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

29 MAY 1986

TO ALL APPLICANTS AND LICENSEES WITH COMBUSTION ENGINEERING (CE) DESIGNED NUCLEAR STEAM SUPPLY SYSTEMS (NSSSs) (EXCEPT MAINE YANKEE)

SUBJECT: IMPLEMENTATION OF TMI ACTION ITEM II.K.3.5, "AUTOMATIC TRIP OF REACTOR COOLANT PUMPS" (GENERIC LETTER NO. 86-06)

Gentlemen:

The purpose of this letter is to inform you of (1) the staff's conclusions regarding the CE Owners Group (CEOG) submittals on reactor coolant pump trip in response to Generic Letters 83-10a and b, and (2) provide guidance concerning implementation of the reactor coolant pump trip criterion. Our Safety Evaluation (SE) on this subject is enclosed for your use.

With regard to the CEOG submittals referenced in Section V of the enclosed SE, we conclude that the methods employed by the CEOG to justify manual reactor coolant pump (RCP) trip are consistent with the guidelines and criteria provided in Generic Letters 83-10a and b. The approved CE Small Break LOCA Evaluation Model was used to demonstrate compliance with 10 CFR 50.46 and Appendix K to 10 CFR Part 50.

We have determined that the information provided by the CEOG in support of the trip-two/leave-two staggered reactor coolant pump trip criterion is acceptable. The generic information presented by the CEOG, however, does not address plant specific concerns about instrumentation uncertainties, potential reactor coolant pump problems and operator training and procedures as requested in Generic Letter 83-10. This information, contained in Section IV of the SE, is now being requested to assess implementation of the RCP trip criterion.

Accordingly, for those applicants and licensees who choose to endorse the CEOG methodology, we request that operating reactor licensees implement the RCP trip criterion based upon the CEOG methodology. Schedules for submittal of information requested in Section IV of the SE (refer to Appendix A for considerations associated with Generic Letters 83-10a and b) should be developed with your individual project managers within 45 days from receipt of this letter. The requested information does not constitute a new requirement but only identifies information specified in Generic Letters 83-10a and b which has not been provided under the CEOG generic program. In the event that licensees decide not to trip the RCP (an option provided for in Generic Letters 83-10a and b), they should respond to the questions in Section IV of the SE and refer to Appendix B of the SE. Applicants should provide the appropriate response to the extent that this information is known at this time.

Those applicants and licensees who choose not to endorse the CEOG methodology should submit a schedule for submittal of plant specific RCP trip criteria or justification for non-trip of RCPs within 45 days of receipt of this letter.

IDHR-5
Info-Ltr.
XRD-8-2
CE.

This request for information was approved by the Office of Management and Budget under clearance number 3150-0011 which expires September 30, 1986. Comments on burden and duplication may be directed to the Office of Management and Budget, Reports Management, Room 3208, New Executive Office Building, Washington, D.C. 20503.

Our review of your submittal of information in response to this letter is not subject to fees under the provisions of 10 CFR 170. However, should you, as part of your response or in a subsequent submittal, include an application for license amendment or other action requiring NRC approval, it is subject to the fee requirements of 10 CFR 170 with remittal of an application fee of $150 per application (Sections 170.12(c) and 170.21) and subsequent semiannual payments until the review is completed or the ceiling in Section 170.21 is reached.

If you believe further clarification regarding this issue is necessary or desirable, please contact Mr. R. Lobel (301 492-9475.)

Sincerely,

Frank J. Miraglia

Frank J. Miraglia, Director
Division of PWR Licensing-B

Enclosure:
Safety Evaluation

cc w/enclosure:
Service Lists

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

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION
COMBUSTION ENGINEERING OWNERS GROUP SUBMITTALS
REACTOR COOLANT PUMP TRIP

I. INTRODUCTION

TMI Action Plan Item II.K.3.5 of NUREG-0737 required all licensees to consider other solutions to the small-break loss-of-coolant-accident (LOCA) problems since tripping the reactor coolant pumps (RCPs) was not considered the ideal solution. Automatic trip of the RCPs in the case of a small-break LOCA was recommended until a better solution was found. A summary of both the industry programs and the NRC programs concerning RCP trip is provided in Generic Letters 83-10a through f, which are included in the NRC report, SECY-82-475, from W. J. Dircks to the NRC Commissioners, "Staff Resolution of the Reactor Coolant Trip Issue" (November 30, 1982). SECY-82-475 also provided the NRC guidelines and criteria for the resolution of TMI Action Item II.K.3.5, "Automatic Trip of Reactor Coolant Pumps."

In SECY-82-475 the NRC concluded "...that appropriate pump trip setpoints can be developed by the industry that would not require RCP trip for those transients and accidents where forced convection circulation and pressurizer pressure control is a major aid to the operators, yet would alert the operators to trip the RCPs for those small LOCAs where continued operation or delayed trip might result in core damage."

