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March 10, 1993
LD-93-043

Docket No. 52-002

Attn: Document Control Desk
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Subject: System 80+™ Instrumentation Diversity

Dear Sirs:

Enclosed with this letter is a report on protection against common mode failure of the digital instrumentation and control systems. Development and submittal of this report was agreed to at the January 21, 1993, meeting with NRC staff.

If you have any questions, please call me or Mr. Stan Ritterbusch at (203) 285-5206.

Very truly yours,

COMBUSTION ENGINEERING, INC.

S. E. Ritterbusch for

160022

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Acting Director
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CMF EVALUATION FOR LIMITING FAULT EVENTS

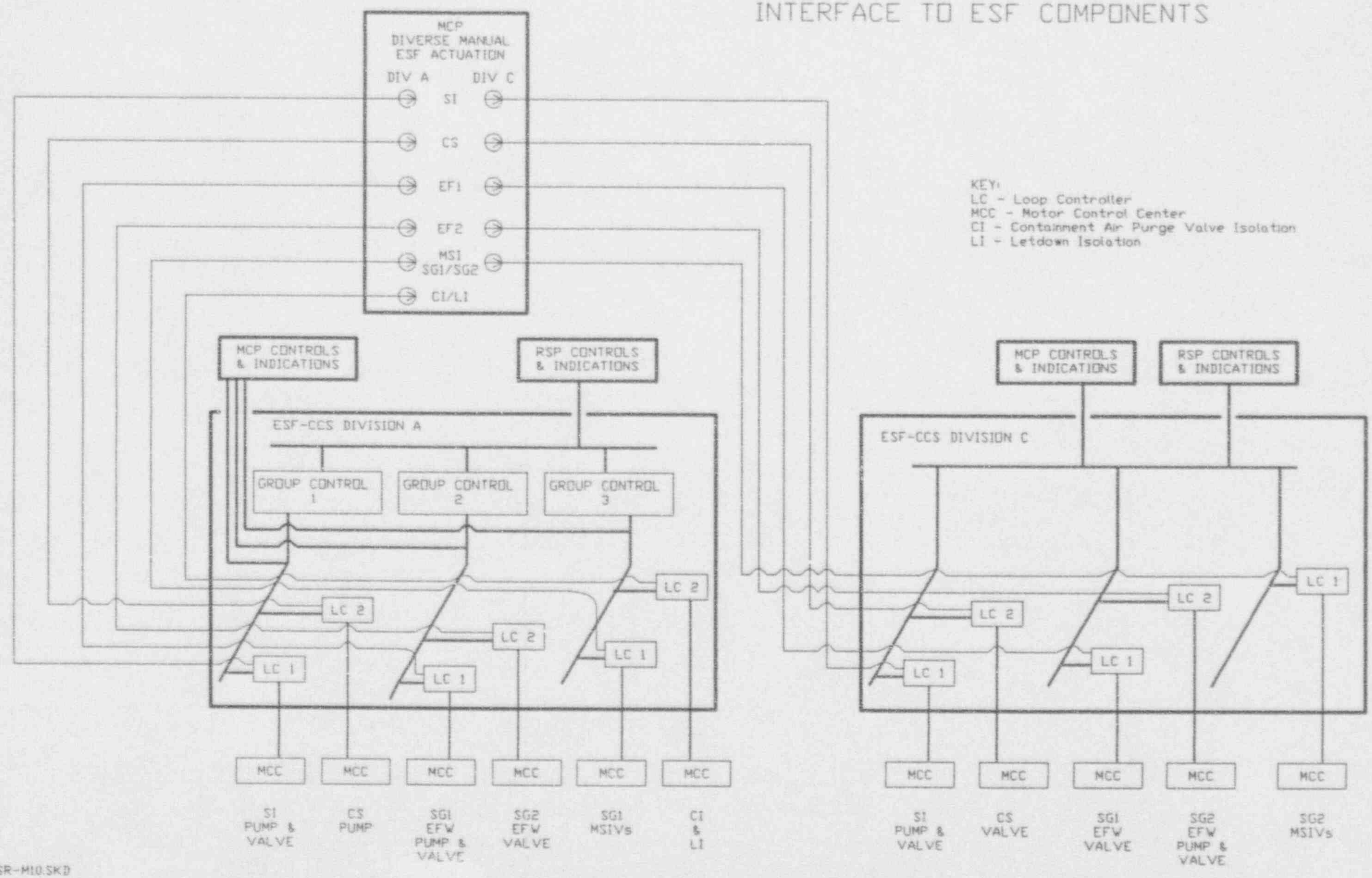
1. INTRODUCTION

The draft NRC policy on common mode failure of protective system software (Reference 1, Issue A) specifies the need to perform an evaluation of the capability of the plant design to cope with the event initiators in Chapter 15 with a postulated pre-existing common mode failure of the protection system software. As a bounding analysis of the capability of the diverse equipment to cope with such a condition, the evaluation in Reference 2 assumed that all automatic responses to systems using the protective software and the capability for manual actuation using these systems would be precluded. The evaluation assumed nominal plant conditions at the initiation of each event and best estimate responses for the diverse reactor trip and emergency feedwater actuation equipment, and for the normal control systems and operator action.

