DUKE POWER COMPANY
P.O. BOX 33189
CHARLOTTE, N.C. 28242

HAL B. TUCKER
VICE PRESIDENT
NUCLEAR PRODUCTION

TELEPHONE
(704) 373-4531

June 10, 1986

Mr. Harold R. Denton, Director
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

ATTENTION: B.J. Youngblood, Director
PWR Project Directorate #4

Subject: McGuire Nuclear Station
Docket Nos. 50-369 and 50-370
NRC DPO Concerns on McGuire Technical Specifications

Dear Mr. Denton:

Mr. T.M. Novak's (NRC/ONRR) July 9, 1985 letter to Mr. H.B. Tucker (DPC) indicated that a review of the McGuire Unit 1 and 2 Technical Specifications was being conducted in response to concerns raised by a member of the NRC staff in a differing professional opinion (DPO) resulting from a review of the proof and review copy of the McGuire Unit 1/2 combined Technical Specifications which existed in mid-January 1983. Duke Power Company's comments were requested on certain plant-specific concerns contained in the DPO (other concerns contained in the DPO were either being considered by the NRC for generic resolution, had been closed by NRC internal review, or were still under review).

Attached is Duke Power Company's response to these concerns. This response is limited to the specified plant-specific concerns and does not address any generic aspects of these specified concerns. Note that the response has potential plant-specific impacts on the station's Technical Specifications (e.g. question nos. 6a, 7d (and 7i, 7k), and 7n) and FSAR (e.g. questions 4a&b, and 4c). Duke will pursue appropriate plant-specific Technical Specification and FSAR revisions following NRC concurrence with the positions contained herein. The Westinghouse Standard Technical Specification issues identified in this response should be resolved on a generic basis (note that Westinghouse review/input was utilized in the development of this response). Note also that generic Technical Specification improvement efforts currently underway by industry (e.g. AIF, WOG, B&WOG) and NRC (TSIP) may impact the DPO's concerns and the resolutions proposed by this response.

As indicated above, the NRC is requested to approve this response prior to Duke proceeding with the appropriate Technical Specification change submittals and inclusion of the informaiton in a future FSAR update. Should there

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be any questions regarding this matter or if additional information is required, please advise.

Very truly yours,

Hal B. Tucker

Hal B. Tucker

PBN/jgm

Attachment

xc: Dr. J. Nelson Grace, Regional Administrator
U.S. Nuclear Regulatory Commission - Region II
101 Marietta Street, NW, Suite 2900
Atlanta, Georgia 30323

Mr. Darl Hood
Division of Licensing
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Mr. W.T. Orders
Senior Resident Inspector
McGuire Nuclear Station

Ms. L.L. Williams, Manager
ESSD Projects, Mid-South Area
Westinghouse Electric Corp.
MNC West Tower
P.O. Box 355
Pittsburgh, PA 15230

Duke Power Company

McGuire Nuclear Station

Response to NRC DPO Concerns

(Question 1)

TABLE 2.2-1

These have been checked against reference 18, Westinghouse (W) RPS/ESFAS Set Point Methodology, Table 3-4 and NOTE FOR TABLE 3-4 on page 3-13, which is described as applicable to McGuire Unit 1, 50-369. At this date, the assumption has been made that this information also applies to McGuire Unit 2, Docket No. 50-370. Please docket this fact or otherwise provide the alternate information.

Response: The data contained in Reference 18 has been confirmed to be valid for both McGuire Unit 1 and Unit 2. The instrumentation hardware (racks, transmitters) are the same for both Units 1 and 2. While the Steam Generators are different (D-2 for Unit 1 and D-3 for Unit 2), there are no differences in the Safety Analysis values. Therefore it can be concluded that the Setpoint Study performed for Unit 1 is applicable, in it's entirety, to Unit 2. The safety analysis performed is valid for both units and use the same equipment/instrumentation resulting in uncertainty values being valid for both units.

(Question 1a)

TABLE 2.2-1, Item 3

Will a time constant of >2 seconds result in a slower response time, which is less conservative.

Response: The dynamic response of the High Positive Rate trip function is similar to the rate/lag function associated with the ΔT trips. The responses of the various dynamic functions are demonstrated in Appendix A of WCAP-8745 (Design Bases for the Thermal Overpower ΔT and Thermal Overtemperature ΔT Trip Functions). As may be seen in the above mentioned figures, an increased time constant results in faster response and thus results in a shorter time from initiation of transient to reactor trip. Therefore, the >2 seconds Tech Spec requirement for the time constant is conservative.

(Question 1b)

TABLE 2.2-1, Item 4

Will a time constant of >2 seconds result in a slower response time which is less conservative?

Reference 18 page 3-13, concerning Set Point Methodology advises that this value is not used in Safety Analyses. This appears in direct contradiction to reference 7, Section 15.2.3, page 15.2-12, revision 7, first para. The Licensee shall evaluate and propose.

Response: The dynamic response of the High Negative Rate trip function is similar to the rate/lag function associated with the ΔT trips. The responses of the various dynamic functions are demonstrated in Appendix A of WCAP-8745 (Design Bases for the Thermal Overpower ΔT and Thermal Over temperature ΔT Trip Functions). As may be seen in the above mentioned figures, an increased time constant results in faster response and thus results in a shorter time from initiation of transient to reactor trip. Therefore, the >2 seconds Tech Spec requirement for the time constant is conservative.

The Revision 7 FSAR analysis referred to in this inquiry was performed prior to the NRC review and approval of WCAP 10297-P-A (Dropped Rod Methodology For Negative Flux Rate Plants). The methodology used prior to WCAP-10297-P-A did not involve an actual determination of the negative flux rate setpoint and/or determination of the maximum dropped rod(s) worths which might not result in a reactor trip. The statement in the FSAR (RCCA group results in reactivity insertion of ∼-1200 pcm which results in a reactor trip within ∼ 2.5 seconds) was meant only to offer support for the DNB analysis performed at lower rod worths but did not actually demonstrate the adequacy of the negative flux rate setpoint.

Upon determination of possible nonconservatisms in the analytical methodology, Westinghouse developed the dropped rod methodology outlined in WCAP-10297-P-A. The revised methodology links the assumptions regarding the negative flux rate setpoint, rod worths and locations, control system behavior, and other factors which influence plant behavior following a dropped rod(s) event. The setpoint thus becomes an integral part of the safety analysis and the table in reference 18 is revised to show a safety analysis limit of 6.9% RTP. The adjustments made to account for various uncertainties results in an STS Trip Setpoint of 5.0% RTP and an STS Allowable Value of 5.5% RTP. Details regarding the revised methodology and basis for the setpoint may be found in WCAP-10297-P-A.

(Question 1c)

<u>TABLE 2.2-1, Item 9</u>

The specified Trip Setpoint & Allowable values agree with those provided under setpoint methodology in reference 18. A disparity does exist between the related SAFETY ANALYSIS LIMITS given as used in Safety Analysis, i.e., 1845 psig in SETPOINT METHODOLOGY/reference 18, Table 3-4, column 12 and the FSAR value for the same analysis in reference 7, Table 15.2.3-1 as 1835 psig. The Licensee shall identify the correct value. [Note also disparity with reference 7, "Analysis of Inadvertent Operation of ECCS During Power Operation", page 15.2-40, revision 43 item 7, "Reactor Trip... is initiated by low pressure at 1800 psia;" This is however relatively conservative with respect to the other values used above.]

The Licensee shall review and clarify.

Response: The analysis of the inadvertent operation of ECCS during power operation had assumed a low pressure setpoint of 1800 psia while other analyses assumed a setpoint of 1835 psig. The reference 18 value for the safety analysis limit was in error but was conservative and since margin exists between implemented and required setpoints, the conservatism did not impact the trip setpoint and allowable values.

The transient analyses have been reanalyzed as a result of the transition to optimized fuel assembly design. The revised analyses assumed a safety analysis limit of 1850 psia (1835 psig) for all transients.

(Question 1d)

TABLE 2.2-1, Item 13

Reference 18, page 3-13, Note 12 describes the Safety Analysis Limit for this item as a value in Table 2.2-1 of the W STS plus 10%. For conservatism, should the Safety Analysis Limit be the W STS value less 10%; is this necessarily conservative for all Licensing Basis occurrences?

Response: The analysis in effect at the time this question was posed is no longer applicable. At present the bounding analysis for the steam generator lo-lo level is the feedbreak analysis. This analysis is done assuming the system starts at full power. In this analysis the safety analysis limit is 23% of narrow range span. As is indicated in the technical specifications this corresponds to a nominal trip setpoint of 40% narrow range span at 100% RATED THERMAL POWER.

(Question 1e)

TABLE 2.2-1, Item 18b

Accidental Depressurization of the main steam system is from zero load. It is unclear from reference 5 Table 7.2.1-4, (page 5 of 5) if for this event, reactor trip on Pressurizer Low Pressure is expected to occur before Safety Injection (when it would not be available at zero power) or whether it is expected to occur from the pressurizer pressure low-(Safety Injection) signal if it initiates SI, or from SI initiated by other initiators. The Licensee shall clarify, and hence its validity with respect to the absence of the signal caused by P-7.

Response: Protection against accidental depressurization of the main steam system is provided by the overpower reactor trips (neutron flux and ΔT) and by the reactor trip which results from the receipt of the safety injection (SI) signal. The safety injection signal is actuated by low steamline pressure, low pressurizer pressure, or high containment pressure. The analysis performed results in SI initiation on low pressurizer pressure and reactor trip will either occur concurrently due to the trip on SI actuation or will occur prior to SI on the overpower trips. The main steam depressurization analyzed in the FSAR is initiated from hot shutdown conditions at time zero (i.e. reactor tripped) since this represents the most conservative initial condition. Thus no explicit assumption is made regarding the cause of reactor trip for the FSAR analysis. As noted in the FSAR and above, should the reactor be just critical or operating at power a reactor trip would occur on the overpower trips or from an SI actuation. In either case, no credit is taken for the reactor trip on pressurizer pressure when reactor power is below the P-7 interlock.