SECY-82-475 also stated: "The resolution provided in the enclosures [Generic Letter 83-10] is intended to ensure that for whatever mode of pump operation a licensee elects, a) a sound technical basis for that decision exists, b) the plant continues to meet the Commission's rules and regulations, and c) as a minimum, the pumps will remain running for those non-LOCA transients and accidents where forced convection cooling and pressurizer pressure control would enhance plant control. This would include steam generator tube ruptures up to approximately the design basis event (one tube)."

The Combustion Engineering Owners Group (CEOG) submitted a report to the NRC in response to the Combustion Engineering specific Generic Letter, 83-10a. The title of the report is "Justification of Trip Two/Leave Two Pump Trip Strategy During Transients" (Reference 1). The CEOG also provided additional information (Reference 2) in response to the NRC staff request for this information, based on the staff's review of the generic submittal. The NRC staff also performed analyses of selected events to support the staff's review (Reference 3).

Appendix A, herein summarizes Section I of the enclosure to Generic Letter 83-10 for "Pump-Operation Criteria that Can Result in RCP Trip During Transients and Accidents," and Appendix B summarizes Section II, "Pump-Operation Criteria That Will Not Result in RCP Trip During Transients and Accidents."

II. SUMMARY

The CEOG proposes using a trip-two/leave-two (T2/L2) strategy. The T2/L2 trip strategy consists of tripping two RCPs, located in diametrically opposed coolant loops, very early in a transient on a low reactor coolant system (RCS) pressure signal independent of the nature of the event. The remaining two RCPs are tripped subsequently after trip setpoints indicating a LOCA are reached.

The goal of the T2/L2 RCP trip strategy is to trip all RCPs in the case of a small-break LOCA, but to have two or more RCPs operating in the event of a non-LOCA, e.g., steam line break (SLB), generator tube rupture or an anticipated operational occurrence (AOO). The incentive for stopping all RCPs during a small-break LOCA is to minimize coolant inventory loss from the RCS. The incentive for operating the RCPs during non-LOCA depressurization events is to maintain the availability of the main spray flow to the pressurizer for better RCS pressure control. The RCP operation also minimizes voiding of the reactor vessel upper head/upper plenum regions by providing some forced coolant flow through this region and provides for better mixing in the reactor vessel downcomer/lower plenum region minimizing pressurized thermal shock (PTS) concerns.

The T2/L2 RCP trip signals and setpoints were selected on a generic basis to provide a simple setpoint scheme with enough flexibility to accommodate plant specific signal and numerical setpoint selection. The generic RCP trip setpoints consist of two tiers. The first setpoint for tripping two RCPs in opposite loops occurs if the RCS pressure decreases below a certain value (e.g., 1300 psia). The setpoint signals for tripping the second two RCPs are low RCS subcooling (e.g., less than 20°F), containment radiation alarm and/or absence of radiation alarm in the secondary cooling system. Each licensee or applicant using this approach would choose one of three sets of setpoint combinations (that is, low subcooling plus containment radiation alarm, or low subcooling plus absence of secondary side radiation alarm, or low subcooling plus containment radiation alarm plus absence of secondary side radiation alarm) for tripping the second two RCPs based on plant specific considerations of signal availability, signal reliability, instrument location, etc.

The CEOG provided calculations for small-break LOCAs, a steam generator tube rupture (SGTR), a SLB, and an increased heat removal (IHR) transient. They also discuss letdown line breaks and "the PLCS (no charging flow and maximum letdown) and PPCS (full main spray) malfunction events." Generic setpoints were used for these analyses: the first two RCPs were tripped when the RCS pressure decreased below 1300 psia; the second two RCPs were tripped when the maximum hot-leg subcooling decreased below 20°F if there was a containment radiation alarm expected. If the containment radiation alarm was not expected or if a radiation alarm was expected in the secondary system (indicating a SGTR), then the second two RCPs were not tripped even if the maximum hot-leg subcooling decreased below 20°F.

The analyses were performed for the 2700 MWt class plants because they have the most restrictive combination of safety injection tank pressure, which affects the worst break size, and high pressure safety injection (HPSI) pump flow, which affects the core cooling capability. A comparative analysis was conducted for the 3410 MWt class plants to demonstrate that the results from the Reference plant bound the core cooling performance of the 3410 MWt System 80 class plants.

The CEOG followed the guidelines provided in Generic Letter 83-10a to justify manual RCP trip for small-break LOCAs. (See Appendix A, Section D). The CEOG studies have shown that:

1. Every Combustion Engineering plant's FSAR emergency core cooling system (ECCS) analysis demonstrates compliance with 10 CFR 50.46 if operator action to trip the RCPs is taken within 2 minutes after the RCP trip criterion is reached.

2. Most probable best estimate analyses indicate that for all Combustion Engineering plants, if the RCPs are tripped within 10 minutes during a small-break LOCA event, the peak cladding temperatures will not exceed the 10 CFR 50.46 limit of 2200°F.