A review of the evaluation was performed in Reference 3. Subsequent discussion of the evaluation with the reviewer and the NRC staff (Reference 4) determined that the capability of the diverse equipment to provide adequate protection had been demonstrated for 19 of the 28 event initiators in Chapter 15. Discussion of the evaluation with NRC management (Reference 5) determined that a revised evaluation would be appropriate for the remaining 9 events while applying more relaxed criteria than those applied in Chapter 15, and crediting use of manual controls implemented in the design to comply with position 4 of the Reference 1 draft policy statement.

The evaluation presented here presents the results of a revised evaluation of the 9 events which demonstrates the capability of the diverse equipment and reasonable operator response to provide adequate protection. The manual controls credited for actuation of Engineered Safety Feature Systems equipment are those presented in Reference 6 and shown in Figure 1-1. These comply with position 4 of the Reference 1 draft policy statement with the addition of a switch to manually actuate closure of the containment air purge valves and a letdown line isolation valve.

FIGURE 1-1
DIVERSE MANUAL ESF ACTUATION
INTERFACE TO ESF COMPONENTS



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2. SUMMARY

The evaluation used the results of CESSAR-DC, Chapter 6 and 15 to estimate the outcome of each event applying the initial conditions, equipment operability, operator actions and acceptance criteria described herein. The emphasis of the evaluation was to ensure a reasonable ability to cope with the events in a manner which preserves core coolability, prevents excessive containment overpressure and relies on reasonable operator response times. The criteria for core coolability, containment pressure and operator time are chosen to be appropriate for the beyond design basis categorization of each event when a concurrent low probability, CMF of the protection system software is also assumed.

2.1 Evaluation Approach

The evaluations of nine events in conjunction with a hypothetical CMF in the NUPLEX 80+ software are enclosed. The nine events are:

1. Total Loss of Reactor Coolant Flow
2. Single RCP Shaft Seizure
3. Single RCP Shaft Break
4. CEA Ejection
5. Letdown Line Break
6. Steam Generator Tube Rupture
7. Main Steam Line Break
8. Feedwater Line Break
9. Loss of Coolant Accident

The evaluation uses best estimate assumptions regarding initial operating conditions (Table 2-1) and assumes continued operability of the RCPs, the main steam and feedwater systems and the NSSS control systems since they are not affected by the CMF. The Alternate Protection System (APS) provides an automatic high pressurizer pressure reactor trip and an automatic actuation of the emergency feedwater equipment on low steam generator level.

2.2 Instrumentation Available to the Operator

Operator response is necessary to help mitigate the short term effects and to accomplish subsequent recovery actions following each event. Diversity in the NUPLEX 80+ equipment and software assures that adequate instrumentation and controls will remain available for timely diagnosis and mitigation of the event initiators with the postulated software CMF.

The NUPLEX 80+ safety related display instrumentation is implemented in 3 segments: DIAS-N (Discrete Indication and Alarm System - Channel N), DIAS-P (Channel P) and DPS (Data Processing System). Since the DIAS-N equipment may be affected by the postulated CMF, this evaluation conservatively assumes that the alarms and displays generated by this system will be disabled. Reference 6 presents the implementation of hardwired communication for the DIAS-P display of key indicators of critical safety functions, as shown in Figure 2-1. These displays comply with Position 4 of Issue A in the Reference 1 draft policy statement. They provide a dedicated display of the Category 1 parameters specified in Regulatory Guide 1.97 and would remain unaffected by the postulated common mode failure in the NUPLEX 80+ protection system software. The parameters displayed are listed in Table 2-2.

The DPS, which provides a redundant and diverse display of the indications and alarms presented by DIAS-N, would not be affected by the postulated failure. The DPS receives information used for display and alarm from the Process-Component Control System (P-CCS), the Power Control System (PCS) and the Engineered Safety Feature-CCS (ESF-CCS). The P-CCS and the PCS would not be affected by the postulated failure. Information provided to the DPS by the ESF-CCS is assumed to become unavailable due to the postulated failure.