(Question 2)

T.S. Page 3/4 1-6

The existing minimum temperature for criticality (In MODES 1 and 2) is given as 551°F. Please advise why this value is less than the programmed set point minimum value of 557°F in reference 20, Fig. 5.3.3-1. Accident evaluations for events from zero power are predicated upon this set point of 557°F, and any variation therefrom in either direction would be unacceptable.

Response: FSAR Figure 5.3.3-1 gives the normal relationship between reactor coolant system temperature and power. The hot zero power temperature employed at McGuire and used in the safety analysis is 557°F. The minimum temperature for criticality is determined such that the moderator temperature coefficient is within its analyzed temperature range, the trip instrumentation is within its operating range, the pressurizer is capable of being in an operable status with a steam bubble, and the reactor vessel is above its minimum RT_{NDT} temperature. The minimum temperature for criticality limit in the McGuire Technical Specifications is 551°F.

The difference between the HZP temperature and minimum temperature for criticality limit is required in order to allow for measurement of the moderator temperature coefficient. Since the moderator coefficient is confirmed to be within safety analysis assumptions at conditions of approximately 551°F - 557°F, the only input parameter to the safety analysis of concern is the initial temperature. The change in initial conditions from 557°F to 551°F for transients occurring at HZP would have a negligible impact on results and would be a less representative input since the majority of time spent at HZP conditions includes temperatures of ~557°F. As noted, the accidents analyzed at hot zero power (HZP) assume an RCS temperature of 557 °F. The FSAR notes that use of a higher initial system temperature yields a large fuel-water heat transfer coefficient, larger specific heats, and a less negative (smaller absolute magnitude) Doppler feedback effect for fast reactivity addition transients like the RCCA Bank Withdrawal from Subcritical and HZP Rod Ejection events. The reduced feedback results in a higher neutron flux peak. For a Steamline Break event, starting from a higher initial RCS temperature results in a greater increase in coolant density from the cooldown. More reactivity is added due to the positive moderator density coefficient and a higher return to power results when compared with the case of a lower initial RCS temperature. Based on these considerations, a higher initial RCS temperature is conservative for the analysis of events from power. The statement that any variation in HZP temperature is unacceptable is also not consistent with the general conservative philosophy used to evaluate nuclear plant safety since only limited analyses are performed to demonstrate adequate safeguards for a range of plant conditions.

(Question 3)

TABLE 3.3-1, Item 6c

During shutdown in MODES 3, 4 and 5, with reactor trip system breakers open, Source Range, Neutron Flux, channel operability requirements specify only one channel operable, and if this same channel is being used to meet the boron dilution alarm requirements of proposed T.S. Page 3/4 1-13 (a), then it is not in accordance with the Boron Dilution Requirements of the FSAR for which at least 2 operable channels would be required; reference 8, page Q 212-24, Item 212.58. The Licensee shall evaluate and propose. Currently, this appears non-conservative.

Response: A review of FSAR Section 15.4.6 (Boron Dilution Accident) does not indicate the number of Source Range Channels required operable; however, These channels are mentioned for Refueling (MODE 6) and start up (MODE 2) Dilution Accidents. For these cases, two channels are required per Tech. Specs. Additionally, MODES 3,4, and 5 are not addressed by this FSAR Section. Boron Dilution analyses during MODES 3,4, and 5 are not part of the McGuire plant licensing basis. As such, any channel operability requirements would not be based on the FSAR analysis.

Generic Letter 85-05 dated January 31, 1985 informed licensees of the Staff position resulting from the evaluation of Generic Issue 22 "Inadvertent Boron Dilution Events". The Staff concluded that the consequences of such events are not severe enough to jeopardize the health and safety of the public. Furthermore, while NRC stated that it would "not require operating plant backfits for boron dilution events at this time, the staff would reqard an unmitigated boron dilution event as a serious breakdown in the licensee's ability to control its plant, and strongly urges each licensee to assure itself that adequate protection against boron dilution events exists in its plants". McGuire personnel believe that adequate protection against boron dilution events exists and that no changes to technical specifications are warranted in this instance.

(Question 4a and 4b)

TABLE 3.3-2, Items 9 & 10

The T.S. specifies a response time of ≤ 2.0 secs. Reference 7, Table 15.1.3-1 provides a time delay of 2.0 secs for these events which conflicts with a value of 1.0 secs in Reference 5, page 7.2-14, rev. 42, item 1(e). The Licensee shall clarify.

Response: The Technical Specification limit of ≤ 2.0 seconds for the time delay of pressurizer pressure trip functions (low and high) is based upon the FSAR Chapter 15 transient analysis which assumed a delay of 2.0 seconds. The values for trip response times in chapter 7 are "typical maximum allowable time delays" and are not necessarily the same as the McGuire specific assumptions. For the sake of clarity, the values provided in chapter 7 will be revised to agree with Chapter 15 and Technical Specifications in a future FSAR update.

(Question 4c)

TABLE 3.3-2, Item 17

The proposed T.S. states that the response time requirement is NA (Not Applicable). This is incorrect since a separate Reactor Trip is an essential part of all ESFAS functions during which safety injection is initiated. The required information is in fact supplied in T.S. Page 3/4 3-30 Table 3.3-5, under the already revised headings proposed above, Reference Items 1i, 2b, 3b, 4b.

This table, under response time, should replace the description as recommended above and alongside each, reference the entry in T.S. Table 3.3-5.

The response given in the Technical Specifications (except for manual actuation of SI) are quoted as ≤2 secs. No docketed information is available on what values were used in accident analysis, and particularly for MSLB, SBLOCA and LOCA events. The licensee should provide this information and confirm its conservatism against the T.S. value, e.g. reference 5, Table 7.2.1-4 (5 of 5) and related Note e on the page entitled "Notes for Table 7.2.1-4" confirms that Pressurizer Low Pressure - Low Level is the first out trip of Safety Injection for the event of "Accidental Depressurization of the Main Steam System." The licensee shall explain this terminology - whether we have Reactor Trip on Pressurizer Pressure - Low which is available at the maximum power output at which this particular event is evaluated, or Pressurizer Pressure - Low (Safety Injection) and provide the associated response time to validate proposed T.S. values.

Response: The NA enter for the required response time of reactor trip upon SI actuation is consistent with the Bases which states that trip functions not utilized in the FSAR transient analyses will have the requirement indicate not applicable in Table 3.3-2 (Reactor Trip System Instrumentation Response Times). However, as stated in Table

3.3-5 (Engineered Safety Features Response Times). The terminology in Note e, Table 7.2.1-4, should be Pressurizer Pressure-Low (Safety Injection). This wording will be corrected in a future update of the FSAR.

(Question 5a)

TABLE 3.3-3, Item 7g

Applicable modes: The current T.S. proposes Modes 1 and 2#. Condition 2# is an invalid MODE since # identifies the P-11 interlock which can be manually effected only at approx. 1900 psig and which can only occur in MODE 3, i.e., the condition should be 3#. The licensee should explain and propose.

Please advise why this limitation at MODE 2 [or 3]# is proposed and how it may relate to plant operating procedures in MODES 3 and 4 and whether this block is in conformance with regulatory requirements.

Response: The defeat of auxiliary feedwater pump auto-start is accomplished by depressing a switch that is interlocked with the P-11 permissive. Thus the auto-start can only be defeated below a pressurizer pressure of 1955 psig. However, the same defeat will prevent auto-start on low-low steam generator level (Table 3.3-3, Item 7c(1)). Since this auto-start capability is required in MODES 1, 2, and 3, the defeat switch is not used in these modes. Therefore the entry for APPLICABLE MODES on Item 7g is not important as it is controlled by the more limiting Item 7c(1).

The statement that P-11 can only occur in MODE 3 is not accurate. MODE 2 is defined as operation with T-avg. $\geq$350°F, K_{eff} $\geq$0.99, and power $\leq$5% RTP. Therefore, subcritical operation with T-avg. $\geq$350°F is in Mode 2 if K_{eff} is not less than 0.99. Critical operation is restricted to T-avg. $\geq$551°F, but even then the pressure-temperature operating limits permit pressures below 1955 psig. As a practical matter, pressure is maintained in the normal operating range ($\sim$2235 psig) during MODE 2. The 2# referred to in the question is retained to require that MODE 2 operation above P-11 is with the Item 7g auto-start enabled.

(Question 5b)

TABLE 3.3-3, Item 8

This is limited in Applicability to MODES 1, 2, 3 by the proposed T.S. Since a LOCA in MODE 4 is part of the Licensing Basis, see later section 3/4.5, ECCS under GENERAL, the licensee should evaluate the reasons for, and the consequences of, not proposing this OPERABLE IN MODE 4, and not being available in MODE 5, to counter the consequences of potential LOCAs and loss of RHR cooling in these MOSES. The proposed T.S. is non-conservative with respect to the Licesing Basis; the Licensee shall evaluate and propose.

Response: This specification is consistent with other standard technical specificaions which require operator action to mitigate the consequences of a LOCA in these modes.

(Question 6a)

TABLE 3.3-4, Item 4d

The trip set point is currently specified at -100 psi/sec. Westinghouse Set Point Methodology for Unit 1, reference 18, shows this value to be "-110 psi"; an additional descriptor is also necessary reading: "with a time constant of 50 secs". The current "Allowable Value" in the T.S. is -120 psi/sec, the same reference 18 Table 3-4 shows this value to be -100 psi; this should again have the additional descriptor reading: "with a time constant of 50 secs".

To discuss negative values and related conservatisms, it is clear to delete the - in -100 as the description reads: "Negative Steam Line Pressure Rate - High so that T.S. values should read as 100 psi and 110 psi. This is also internally consistent with the descriptor in Table 2.2-1, Item 4, namely: Power Range, Neutron Flux High Negative Rate, 5% of RTP with a time constant of 2 seconds.

Response: Since no safety analysis limit exists for the negative steam line pressure rate setpoint (i.e., it is not assumed in transient analyses), the Setpoint Methodology (Reference 18) listed the T.S. values. The T.S. limits were revised at a later date and thus a discrepancy between the Reference 18 and T.S. values exists.