The CEOG concluded that automatic reactor coolant pump trip is not required since adequate time for manually tripping the RCPs is demonstrated using 10 CFR Part 50, Appendix K assumptions as well as most probable best estimate analyses results. It was also shown that, using best estimate analyses for small-break LOCAs, tripping the RCPs at minimum inventory would not result in peak cladding temperatures greater than 2200°F. Therefore, the time available to the operator to trip the RCP for a small-break LOCA is unlimited. However, the CEOG does not propose operation of the RCPs during a small-break LOCA and RCP trip is required. A positive indication for RCP trip occurs within 1 minute for the limiting small-break LOCA, requiring that all four RPCs be tripped. An analysis of an inadvertently stuck open power operated relief valve (PORV) demonstrated that positive indicators to trip all four RCPs would occur within 200 seconds.

The CEOG has thus demonstrated that all four RCPs will be tripped for breaks from 0.0075 ft^2 to 0.1 ft^2, which bounds their previously shown region of 0.02 ft^2 to 0.1 ft^2 where RCP trip is necessary to prevent exceeding 10 CFR 50.46 limits. They have also demonstrated that peak clad temperatures will not be excessive using their RCP-trip strategy for conservative best-estimate analyses.

The CEOG analyzed a design-basis double-ended guillotine SGTR event. For this event, the RCS pressure decreases below the proposed setpoint value and the hot leg subcooling margin decreases to about 4°F. There would be a steam generator secondary radiation alarm but no containment radiation alarm for the SGTR (under normal circumstances); therefore, two RCPs would be tripped on low pressure but the remaining two pumps will be allowed to continue to run. The CEOG has thus demonstrated that the second set of RCPs will not be tripped for SGTRs up to the design-basis SGTR.

The CEOG analyzed a double-ended-guillotine SLB at the steam-generator outlet nozzle to determine how well the RCP trip setpoints worked for this type of IHR accident. Best-estimate assumptions were used except that no moisture carryover was assumed during the steam generator blowdown to give faster depressurization and cooldown. The 1300 psia setpoint was reached, and the first two RCPs were tripped after a 30 second delay. Hot leg subcooling never decreased below the 20°F setpoint so the second two RCPs continued operating throughout the transient.

For the SLB event, there would be no secondary side radiation alarm and most probably no containment radiation alarm. The first of these indications would signal a trip of the second two pumps if it were not for the subcooling criterion. The lack of a containment radiation alarm would have resulted in the second two pumps not being tripped even if the subcooling criterion had been met. Thus the RCP trip strategy would result in manual tripping of the first two RCPs on low pressurizer pressure, and no manual tripping of the second two RCPs due to the loss of indicated subcooling in at least one hot leg. The T2/L2 strategy thus trips only the first two RCPs for the SLB and leaves the other two running throughout the transient.

An inadvertent increase in turbine power from no load to full power was analyzed to evaluate the effectiveness of the generic RCP trip setpoints for an IHR AOO. This event causes the greatest rate of cooldown and depressurization of any IHA AOO, thereby presenting the greatest challenge to the RCP trip criteria.

A best-estimate calculation was performed in which the RCS pressure only reached a minimum of 1700 psia so none of the RCPs were tripped. The hot leg subcooling never decreased below about 110°F so even if the RCS pressure had indicated that the first two RCPs should be tripped, the second two would have kept running. The CEOG guideline for keeping at last two RCPs running is thus met for this type of transient.

Other transients for which the reactor might automatically trip on low pressurizer pressure followed by high pressure safety injection actuation include the letdown line break events and the PLCS (no charging flow and maximum letdown) and PPCS (full main spray) malfunction events. However, timely operator action would prevent an automatic reactor trip, and the plant could then be manually shut down using appropriate plant procedures without actuating safety injection.

For these events, an automatic reactor trip on low pressurizer pressure resulting in subsequent RCP trip is not expected to occur for a long period of time (probably more than 30 minutes). According to the American National Standards Institute criteria for safety related operator actions documented in draft ANSI-N660, operator actions can be assumed within 20 minutes after the start of the above transients. Therefore an automatic reactor trip for these events would be highly unlikely. Assuming no manual operator actions to correct the cause of the PPCS malfunction event, an automatic reactor trip on low pressurizer pressure will eventually occur. The first two RCPs would then be maually tripped for the PPCS malfunction event due to the RCS pressure decreasing below the pressure setpoint of 1300 psia. However, the second two RCPs would not be tripped since the hot leg subcooling will remain well above the 20°F setpoint. For the letdown line break and the PLCS malfunction events, if no operator actions are assumed and should a reactor trip on low pressurizer pressure occur, the first two RCPs would be manually tripped upon reaching the low pressure setpoint. Additionally, as the hot leg subcooling decreases to the 20°F setpoint, the second two RCPs would be manually tripped if the loss-of-subcooling with no steam plant radiation alarm criteria is used. Use of the other two combinations ((a) loss-of-subcooling with no containment radiation alarm or (b) loss-of-subcooling with no steam plant radiation alarm and no containment radiation alarm) will not lead to tripping of the second two RCPs due to the absence of containment radiation alarms for these events.