The P-CCS and PCS obtain key plant parameters either from isolated safety channel signals at the Auxiliary Process Cabinets or via control channel sensors which are separate from the safety equipment. The P-CCS and PCS obtain the sensed parameters in Table 2-2 via the former method. The DPS performs signal validation of this information and then compares the validated value for each parameter to the validated value determined by DIAS-N and generates an alarm if they are inconsistent. As a result, the operator will be alerted if a failure occurs in either display system, and can compare their respective indications to the DIAS-P display to determine which system is providing reliable information.

The PCS implements independent control channel sensors for excore neutron flux data and detection of dropped control rods. Therefore, the DPS display of core power, and the core mimic representation of a successful reactor trip are not affected by the postulated failure.

The DPS provides alarms for reactor trip, pre-trip and ESF actuation which would not be affected by the postulated failure.

Detection of high radiation levels in the secondary system, such as in the SG blowdown or the condenser, is performed by a radiation monitoring system which is diverse from the protection system and would not be affected by the postulated failure. Monitored information from this system is data linked to both the DPS and the DIAS. Therefore, the DPS displays of high radiation alarms in these areas would remain operable with the postulated failure.

2.3 Estimate of Operator Response for Manual Actuation

The operator response times are estimated for these events by reviewing the actual sequence of steps called for in the Emergency Procedure Guidelines. Since the DPS provides appropriate alarms and parameter indications which can be confirmed against the DIAS-P displays, each step or manipulation in the sequence is estimated to take 1 minute. The total time estimated for the operator actions specified below is determined by summing the time required for the individual sequential steps leading to that actuation.

Based on the information provided by the DPS to indicate that a reactor trip is needed and has not occurred, a best estimate of the operator response indicates that a reactor trip would be manually actuated within 5 minutes of reaching a trip condition. This applies for the RCP shaft seizure, RCP shaft break, letdown line break, steam generator tube rupture, main steam line break and the LOCA. The APS would initiate an automatic trip for the other events.

For the main steam line break outside containment, the DPS's validated display of SG pressure and RCS temperature (confirmed by the DIAS-P display) and alarms, would provide indication of the need to close the MSIVs. A best estimate of the time required for the operator to perform and confirm a manual reactor trip, and then reach this step in the emergency procedures indicates that manual initiation of MSIV closure would be performed within 15 minutes of event initiation.

For the feedwater line break at the economizer nozzle, the reactor trip would be initiated automatically by the Alternate Protection System on high pressurizer pressure. The DPS's validated display of SG pressure and containment pressure (confirmed by the DIAS-P display) and alarms, would provide indication of the need to close the MSIVs and actuate containment spray. A best estimate of the operator response to confirm the automatic trip and proceed through the emergency procedures indicates that manual closure of the MSIVs would occur at 10 minutes and manual actuation of containment sprays at 16 minutes.

For a loss of coolant accident, including a CEA ejection, alarms and validated displays for low pressurizer pressure (confirmed by the DIAS-P display) would provide indication of the need to manually initiate reactor trip and safety injection. A best estimate of this response indicates that both actions would be taken within 15 minutes of reaching the trip condition.

For the letdown line break, as discussed in the Reference 2 evaluation, the following alarms, provided by the DPS, would almost immediately alert the operator of the event:

Regenerative Heat Exchanger high exit temperature alarm.

Letdown line low pressure alarm (downstream of the break).

Auxiliary building high radiation.

Auxiliary building high temperature and high humidity.

A pressurizer low level alarm should occur within one minute, and within a few minutes, alarms indicating a high sump level in the auxiliary building and a low level in the volume control tank would occur. Based on these alarms and indication of a continued letdown flow with a continued decrease in pressurizer level, the operator should be able to determine the need to isolate the leak within 10 minutes. The operator is estimated to attempt isolation via the ESF-CCS, determine that this has failed and initiate isolation via the hardwired controls within 15 minutes of event initiation.

For the steam generator tube rupture, as discussed in the Reference 2 evaluation, isolation of the affected steam generator is normally initiated by operator action, per the emergency procedures. The DPS provides high radiation alarms and indications appropriate for these actions. The delays involved in determining a lack of response to the ESF-CCS MSIS signal and initiation of manual closure of the main steam isolation valves via the hardwired controls and termination of normal feedwater flow via the P-CCS should not result in radiological releases beyond the Chapter 15 criteria.