In order to correct a typographical error and adequately define the setpoint, a T.S. revision will be pursued in the following form:

	Trip Setpoint	Allowable Value
4d. Negative Steam Line Pressure Rate-High	$\leq$100 psi with a rate/lag function time constant $\geq$50 seconds	$\leq$120 psi with a rate/lag function time constant $\geq$50 seconds

(Question 6b)

TABLE 3.3-4, Items 7c(1) and (2)

This technical specification provides that the motor-driven AFW Pumps start on low-low in one SG whereas the turbine driven pumps require low-low in two SGs. This appears to be in conflict with the accident evaluation in the Licensing Basis FSAR as elaborated below. [This however is not conflict with the Instrumentation & Control Logic of the FSAR.]

- Reference 7 Related Section 15.4.2.2.2 concerning Main Feed Line Rupture (MFLR) under the Title of Major Assumption 10.

"The auxiliary feedwater system is actuated by the low-low Steam Generator Water Level Signal. The auxiliary feedwater system is assumed to supply a total of 450 gpm to three intact steam generators.

- Reference 5, Section 10.4.7.2.2 states that "Travel stops are set on the steam generator flow control valves such that the turbine driven pump can supply 450 gpm to three intact steam generators while feeding one faulted generator and both motor driven pumps together can supply 450 GPM to three intact steam generators while feeding one faulted generator. The Throttle positions allow all three pumps to supply a total flow of 1400 gpm to 4 intact steam generators".

- Reference 7 Related Section 15.4.2.2.2, page 15.4-13a (revision 38), states: "The single active failure assumed in the analysis is the turbine driven auxiliary feedwater pump. The motor driven pump that is headered to the steam generator with the ruptured main feedline supplies 110 gpm to the intact steam generator. The motor driven pump that is headered to two intact steam generators supplies 170 gpm to each. This yields a total flow of 450 to the intact steam generators one minute after reactor trip. At 30 minutes following the rupture, the operator is assumed to isolate the auxiliary feedline to the ruptured steam generator which results in an increase in injected flow of 80 gpm".

The sequence of events in the accident evaluation in Reference 7, Table 15.4-1 shows that after the accident is initiated at a programmed value of SG level, the low-low SG level in the ruptured SG is reached at 20 secs. later, and auxiliary feedwater [at 450 gpm] is delivered to the intact steam generators in 61 sec.

It appears, based on the above information, that on SG low-low in the ruptured SG, both the motor driven and the turbine driven pumps are initiated (with the single failure being in the turbine driven pumps). This is not in accord with the T.S. If it is assumed that low-low level in the other SGs is also reached at the same time by bubble collapse, please justify. We note that the Reactor & Turbine Control System is designed so that under normal operation, collapse of SG level on Turbine Trip will not cause a reactor trip; also at this time, main steam from intact SGs is being lost to the faulted SG so that whereas inventory is lost, a full collapse need not occur.

The proposed T.S.s Item 7c(1) and 7c(2) appear to be non-conservative in respect of accident analysis used in the Licensing Bases. The licensee shall clarify, evaluate and propose.

Response: It appears that the question is "Since one motor-driven pump supplies 110 gpm to an intact generator and the other otor driven pump supplies 170gpm to intact generators, where does the remaining 170 gpm (450 - 110 - 170), supplied to the intact generators, come from if not from the turbine-driven pump?". The new FSAR Chapter 15 analyses for optimized fuel make clear that the "two motor-driven pumps together deliver 450 gpm to the three intact steam generators allowing for spillage out of the break (Section 15.2.8.2, page 15.2.8, 1984 Update). To clarify exactly the analysis assumption - One moter driven auxiliary feedwater pump supplies 110 gpm to an intact steam generator (the remainder spills out the break in the faulted loop) and the other motor driven pump supplies 170 gpm to each of the other two intact steam generators, this totals to 450 gpm.

If the failure of a motor driven pump is assumed, the turbine driven pump alone would supply at least 450 gpm to the intact loops. The turbine driven pump is actuated on low-low level in at least two steam generators. It is assumed that low-low level is reached in the other (non-faulted) steam generators as a result of the bubble collapse following turbine trip when the low-low level reactor trip is actuated from the faulted loop. This occurs because for this accident condition (i.e. not normal operation) the mass inventory in the intact steam generators is reduced significantly prior to reactor trip on low-low level in the faulted loop. The shrinkage caused by bubble collapse from this reduced mass condition would cause low-low level to be reached in the other steam generators.

(Question 6c)

TABLE 3.3-4, Item 9

Confirm the bases for the set points and allowable values specified.

Response: The bases for the setpoints and allowable values specified are to ensure Auxiliary Feedwater capability upon loss of power while minimizing the possible initiation of the sequence with the voltage greater than the limits of associated motors.

(Question 7a)

TABLE 3.3-5, Item 2a

A value of $\leq$ 27 secs (without offsite power) is given. Reference 5, page 7.3-8 shows that initiation time of ESFAS from this source is a maximum of 1 sec.

No events in Reference 7, Section 15, have been directly analyzed using this sensor as the prime initiator above the P-11 interlock although it is relied upon for diverse protection. However, it is the only automatic initiation of Safety Injection protection below [P-11]. Other events dependent upon a SI generating signal, particularly circumstances described under Items 3a and 4a below, shows safety analyses limits of $\leq$ 12 secs (with offiste power) and $\leq$ 22 secs (without offsite power).

At this time, the proposed T.S. value is less conservative than others used in Safety Analysis. The licensee shall evaluate this difference and propose accordingly.

Response: The entry for Table 3.3-5, Item 3a is identical to Item 2a for the loss of off site power case, i.e., each is 27 seconds. As explained in the Notes for Table 3.3-5, the difference between Item 4a and Items 2a and 3a is that 4a does not include a delay for the RHR pumps to attain their discharge pressure. This is appropriate since Item 4a deals with steam line break protection, as opposed to LOCA protection. The RHR pumps, although started for a steam line break, are not expected to deliver flow because of the higher RCS pressure. Therefore, the additional 5 second delay for these pumps to attain their discharge pressure is not relevant to ESF response time for this actuating signal.

(Question 7b)

TABLE 3.3-5, Item 2b

The descriptor (From SI), should be deleted as it is incorrect. The response time given is $\leq$ 2 secs and this different from the FSAR, Reference 5, page 7.3-8 which gives a maximum time of 1 sec. This value is less conservative than the FSAR and the licensee shall evaluate and propose accordingly.

Response: The descriptor "(From SI)" is correct in that the allowable delay for a reactor trip due to the SI actuation signal is 2 seconds. This value is independent of the setpoint and associated delay of the initiator of SI. The reference 5, page 7.3-8 maximum time of 1.0 second is the limit on the delay associated with SI actuation upon exceeding the high containment pressure setpoint.

No credit is taken for reactor trip signal resulting from safety injection signal in any LOCA analysis. In the McGuire Unit 1 initial core large break LOCA analysis no credit is taken for reactor trip (rod insertion) at all. In the McGuire Unit 1 initial core small break LOCA a low pressurizer signal causes the reactor to trip. No credit for the control rods is taken until they are fully inserted.

(Question 7c)

TABLE 3.3-5, Item 2d

The proposed T.S. values are 18[(3)] (with offsite power) and 28[(4)] without offsite power. Reference 5, page 7.3-8 shows that initiation of ESFAS from this source is 1 sec.

Table 3.6-2 shows Maximum Isolation Times of up to 15 secs for Reactor Coolant Pressure Boundary Isolation valves. A minimum total time to containment and isolation [for the RCPB] of 16 secs seems feasible, plus 10 secs giving 26 secs total without offsite power.

The proposed T.S. values should be checked against those used as Safety Analysis limits for related Conditions II, III, and IV occurrences using SI. Values used by licensee shall be provided, compared with Item 2d, and any differences evaluated.

Response: Following a design basis large LOCA, the isolation valve closure time depends upon the time when fuel failure occurs and fission products are released to the containment environment. The only isolation valves explicitly considered in the radiological consequences analysis of a LOCA are those in the containment purge and pressure relief lines which connect containment to the environment. For isolation valves in lines filled with process fluid a relatively long time is needed for the associated piping system to drain of fluid and expose the valve seat to the containment gases or for activity to migrate, due to the concentration gradient, through the process fluid and out the isolation valve. Hence, as long as isolation valve closure times for process lines are short (less than 1 min. per ANS 56.2) they need not be modeled in the dose calculations.

(Question 7d)

TABLE 3.3-5, Item 2e

This is given as N.A. This is not so; response times have been used to minimize offsite consequences of any Condition occurring whilst containment purge and exhaust is being used. This proposed T.S. is less conservative than the licensing basis. The license shall evaluate and propose.

Response: Section 15.B.2 of the McGuire FSAR considers the case of a LOCA concurrent with lower containment pressure relief. The results of the additional offsite dose due to this accident are presented in table 15.0.11-1. One of the parameters used to evaluate this case is the isolation time for the Containment Air Release and Addition (VQ) System valves which are used in venting lower containment. Table 15.B.2-1 indicates the isolation time for these valves is 4 seconds. Section 9.5.12.3 indicates that these valves auto close on a containment isolation, and that they have a 3 second closure time.

A technical specification revision to show a response time of $\leq$ 4 seconds for this item will be pursued. This would be consistent with the allowable 1 second for generating an ESF response as indicated on page 7.3-8 of the McGuire FSAR and the 3 second valve closing time as indicated above.

(Question 7e)

<u>TABLE 3.3-5, Item 2f</u>

The licensee proposes N.A. but earlier review shows AFW initiation on Containment Pressure-High and especially in MODES 3 and 4. This is less conservative than the licensing basis; the licensee shall evaluate and propose.

Response: No credit is taken for AFW flow being initiated from a Containment Pressure - High signal in analyses.

(Question 7f)

<u>TABLE 3.3-5, Item 3a</u>

Values of ≤ 27[(1)]/12[(3)] secs are proposed. Reference 5, page 7.3-8, shows a maximum initiating time of ESFAS 1.0 secs from this signal.

