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ACRS ECCS SUBCOMMITTEE
MEETING MINUTES
JULY 31, 1985
WASHINGTON, DC

PURPOSE: The purpose of the meeting was to: (1) review the proposed revision to 10 CFR 50.46 and Appendix K; (2) to review the implementation of the GE Appendix K analysis effort; (3) discuss resolution of the issue of RCP trip given a SB LOCA; (4) review the report of the NRC investigation team regarding the June 9, 1985 loss of all feedwater event at the Davis Besse plant; and, (5) discuss NRR's ECCS-related issues of ongoing concern.

ATTENDEES: Principal meeting attendees included:

ACRS
D. Ward, Chairman
J. Ebersole, Member
H. Etherington, Member
C. Mark, Member*
G. Reed, Member*
C. Siess, Member*
F. Remick, Member*
P. Shewmon, Member*
C. Wylie, Member
I. Catton, Consultant
V. Schrock, Consultant
H. Sullivan, Consultant
T. Theofanous, Consultant
C. L. Tien, Consultant
P. Boehnert, Staff

NRC
B. Sheron, NRR
L. Shotkin, RES
W. Beckner, RES
E. Throm, NRR
K. Goetz, NRR
N. Lauben, NRR
E. Rossi, NRR
C. Heltemes, AEOD

B&W
R. Schomaker
J. Paljug

CE
G. Menzel

W
A. Gagnon

* Part Time

DESIGNATED ORIGINAL
Certified By BJR

MEETING HIGHLIGHTS, AGREEMENTS AND REQUESTS

1. W. Beckner discussed the RES plan to revise 10 CFR 50.46 and Appendix K. The Staff approach is to allow best estimate calculations, combined with uncertainty evaluations, to be used as EM's. The existing Appendix K Rule would be grandfathered for licensees who do not wish to use the new approach. A draft of the new Rule has been developed. The major tasks remaining are to develop a Regulatory Guide and "White Paper" (Research Report) that justifies the Rule change.

   RES evaluated various options for the form of the Rule and supporting implementation guidance. In response to Drs. Catton and Theofanous, RES said the focus of the effort will be to determine that the BE models give the "right answer for the right reasons". In response to Mr. Ward, Dr. Beckner said RES wants a less proscriptive Rule because of the still-significant uncertainty in some LOCA models. RES/NRR has settled on the approach of a less specific Rule (than currently in place), with guidance for implementation provided in a Regulatory Guide.

   The schedule for the Rule change was noted (Fig. 1). RES expects to get the Rule and accompanying Regulatory Guide and research Report (White Paper), to the Commission by December 1985. Dr. Theofanous said the research Report should be issued with the Rule in order to afford time for evaluation of this information. RES indicated the Report may not be available prior to issuance of the Rule and Regulatory Guide.

   In response to Dr. Sullivan, Dr. Sheron (NRR) indicated that SECY 83-472 would be incorporated into the new Rule requirements.

2. Dr. Sheron discussed the status of SECY 83-472 which was instituted by the NRC Staff in late 1983. The general approach of 83-472 is that one can use a BE with the required Appendix K features as long as the subject EMs calculated PCT is greater than the 95% certainty level of the BE calculated PCT.

To date, no one has applied for use of the 83-472 approach. NRR understands that the BWR-2 non-jet pump plants want to make use of this approach. They plan to submit a justification for use of the GE SAFER code in the fall of 1985.

As for the PWR licensees, W plans to make a model submittal in the fall of 1985 using COBRA-TRAC. The methodology for use of this new model will be submitted in Spring 1986 for 2-loop plants and in late 1986 for 4-loop plants. CE plans to submit a SB model in late fall 1985. B&W has no plans for any model submittals at this time. Exxon plans model submittals in early 1987 (PWRs) and early 1988 (BWRs). Exxon is leaning toward use of TRAC for their new models.

Further Subcommittee discussion focused on the issue of model accuracy vis-a-vis uncertainty. NRC said they are not deemphasizing model accuracy for a final right answer. Dr. Sheron said the NRC is not "selling the store" on this issue and that the Subcommittee and ACRS will be deeply involved in the reviews of the new models. He said the Staff is still on the learning curve and will eagerly seek ACRS guidance on this effort.