The manual tripping of any of the RCPs for the above transients is considered very low since there is adequate time for the operator to correctly diagnose the events and take appropriate actions without RCP trip. However, even if the first two RCPs were tripped, it is very likely that the second two RCPs would remain operating.

This approach for these other transients is satisfactory because the operator has so much time to diagnose the event and take appropriate action without tripping any RCPs and the probability of tripping all four RCPs is very low.

The CEOG strategy presented does differentiate between LOCAs and other transients. The decision to trip the second two RCPs requires that a LOCA be distinguished from the other two types of accidents which have similar depressurization characteristics: SGTR and SLB. The presence of a containment radiation alarm or the lack of a steam plant radiation alarm indicates that the event is a LOCA rather than a SGTR. A SLB may involve low level radiation releases, thus activating a radiation alarm, particularly the containment alarm for an inside containment SLB. Thus, a radiation alarm cannot be used to differentiate between a LOCA and a SLB. However, a LOCA results in loss of subcooling in the RCS, while a SLB will actually cause an increase in subcooling, particularly in the RCS loop with the affected steam generator. Therefore, RCS subcooling can be used to clearly distinguish between a LOCA and a SLB. However, a SGTR will also cause a loss of RCS subcooling. Thus, it was shown that no single criterion can be used to determine whether or not to trip the second two RCPs. Therefore, the combination of low RCS subcooling and no steam plant radiation alarm and a containment radiation alarm clearly indicates if the second two RCPs should be tripped. However, plant specific requirements may dictate selection of either of the two-parameter combinations: (a) low RCS subcooling and a containment radiation alarm or (b) low RCS subcooling and no steam plant radiation alarm. Combination (a) indicates a LOCA directly while combination (b) indicates a LOCA by eliminating non-LOCA depressurization events.

An AOO would not normally cause a depressurization severe enough to trip the first two RCPs, but if it did, it is expected that there would not be a loss of RCS subcooling.

A LOCA outside containment (letdown or charging line break) may result in a secondary side radiation alarm. Operator judgement is necessary to diagnose this type of event, which can be isolated. For breaks less than 0.02 ft^2 in the Reference 2700 MWt plant, RCP operation does not affect core uncovery. A double-ended rupture of a letdown or charging line has a break size of 0.016 ft^2. A SGTR would result in actuation of this alarm since there is direct leakage from the primary to the secondary side. Thus, the absence of this alarm provides an indication of a LOCA.

The basis for the setpoints selection was described in the CEOG submittal. The methodology used is based on the fact that following a small-break LOCA, the RCS pressure stabilizes at a pressure sufficiently high above the steam generator (SG) secondary side pressure to remove the core fission product decay heat.

Based on the results of the analyses, the nominal setpoint for tripping the first two RCPs is 1210 psia for the 2700 MWt class, and 1320 psia for Arkansas Nuclear One, Unit 2. A separate calculation determined the nominal RCS pressure setpoint to be 1361 psia for the 3410 MWt class plants. The setpoint for the System 80 plants is 1400 psia, which was derived from a comparison of SG safety relief valve setpoints.

The actual RCS pressure used for the setpoint to trip the first two RCPs should include an allowance for instrument error. For example, assuming the normal operating pressurizer pressure uncertainty is about ± 45 psi for the Reference 2700 MWt plant, then the resulting RCS pressure setpoint would be 1210 psia plus 45 psia which equals 1255 psia. The exact setpoint value must be determined on an individual plant specific basis, including an assessment of instrument inaccuracy for abnormal operating conditions.

The loss of RCS subcooling in both coolant loops is symptomatic of a LOCA. Thus, the nominal RCS subcooling setpoint is 0°F. As with the RCS pressure setpoint, an estimate of the instrument error must be factored into the actual subcooling setpoint. The actual setpoint value used should include an assessment of the plant specific RCP operating limits. Each licensee or applicant must evaluate the plant conditions required to maintain RCP operating equipment integrity.

In general, we believe the radiation monitors required for RCP trip can perform as expected, and can be used for this purpose. However, we note that NUREG-0737 Item II.F.1(3), "In-Containment High Radiation Monitor" was intended to detect core damage (approximately 10,000 R/hr). The sensitivity to detect one R/hr needs to be addressed by each licensee (see Implementation, below).

In addition to the establishment and justification of a RCP trip criterion, Generic Letter 83-10 also requested that licensees and applicants establish guidelines and procedures for cases where RCP trip can lead to hot, stagnant fluid regions at RCS high points and to describe symptoms of RCS voiding caused by flashing of hot, stagnant fluid regions, including the effects on the pressurizer, and to specify guidance for detecting, managing and removing the voids.