The value of 12 secs (with offsite power) is consistent with safety analysis limits given for the MSLB in reference 7, page 15.4-10, Section 7 where "In 12 seconds, the valves are assumed to be in their final position and pumps are assumed to be at full speed". For the other case with Loss of Offsite Power (LOOP) "an additional 10 secs delay is assumed to start the diesels and to load the necessary equipment onto them". Further, this particular analysis appears to initiate the event on Pressure Pressure-Low (SI).

The proposed value of ≤ 12 secs appears within the licensing basis of 12 secs. The proposed value of 27 secs (with LOOP) is however larger than the value of 22 seconds from the reference described above (i.e., 12 secs + 10 secs delay for start of diesel). This value of 27 secs therefore appears less conservative than the FSAR, reference 7, page 15.4-10, and the licensee shall evaluate and propose.

Response: This question is related to the question on Item 2a. For a steam line break the RHR pumps are not expected to deliver inventory and the additional 5 second delay for them to attain their discharge pressure is not included in the safety analysis.

(Question 7g)

<u>TABLE 3.3-5, Item 3b</u>

The descriptor (from SI) is incorrect and should be deleted.

A value of ≤ 2 secs is proposed. The FSAR in Reference 5, page 7.3-8, quotes a value of ≤ 1 secs. The proposed T.S. value appears less conservative than the Safety Analysis Limit and the licensee should evaluate and propose.

Response: The descriptor "(from SI)" is correct in that the allowable delay for a reactor trip due to the SI actuation signal is 2.0 seconds. This value is independent of the setpoint and associated delay of the initiator of SI. The Reference 5, page 7.3-8, maximum time of 1.0 second is the limit on the delay associated with SI actuation upon exceeding the Pressurizer Pressure - Low setpoint.

The chapter 15 safety analyses do not take credit for a reactor trip from an SI signal initiated by low-low pressurizer. (Ref. Question 7b Response).

(Question 7h)

TABLE 3.3-5, Item 3d

The proposed T.S. is $\leq 18^{(3)}/28^{(4)}$ secs. Reference our comments and requirements under Item 2d above.

Response: Reference our response under item 2d above.

(Question 7i)

TABLE 3.3-5, Item 3e

The proposed T.S. is NA. Reference our comments and requirements under 2e. above.

Response: Reference our response under Item 2e above.

(Question 7j)

TABLE 3.3-5, Item 3f

The licensee proposes NA (not applicable).

Safety injection logic closes the main feedwater isolation valves for every event in which SI is initiated (reference earlier sections of this review Table 3.3-4, proposed Item c). Therefore, every such event initiated by a SI initiator must be analyzed with a restoration of AFW and a related response time. It is outside the licensing basis to not propose a value for this response time. This T.S. value is therefore non-conservative; the licensee shall evaluate and propose.

Response: The only non-LOCA transient which assumes ESF actuation on Pressurizer Pressure Low-Low is the Main Steamline Depressurization event (Inadvertent Opening of a Steam Generator Safety, Relief, or Dump Valve). For this event it is conservatively assumed that auxiliary feedwater is actuated at the maximum flow rate at the initiation of the event to accentuate the cooldown. Any delay in auxiliary feedwater actuation would be beneficial and therefore a response time requirement is not applicable or appropriate.

(Question 7k)

TABLE 3.3-5 Item 4e

The proposed T.S. is NA. Reference our comments and requirements under Item 2d above.

Response: Reference our response under Item 2e above.

(Question 7l)

TABLE 3.3-5, Item 4h

The proposed T.S. value is $\leq$ 9 secs.

Reference 5, page 7.3-8 states that the maximum allowable times for generating steam break protection are (1) from steam line pressure rate, 2 secs, and (2) from steam line pressure-low, 2 secs. Further, Reference 7, page 15.4-6 states that the fast acting steam line stop valves are "designed so close in 5 secs...". A minimum closure of 7 secs seems likely.

For actual safety analysis limits, Reference 7, Table 15.4-1 (1 of 4) and 15.4-1 (2 of 4) both show a difference of seven (7) secs between arriving at the "Low Steam Line Pressure Setpoint" and "All Main Steam Isolation Valves Closed." [In the case of Feedwater System Pipe Rupture].

The proposed T.S. value of $\leq$ 9 secs is therefore greater than the Safety Analysis Limit.

The proposed T.S. must therefore be considered less conservative for this event. The licensee shall evaluate and propose.

Response: Item 4h in Technical Specification Table 3.3-5 has been changed to a limit of $\leq$ 7 seconds (Ref. Amendment nos. 29 (Unit 1) and 10 (Unit 2)).

(Question 7m)

TABLE 3.3-5, Item 5a

Licensee shall provide the Safety Analysis Limit and compare with the proposed value of $\leq$ 45 secs. Evaluate and propose as necessary.

Response: The response time for containment spray following a high containment pressure signal is specified at 45 seconds in the McGuire Technical Specifications. This value is consistent with the FSAR containment analysis actuation assumption as shown in FSAR Table 6.2.1-13c. Event times from the McGuire limiting case break mass/energy release analysis are reported in Table 6.2.1-29; the time of spray actuation has no effect on the mass/energy releases calculated.

(Question 7n)

TABLE 3.3-5, Item 6b

The proposed T.S. is ≤ 13 secs.

Reference 7, Table 15.1.3-1 shows that "High Steam Generator level trip of the feedwater pumps and closure of feedwater system valves, and turbine trip" is based on an ESFAS time delay of 2.0 seconds.

Table 3.6-2 of the T.S. provides isolation times of ≤ 5 secs for Main Feedwater Containment Isolation and ≤ 10 secs for Main Feedwater to Auxiliary Feedwater Isolation.

A total time to isolation of MFW of ≤ 13 secs seems appropriate to available equipment.

However the current safety analysis depending on this response time is that for the Excessive Cooldown occurrence under Reference 7, page 15.2-28, and for this, no value is quoted for isolation of main feedwater which is the initiator of the event. However, Figure 15.2.10-2 shows that with initiation of the event caused by one faulty control valve, it takes 32 secs to reach the SG High-High Level with a mass increase of 35% of initial, and thereafter does not increase further. This implies zero closure time. Since it is expected to take another 13 secs to actually isolate, we could assume an additional mass increase of another 13% to give a total of approximately 1.48 the initial value.

The above additional Main Feedwater level can affect the consequences of the event at power, if there has been a trip, with a potential for power restoration and/or overfill of the SG to cause water ingress into the main steam lines. Additionally, it can have consequences of potentially larger importance for the event occurring from subcritical zero power.

Reference also our concerns under item Table 3.3-4, Items 11b and 11a above.

The licensee shall evaluate the related concerns, including the extended MFW valve isolation times, to determine their safety significance, and propose as required. Until that time, it must be concluded that since a zero (0) value has been used in the current analysis, the licensee has a potentially non-conservative situation with respect to regulatory requirements of reactivity control and regulatory concerns for flooding of the main steam lines.

Response: Excessive Feedwater Flow at Full Power is analyzed in Section 15.1.2 of the McGuire FSAR. Table 15.1.2-1, page 1 of 2, 1984 Update, gives the sequence of events for this analysis. The High-High SG Level setpoint is reached at 27 seconds with feedwater isolation occurring 9 seconds later. This 9 second value agrees with the values used for feedwater isolation on Safety Injection.

To be consistent with the current safety analysis the Technical Specifications value for item 6b of Table 3.3-5 should be $\leq$ 9 seconds. Another alternative is to reanalyze the Excessive Feedwater Flow event with the longer delay time. Duke will pursue a Technical Specification revision or reanalysis.

(Question 7o)

TABLE 3.3-5, Item 12

Response time proposed as $\leq$ 60 secs.

The licensee shall provide the bases for this value, evaluate against this $\leq$ 60 secs, and propose as necessary.

Response: The automatic switchover to recirculation is initiated when the level setpoint in the RWST is reached. The setpoint determination includes allowances for switchover delay $\geq$ 60 seconds and plant procedures test to ensure switchover delay $\leq$ 60 seconds per Table 3.3-5, Item 12.

General Response to Questions 8a-8e:

These questions in general deal with the conservatism of the FSAR Chapter 15 safety analyses for events initiated from MODES 3-5. Specifically the question of the number of RCS loops in operation, for heat removal or other purposes, appears many times. Since the McGuire Technical Specifications and Westinghouse Standard Technical Specifications are identifical for MODES 3-5 for T.S. 3.4.1, Reactor Coolant Loops and Coolant Circulation, any questions regarding these matters should be resolved on a generic basis and are not specific to McGuire. Therefore, the responses to each question will deal only with items which are specific to McGuire.

(Question 8a)

SECTION 3/4.4.1, G.2.6.1 OCCURRENCES WITH RAPID REACTIVITY INCREASE

Concerning "Uncontrolled Rod Cluster Control Assembly Bank Withdrawal from Sub-critical Condition."

Current docketed analysis in reference 7, Section 15.2.1, page 15.2-2 is based on four operating loops. This event is possible down to and including Mode 5. Current FSAR analysis trips the reactor on Power Range, Neutron Flux Low

Setpoint (25%) at a Safety Analysis Limit of 35% (reference page 15.2-3, Item 3). The principal determinant of ultimate power level is Doppler coefficient; contribution of moderator reactivity coefficient is negligible (reference page 15.2-3, Items 1 & 2). The event is initiated from hot zero power (reference 7, page 15.2-4, Item 3). 4 RCS pumps are operating.

Given the circumstances of the proposed T.S., any T.S. allowing OPERABILITY of less than 4 RCS Loop in MODE 3 would be in nonconformance with the current FSAR in a nonconservative manner, and the licensee would be required to evaluate and propose. Furthermore, increased boron concentrations would not change this requirement.