In response to Dr. Sullivan, Dr. Sheron said NRR has no concern with use of TRAC or RELAP-5 by the industry for licensing use. Dr. Schrock asked if the generic decay heat curve has been approved for use by a prospective licensee. Dr. Sheron said a licensee will have to justify use of that curve or use of a plant specific curve. Dr. Schrock said this item needs to be addressed in the draft

Regulatory Guide. NRR agreed. Dr. Tien said whether or not one can even use the generic curve needs to be addressed. After further discussion, Dr. Sheron said he would check on this point with his Staff and discuss it at a future meeting of the Subcommittee.

3. The resolution of the TMI issue on RCP trip given a SB LOCA was reviewed. Representatives of B&W, CE and W made presentations. NRR commented on their review of the vendor submittals. Highlights included:

   ° The B&W Owners Group position on RCP trip is: (1) RC pump trip is recommended for SB LOCA, (2) loss of subcooling margin is an appropriate signal indicating SB LOCA, and (3) RC pump trip can be achieved safely and reliably by the operator. Dr. Schrock asked what decay heat curve was used for the BE SB LOCA trip setpoint. B&W said they would check on this point and inform the Subcommittee. Dr. Catton questioned whether B&W examined whether the RCPs should be tripped for an overcooling transient. B&W looked at mild overcooling transients but not severe transients. In response to Dr. Theofanous, B&W said they would supply information on the time needed to depressurize the RCS via a single PORV. In response to Mr. Ward, B&W said the ATOG procedures call for RCP trip on loss of subcooling and if the trip is a mistake - instructions are to restart the RCP's.

   For a SGTR - a single SGTR will not result in loss of subcooling, therefore the pumps are left on. For rupture of more than one tube, the RCPs would be tripped on loss of subcooling margin.

° G. Menzel (CE) discussed the CEOG/CE RCP trip strategy. The CE OG strategy is to "trip 2/leave 2". The goals of this strategy are to: (1) trip all RCPs for SB LOCAs to minimize inventory loss, (2) maintain forced coolant flow of at least two RCPs for non-LOCA's (SGTR, SLB) to maintain pressurizer spray and to minimize upper head voiding, (3) meet NRC guidance in generic letter 83-10. CE performed a BE analysis (Fig. 2) to demonstrate that if the second two RCPs are not turned off, or turned off at the worst time, the core remains cooled (PTC $<$ 2200°F). In response to Dr. Theofanous, Mr. Menzel said the CE analysis shows that if four RCPs are left running for a SB LOCA the core will uncover in $\sim$10 minutes, if two are left running no core uncovery occurs. Dr. Theofanous was skeptical of this result. CE reviewed the signals used for RCP trip (Fig. 3). In response to Mr. Ward, CE said the trip 2/leave 2 strategy is awaiting NRC approval.

° W performed analyses to justify manual RCP trip. The principle requirements for trip criteria are: (1) trip RCPs when needed for SB LOCAs, and (2) maintain RCPs operational when beneficial to plant recovery (i.e., SGTR). W developed three criteria that a given plant can elect to implement. These criteria are to trip on either: (1) RCS wide-range pressure, (2) RCS subcooling, or (3) primary/secondary Delta-P. All three criteria have been shown to demonstrate adequate discrimination capability between SB LOCAs and other events for which RCP trip is not desirable as well as satisfy the requirements of Generic Letter 83-10. In response to Mr. Ebersole, W said each plant will submit a specific RCP trip criterion analysis. W has run analyses that show that there is at least 10 minutes of operator action time available to trip RCP's for a SB LOCA. The above trip criteria has been approved by the NRC.

4. NRR (E. Throm) discussed their review of the PWR vendors resolution of the RCP trip issue. The NRC Generic Letter (83-10) said manual RCP trip would be allowed <u>if justified</u>. Further, the licensees must demonstrate compliance with all NRC rules and regulations for manual RCP trip. Key points noted included:

   ° NRC approved the W manual RCP trip criterion in June 1985. NRC has some plant-specific implementation issues to be addressed for W plants (Fig. 4). In response to Subcommittee concerns, Dr. Sheron said the whole aim of the NRC approach to this issue was to have the Industry assure the safest operating mode for their plants - considering all aspects of RCP operation. In response to Mr. Etherington, NRC said Maine Yankee, Haddam Neck and Yankee Rowe are addressing resolution of this issue independent of the "generic" resolution approaches discussed above.