2.4 Non-LOCA Coolability Criterion

Reference 7 describes a large data base of PWR and BWR test data for power-cooling mismatch (PCM) and subsequent departure from nucleate boiling (DNB) that test rods were subjected to. The test rods were subjected to dryout and clad heatup conditions under a wide range of conditions bounding the range considered for non-LOCA design basis events. The test data shows the cladding integrity is preserved despite significant exposures to high temperatures (T>1300F) for significant times (t>>30 minutes). Therefore, Figure 2-2 (which is a reproduction of Figure 5 of Reference 7) is used to demonstrate that the fuel cladding is not embrittled and remains coolable during a combined limiting fault and a CMF in the NUPLEX 80+ software.

In addition to Figure 2-2 (time-at-temperature), the fuel cladding integrity was reviewed relative to a best-estimate small break LOCA clad rupture model. This model, based on a strain-to-failure criterion, is appropriate to use when low cladding temperatures ($T<1600^{\circ}F$) are achieved at slow heatup rates ($dT/dt<20^{\circ}F/sec$) and persist for long durations. This model also indicates that cladding rupture will not occur unless the cladding is subject to a temperature of more than 1300F for well over 30 minutes.

2.5 Event Definitions

Large break LOCA's inside containment are accommodated by the leak detection capabilities in System 80+. This capability allows significant time for the operator to shutdown and depressurize the plant prior to a break in the main pipes or the large SI lines. For breaks in smaller lines (e.g., the 6" pressurizer safety valve line) the capability of the diverse equipment and operator action to provide protection are evaluated. The core coolability acceptance criteria used are the 10CFR50.46 criteria. Operator action is credited to mitigate the event and realistic assumptions are made regarding initial operating conditions and equipment operability.

Large steam line breaks inside containment are also accommodated by the leak detection capability in System 80+. This capability allows significant time for the operator to shutdown and depressurize the plant before a break can occur inside containment. There are no small steam lines inside containment.

Steam line breaks outside containment are considered, including the double-ended break of a main pipe. The steam line break is considered for its impact on core overpower and core coolability. Figure 2-2 is used to ensure adequate core coolability. Operator action is assumed at 15 minutes to perform steam and feedwater line isolation, reactor trip, and safety injection actuation using available diverse equipment.

Double-ended feedwater line breaks are considered inside containment. Check valves inside the containment prevent steam generator blowdown for breaks outside containment. Hence, the feedwater line break inside containment and downstream of the check valves is evaluated for its impact on containment pressure. The evaluation assumes the lack of automatic steam/feedline isolation and the continued addition of main feedwater to the steam generators. The acceptance criterion is the ASME Service Level C stress limit corresponding to approximately 145 psia.

The letdown line break outside containment and the steam generator tube rupture events are slow depressurization events for which the control systems have more significant benefit. These events allow at least 15 minutes for operator intervention without fuel damage.

The loss of flow, RCP shaft seizure and RCP shaft break events were evaluated crediting the best-estimate overpower margin of about 135% in the System 80+ design. This allows these events to remain below the 10CFR100 offsite dose limit. Fuel failures for the loss of flow are assumed for all rods in DNB. Since the RCP shaft seizure and shaft break events have much lower probabilities, it is more appropriate to use a less stringent coolability criterion. Therefore, the coolability criterion of NUREG-0562 (Figure 5) is used. The CEA ejection also utilizes the NUREG-0562 time-at-temperature curve to ensure core coolability during and after the event. The CEA ejection recovery actions by the operator are the same as for post-LOCA actions and are assumed to start after 15 minutes.

TABLE 2-1

INITIAL OPERATING CONDITIONS

RCS Flowrate	461,200 gpm
RCS Pressure	2250° psia
RCS T_{hot}	615°F
RCS T_{cold}	556
Core Power	3914 MWt
Axial Shape Index	± 0.1
Radial Peaking Factor	1.50

TABLE 2-2

KEY INDICATORS OF CRITICAL FUNCTION STATUS

DISPLAYED CONTINUOUSLY VIA DIAS-P

Sensed Parameters:

RCS Pressure

Coolant Temperature (Hot)

Coolant Temperature (Cold)

Containment Pressure (Wide Range)

Containment Pressure (Narrow Range)

Steam Generator Pressure

Steam Generator Level (Wide Range)