Additional events of a similar nature, with a rapid increase in reactivity include:

a) Uncontrolled Boron Dilution (reference 7, page 15.2-13).

b) Startup of an Inactive Reactor Coolant Loop (reference 7, page 15.2-19, revision 7).

c) Excessive Heat Removal Due to Feedwater System Malfunction (reference 7, page 15.2-30, revision 7) concerning initiation with the reactor at zero power). Until the licensee clarifies availability of MFW during MODES 3 through 5, this must be considered a potential occurrence.

d) Single rod cluster control assembly withdrawal (reference 7, Page 15.3-9, revision 7). Although the Licensing Basis is at 100% power, the circumstances from zero power should be reviewed.

e) Rupture of a Control Rod Drive Mechanism Housing, at Zero Power (reference 7, Page 15.4-30; revision 42).

f) Major Rupture of a Main Steam Line (see below).

Response: No McGuire specific concerns are raised in this question. Refer to the general response to Questions 8a-8e.

(Question 8b)

SECTION 3/4.4.1, G.2.6.2 STEAM LINE BREAKS

Concerning "Major Rupture of a Main Steamline."

This Event is discussed in Accident Analyses in Reference 7, Section 15.4.2 and Reference 8, Item 212.75, page Q 212-47d & e, Item 25. Reference 8 proposes that the resulting impact on shutdown margins from this event during MODES 3, 4, and 5 are improved over that of the design basis (hot zero power, just critical, Tavg = 557°) as:

> "Operating Instructions require that the boron concentration be increased to at least the cold shutdown boron concentration before cooldown is initiated. This requirement insures a minimum of 1% $\Delta k/k$ shutdown margin

at a Reactor Coolant System temperature of 200°F. This condition assures that the minimum shutdown margin experienced during the streamline rupture from zero power shown in the safety analysis is less than the case where safety injection actuation is manually blocked on low steamline pressure and low pressurizer pressure."

This position gives no measure of the resulting shutdown margins and/or power level and, the consequences of a stuck rod, with only 2 RC loops operating instead of four. It is conceivable that two loop operation may be less conservative than either 4 RCPs continuing to operate or 4 RCPs tripped on Safety Injection, due to an increased cooldown in the core due to circulation (compared to the tripped case) but a much decreased core flow rate to handle the event. The potential short term consequences of bulk voiding and loss of circulation in the non-operable loops cannot be ignored.

If during cooldown, a MSLB cools the RCS down to 212°F e.g., the residual shutdown margin will be 1% delta k/k whereas the proposed T.S. margin at Zero Power according to T.S. Page 3/4 1-1, was 1.6 delta k/k. Please clarify, and at what condition during cooldown the 1.6% delta k/k is reached.

Given the circumstances that the "Operating Instructions" described above are not a part of the proposed T.S., any T.S. allowing operability of less than 4 RCS loops in MODE 3 would be in non-conformance with the current Licensing Basis Safety Analysis in the FSAR in a non-conservative manner, and the licensee would be required to evaluate and propose.

For this licensing basis event, from Zero Power, Reactor Trip does not occur on Power Flux Trip, but on Pressurizer Pressure-Low (SI) (above P-11) [reference our required confirmation of this in an earlier item] so the Power Flux Trip is not required to be Operable.

At less than P-11, these circumstances are changed for the MSLB, and reactor trip does not occur until Containment - Hi is achieved, for a break inside containment.

For a break outside containment, however, high negative steam rate isolates main steam isolation valves only, but there is no Safety Injection, no Reactor Trip (on SI), and under the existing proposed T.S. no safety related Reactor Trip System Instrumentation of any nature to trip the reactor and insert the movable control rods to benefit from potentially increased available shutdown margin. In addition to all this, the licensee proposes that MSIV closure times under these conditions is Not Applicable.

Given the circumstances of the proposed T.S., the T.S. allowing OPERABILITY of less than 4 RCS Loop in MODE 3 under these circumstances would be in nonconformance with the current Licensing Basis FSAR in a nonconservative manner, and the licensee would be required to evaluate and propose.

Additional events which exhibit a rapid cooldown and depressurization of the RCS; are:

a) Accidental Depressurization of the main steam system at no load, (reference 7, page 15.2-35, revision 36).

b) Minor Secondary System Pipe Breaks [at no load]; reference 7, page 15.3-4, revision 27).

Response: Changes in the Technical Specifications and plant procedures have occured since the DPO questions were posed (boration to cold shutdown prior to starting cooldown is no longer required). The required shutdown margin for RCS temperatures above 200°F is 1.3% $\Delta k/k$. The shutdown margin requirement for temperatures equal to or less than 200°F is 1.0% $\Delta k/k$. Variations in initial conditions for the steamline break transient were analyzed in WCAP-9226 and support the conservative assumptions in the FSAR analysis.

Closure times for the Main Steam Isolation Valves (MSIVs) are implied in the Technical Specifications. In Table 3.3-5, Items 4h, 5c, and 8, response times are given for the Steam Line Isolation function. This time includes the MSIV closure time. Other concerns raised in this question are generic. Refer to the general response to Questions 8a-8e.

(Question 8c)

SECTION 3/4.4.1, G.2.6.3 LOSS OF PRIMARY COOLANT

Concerning: "Small Break LOCA".

This is discussed in reference 7, Section 15.3.1, for a SBLOCA from rated power, and reference 8, Item 212.75, page Q 212-47b for a SBLOCA between RCS conditions of 1900 psig and 1000 psig/425°F in Hot Standby, and Q212-64, Item 3 together with SER Supp. No. 2, reference 12, page 6-8 for the remaining situations. See also in general, reference 12 pages 6-6 to 6-8 in respect of ECCS System Performance Evaluation from Hot Standby to and including RHR.

The FSAR analysis for SBLOCA in reference 7, Section 15.3.1 states that:

"During the earlier part of the small break transient, the effect of the break flow is not strong enough to overcome the flow maintained by the reactor coolant pumps through the core as they are coasting down following trip: therefore upward flow through the core is maintained."

Topical Report, WCAP 8356 (reference 19) is the basis (reference 8, page Q 212-47b, last paragraph) for the SBLOCA calculations to the same reference 8. These were undertaken with all pumps initially running followed by either a) all pumps tripped or b) continuing to run. The general conclusion from this report, reference 27, page 4-31, is that:

"Due to the action of the running (non-tripped) pumps, less negative core flow occurs from the flow reversal compared to the case [ ] where pumps are immediately tripped." and "The net result of these effects is a smaller peak clad temperature for the pumps running case compared to the pumps tripped case. Hence, for ECCS analyses for W 4 loop plants the reactor coolant pumps are assumed to be tripped at the initiation of a postulated LOCA and a locked rotor pump resistance is used for reflood."

At this time therefore, the NRC must conclude that RCS pump operation and coastdown is important in reducing the loss of core level subsequent to the event; also in maintaining unseparated two phase flow conditions and in ensuing rapid boron (mixing and) injection to the core. Rapid boron injection would not be an important issue if boron concentrations are already at cold shutdown values, but minimizing loss of core level is important.

Until further evaluations are made, we must conclude that the current Safety Analysis Limits of the SBLOCA event is 4 RCS pumps OPERABLE in MODE 3 down to 425 psig/350°F. The current proposed T.S. are therefore nonconservative and the licensee must evaluate and propose.

Given the circumstances of the proposed T.S., operability of less than 4 RCS loops in MODE 3 would be in non-conformance with the current Safety Analyses Limits in a non-conservative manner and the licensee is required to evaluate and propose.

Additional events of a similar nature to the SBLOCA events include:

a) Accidental Depressurization of the Reactor Coolant System (reference 7, page 15.2-33, revision 7).

b) Steam Generator Tube Rupture (reference, page 15.4-13a, revision 38).

c) Rupture of a Control Rod Drive Mechanism Housing at Zero Power (reference 7, page 15.4.6, revision 42).

Both events a) and b) are analyzed in the Licensing Bases at full power and use Pressurizer Pressure-Low as a first reactor trip. At zero power, with current proposed T.S. this reactor trip is proposed as Not Operable.

For event c), from Zero Power, the Power Range Neutron Flux, High Setpoint trips the reactor; Pressurizer Pressure-Low (SI) initiates Safety Injection; reference 7, page 15.4-29, revision 43, paras. 1 and 5. Whereas both these protections are proposed by the T.S. in MODE 2, they are not proposed for MODE 3 which differs from the circumstances of MODE 2 by only a marginal reduction in RCS temperature.

The FSAR, reference 7, Table 15.4.6-1, revision 42, shows this occurrence as being the only event at zero power, analyzed to a smaller No of RCPs than 4; it has been analyzed for 2 only. This is an accident with substantial but "acceptable to Condition IV occurrences" consequences in terms of fuel cladding damage and RCS overpressurization, but it required at least two RCPs to achieve that (in the Licensing Basis). Even the two RCPs required in this event are not proposed as being required for MODE 3.

The proposed circumstances in MODE 3 are clearly nonconservative with respect to the Licensing Bases. The licensee shall evaluate and propose.

Concerning the large break "Loss of Coolant Accident." This is discussed in Accident Analyses in Reference 7, Section 15.4.1 for a LOCA from rated power; in Reference 8, Item 212.75, page Q 212.47, for a LOCA between RCS conditions of 1900 psig and 1000 psig/425°F in Hot Standby; in Item 212.90 (6.3), page 212-61, for a LOCA at and less than 1000 psig/425° in Hot Standby, and on page Q 212-61b, Item 29 for a LOCA in the RHR Mode at 425 psig/350°F.

As for the small break LOCA, these analyses are presumably based on 4 RCS loop operation, with in general, loss of power to RCS pumps on Safety Injection.

The large break LOCA analyses used the Topical Report WCAP-8479, reference 7, page 15.4-1. At this time, we expect no difference in the importance of RCPs to that discussed under the paragraph commencing "concerning small break LOCA" which used the W Topical Report WCAP 8356 (reference 19) and which applied to both large and small break LOCAs.

Given the circumstances of the proposed T.S., any T.S. allowing OPERABILITY of fewer than 4 RCS loops in MODE 3 would be in nonconformance with the Licensing Bases FSAR in a nonconservative manner, and the licensee is required to evaluate and propose.