   ° CE has also justified manual RCP trip and NRC approval is expected in August 1985. NRC has a residual concern with operation of essential service water for RCP operation (Fig. 5). This is being addressed by the CE Owners Group.

   ° B&W has also justified manual RCP trip. NRC's SER should be issued in August 1985. A residual issue to be addressed concerns restoration of RCP seal bleedoff given a pump trip (Fig. 6).

   ° Drs. Catton and Theofanous urged NRC to compare the vendor's calculations of RPS inventory with NRC-sponsored calculations run with TRAC. NRC said they would make some comparisons and submit a report to the Subcommittee.

5. Ms. K. Goetz (NRR) discussed the issue of the effect of multiple instrument tube failures at W plants vis-a-vis SB LOCA considerations. This concern arose when it was discovered that equipment located above the seal table is not seismically qualified (Fig. 7). Failure of this equipment during a seismic event could result in rupture of one or more of the instrument tubes. W has determined that the worse case event would rupture no more than three tubes. NRC calculations, done conservatively, show no core uncovery for rupture of at least six tubes.

   NRC has sent an I&E Information Notice to all licensees and W has sent notice to its respective licensees. The Resident Inspectors are also checking for potential problems at their respective plants. In response to Mr. Ward, Dr. Sheron said NRC has not confirmed the W failure analysis. He said he would check what NRC follow-on actions, if any, are planned for this issue.

6. N. Lauben reviewed the status of the W 2-loop UPI ECCS EM model revision effort. Figure 8 provides the details.

   The current status of the Exxon ECCS EM model errors issue was also discussed (Figs. 9-10).

   Mr. Lauben also reviewed the recent problem discovered with the CE ECCS EM. The problem is similar to what was found with Exxon, i.e., the axial shaping curve used in the EM is flatter than originally assumed, resulting in a higher PCT. There is no safety problem due to the margin in the Appendix K analysis (Fig. 11).

7. E. Throm discussed the use of the nuclear plant analyzer (NPA) for analysis of the Davis Besse (DB) event. Unfortunately, problems with the INEL Computer, not the NPA software, prevented NRR getting any results of analysis of the DB event.

NRR had LANL run some analyses (Fig. 12) for support of the DB Investigative Team. The results obtained are preliminary, and LANL is polishing the output (Fig. 13).

8. E. Rossi overviewed the results of the NRC Investigative Team investigation of the Davis Besse loss of all feedwater event of June 9, 1985. A Report (NUREG-1154) has been released which details the results of the investigation. Key points of the presentation were:

   ° The Team charter was to identify the root cause(s) of the event. They were not chartered to make any recommendations as a result of their work.

   ° Troubleshooting of the equipment failures seen is not yet complete. Therefore the root cause(s) of all failures hasn't been conclusively identified.

   ° Figures 14-19 list the sequence of key events. Mr. Rossi detailed specifics of the event sequence.

   ° In response to Subcommittee questions, Mr. Beard noted that there were investigations conducted in parallel with the NRC Team effort by both B&W and INPO. The B&W and INPO investigations were conducted at the behest of the Utility. There was essentially no interaction between the NRC and INPO/B&W investigations.

   ° There were a number of operator actions required to be performed outside the control room in order to restore AFW flow (Fig. 20).

° G. Reed said he believes the root cause of this event was poor plant and equipment design not poor maintenance practices. J. Ebersole also echoed this opinion. Mr. Ward observed that had the plant been properly maintained, the event would most likely have not occurred.

° Results of the on-going troubleshooting of the failed equipment were reviewed (Figs. 21-22). In some cases, troubleshooting will need to await plant operation to run hot tests (Item 4, Fig. 21).

° Human Factors aspects of the accident that were noted included: (1) the layout of the SFRCS control panel contributed to the operator error which resulted in temporary isolation of both SG's as heat sinks, (2) operators did not follow emergency procedure (feed and bleed not initiated when required per procedures, (3) difficulty in resetting AFW pump overspeed trips, (5) STA not required (arrived too late to be of help), and (4) emergency notification was not timely or complete.