Pressurizer Level

Neutron Flux Power Level (Safety Channels

Reactor Cavity Level

RCS Radiation Level

Containment Area Radiation

Containment Hydrogen Concentration

Containment Isolation Valve Position

Emergency Feedwater Storage Tank Level

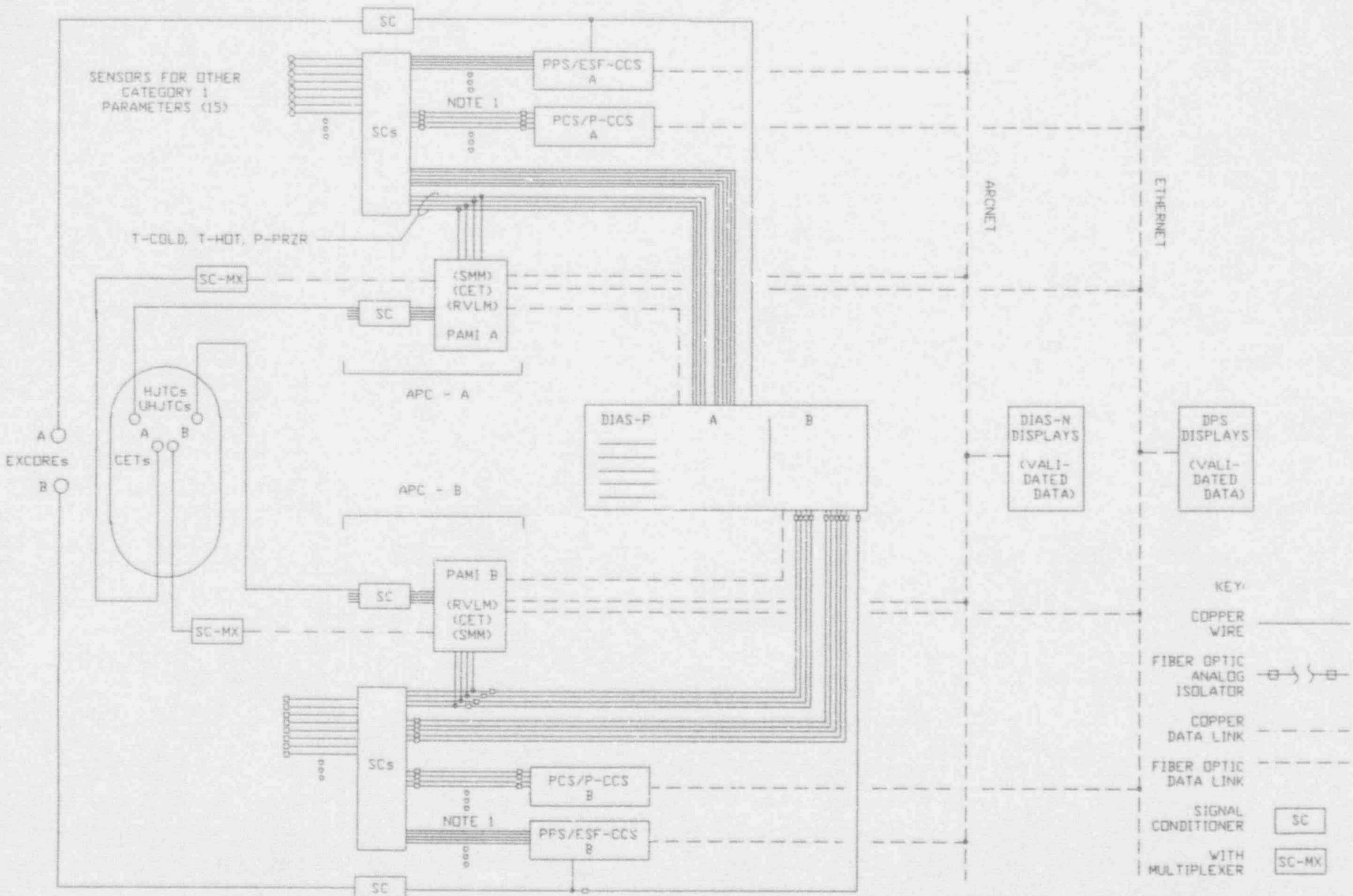
Calculated by PAMI Computer:

Core Exit Temperatures

Reactor Vessel Coolant Level

RCS Subcooling

FIGURE 2-1
DIVERSITY IN DISPLAY OF CATEGORY 1 PARAMETERS



NOTE 1 - A SEPARATE WIRE IS PROVIDED FOR EACH SIGNAL. NOT ALL CATEGORY 1 PARAMETERS ARE COMMUNICATED TO BOTH THE PPS AND THE ESF-CCS.

