275F unless:

   a. Pressurizer water volume is less than 50% as indicated on [LI-1RC-459, 460 or 461] or 33% as indicated on [LI-1RC-462].

-OR-

RESIDUAL HEAT REMOVAL SYSTEM

SECTION 4 - OPERATING PROCEDURES

A. SYSTEM STARTUP (PLANT COOLDOWN)

Purpose

This procedure describes the start-up of the Residual Heat Removal System (RHS) during the plant cooldown when the Reactor Coolant System (RCS) is at or below 350F and 430 psig. It involves establishing cooling water flow to the RH heat exchangers, reactor coolant flow to the RHS and starting the RH pumps to establish RCS cooldown.

Precautions

1. Ensure a reactor coolant pump is in operation prior to increasing RHS boron concentration.

2. If the RCS is greater than 120F, it is necessary to provide CCR water to the RHS Pump Seal Coolers.

Initial Conditions

1. During plant cooldown, one reactor coolant pump preferably "1A" or "1C", will be operated continuously until the reactor coolant temperature is reduced to less than 200F.

2. Motor control center breakers for [MOV-1RH-700, 720A, 701 and 720B] are open at [MCC1-E5 and E6].

3. RHS System Startup Checklist has been completed (1.10.3.D).

Instructions

1. Place the standby reactor plant component cooling water pump, heat exchanger and reactor plant river water pump in service in accordance with Procedure 1.15.4.D "System Preparation for RHS Operation".

2. Reduce the number of components supplied by CCRS to a minimum by isolating, where not absolutely required, the following equipment:

   a. Fuel Pool Heat Exchangers

   b. Containment Penetration Cooling Coils

   c. Refueling Water Refrigeration Units

   d. CRDM Shroud Ventilating Units Cooling Coils (if no CRDM are energized and RCS temperature is less than or equal to 300F).

D. SYSTEM STARTUP CHECK LIST

	Initial/Date
1. The Reactor Coolant System is at or below 350F and 430 PSIG.	______/____
2. Power supplies and control switches necessary for operation are energized.	______/____
3. Consult valve status print for valves that need to be realigned.	______/____
4. The Residual Heat Removal System has been filled and vented (only if coming off clearance where it was drained).	______/____