° The safety parameter display system was "down" during the event. The SPDS at DB has a poor reliability history. The Team believes had the SPDS been functional, it would have been an aid to the operators. During Subcommittee questions however, Mr. Rossi indicated that the SPDS would not have been a crucial aid for recovery of this particular event.

° The major conclusion of the Team was that the underlying cause of the event was the licensee's lack of attention to detail in the care of plant equipment. The licensee has a history of performing troubleshooting, maintenance and testing of equipment, and of evaluation of operating experience related to equipment in a superficial manner and, as a result, the root

causes of problems were not always found and corrected. Operator interviews made clear that equipment problems were not aggressively addressed and resolved beyond compliance with NRC regulatory requirements.

° Other key findings include:

  ° A key safety significance is that multiple equipment failures occurred.

  ° If safety-related auxiliary feedwater system equipment had functioned, operator error would not have had a significant effect.

  ° Testing is likely to have detected causes of auxiliary feedwater system pump and valve malfunctions.

  ° Neither SFRCS (steam/feedwater rupture control system) nor the auxiliary feedwater system meet single failure criterion for all design basis accidents.

  ° Electric motor-driven startup feedwater pump availability improved safety margin.

  ° Operator understanding of procedures, designs, and equipment operation and operator training played a crucial role.

  ° Locked doors and valves were a potential impediment to plant recovery.

  ° Some post-TMI improvements made positive contributions; others were not used.

° Operator training and understanding of systems and equipment are key to success in mitigating events outside plant design basis.

° Operators at other plants may be reluctant to initiate make up/high pressure injection cooling without delay to consider alternatives.

° Instrumentation available on June 9 was not adequate to inform operators that criteria for make up/high pressure injection cooling had been reached.

° Mr. Heltemes (AEOD) said that the EDO will summarize actions for follow-on of the DB event and assign these actions to given NRC offices.

° In response to Dr. Sullivan, Mr. Rossi said he believed the investigative Team concept worked very well and should be repeated on all future significant events. The Subcommittee congratulated Mr. Rossi for an excellent presentation and a job well-done by the Team.

9. The meeting was adjourned at 6:55 p.m.

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NOTE: Additional meeting details can be obtained from a transcript of this meeting available in the NRC Public Document Room, 1717 H Street, N.W., Washington, D.C., or can be purchased from Ann Riley & Associates, Ltd., 1625 I Street, N.W., Suite 921, Washington, DC 20006 (202/293-3950).

FIG. 1

ECCS RULE REVISION SCHEDULE

COMMISSION PAPER TO EDO	NOVEMBER 1985
REGULATORY GUIDE (DRAFT FOR COMMENT)	NOVEMBER 1985
RESEARCH REPORT (DRAFT FOR COMMENT)	DECEMBER 1985
PAPER TO COMMISSION	DECEMBER 1985
NOTICE OF PROPOSED RULEMAKING	EARLY CY 1986
COMMENT PERIOD END	MID-CY 1986

CORE COOLING PERFORMANCE

DURING WORST SBLOCA SCENARIO

CONCERN:

WOULD CORE OVERHEAT DURING WORST SBLOCA IF SECOND TWO RCPs WERE LEFT RUNNING AND WOULD FAIL OR BE TURNED OFF AT WORST TIME

ANALYSIS ASSUMPTIONS:

CONSERVATIVE BEST ESTIMATE; MAJOR FEATURES:

- o REFERENCE PLANT: 2700 MWT,
- o ECC FLOW FROM 1 HPSI TRAIN ONLY, MINIMUM FLOW
- o 1.0 MULTIPLIER ON 1971 ANS DECAY HEAT
- o HEM BREAK FLOW MODEL
- o TURBINE BY-PASS SYSTEM AVAILABLE OR STEAM GENERATOR SECONDARY SIDE PRESSURE AT STEAM SAFETY VALVE SETPOINT

RESULTS:

PEAK CLADDING TEMPERATURE: 1200°F FOR TBS ANALYSIS
1660°F FOR SSV ANALYSIS

T2/L2 STRATEGY INHERENTLY SAFE FOR REFERENCE PLANT (MOST ADVERSE CONDITONS), AND OTHERS

F162

SIGNALS FOR RCP TRIP

BASIC APPROACH

- o SIMPLE-TO-INTERPRET SIGNALS
- o MINIMIZE NUMBERS OF SIGNALS
- o PROVIDE FEXIBILITY FOR PLANT-SPECIFIC IMPLEMENTATION
- o USE OF EXISTING INSTRUMENTATION
- o MEET NRC GUIDANCE (GENERIC LETTER 2-8-83)