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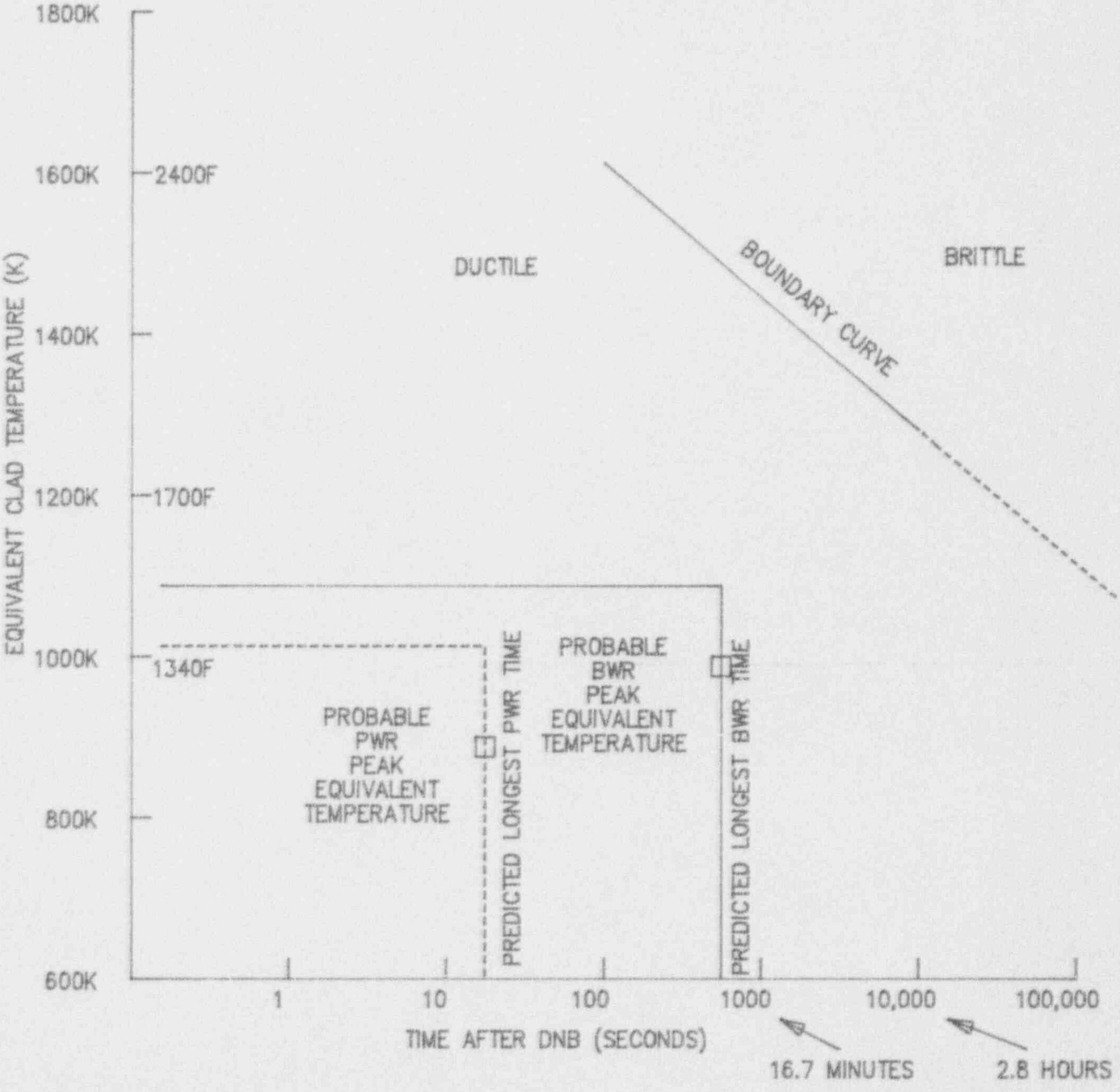
FIGURE 2-2

COMPARISON OF PREDICTED BWR AND PWR UPSET CONDITION PCT AND TIME AFTER DNB WITH FBRB/ANL ZIRCALOY DUCTILE-BRITTLE BOUNDARY CURVE



NOTE:
REPRODUCTION OF
FIG. 5 NUREG-0562

3. INDIVIDUAL EVENT EVALUATIONS

3.1 Total Loss of Forced Reactor Coolant Flow

This event is caused by the simultaneous loss of power to the 13.8 KV electrical buses supplying the Reactor Coolant Pumps (RCPs). The only credible failure that can result in the simultaneous loss of power to these buses is a complete loss of offsite power to the unit main and auxiliary transformers that would also result in a turbine-generator (T/G) trip and loss of normal electrical power to station equipment.

The postulated common mode software failure is assumed to preclude PPS initiation of a reactor trip on low RCP speed. However, upon the T/G trip, a rapid reduction in reactor power would be initiated by the Reactor Power Cutback System (RPCS). A full reactor trip would occur soon thereafter, as follows.