5. Deviations from above conditions and reasons:

____

____

____

____

____

____

____

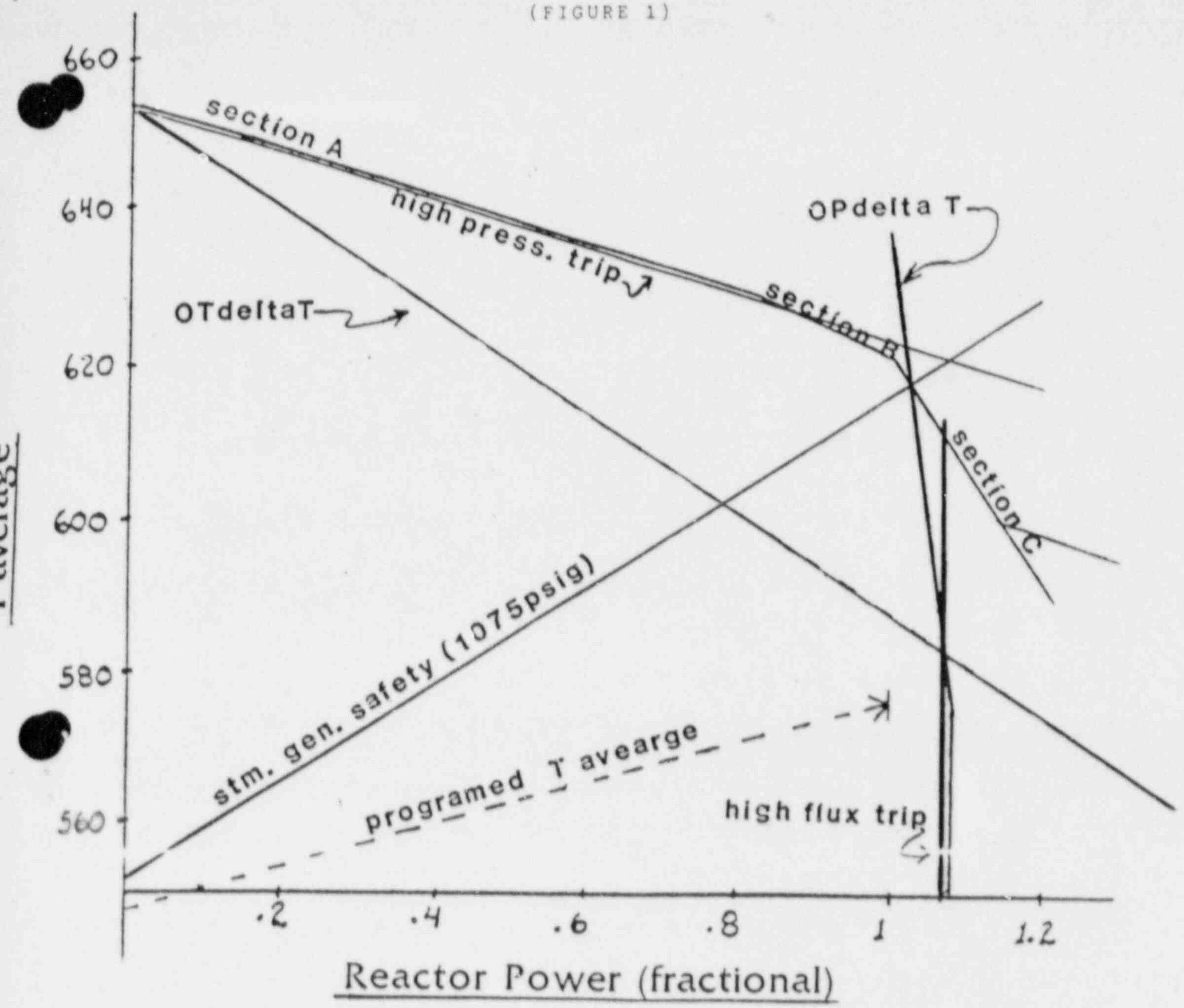
____

____

____

Startup Check List completed ____________________ ____________
SS or SOF Date

(FIGURE 1)



660
640
620
600
580
560
T average
section A
high press. trip
OTdeltaT
OPdelta T
section B
section C
stm. gen. safety (1075psig)
programed T avearge
high flux trip
.2
.4
.6
.8
1
1.2
Reactor Power (fractional)

SAFETY LIMIT CURVE

Section A - provides limits to ensure that core power is directly determinable from the subcooled calculation, $Q = \dot{m}\, c_p\, (T_H - T_C)$.

Section B - provides limits to ensure that the bulk fluid exiting the core is less than or equal to 15% steam quality thus providing a high confidence that the hottest channel will not exceed the design hot channel factors

Section C - provides limits to ensure that the departure from nucleate boiling ratio (DNBR) is always greater than or equal to 1.3

As can be seen by reference to Figure 1 on the preceeding page:

1) The steam generator safeties (only 1 valve setpoint shown) provide the 1st means of protection to ensure that coolant temperature parameters will not exceed the limits of Section A up to approximately 78% power.

   a) The OT T derived setpoint trip and the high pressure trip back up the steam generator safeties over the 78% power range.

2) Beyond 78% power up to 109% power, the OtΔT trip provides the 1st means of protection to ensure that the limits of the B and C sections are maintained.

   b) The steam generator safeties provide backup protection to the OTΔT trip up to approximately 103% power at which point the OPΔT trip provides the backup.

3) Beyond 109% power, the high flux trip provides protection from exceeding the limits of the C section of the curve. It is backed up alternately by the OPΔT trip, and the OTΔT trip.

4) The low flow trip functions as a tertiary backup to each of the protective features shown. The curve, as drawn (Sections A, B, and C), are based on core flow equal to 90% of nominal. Any flow less than 10% will force a trip if a trip has not been caused by OTΔT, OPΔT, high flux or high pressure.

5) The high pressure trip (2385 psig) provides a secondary backup to OTΔT over the range of the A Section of the curve.

6) The steam generator safeties control coolant temperatures without causing a trip provided the OTΔT derived setpoint is not reached. Of course, depending on the dynamic situation in the core, the steam generator safety protection line could be exceeded resulting in a trip from OTΔT or high pressure.

3/4.7.1.4 ACTIVITY

The limitations on secondary system specific activity ensure that the resultant off-site radiation dose will be limited to a small fraction of 10 CFR Part 100 limits in the event of a steam line rupture. This dose also includes the effects of a coincident 1.0 GPM primary to secondary tube leak in the steam generator of the affected steam line. These values are consistent with the assumptions used in the accident analyses.

3/4.7.1.5 MAIN STEAM LINE ISOLATION VALVES

The OPERABILITY of the main steam line isolation valves ensures that no more than one steam generator will blowdown in the event of a steam line rupture. This restriction is required to 1) minimize the positive reactivity effects of the Reactor Coolant System cooldown associated with the blowdown, and 2) limit the pressure rise within containment in the event the steam line rupture occurs within containment. The OPERABILITY of the main steam isolation valves within the closure times of the surveillance requirements are consistent with the assumptions used in the accident analyses.

AOP-10 MALFUNCTION OF NUCLEAR INSTRUMENTATION

This procedure provides instructions for coping with the malfunctioning nuclear instrumentation under the following conditions:

Source Range NIS Channels Malfunctions

Mode 2 or with reactor trip breakers closed
Power Level less than P6
Power Level greater than P6

Modes 3, 4, and 5 with Reactor Trip Breakers open

Intermediate Range NIS Channels Malfunctions

Modes 1 and 2 or with reactor trip breakers closed
Power Level less than P6
Power Level less than 5% but greater than P6
Power Level greater than 5%

Power Range NIS Channels Malfunctions

Modes 1 and 2
Power Level less than or equal to 5%
Power Level greater than 5%

Symptoms

Failure of a channel may be evidenced by erratic indication, loss of indication, drift of indication or trip settings, unexplained trips, loss of supply voltages, and/or annunciator alarms.