SIGNALS USED

o PRIMARY SYSTEM PRESSURE - FOR TRIPPING FIRST TWO RCPs

o PRIMARY SYSTEM SUBCOOLING

COMBINED WITH

o CONTAINMENT RADIATION

AND/OR

o LACK OF STEAM PLANT RADIATION

- FOR TRIPPING SECOND TWO RCPs

FIG. 3

Reactor Coolant Pump Trip

Plant Specific Implementation Issues

* Selection of Trip Criterion
  - Instrumentation Uncertainties
  - Normal/Adverse Containment
* Service Water Loss / Restoration
  - Containment Isolation
  - Pump Seal Failure
* RCP Trip Reliability
  - Components / Locations
  - Normal/Adverse Containment
* Operator Training & Procedures
  - RCP Trip / Restart
  - Voids
  - Natural Circulation Cooldown

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FIG. 4

Combustion Engineering RCP Trip

* CEOG response concerning Essential Service Water for RCP operation was not acceptable
* Additional information requested from CE licensees
* Information provided is currently being reviewed , will be included in SER
* Most CE plants isolate essential water on SI or high containment pressure, therefore rely on the operator to restore

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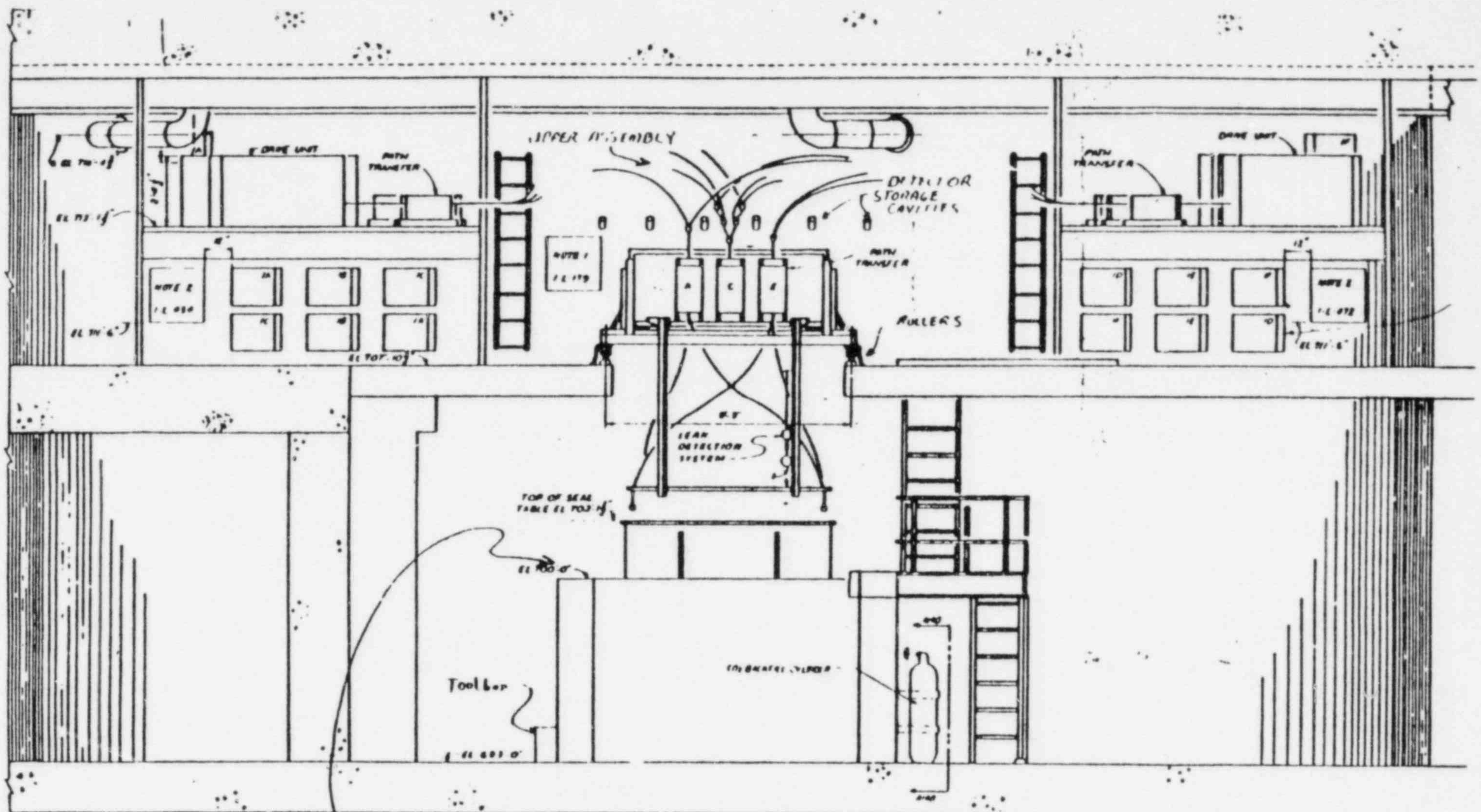
FIG. 5