The non-LOCA depressurization and overcooling transients evaluated by the CEOG have a potential for causing void formation in the upper head region of the reactor vessel with single phase liquid conditions in the rest of the RCS. This void formation is maximized for the case with no RCPs operating due to the nearly complete thermal decoupling of the upper head of the reactor vessel from the rest of the RCS. Analyses of this scenario for the non-LOCA transients were completed and documented in Reference 5. These analyses indicate that upper head voiding is not extensive enough to uncover the reactor vessel hot legs. The main impact of the reactor vessel upper head void is a slower pressure response, since only this relatively stagnant region reaches saturation and it acts like a pressurizer. The slower pressure response can hold up the pressure for SGTR and SLB events. This will increase the primary to secondary leakage during a SGTR event and reduce the safety injection flow during a main SLB event. However, the impact of these effects does not result in a violation of the criteria specified by the Standard Review Plan guidelines even though upper head voiding has an impact upon transient values of plant parameters.

C-E Emergency Procedure Guidelines (EPGs) (Reference 5) address the control of RCS voids. For void formation in the upper head region to occur, the pressurizer does not have to drain. Depressurization of the system to saturation conditions is sufficient for voids to be generated (e.g., after a SLB, the rate of depressurization is such that this situation exists). Although natural circulation will not be impeded since the upper head voids do not expand beyond the top of the hot legs, an asymmetric cooldown, as discussed in Reference 4, will exist. Precautions as detailed in Reference 4 to prevent voids from forming in the affected steam generator loop need to be considered and are contained in Reference 5.

The use of the T2/L2 strategy keeps two RCPs running except for small-break LOCAs so the continued flow minimizes voiding in the RCS high points by providing forced coolant flow through these regions to prevent hot stagnant regions from occurring.

Item I.1.e of the enclosure to Generic Letter No. 83-10 expresses the concern that "Transients and Accidents which produce the same initial symptoms as a LOCA (i.e., depressurization of the reactor and actuation of engineered safety features) and result in containment isolation may result in the termination of systems essential for continued operation of the reactor coolant pumps (i.e., component cooling water and/or seal injection water)." It is further stated that, "In particular, if a facility design terminates water services essential for RCP operation, then it should be assured that these water services can be restored in a timely manner once a non-LOCA situation is confirmed, and prevent seal damage or failure."

The generic CEOG submittal did not address this concern, therefore we requested that each licensee address the issue. The responses are provided in References 6 through 14.

(Note: Responses from Palo Verde-1 and Waterford-3, are not available at this time; these responses will be addressed at the time the plant-specific Implementation SE is issued).

In general, essential RCP service water may be lost due to a safety injection actuation signal (SIAS), on low RCS pressure. SIAS is expected to occur during a SGTR event. Once the non-LOCA situation is confirmed per the EPGs, the operator is instructed to reestablish component cooling water (CCW) to the RCP seals and pump coolers by overriding the isolation signal(s). If timely reestablishment of the CCW cannot be accomplished, the remaining two RCPs are tripped. Seal cooling may be needed to prevent seal damage. The EPGs (Reference 5) developed by Combustion Engineering for the CEOG provide guidance with respect to maintenance of auxiliary systems which support RCP operation. The EPGs have been approved by the NRC.

The CE licensees emphasized that, although the T2/L2 strategy provides for effective plant cooldown, plant operations are bounded by FSAR analyses which do not credit RCP operation. Therefore, if RCP cooling services are not restored and RCP operations are terminated, the plant can be shut down safely.

At Calvert Cliffs 1 and 2 and at San Onofre 2 and 3, a containment isolation actuation signal (CIAS) results in an interruption of CCW. The EPGs are relied on to restore CCW for continued RCP operation.

With proper seal injection and seal return, integrity of the seals can be maintained indefinitely on loss of component cooling water to a running RCP. However, the RCP motors cannot be run indefinitely on a loss of cooling water. If it is desired to continue RCP operation, cooling water must be reestablished within a given time frame as indicated in EPGs to preclude damage.

The generic nature of the CEOG submittal, concerning the RCP trip setpoint selection, by nature does not include any actual plant specific information. We have therefore included a section (Implementation), herein, which describes those plant specific items we require to be addressed when incorporating the RCP trip criterion into the plant procedures.

III. CONCLUSIONS

We have determined that the information provided by the CEOG for the justification of manual RCP trip is acceptable. The methods employed by the CEOG to justify manual RCP trip are consistent with the guidelines and criteria provided in Generic Letter 83-10a and 83-10b. The approved Combustion Engineering Small Break LOCA Evaluation Model was used to demonstrate compliance with 10 CFR 50.46 and Appendix K to 10 CFR Part 50.

We have determined that the information provided by the CEOG in support of the trip-two/leave-two staggered RCP trip criterion is acceptable.

We believe the analyses methods employed by the CEOG are capable of qualitatively providing the appropriate information to evaluate the loss-of-subcooling RCP trip criterion.