Automatic Actions

Reactor may trip and/or rod control may be blocked and/or turbine runback may occur depending on type of failure.

Manual Action

A. Source Range Channels (N-31, N-32)

1. Mode 2 - with power level less than P6 (less than 1 x 10 E-10 Amps) or with reactor trip breakers closed.

a. Single Channel Malfunction

(1) Restore the inoperable channel to OPERABLE status prior to increasing thermal power above the P-6 setpoint.

(2) Turn the Audio Count-Rate Channel Selector switch to the operating channel.

b. Malfunction of Both Channels.

Power Range Channel 3 (N-43)	BS-432 C-1	Overtemperature Delta T trip
Process Rack No. 14	BS-432 C-2	Overtemperature Delta T rod stop/runback

(8) At Process Rack 29, place the POWER MISMATCH SWITCH to the DEFEAT position (if N-44 failure).

(9) If reactor power is to be increased, restore the inoperable channel to operable status within 24 hours after increasing thermal power above 5% of rated thermal power, otherwise reduce thermal power to less than 5% of rated thermal power within the following 6 hours.

b. Malfunction of more than one Power Range channel

(1) The reactor shall be brought to hot shutdown (Mode 3) within 1 hour.

2. Mode 1 - with power level greater than 5%.

NOTE: If a malfunction of a power range channel prevents the P-10 interlock from clearing on lowering power to less than 10%, refer to A.3.b of this procedure for malfunction of both source range detectors.

a. Single Channel Malfunction

(1) Place the malfunctioning channel in a tripped condition within 1 hour by performing steps (1) through (8) of the Single Channel Malfunction for power levels less than or equal to 5% above.

(2) Perform <u>either</u> of the following:

Restrict power to less than or equal to 75% and reduce the Power Range Neutron Flux trip setpoint to less than or equal to 85% within 4 hours, or

Monitor the Quadrant Power Tilt Ratio at least once every 12 hours, using the movable neutron flux detectors.

b. Malfunction of Two or more Channels

(1) The reactor shall be brought to hot shutdown (mode 3) within 1 hour.

desirable to have an RCP trip parameter and setpoint which ensures pump trip for the range of small break LOCAs where pump trip is required, but does not lead to pump trip for most SGTRs and non-LOCAs. Although it is beneficial to keep the RCPs running during a SGTR or non-LOCA event, tripping the RCPs would not violate any safety criteria since the design of plant safety systems and the FSAR analysis for these accidents are based on concurrent loss of offsite power, and therefore on RCP trips.

In NRC Generic Letters 83-10c and 10d (References 1 and 2), the NRC addressed the question of developing RCP trip setpoints which do not cause RCP trip for those transients and accidents where forced circulation and pressurizer pressure control is a major aid to the operator, yet alert the operators to trip the RCPs for those small LOCAs where continued operation and subsequent trip might result in core damage. The NRC concluded that the need for RCP trip following a transient or accident should be determined by each plant considering Owners Group input, and provided guidance for the development of satisfactory RCP trip setpoints. This guidance indicated that the setpoints should be designed to ensure that the RCPs will be tripped for all LOCAs in which RCP trip is considered necessary, but should also ensure continued RCP operation during SGTRs up to and including the design basis tube rupture. The evaluation to establish the RCP trip parameters and setpoint should be capable of demonstrating and justifying that the proposed RCP trip parameters and setpoints are adequate for small LOCAs, but will not result in RCP trip for other non-LOCA transients and accidents (e.g., SGTRs).

An evaluation of alternate RCP trip parameters has been performed for Westinghouse plants to establish a parameter which will reduce the probability of RCP trip for SGTRs and non-LOCAs, while still providing for timely RCP trip for small break LOCAs. The results of this evaluation (see Reference 5), can be used to establish the appropriate RCP trip parameter and setpoints for use in Emergency Operating Procedures based on the Emergency Response Guidelines.

For a small break LOCA, the RCP trip parameter must provide an indication of the need for RCP trip before the RCS coolant inventory decreases to the point where the break would be uncovered if the RCPs are tripped. Thus, parameters that are indicative of decreasing RCS coolant inventory should be suitable for use as potential RCP trip parameters. The evaluation of alternate RCP trip parameters was limited to the potential parameters which can generally be implemented using existing qualified instrumentation. The alternate RCP trip parameters which were evaluated are RCS pressure, reactor coolant subcooling, and steam generator pressure-dependent RCS pressure.

In establishing the setpoint for any of the potential RCP trip parameters, the uncertainty in the instrument readings must be considered. One of the factors which can affect the instrument uncertainty is environmental conditions. The environmental conditions inside the containment during an accident can vary, depending upon the

EXHIBITS: Morabito's Index and 1 - 5

UNITED STATES NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

In the Matter of:	)	
ALFRED J. MORABITO	)	
(Senior Operator License for Beaver Valley Power Station, Unit 1)	)	Docket No. 55-6075 ASLPB 87-551-02-SP

Place: Pittsburgh, Pennsylvania

Date: February 22, 1988

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