Babcock & Wilcox RCP Trip

* Seal bleedoff required, some plants rely on ATOG to reset bleedoff, some plants redirect the bleedoff to quench tank

* CCW must be restored to a running pump

* BWOG recognizes use of a high-high containment pressure signal for isolation can resolve issue



NOTE: THE SEAL TABLE PLATFORM AREA IS EQUIPPED WITH A HANDRAIL WHICH IS NOT SHOWN IN THIS DRAWING

LOCATION OF THE INCORE INSTRUMENTATION SYSTEM EQUIPMENT IN THE INSTRUMENT ROOM

FIGURE 9

FIG. 7

2 LOOP UPI-MODEL REVISION STATUS

- MEETING WITH VENDORS AND UTILITIES TO DISCUSS PRELIMINARY PROPOSALS FOR NEW MODELS

  WESTINGHOUSE - 1-10-85

  COMBUSTION - 2-12-85

  EXXON - 3-6-85

- UTILITIES MADE VENDOR SELECTIONS AND SUBMITTED MODEL DEVELOPMENT PROGRAM PLANS TO NRC IN MARCH AND APRIL

  - WESTINGHOUSE - PRAIRIE ISLAND, POINT BEACH
    COMBUSTION - KEWAUNEE, GINNA

  - BOTH PLANS BASED ON 83-472 METHODOLOGY

- FOLLOWUP MEETING WITH WESTINGHOUSE AND SELECTED UTILITIES ON 6-28-85

- FOLLOWUP WITH CE SCHEDULED FOR FALL 85

- EM SUBMITTAL TARGET DATES:

  WESTINGHOUSE - 5-86

  COMBUSTION - 12-86

FIG. 8

AFFECTED PLANTS AND STATUS

PLANT	STATUS
PALISADES	CURRENT ANALYSES DO NOT HAVE EXXON ERRORS
H.B. ROBINSON	CURRENT ANALYSES DO NOT HAVE EXXON ERRORS
FORT CALHOUN	REVISED ANALYSIS SUBMITTED SER ISSUED -FULL COMPLIANCE
ST. LUCIE 1	REVISED ANALYSIS SUBMITTED SER ISSUED -FULL COMPLIANCE
D.C. COOK 2	REVISED ANALYSIS SUBMITTED SER ISSUED -FULL COMPLIANCE

FIG. 10

AFFECTED PLANTS AND STATUS (CONT'D)

PLANT	STATUS
GINNA	SER ISSUED SUFFICIENT PCT MARGIN FOR K(Z) REVISED ANALYSIS- JAN.,1986
D.C. COOK 1	SER IN PREPARATION SUFFICIENT PCT MARGIN FOR K(Z) REVISED ANALYSIS- OCT.,1985
KEWAUNEE	SER ISSUED FQ PENALTY OF -0.05 IMPOSED REVISED ANALYSIS- OCT.,1985
PRAIRIE ISLAND	SER ISSUED FQ PENALTY OF -0.05 IMPOSED REVISED ANALYSIS- OCT.,1985
YANKEE ROWE	LIMITS ON CONTROL RODS IMPOSED REVISED ANALYSIS- OCT.,1985

CE ECCS MODEL PROBLEM

STATUS

- NO SAFETY PROBLEM, EXISTING MODELS RE APPENDIX K HAVE MUCH MARGIN.