We have concluded that the CEOG has developed acceptable criteria for tripping the RCPs during small-break LOCAs and to minimize RCP trip for SGTR and non-LOCA events.

IV. IMPLEMENTATION

The generic information presented by the CEOG does not address plant specific concerns about instrumentation selection and uncertainties, and operator training and procedures as requested in Generic Letter 83-10. Appendix A contains a summary related to these issues and may be used as a guideline to assure that these issues are adequately addressed.

In order to complete the response to Generic Letter 83-10a, each CE applicant and licensee is required to submit the following information to the NRC for plant specific reviews:

1. Identify the instrumentation to be used to determine the RCP trip setpoints, including the degree of redundancy of each parameter signal needed for the criteria chosen.

2. Identify the instrumentation uncertainties for both normal and adverse containment conditions. Describe the basis for the selection of the adverse containment parameters. Address, as appropriate, local conditions such as fluid jets or pipe whip which might influence the instrumentation reliability.

3. In addressing the selection of the criterion, consideration of uncertainties associated with the CEOG supplied analyses values must be provided. These uncertainties include both uncertainties in the computer program results and uncertainties resulting from plant specific features not representative of the CEOG generic data group.

4. Identify all plant procedures (except for those concerning normal operations such as normal cooldown) which require RCP trip guidelines. Reference to the CEOG EPGs is acceptable if endorsed by the licensee. Include training and procedures which provide direction for use of individual steam generators with and without operating RCPs.

REFERENCES

1. Combustion Engineering Nuclear Power Systems Division, "Justification of Trip-Two/Leave-Two Reactor Coolant Pump Trip Strategy During Transients," (Prepared for the C-E Owners Group) Combustion Engineering report CEN-268 (March 1984).

2. Combustion Engineering Nuclear Power Systems Division, "Response to NRC Request for Additional Information on CEN-268," (Prepared for the C-E Owners Group) Combustion Engineering report CEN-268 Supplement 1-NP (November 1984).

3. LA-UR-85-3501, "Technical Evaluation Report for the TRAC Analyses of Small-Break Loss-of-Coolant Accident to Evaluate Combustion Engineering Models Used to Establish Reactor-Coolant-Pump Trip Setpoint Criteria," G. J. E. Willcutt, Jr., LANL, August 1985.

4. Combustion Engineering, Inc., "Effects of Vessel Head Voiding During Transients and Accidents in C-E NSSSs," Combustion Engineering report CEN-199 (March 1982).

5. Combustion Engineering, Inc., "Combustion Engineering Emergency Procedure Guidelines," Combustion Engineering report CEN-152, Revision 01 (November 1982).

6. Arkansas Nuclear One - Unit 2, letter 2CAN058507, dated May 23, 1985, J. Ted Enos to James R. Miller (NRC).

7. Calvert Cliffs Unit 1 and Unit 2, letter dated June 4, 1985, A. E. Lundvall, Jr., to J. R. Miller (NRC).

8. Fort Calhoun 1, letter LIC-85-215, dated May 23, 1985, R. L. Andrews to J. R. Miller (NRC).

9. Millstone 2, letter B11555, dated May 30, 1985, J. F. Opeka to J. R. Miller (NRC).

10. Palisades, letter dated July 2, 1985, J. L. Kuemin to Director, NRC.

11. Palo Verde Unit 1 - (not available)

12. San Onofre Unit 2 and Unit 3, letter dated June 5, 1985, M. O. Medford to G. W. Knighton (NRC).

13. St. Lucie Unit 1, letter L-85-209, dated June 3, 1985, J. W. Williams, Jr., to J. R. Miller (NRC).

14. St. Lucie Unit 2, letter L-85-280, dated July 22, 1985, J. W. Williams, Jr., to J. R. Miller (NRC).

APPENDIX A

PUMP-OPERATION CRITERIA THAT CAN RESULT IN RCP TRIP DURING TRANSIENTS AND ACCIDENTS

A. The NRC staff has concluded that if sufficient time exists, then manual action is acceptable for tripping the RCPs following a LOCA provided certain conditions are satisfied.

B. Potential problem areas should be considered in developing RCP-trip setpoints and methods.

   1. Tripping RCPs causes loss of pressurizer sprays.

      a. This produces a need to use PORVs in some plants to control primary pressure.

      b. PORVs have frequently failed to close.

      c. Despite testing, PORV operational reliability has not improved significantly.

   2. Tripping RCPs tends to produce a stagnant region of hot coolant in the reactor-vessel upper elevations.

      a. Hot stagnant coolant has flashed and partially voided the upper vessel region during depressurization or cooldown operation events.

      b. Operators are not completely familiar with the significance of an upper-head steam bubble.

      c. Operators have difficulty controlling coolant conditions to avoid or control flashing.

      d. Operators may take precipitous actions when a steam bubble exists.

   3. After tripping the RCPs, decay-heat removal by natural circulation is required. This procedure is used less frequently than controlling with the RCPs and it places more demand on the operators to control the primary-system conditions.