Response: No McGuire specific concerns are raised in this question. Refer to the general response to Questions 8a-8e.

(Question 8d)

SECTION 3/4.4.1, G.2.6.4 OCCURRENCES CAUSING AN INITIAL INCREASE IN RCS TEMPERATURE

Those events causing increases in RCS temperature are of concern because of the potential influence of the positive moderator temperature coefficient resulting from the increased boron concentration. These could be:

a) Main Rupture of a Main Feed Line (Reference 7, page 15.4-[illegible], revision 30), although this is normally evaluated at Rated power with no provision for evaluation at zero power.

b) Startup of an Inactive Reactor Coolant Loop.

c) Loss of Offsite Power (reference 7, page 15.2-19, revision 7).

d) Partial Loss of Forced Reactor Coolant Flow (Reference 7, page 15.2-16, revision 7).

e) Complete Loss of Forced Reactor Coolant Flow (Reference 7, page 15.3-7, revision 7).

Except for item b; all these events are licensing bases events from rated power, and not zero power, so that their importance would normally be minimal except for the positive Moderator Temperature Coefficient and the complete lack of safety-related Reactor Trip protection proposed with the Reactor Trip System Instrumentation T.S. At this time we see no protection against positive temperature coefficients in MODE 3 [4, 5, & 6].

Given the circumstances of the proposed T.S., operability of less than 4 RCS loops in MODE 3 would be in nonconformance with the current Safety Analyses Limits in a nonconservative manner. The licensee is required to evaluate and propose.

Response: No McGuire specific concerns are raised in this question. Refer to the general response to Questions 8a-8e.

(Question 8e)

T.S. 3.4.1 CONCLUSIONS

Occurrence II, III and IV Events in MODES 3, 4, and 5 can result in returns to power with high peaking coefficients requiring effective reactivity control and/or reactor core flow for RCS protection, including DNBR, at the very substantially reduced pressure levels in the loop [2250 psig to 425 psig and less]. Concomitant decreases in RCS temperatures are beneficial, but the importance of RCS pressure may be dominant. Acceptable RCS protection therefore requires RCS flows which are substantial, and/or effective reactivity control including combined action to limit potential reactivity excursions.

At this time, with the proposed T.S., 4 RCS loops (with increased Reactor Trip Protection) would be required at entry into and during MODE 3 to meet the requirements of just the Licensing Basis Events From Zero Power. In MODE 4, operation of 4 RCS Loops, whilst on RHR, may be undesirable because of the substantial additional burden on the RHR system; so nonoperability of all RCPs must be compensated by other controllable factors such as inserting all movable control assemblies and removing power from the Reactor Trip System Breakers, closure of Main Feedwater [Containment] Isolation valves to both Main and Auxiliary Feedwater Systems, closure of Main Steam Isolation Valves, and Boration Control measures additional to those included in the proposed T.S. An additional available alternate action is to use, within MODE 4, a minimum set of RCPs (and loops) as established by Safety Analysis, to cool the plant down to effectively zero pressure (gauge) in the Steam Generators [or less if the condenser was still available] before transferring the heat sink to the RHR system. This would ensure control of steamline break, and LOCA events, small and large, down to conditions where RCS flows are not necessary.

The current T.S. are nonconservative in respect to the Licensing Basis in respect to these concerns. The Licensee shall evaluate and propose.

Response: No McGuire specific concerns are raised in this question. Refer to the general response to Questions 8a-8e.

(Question 9)

T.S. Page 3/4 4-2

Earlier concerns under General 2.6.1 addressed the need to evaluate the consequences of the startup of an inactive Reactor Coolant Loop in this MODE. No apparent T.S. provision has been provided in the proposed T.S. The licensee shall evaluate and propose.

ACTION b. states:

> "With no reactor coolant loop in operation, suspend all operations involving a reduction in boron concentration of the Reactor Coolant System and immediately initiate corrective action to return the required reactor coolant loop to operation."

This instruction is invalid. The only Licensing Basis action available is the Emergency Operating Guidelines for natural circulation. This proposal is nonconservative with respect to the Licensing Basis. The licensee shall evaluate and propose.

Response: The actions included in ACTION b. are 1) suspend deboration operations and 2) immediately initiate action to restore forced circulation. The actions are obviously valid responses to the condition. There is no Emergency Operating Procedure at McGuire for natural circulation. There is Abnormal Procedure AP/1&2/A/5500/09, Plant Operations During Natural Circulation, which addresses the initiation, verification, and maintenance of natural circulation. This procedure would be implemented under this condition.

(Question 10)

T.S. Page 3/4 4-3

The licensee shall evaluate as outlined earlier under item, General, for RCS loops operability requirements and make proposals relative to the status of many elements of the protection and operations system to ensure that RCS safety is maintained for related Condition II, III and IV occurrences. At this time, with the proposed T.S. in which limited boration is used and Reactor Trip System safety related instrumentation and Safety Injection instrumentation are all but eliminated, the safety status of the facility is outside the Licensing Basis of the FSAR in a nonconservative manner.

Each of the OPERABLE loops, whether RCS or RHR, are to be energized from separate power divisions to protect against single failure of a bus or distribution system. When the RCS systems are used, the related Auxiliary Feedwater Systems are also required to be operable.

The additional requirement proposed, for two RCS loops to be operable whenever RHR loop/s are in operation, is based upon reference 8, page Q 212-55 and 56, to provide for the failure of a single motorized valve in the RHR/RCS suction line in both MODES 4 and 5 and the possible non-availability of offsite power sources. The FSAR provides, that on failure of the valve:

> "Approximately 3 hours are available to the operator to establish an alternate means of core cooling. This is the time it would take to heat the available RCS volume from 350°F to the sturation temperature for 400 psi (445°F), assuming the maximum 24 hours decay heat load.
>
> To restore core cooling, the operator only has to return to heat removal via the steam generators. The operator can employ either steam dump to the main condenser or to the atmosphere, with makeup to the steam generators from the Auxiliary Feedwater System. The time required to establish the alternate means of heat removal is only the few minutes necessry to open the steam dump valves and to start up the Auxiliary Feedwater System."

The applicability MODE 4, is necessarily qualified by [less than 425 psig/350°F] by the LOCA analyses already referenced above under our Review Section 3/4 4.1 Subsection G.2.6.3 "concerning Large Break loss of coolant accident." See Reference 8, page Q 212-47d where it is described that

> "After several hours into the cooldown procedure (a minimum time is approximately four hours) when the Rcs pressure and temperature have decreased to 400 psig and 350°F."

And arising from a later revision 25, the FSAR Advises on page Q 212-61b Revision 29 concerning ECCS calculations in a later submittal under Revision 28 that

> "The response provided in Revision 28 addressed the subject of operator actions and ECCS availability. Consistent with the information provided in Revision 28, a postulated LOCA in the RHR mode at 425 psig RCS pressure has been assessed."

Surveillance requirement 4.4.1.3.2 should verify SG water level at the Safety Analysis Limit for the Licensing Basis, which is the no-load programmed level, not the current proposed T.S. valve which is the S.G. Low-Low Level [Reactor Trip] and AFW actuation. This proposed T.S. is nonconservative with respect to the current Safety Analysis Limits and the licensee shall evaluate and propose.

Surveillance requirement 4.4.1.3.3, verifying one loop in operation every 12 hours, is unsupportable as all protective trips on low flow in the RCP loops in this condition have been removed. If low flow channel trips on the RCP loops are not required to be operable why should the related alarm be operable. A low flow alarm for the RHR has been provided by the FSAR under reference 8, page Q 212-56, Item:

> "Case 1: The Reactor Coolant System is closed and pressurized.
>
> The operator would be alerted to the loss of RHR flow by the RHR low flow alarm. (This alarm has been incorporated into the McGuire design)."

Since currently, these two types of alarms are the only means of alerting the operator to a loss of flow condition in the loop, which is beyond the Safety Analysis Limits, the alarms on both the RCS and loop flows should be safety-related and included within the T.S.; and without further analysis at this time, two loops should be placed in operation. A proposal is made by the NRC for low flow alarms in each of the separated cooling systems, under proposed T.S. page 3/4 4-6a of this review. Regular surveillance should be proposed to ensure that they remain operable as appropriate, over a specified surveillance period.

The Surveillance requirement, every 12 hours is intended to ensure not only that the system is operating, but that it is operating at process conditions which can be evaluated to show that the equipment is capable of performing its design basis Safety Function. The current surveillance requirements for this item, i.e., for the RCS and RHR systems in Hot Shutdown in T.S. Item 4.4.1.3.3, are absent this information; it is therefore nonconservative and the licensee shall evaluate and propose.

Item 4.4.1.4.4 (Proposed). It is proposed that an additional item be inserted which reads: "The related auxiliary Feedwater System shall be determined OPERABLE as per the requirements of T.S. 3.7.1.2 [and 3.7.1.2.a as applicable]." Current proposed T.S.s on T.S. page 3/4 7-4 are nonconservative in this matter by not providing any operability requirements for AFW in this MODE. The licensee shall evaluate and propose.

An additional item is also required in which Atmospheric Dump Valves operability is established. The current T.S. are nonconservative in this matter; they make no provision for operability of this item (see later proposed T.S. page 3/4 7-8a). [General comment: operability of each SG water level, AFW and atmospheric dump valves in this MODE is probably better defined under each of these items in their particular sections of the T.S. See later Sections of this Review as identified above].

Response: Several separate questions are raised here. The McGuire specific ones are answered as follows:

1) Each RHR train is powered from a separate 4160V bus in the Essential Auxiliary Power System. Each reactor coolant pump is powered from a separate 6900V bus in the Normal Auxiliary Power System.

2) It should be noted that the requirement of maintaining a specific level in the steam generator to verify operability was imposed by the NRC and has no firm basis within Westinghouse. However, for an RCS loop to be operable, sufficient inventory is required in the secondary side for heat removal. In MODE 4 this can be assured by keeping the tube bundle covered. A reasonable way of ensuring this is to require that the secondary side level indicates within the narrow range span. Accounting for errors, an indicated level at the low-low level setpoint assures that the level is at least at the bottom of the narrow range span.