- WORST CASE IS TOP PEAKED WITH F_Z = 1.52, MAINTAINED MAX Kw/FT. PCT IS INCREASED BY 34°F.

- 3 PLANTS WOULD LIKELY EXCEED 2200°F WITH CURRENT MODEL.

PLANT	CURRENT PCT
SONGS 3	2183
WATERFORD 3	2188
PALO VERDE	2169

- SONGS 3 - CANNOT EXCEED Kw/FT, WHICH WOULD CAUSE PCT TO EXCEED 2200°F FOR BALANCE OF CYCLE 1 (40 DAYS) DUE TO DNBR LIMITS.

- WATERFORD - SUFFICIENT MARGIN BY NOT INCLUDING CONTAINMENT PURGE.

- PALO VERDE - HAS ADMINISTRATIVELY REDUCED PEAK LHGR BY 0.1 Kw/FT.

- ALL WILL COMMIT TO EVENTUAL REANALYSIS.

FIG. 11

Summary of LANL Analyses

* Requested by the Davis-Besse Incident Investigation Team

* Five Analyses

1. Plant Transient
2. Core Dryout
3. Feed/Bleed at SG Dryout
4. Feed/Bleed 5 minutes later
5. Feed/Bleed 30 minutes after SG low level reached

* Cases 2 and 5 not yet done

* Case 1 resonable results

* Cases 3 and 4 sucessful

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FIG. 12

Summary of Staff Simplified Davis-Besse Calculations

CASE NO.	POWER LEVEL	NO. OF MU PUMPS	SUFP	ACTUATION TIME	SG DRYOUT TIME MIN	SATURATION TIME MIN	CORE UNCOVERY TIME MIN	MINIMUM RCS LIQUID VOLUME CU.FT.
1	100%	0	NO	N/A	5	33	55	N/A
2	90%	0	NO	N/A	4	35	60	N/A
3	75%	0	NO	N/A	3	40	72	N/A
4	90%	1	NO	SG DRYOUT	4	45	99	N/A
5	75%	1	NO	SG DRYOUT	3	55	170	N/A
6	100%	2	NO	SG DRYOUT	5	46	N/A	3710
7	100%	2	NO	20 MINUTES	5	39	148	N/A
8	75%	2	NO	SG DRYOUT	3	77	N/A	6435
9	100%	0	YES	20 MINUTES	5	46	120	N/A
10	100%	1	YES	SG DRYOUT	5	**	N/A	10450
11	100%	1	YES	20 MINUTES	5	91	N/A	>6435
12	100%	2	YES	20 MINUTES	5	**	N/A	10450
13	90%	2	NO	10 MINUTES	4	50	N/A	5433

Note 1: Liquid volume to top of core is 3470 cubic feet.
Note 2: All cases assume no depressurization with PORV.
** : System remains subcooled.

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FIG. 13

Sequence of Events.

- T = 0 MIN. (1:35:00) — Main Feedwater Pump No. 1 Trips (Partial Loss of Main Feed)
- T = 1/2 — Reactor Trip and Turbine Trip
- T = 1/2 — Main Steam Isolation Valves Close (Spuriously)
- T = 5 — OTSG Levels Begin to Fall (Complete Loss of Main Feed)
- T = 6 — Secondary Side Reactor Operator Initiated Steam and Feedwater Rupture Control System (SFRCS) on Low Steam Pressure (Complete Loss of Auxiliary Feed)

FIG. 14

Sequence of Events (Continued)

- T = 6 3/4 MIN. Auxiliary Feedwater Pump Turbines Trip on Overspeed
- T = 7 Operator Error in SFRCS Corrected
- T = 7 Auxiliary Feedwater Valves Fail to Re-Open

FIG 15

SEQUENCE OF EVENTS (CONTINUED)

- T = 9 MIN. EQUIPMENT OPERATORS DISPATCHED TO:
  - -- OPEN AUXILIARY FEEDWATER VALVES
  - -- RESTORE AUXILIARY FEEDWATER PUMPS TO SERVICE
- T = 9 ASSISTANT SHIFT SUPERVISOR LEFT CONTROL ROOM TO MAKE STARTUP FEED PUMP AVAILABLE FOR SERVICE