C. Consider the following guidelines in developing RCP-trip setpoints.

   1. Demonstrate and justify that proposed RCP-trip setpoints are adequate for small-break LOCAs but will not cause RCP trip for other non-LOCA transients and accidents such as SGTRs.

      a. Assure that RCP trip will occur for all primary-coolant losses in which RCP trip is considered necessary.

      b. Assure that RCP trip will not occur for SGTRs up to and including the design-basis SGTR.

c. Assure that RCP trip will not occur for other non-LOCA transients where it is not considered necessary.

d. Perform safety analyses to prove that a, b, and c above are achieved.

e. Consider using partial or staggered RCP-trip schemes.

f. Assure that training and procedures provide direction for use of individual steam generators with and without operating RCPs.

g. Assure that symptoms and signals differentiate between LOCAs and other transients.

2. Exclude extended RCP operation in a voided system where pump head is more than 10% degraded unless analyses or tests can justify pump and pump-seal integrity when operating in voided systems.

3. Avoid challenges to the PORVs where possible.

   a. If setpoints lead to RCP trip even though it is neither required nor desirable for transients or accidents with offsite power available, assure that challenges to the PORVs are avoided that would normally be handled by using pressurizer sprays.

   b. Challenges to PORVs could be eliminated by using heated auxiliary pressurizer sprays from a source other than the RCP discharge.

   c. If submittal recommends use of PORVs to depressurize, then licensees need to develop a program for upgrading the PORVs' operational reliability.

4. Establish guidelines and procedures for cases where RCP trip can lead to hot, stagnant fluid regions at primary-system high points.

   a. Describe symptoms of primary-system voiding caused by flashing of hot, stagnant fluid regions including effects on the pressurizer.

   b. Specify guidance for detecting, managing and removing the voids.

   c. Train operators concerning the significance of primary-system voids for both non-LOCA and LOCA conditions.

5. Assure that containment isolation will not cause problems if it occurs for non-LOCA transients and accidents.

a. Demonstrate that, if water services needed for RCP operation are terminated, they can be restored fast enough once a non-LOCA situation is confirmed to prevent seal damage or failure.

b. Confirm that containment isolation with continued pump operation will not lead to seal or pump damage or failure.

6. RCP-trip decision parameters should provide unambiguous indicators that a LOCA has occurred and the NRC-required inadequate-core-cooling instrumentation should be used where useful in indicating the need for a RCP trip.

7. NRC recommends that the licensee use event trees to systematically evaluate their setpoints to minimize the potential for undesirable consequences because of a misdiagnosed event.

a. Evaluate setpoints for events with RCP trip when it is preferable the RCPs remain operational.

b. Evaluate setpoints for events where early RCP trip does not occur and a delayed trip may lead to undesirable consequences.

D. NRC's guidance for justification of manual RCP trip in the licensee submittals is summarized in this section. This guidance had two purposes. It was intended to assist plants that can and should rely on manual trip to justify it, and it was also intended to help identify those few plants that may not be able to rely on manual trip.

1. Analyses should demonstrate that the limits set forth in 10 CFR 50.46 are not exceeded for the limiting small-break size and location using the RCP-trip setpoints developed with the guidance of part C above.

a. Assume manual RCP trip does not occur earlier than 2 minutes after the RCP-trip setpoint is reached.

b. Include allowance for instrument error.

c. Generic analyses are acceptable if they are shown to bound the plant-specific evaluations.

2. Determine the time available to the operator to trip the RCPs for the limiting cases if manual RCP trip is proposed.

a. Perform the analysis for the limiting small-break size and location identified in D.1 above.

b. Use the most probable best-estimate analysis to determine the time available to trip the RCPs following the time when the RCP-trip signal occurs.

c. Most probable plant conditions should be identified and justified by each licensee.

d. NRC will accept conservative estimates in the absence of justifiable most probable plant conditions.

e. Justify that the time available to trip the RCPs is acceptable if it is less than the Draft ANSI Standard N660.

(1) Include an evaluation of operating experience data.

(2) Address the consequences if RCP trip is delayed beyond this time.

(3) Develop contingency procedures and make them available for the operator to use in case the RCPs are not tripped in the preferred time frame.

(4) No justification is required if the time available to trip the RCPs exceeds the Draft ANSI Standard N660.

E. Assure that good engineering practices have been used for the following areas.

1. Establish the quality level for the instrumentation that will signal the need for RCP trip.

   a. Identify the basis for selection of the sensing-instruments' design features.

   b. Identify the basis for the sensing-instruments' degree of redundancy.

   c. Licensees can take credit for all equipment available to the operators if they have sufficient confidence in its operability during the expected conditions.

2. Ensure that emergency operating procedures exist for the timely restart of the RCPs when conditions warrant.

3. Instruct operators in their responsibility for tripping RCPs for small-break LOCAs including priorities for actions after the engineered safety features actuation occurs.