The safety analysis limit for reactor trip on lo-lo SG level is a function with a value of 0% at no-load conditions. Adding allowances for reference leg heatup and instrument error gives the value of 12% used as the T.S. trip setpoint. The T.S. value is therefore conservative with respect to the safety analysis limit.

3) The low flow alarms on the RHR loops are to alert the operator to insufficient flow under RHR conditions. They have no relation to the low flow reactor trip which inserts the control rods to control reactivity during low flow conditions at power. Boron is employed for reactivity control in the shutdown modes while rod insertion is impossible (if the rods are already inserted) or unnecessary (because of the boration).

The current surveillance 4.4.1.3.3 requires verifying one RCS or RHR loop in operation at least every 12 hours. The concern raised apparently centers around the assertion that core cooling could be lost without the knowledge of the operator since no protective functions or alarms are required to be operable by the technical specifications. However, it is expected that there would be multiple indications of any problems that could cause a loss of coolant loop. Although the appropriate alarms are not required by the technical specifications to be operable, there is no reason to believe that all relevant alarms and other indicators would be inoperative during this mode.

The other issues raised in this question are not specific to McGuire. Refer to the general response to Questions 8a-8e.

(Question 11a)

<u>T.S. SECTION 3/4.5</u>

At less than 400 psig and 350°F, the operator aligns the Residual Heat Removal System. The valves in the line from the RWST are closed.

Response: This "question" is merely a statement of operator action to align RHR. It remains true and requires no response.

(Question 11b)

<u>T.S. 3.5</u>

Below 400 psig, the system is in the RHR cooling mode. The RHR system would have to be realigned as per plant startup procedure. The operator would place all safeguards systems valves in the required positions for plant operation and place the safety injection, centrifugal charging, and residual heat removal pumps along with SI accumulator in ready and then manually actuate SI.

Response: This "question" is merely a statement of operator action to align the ECCS for use from a shutdown condition. It remains true and requires no response.

(Question 11c)

T.S. 3.5

The response provided in Revision 28 [above] addressed the subject of operator actions and ECCS availability. Consistent with the information provided in Revision 28, a postulated LOCA in the RHR mode at 425 psig RCS pressure has been assessed. The initial conditions would be reached four hours after reactor shutdown. The integrity of the core after a postulated LOCA is assured if the top of the core remains covered by the resultant two-phase mixture. A conservative indication of time available for operator action is obtained by calculating the time required for the top of the core to just uncover. A calculation has been performed to confirm that margin for operator action does exist to prevent core uncovery. This conclusion persists even under an assumption of ten minute delay for operator reaction time.

Assumptions:

(a) The system pressure essentially reaches equilibrium with containment by the time the volume of water above the bottom of the hot legs is removed.

(b) Upper plenum fluid volume between the top of the core and bottom of hot legs is the only upper plenum fluid considered.

(c) Volume between the core barrel and baffle is conservatively neglected.

(d) 120% of the ANS decay heat curve for four hours after shutdown is utilized.

Using the void fractions developed from the Yeh correlations and utilizing a hydrostastic pressure balance, the height of the steam-water mixture in the upper plenum was generated. Incorporating the plant geometry, the total liquid mass in the downcomer, core, and upper plenum was calculated, i.e., a mass-initial condition. Again by hydrostatic pressure balance, the height of liquid in the downcomer when the top of the core is just about to uncover was calculated. This information along with core volume is used to develop a mass-final condition. That is, the mass is liquid contained just before the core is uncovered. Utilizing the boil-off rate for the four hour time after shutdown, the time needed to evaporate a mass of mass-initial minus mass-final is calculated. This time was compared to the ten minute assumption for operator reaction time.

"Utilizing the preceding approach, the time calculated to just initiate an uncovery of the core is 13 minutes. The conclusion is that even for the conservative method outlined above, there exists adequate margin to retain a safe core condition even in relation to a ten minute operator-response-time assumption."

These operator requirements are verified, in general, by reference 12, SER Supplement 2, page 6.6-6.8, under "Emergency Core Cooling System - Performance Evaluation", and pages 7-1 and 7-2 under "Upper Head Injection Isolation Valves".

Additionally, the status of the ECCS systems from entry into the RHR MODE through cooldown, i.e., from 425 psig/350°F through MODE 5 is clarified by the following extract from reference 11, suppl. SER No. 1, pages 5-1 and 5-2 which confirms continuance of the alignment at the end of MODE 3 425 psig/350°F through both MODES 4 and 5.

Response: This "question" is largely a quotation from the FSAR. The last two paragraphs, while not from the FSAR, are simply statements introducing a quotation from the SER. Therefore, this requires no response.

(Question 12a)

T.S. 3.5.1.1.d.

Nitrogen cover pressure is quoted at between 400 and 454 psig. The Licensing Basis FSAR, reference 4, page 1 of 5 revision 39 in Table 6.3.2-1 specifies a normal operating pressure of 427 psig. Making an allowance for channel error and drift, should not this value be a higher setpoint of approximately 450 psig? The specified setpoint values proposed in the T.S. of 400 to 454 psig can therefore give actual values which are lower than in the Licensing Basis FSAR and be non-conservative. The Licensee shall evaluate and propose.

Response: The bases for the T.S. 3.5.1 limit of Cold Leg Accumulator cover pressure of between 400-454 psig is the assumed value in the LOCA analysis (FSAR Chapter 15). Allowance for channel error and drift are accounted for in the determination of the T.S. requirements. The numbers in Table 6.3.2-1 are nominal and minimum values as required by T.S. 3.5.1 and are in agreement with the T.S. 3.5.1 limits. Recent Technical Specification changes (Ref. unit 1/2 License Amendments 57/38) associated with the removal/isolation of the UHI System involve revising the Cold Leg Accumulator cover pressure to between 585 and 639 psig.

(Question 12b)

T.S. 4.5.1.1.1.d.1

The licensee shall verify that the set points for the relief valve on the Accumulators are included in the Inservice Testing Program at the facility.

Response: The Cold Leg Accumulators Relief Valves (NI-52, 63, 74, and 86) are not required to perform a safety function either to shutdown the reactor or to mitigate the consequences of an accident. The inservice testing program requirement to test all class 1, 2, & 3 valves was changed to valves which are required for safe shutdown of the reactor or mitigating the consequences of an accident.

Consequently these relief valves are not included in the McGuire Nuclear Station pump and valve inservice testing program required by 10 CFR 50.55a(g). These valves (and setpoints) are tested following maintenance only.

(Question 13)

T.S. 3.5.1.2.d

It is proposed that an additional item limiting the range of actual water temperatures in the accumulator to between 70 and 100°F in accordance with reference 29, page (1 of 5), revision 39, in Table 6.3.2.1 is necessary to confirm the Safety Analysis Limits for the UHI Accumulator. It is also proposed that it be added as an additional surveillance element to T.S. 4.5.1.2.a. Its absence from the proposed T.S. renders it potentially non-conservative with respect to the Licensing Basis. The licensee shall evaluate and propose.

The licensee shall verify that the relief valve set point on the Accumulator is included in the Inservice Testing Program at the facility.

Response: FSAR Table 6.3.2.1 provides the expected operating temperature range for the UHI accumulator water and not Safety Analysis limits as stated above. The Safety Analysis value related to UHI water temperature is assumed to be the upper bound value of 100°F.

The Upper Head Injection Accumulator Relief Valve (NI-279) is not required to perform a safety function either to shutdown the reactor or to mitigate the consequences of an accident. The Inservice Testing Program requirement to test all class 1, 2, & 3 valves was changed to valves which are required for safe shutdown of the reactor or mitigating the consequences of an accident. Consequently this relief valve is not included in the McGuire Nuclear Station pump and valve inservice testing program required by 10CFR 50.55a(g). This valve (and setpoint) is tested following maintenance only.

(Question 14)

T.S. 4.5.2.h.

Concerning Flow Balance Tests in the ECCS System. The licensee shall provide the bases for the flow distributions specified and further advise how they might meet minimum flow conditions to intact loops during accident occurrences.

Response: The bases for the limits as specified in T.S. 4.5.2.h are the assumed ECCS flows used in the LOCA analysis. ECCS flow injected to the broken cold leg is assumed to spill in LOCA analyses, so limits are placed on the branch line totals to ensure that adequate flow reaches the intact loops.

(Question 15)

T.S. SECTION 3/4.5.3

This T.S. does not disallow the additional CCP and 2 Safety Injection Pumps (SIPs) from 350°F down to 300°. This again is non-conservative with respect to the LCOs of the Licensing Basis FSAR which allows only one (1) CCP, and the remainder i.e., one (1) CCP and any other reciprocating charging pump and 2 SIPs are to be electrically isolated against inadvertent operation. This proposed T.S. is again non-conservative in respect of overpressure protection when compared with the current Licensing Basis. The licensee shall evaluate and propose.

The proposed T.S. allows one (1) CCP and one (1) SIP whenever the RCS temp is less than 300°F. The LCO of the Licensing Basis FSAR allows only one (1) CCP because of overpressure protection; reference earlier information under earlier T.S. Section 3/4.5. Item: "General". The proposed T.S. is therefore non-conservative with respect to the Licensing Basis. The licensee shall evaluate and propose.

Response: This question appears to be related to the discussion of FSAR Section 5.2.2, "Overpressurization Protection". Although it is stated in two places that Technical Specification 3.5.3.a violates the FSAR Licensing Basis, Section 5.2.2 contains no discussion of ECCS pump operability between 300°F and 350°F. It is further stated, in the discussion of Section 5.2.2., that the McGuire Technical Specification 3.5.3.a. differs markedly from the Westinghouse Standard Technical Specification 3.5.3.a. Comparing the two we find no differences in the number or type of ECCS pumps required to be operable or inoperable. The McGuire lower limit is 300°F compared with Standard lower limit of 275°F. We therefore conclude that the McGuire Specification does not differ from the Standard one in a non-conservative manner.