The loss of normal electric power to station equipment would include the 4.16 KV non-safety buses that power the motor-generator sets that provide power to the Control Element Drive Mechanisms. As discussed in the Reference 1 evaluation, on loss of power, the Control Element Drive Mechanisms (CEDM) motor-generator sets would begin to coast down and an under voltage relay would open an output breaker. This would cut power to the CEDMs, allowing the control rods to drop into the core by gravity. Even quicker action would be taken by an output contactor on each motor-generator set, that will open at four seconds after power is lost on the bus, cutting power to the CEDMs and causing the CEAs to drop into the core at that point.

A best estimate evaluation of this transient accounting for the best-estimate overpower margin available indicates that the power reduction is sufficiently rapid that no fuel pins experience departure from nucleate boiling and radiological releases remain well within 10CFR100 guidelines.

3.2 Single RCP Shaft Seizure

The Reference 2 evaluation estimated that with a shaft break in one RCP, the remaining 3 RCPs would provide about 75% of the nominal full power core flow. A best estimate of the fluid conditions in the core under this condition without a trip indicates that the DNBR would remain above the SAFDL without tripping the reactor. Under off normal conditions of operation, the fuel would be maintained well below the Figure 2-2, time-at-temperature curve. Hence, core coolability is preserved under all conditions. This evaluation did not credit action of the Reactor Regulating system which would perform automatic insertion of control rods, reducing reactor power to maintain average coolant temperature and therefore provide additional margin.

Alarms and indications would be provided via equipment not affected by the CMF to support operator action to trip the reactor. Therefore, use of normal controls and operator action provides adequate mitigation of this event.

3.4 CEA Ejection

As discussed in the Reference 2 evaluation, the Alternate Protection system (APS) initiates a reactor trip on high pressurizer pressure at about 2420 psia to provide reactivity control. A best estimate evaluation assuming nominal initial conditions and applying the time-at-temperature criterion determined that cladding temperatures remain well below the Figure 2-2 limit demonstrating the core remains coolable. Operator action at 15 minutes, to regain RCS inventory and provide long term heat removal, would adequately protect the core from uncovering in the same manner as for the LOCA (paragraph 3.9).

3.5 Letdown Line Break Outside Containment

As discussed in Reference 2, operator action to actuate letdown isolation within 30 minutes would provide adequate mitigation for this event. The evaluation indicates that there would be no DNB violation for more than 15 minutes even under the worst case (Chapter 15) initial operating parameters. The hardwired manual controls proposed in Reference 6 will be augmented to include a switch for closing a letdown isolation valve and the containment air purge valves. With this additional diverse feature, the operator would be able to respond to isolate the leak within 15 minutes, terminating the event. Since there is no fuel damage, 10CFR100 offsite dose guidelines are met.

3.6 Steam Generator Tube Rupture

The Reference 2 evaluation discusses the means available via normal control systems and operator action to accomplish reactivity control, RCS inventory control and RCS heat removal. That evaluation identifies the need to provide diverse means for manual closure of the MSIVs in order to control radiological emissions. The hardwired manual controls proposed in Reference 6 provide this capability.

The SGTR event will be helped by the normal NSSS control actions which compensate for the depressurization, inventory loss and decreased subcooling. The PLCS maximizes charging and minimizes letdown. The PPCS heaters help to offset depressurization anu decreased subcooling. The feedwater control system (FWCS) reduces the main feedwater flow to avoid overfilling the SGs and the steam bypass control system (SBCS) augments the turbine/generator (T/G) and/or main steam safety valves (MSSVs) if excess steam must be vented. As a result of the best-estimate overpower margin and the slow nature of this event, the reactor can remain at full power for at least 15 minutes without DNB violation and without draining the pressurizer or overfilling the steam generators. Since there is no fuel damage, 10CFR100 offsite dose guidelines are met.

3.7 Main Steam Line Break

Main steam line leakage detection capability is provided for leakage inside containment. For steam lines inside containment, a detectable leakage occurs long before a major pipe rupture occurs. Thus, ample time is available for the operator to shutdown and depressurize prior to a pipe rupture.

Main steam line leakage detection outside containment is less precise and reliable. Therefore, this evaluation considers double-ended breaks outside containment. The assumed absence of an automatic reactor trip and automatic main steam and feedwater isolation challenges the ability to maintain core coolability. However, the nominal overpower margin in the core, doppler reactivity feedback to limit the power increase and the T/G auto-controlled shutdown help to mitigate the effect of the assumed failures.