FIG 16

SEQUENCE OF EVENTS (CONTINUED)

- T = 12 3/4 MIN. — AUXILIARY FEEDWATER ISOLATION VALVE FOR OTSG NO. 2 OPENED BY EQUIPMENT OPERATORS
- T = 14 — BOTH STEAM GENERATORS "DRIED OUT" - EMERGENCY PROCEDURE CRITERION FOR INITIATING MAKE UP/HIGH PRESSURE INJECTION COOLING
- T = 16 1/4 — PRESSURIZER PILOT OPERATED RELIEF VALVE (PORV) FAILS TO CLOSE AFTER THIRD ACTUATION - PORV BLOCK VALVE CLOSED 1/2 MINUTE LATER

FIG 11

Sequence of Events (Continued)

- T = 16 1/2 MIN. — Flow Obtained from Startup Feed Pump to OTSG No. 1
- T = 18 1/2 — Flow Obtained from Auxiliary Feed Pump No. 2
- T = 18 1/2 — Peak Reactor Coolant Temperature 592°F (Normal Post-Trip 550°F)
- T = 19 3/4 — Flow Obtained from Auxiliary Feed Pump No. 1

Fig. k

Sequence of Events (Continued)

- T = 22 MIN. Cooldown of Reactor Coolant System from Rapid Feed of Steam Generators
- T = 23 High Pressure Injection in Piggyback Mode to Maintain Pressurizer Pressure and Level
- T = 23 Minimum Reactor Coolant System Pressure 1716 psig (Normal Pressure 2150 psig)
- T = 29 Plant Essentially Stable

#16.15

Operator Actions Outside Control Room (Continued)

- Startup Feedwater Pump
  - -- Required Opening 4 Valves
  - -- Required Inserting Fuses in Breaker Control Circuit
- Auxiliary Feedwater
  - -- Required Opening Isolation Valves
  - -- Required Resetting of Pump Turbine Trip Throttle Valves (Difficulties Were Encountered)

FIG. 2C

Table 5.1 Summary of Equipment Troubleshooting Results

ITEM	NATURE OF FAILURE	PROBABLE ROOT CAUSE	COMMENTS
1. Main Feedwater Turbine	Overspeed	Control System Electronic Circuit Card Failure	Pre-existing Control System Problems Have Not Been Resolved
2. Closure of MSIVs	Spurious Actuation of SFRCS	Not Identified	Troubleshooting Activities Have Not Yet Begun
3. Steam Safeties, Atmos. Vents	Abnormal Pressure Control	Not Identified	
4. Aux. Feedwater Turbines	Overspeed	Condensate Flow to Turbines From Steam Supply Lines During Turbine Start	Testing with Plant Hot Needed to Verify Cause
5. AFW Containment Isolation Valves	Would Not Re-Open	Improper Settings for Torque Switch Bypass Contacts	
6. Steam Supply Valve to AFPT #1	Short Cycle	Not Identified	Failure Could Not Be Reproduced Improper Torque Switch Bypass Contacts Could Be Problem
7. Source Range NI	Failed, Low	Not Identified	Failure of One of Two Channels Could Not Be Reproduced
8. PORV	Did Not Close	Disassembly of Valve and Testing of Control System Failed to Reveal Cause	Cause May Never Be Identified
9. S/U Feedwater Control Valve	Did Not "Reset"	Indication Problem Only - Indicator Lamp	
10. Recovery of AFP Turbine	Trip-Throttle Valve Operational Difficulties	Lack of Operator Training	Not a Hardware Problem

Table 5.1 Summary of Equipment Troubleshooting Results (Continued)

ITEM	NATURE OF FAILURE	PROBABLE ROOT CAUSE	COMMENTS
11. AFP #1 Suction Transfer	Transfer to Service Water	Not Identified	
12. Turbine Turning Gear	Did not Engage		Troubleshooting Not Reviewed by Team
13. Control Room HVAC	Spurious Transfer to Emergency Mode		Troubleshooting Not Reviewed by Team
14. Turbine Bypass Valve	Structured	Water Hammer, Valve Mis-Assembly	Cause of Water Hammer Not Yet Known

F/16.