(Question 16)

T.S. 3.7.1.2.b.

The licensee has deleted operability requirements for the steam-turbine driven auxiliary feedwater pump at steam pressures of less than 900 psig. This is not in accord with current accident analyses and no justification has been provided: Reference 15, Recommendation GL-3, requires the steam-turbine AFW pump in the event of complete loss of AC power for a period of 2 hours and beyond. This will require operability down to the lowest pressures for which the turbine is provided as described in reference 22, Table 10.4.7-6 where the range of operating pressures provided for is from 110 psig to 1205 psig. This will also provide for operability down to and including MODE 4 (and availability from MODE 5) to cover licensing requirements discussed elsewhere under Table 3.3-3, ESFAS INSTRUMENTATION, Items 7a through f.

We note two principal features relating to the service conditions of the turbine-driven feedwater pumps:

a. They are supplied with steam from two steam generators from main steam lines after the flow restriction orifices at outlets from the Steam Generators.

b. They would normally be expected to perform early in the transient and continue to function according to design flow requirements throughout the occurrence.

The licensee should explain how the proposed T.S. ensures that the turbine driven pump maintains its flow performance required by accident analyses when steam line pressures could drop substantially below the Steam Generator pressures due to presence of the SG flow restrictions and until main steam isolation valves are isolated on steam line pressure of less than 565 psig (< provides for channel drift and errors).

The licensee shall evaluate the above comments and propose technical specifications which will ensure operability of the turbine-driven AFW pump over the range of conditions expected from design basis accident analysis, and other less bounding events, down to and including MODE 4 as discussed in the Licensing Basis.

In his evaluation, the licensee should advise if Item 1e of Table 3.3-5 ESFAS INSTRUMENTATION, Steam Line-Pressure Low, is derived from steam line sensors and after the SG orifices, or if it is taken from pressure sensors on the Steam Generator. The licensee should then advise what has been used in assessing Steam Generator pressure response and turbine driven AFW pump response in the Condition III and especially Condition IV occurrences of the Licensing Basis, and if the existing accident analyses remain valid.

Response: The footnote deleting operability requirements for the Steam Turbine-Driven Auxiliary Feedwater Pump (TDAFP) at steam pressures <900 psig was added in an attempt to correct a conflict between the LCO with its applicability of Modes 1, 2, and 3 and Surveillance Requirement 4.7.1.2.a.2 which defines operability of the TDAFP as developing a discharge pressure of $\geq$ 1210 psig at a flow of $\geq$900 gpm when the secondary steam supply pressure is >900 psig (to delevlop a discharge pressure of 1210 psig the TDAFP requires steam at $\geq$ 900 psig, but supply steam pressure can be <900 psig during startups/shutdowns). The Technical Specification's bases for operability of the Auxiliary Feedwater System is to ensure that the Reactor Coolant System can be cooled down to <350°F from normal operating conditions in the Event of a total loss of offsite power, with the TDAFP capable of delivering a total feedwater flow of 900 GPM at a pressure of 1210 psig to the entrance of the Steam Generators to meet this function. Under normal operating conditions source steam at >900 psig is Available and the TDAFP is capable of performing this function. However, as indicated in Question 16 and Items 1 and 2 below, the TDAFP is also required with steam pressures <900 psig.

1. During a condition IV feedline break all steam generators will depressurize prior to closure of the Main Steamline Isolation Valves (MSIV's). The low steamline pressure set point for closing the MSIV's is about 585 psig. However, errors due to seismic and environmental conditions as well as instrumentation inaccuracies may result in a steam generator pressure as low as 285 psig prior to MSIV closure. Therefore the turbine driven Auxiliary Feedwater pumps must be capable of delivering the minimum required flow for feedline break with a steam generator motive supply pressure as low as 285 psig.

2. The ability to commence a plant cooldown must be maintained following transient and accident conditions. Following design basis faulted conditions with specific single failure assumptions, it may be necessary to commence a plant cooldown with only a turbine driven Auxiliary Feedwater System pump available. Consequently the turbine driven pump must be capable of delivering the minimum required flow for cooldown with a steam generator motive supply pressure as low as 100 psia corresponding to a primary side hot leg temperature of 350°F during a natural circulation cooldown, which is maximum operating temperature for Residual Heat Removal System Operation.

Therefore, The Tech. Spec's Surveillance requirements/Bases do not adequately define the operability requirements for the TDAFP and consequently the Technical Specification does not ensure operability of the TDAFP over the range of conditions expected from Design Basis Accident Analysis and other less bounding events. All other circumstances (or accident conditions) besides the limiting condition of loss of Offsite Power during full power operation pose less severe demands on the TDAFP. For the Main Steamline Break, the intact Steam Generator is fully capable of supplying the steam requirements of the pump turbine. With source steam < 900 psig the TDAFP is capable of providing feed flow but at a discharge pressure below 1210 psig. Since the McGuire Technical Specification is essentially indentical to the Westinghouse Standard Technical Specification (with the exception of the "correcting" footnote), this discrepancy between the LCO and the Surveillance Requirements/Bases should be resolved on a generic basis and is not specific to McGuire.

With regard to providing operability down to and including Mode 4 (and availability from Mode 5), the bases of the auxiliary Feedwater System Technical Specification is that its operability (including the capacity of the TDAFP) ensures that adequate feedwater flow is available to remove decay heat and reduce the Reactor Coolant System Temperature to <350°F (i.e. Mode 4) when the RHR System may be placed into operation. Therefore the bases does not require System Operability in Modes 4 or 5. Since the McGuire and Westinghouse standard technical specifications bases are essentially identical, any desired changes to this bases should be pursued on a generic basis.

Item 1e of T.S. Table 3.3-3 "Steam Line Pressure-Low" is derived from steam line sensors downstream of the steam generator flow restriction orifices.. The steam flow restrictors do not cause a significant pressure drop except during a double ended steam line break. The blowdown phase of this accident lasts only a few seconds. The accurate pressure sensing in the steam lines (i.e. generation of a "Steam Line Pressure-Low" signal) takes less than 2 seconds and steam line isolation less than 7 seconds. (The main steam line break accident is descussed in Chapters 6 and 15 of the FSAR).

(Question 17)

T.S. SECTION 3/4.7.5

Reference 6, page 9.2-13, revision 39, states that "In the event of solid layer of ice" forms on the SNSWP, the operating train [of the Nuclear Service Water [NSW] system] is manually aligned to the SNSWP. The Licensee shall provide the safety-related reason for this action and advise if this operator action conflicts with the response times proposed under Table 3.3-5. Given a Safety Related reason, surveillance requirements ensuring this action should be included under either T.S. Section 3/4.7.5 NSWS or this particular T.S. Section 3/4.7.5 STANDBY NSWP. Absent this surveillance requirement on a safety-related issue, the proposed T.S. would be non-conservative. The Licensee shall evaluate and propose.

Response: This action has been deleted. See Section 9.2.2, Nuclear Service Water System and Ultimate Heat Sink, 1984 Update.

(Question 18)

T.S. 3/4.9.1

The current SER, Supplement No.1, reference 11, page 15-1, provides that:

During refueling the applicant has committed to isolate all sources of unborated water connected to the primary system refueling/canal/spent fuel.

We do note that surveillance requirement T.S. 4.9.1.3 does provide for verifying that valve no.1NV-250 is closed, under administrative control in support of this. However we do note that according to reference 7, page 15.2-15, item Q 212-58, this valve 1NV-250 is to be locked closed during refueling. The current position could be nonconservative if the valve is not specifically locked under the proposed administrative control. Also notice, that reference 7, page 15.2-14, revision 10, states that:

> "The other two paths are through 2 inch lines, one of which leads to the volume control tank with the other bypassing this tank. These lines contain flow control valves 1NV-171A and 1NV-175A respectively."

Why are T.S.s not applied to the closure of these valves also? The proposed T.S. may be nonconservative with respect to the Licensing Basis. The licensee shall evaluate and propose.

Response: Valve 1NV-250 is specifically required to be locked closed under the Administrative Controls (i.e. Station Procedures). This Valve is upstream of valves 1NV-171A and 1NV-175A and isolates the flow path.

(Question 19)

T.S. SECTION 3/4.9.8

The ACTION statement provides that with no RHR loop operable, the containment should be closed within 4 hours. Information in reference 8, page Q 212-56 under Case 2 shows that if RHR is absent [by isolation of the RCS/RHR inlet valve] that:

> "Approximately 2.5 hours are available to the operator to establish an alternate means of core cooling. This is the time it would take to heat 300,000 gallons of water in the refueling canal from 140°F to 212°F, assuming the maximum 24 hours decay heat load."

The current value of 4 hours appears less conservative than this calculated value of 2½ hours in the FSAR. The licensee shall evaluate and propose.

Review of available responses to the consequences of a fail closed RCS/RHR isolation valve, include many procedures using the containment sump. To allow for this single failure contingency, the licensee should therefore ensure that the containment sump will be operable during this mode, and with an appropriate surveillance procedure. There should also be provision for available fire pumps and necessary hoses to be assuredly available to enable use of the alternate procedures which have been described in reference 8, pages Q 212-56 and 57, revision 25. The current T.S. must be considered non-conservative. The licensee shall evaluate and propose.

Response: The McGuire Technical Specification 3.9.8 is the same as the Westinghouse Standard Technical Specification (STS) 3.9.8. Since there is nothing unique about McGuire's 3411 MWt power level, its decay heat characteristics, or its 23 feet level requirement, this question should be addressed on a generic basis.

(Question 20)

T.S. SECTION 4.9.8.2

The current ACTION statement calls for containment closure in 4 hours [i.e. 240 mins]. Earlier conservative calculations for this MODE show that loss of all RHR in this MODE can cause boiling in 5 minutes and core uncovery in 100 mins. Given the circumstances, containment enclosure should be effected immediately, commencing RHR low flow alarms. The Licensee shall evaluate, and propose. The current T.S. appears nonconservative with respect to the Licensing Basis.

Response: See the response to the previous item since McGuire is also in accordance with Westinghouse Standard Technical Specification on this item.