The large energy extraction caused by the break reduces steam pressure dramatically and the T/G shuts down which terminates the resupply of water to the condensate system. The FWCS will tend to increase flow to the steam generators based on low level and high steam flow measured in the SG integral nozzle/venturis.

The net effect is that after about the first 10 seconds the core overpower would exceed the nominally available 135% overpower margin. However, for more than 15 minutes, cladding temperatures remain well below the Figure 2-2 "time-at-temperature" limit demonstrating the core remains coolable.

At 15 minutes, the operator can trip the reactor and initiate MSIV closure using the diverse manual controls on the main control board. Final plant cooldown can thereafter be conducted using the steam driven EFW pumps and the MSIV bypass line to direct steam releases to the condenser.

3.8 Feedwater Pipe Break

Rupture of a feedwater line downstream of the in-containment check valves would result in a leak from the associated steam generator to the containment. The leak area can be as large as about 1 ft^2 if the leak occurs in one of the 14 inch economizer lines.

The Alternate Protection System (APS) ensures adequate core coolability for the feedwater line break by providing a reactor trip on a high pressurizer pressure (HPP) condition and provides emergency feedwater actuation upon low SG level. The automatic pressurizer pressure and level controls help to limit the maximum RCS pressure via pressurizer spray and reduced charging and increased letdown. Since a HPP trip is achieved core coolability is acceptable.

An evaluation of the potential mass and energy release to the containment indicates that operator action to actuate containment spray and close the MSIVs within about 10 minutes of event initiation would maintain the containment pressure below the design limit. Furthermore, for 15 minutes the pressure will remain well below the ASME Service Level C limit for the containment sphere (about 145 psia). Containment pressure, steam generator pressure and level alarms would provide indication of the need for operator action.

Manual action would be taken to terminate normal and emergency feed to the affected steam generator. Continued core decay heat removal could be provided via the intact steam generator using the emergency feedwater system, which would be automatically actuated by the APS, and by relieving steam through the main steam safety valves or the steam dump and bypass system using the MSIV bypass valves. Cooldown could also be accomplished via the ADVs, using the valve handwheels if necessary.

3.9 Loss of Coolant Accident

For pipes which are 12 inches or larger in diameter, a detectable leak would occur significantly in advance of a major rupture. Thus, the operator would have sufficient time to shutdown and depressurize the plant prior to a large break occurrence. This evaluation credits this characteristic of large pipes and the System 80+ leak detection equipment to cope with large breaks. A failure of pipes smaller than 12 inches may not allow sufficient time for leak detection prior to break. Therefore, they require additional evaluation crediting the capability of diverse equipment and operator action for mitigation.

A best-estimate evaluation was performed of the response to breaks in branch lines connected to the RCS which are smaller than 12 inches in diameter. The evaluation determined that the most limiting failure is the largest branch line (6 inch line) break on the top of the pressurizer. Continued operation of the RCPs helps to maintain core cooling without a reactor trip. The moderator voiding which occurs helps by reducing core power, hence, reducing the cooling requirement. Operator action to trip the reactor and initiate safety injection pumps in 30 minutes results in acceptable cladding temperature and oxidation (within 10CFR50.46). The hardwired manual controls proposed in Reference 6 will be augmented to include a switch for closing the containment air purge valves to minimize offsite radiological releases.

4. REFERENCES

(1) Letter from D. Crutchfield of NRC to E. Kintner, Draft Commission Paper "Design Certification and Licensing Policy Issues Pertaining to Passive and Evolutionary Advanced Light Water Reactor Designs," July 6, 1992.

(2) ALWR-IC-DCTR-31, "Evaluation of Defense-In-Depth and Diversity in the ABB-CE NUPLEX 80+ Advanced Control Complex for the System 80+ Standard Design," ABB-CE, September 1992.

(3) J. V. Palomer, R. H. Wyman (LLNLL), "A Review of the CE 80+ FMEA and D&DID Analysis," December 8, 1992.

(4) January 6, 1993 Meeting of ABB-CE I&C staff and NRC I&C staff with Lawrence Livermore reviewers to discuss their review results for the ABB-CE D&DID Evaluation.

(5) January 11, 1993 Meeting in Windsor, CT. of ABB-CE Management with NRC Management on the Status of the Design Certification Review of System 80+.

(6) LD-93-011, "DSER (Open Item 7.2.2.2-1) Response Submittal," February 2, 1993.

(7) R. Van Houten, "Fuel Rod Failure as a Consequence of Departure from Nucleate Boiling or Dryout," USNRC, NUREG-0562, June, 1979

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