APPENDIX B

PUMP-OPERATION CRITERIA THAT WILL NOT RESULT IN RCP TRIP DURING TRANSIENTS AND ACCIDENTS

Consider the following guidelines if the submittal concludes that keeping the RCPs running is both the preferred and safest method of pump operation for small-break LOCAs and other transients and accidents.

A. Evaluate inventory loss.

1. Complete evaluation of LOFT Test L3-6 through the ECCS recovery phase.

2. Evaluate all modeling differences expected between LOFT and a PWR analysis.

B. Evaluate pump integrity.

1. Justify how pump-seal and pump structural integrity will be assured during extended two-phase flow performance.

2. Include the consequences of pump and/or pump-seal failure in the analyses if their integrity cannot be assured.

3. Include one of the following if continuous RCP operation is expected even with a containment isolation signal.

   a. Evaluate the capability to continue RCP operation without essential water services.

   b. Evaluate the capability to rapidly restore essential water services.

4. Evaluate the RCPs' capability to operate in the accident environment.

5. Evaluate the consequences of RCP failure at any time during the accident if continuous operation in the accident environment cannot be assured.

C. Ensure acceptability of results.

1. Analyses should demonstrate that the 10 CFR 50.46 ECCS acceptance criteria are met with a model in compliance with Appendix K to 10 CFR Part 50.

2. Assume continuous pump operation and also RCP trip at various times if continuous pump operation cannot be assured.

3. NRC will consider a request for an exemption to 10 CFR 50.46 requirements if analyses indicate compliance cannot be achieved.

   a. Submittal concludes that compliance with 10 CFR 50.46 would require operating the plant in a less safe condition. This needs to be supported with a risk/benefit analysis that can take credit for all equipment expected to remain operational during the accident.

   b. Submittal concludes the design modifications would not be cost-effective to implement from a safety standpoint.

List of Recently Issued Generic Letters

Generic Letter No.	Subject	Date of Issuance	Issued To
86-10	Implementation of Fire Protection Requirements	04/24/86	All Power Reactor Licensees and Applicants f/Power Reactor Licenses
86-09	Technical Resolution of Generic Issue No. B-59-(N-1) Loop Operation in BWRs and PWRs	03/31/86	All Licensees of Operating BWRs and PWRs and License Applicants
86-08	Availability of Supplement 4 to NUREG-0933 "A Prioritization of Generic Safety Issues"	03/25/86	All Licensees of Operating Reactors Applicants for OLs and Holders of CPs
86-07	Transmittal of NUREG-1190 Regarding the San Onofre Unit 1 Loss of Power and Water Hammer Event	03/20/86	All Reactor Licensees and Applicants
86-06	Implementation of TMI Action Item II.K.3.5 "Automatic Trip of Reactor Coolant Pumps"	05/29/86	All Applicant and Licensees with CE designed Nuclear Steam Supply Systems
86-05	Implementation of TMI Action Item II.K.3.5, "Automatic Trip of Reactor Coolant Pumps	05/29/86	All Applicants and Licensees with B&W Designed Nuclear Steam Supply Systems
86-04	Policy Statement on Engineering Expertise on Shift	02/13/86	All Power Reactor Licensees and Applicants for Power Reactor Licenses
86-03	Applications for License Amendments	02/10/86	All Power Reactor Licensees and OL Applicants
86-02	Technical Resolution of Generic Issue B-19 Thermal Hydraulic Stability	01/23/86	All Licensees of Operating BWRs
86-01	Safety Concerns Associated with Pipe Breaks in the BWR Scram System	01/03/86	All BWR Applicants and Licensees

This request for information was approved by the Office of Management and Budget under clearance number 3150-0011 which expires September 30, 1986. Comments on burden and duplication may be directed to the Office of Management and Budget, Reports Management, Room 3208, New Executive Office Building, Washington, D.C. 20503.

Our review of your submittal of information in response to this letter is not subject to fees under the provisions of 10 CFR 170. However, should you, as part of your response or in a subsequent submittal, include an application for license amendment or other action requiring NRC approval, it is subject to the fee requirements of 10 CFR 170 with remittal of an application fee of $150 per application (Sections 170.12(c) and 170.21) and subsequent semiannual payments until the review is completed or the ceiling in Section 170.21 is reached.

If you believe further clarification regarding this issue is necessary or desirable, please contact Mr. R. Lobel (301 492-9475.)

Sincerely,

Frank J. Miraglia, Director
Division of PWR Licensing-B

Enclosure:
Safety Evaluation

cc w/enclosure:
Service Lists

Distribution:
All CE PMs
Memo File
PKreutzer
AThadani

C H Berlinger
PWR-A/RSB
C. Berlinger 1/22/86

PWR#8	PWR#8	PWR#8	DPWR-B
PKreutzer	DJaffe;ef	AThadani	FMiraglia
1/2/85	1/2/86	2/10/86	2/20/85

AT

DMc 2/18/86