ATTACHMENT 1
PROPOSED CHANGES TO THE TECHNICAL SPECIFICATIONS

LICENSE AMENDMENT APPLICATION
STI/AOT EXTENSIONS FOR ECCS AND RCIC ACTUATION INSTRUMENTATION
HOPE CREEK GENERATING STATION
FACILITY OPERATING LICENSE NPF-57 NLR-N93014
DOCKET NO. 50-354 LCR 93-02

I. DESCRIPTION OF THE PROPOSED CHANGES

This license amendment application proposes to change Technical Specification (TS) 3/4.3.3, "EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION" and TS 3/4.3.5, "REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION" along with their associated Bases, such that:

A. The allowed out-of-service time (AOT) for surveillance testing specified in Note (a) to Table 3.3.3-1 is extended from 2 to 6 hours.

B. The AOTs for maintenance specified in Action Statements 30 through 35 of Table 3.3.3-1 are extended to 24 hours.

C. The channel functional test requirements specified in Table 4.3.3.1-1 are extended from monthly to quarterly for the following trip functions:

1. Core Spray System:

   a. Reactor Vessel Water Level - Low Low Low, Level 1
   b. Drywell Pressure - High
   c. Reactor Vessel Pressure - Low (Permissive)
   d. Core Spray Pump Discharge Flow - Low (Bypass)
   e. Core Spray Pump Start Time Delay - Normal Power
   f. Core Spray Pump Start Time Delay - Emergency Power

2. Low Pressure Coolant Injection Mode of RHR System

   a. Reactor Vessel Water Level - Low Low Low, Level 1
   b. Drywell Pressure - High
   c. Reactor Vessel Pressure - Low (Permissive)
   d. LPCI Pump Discharge Flow - Low (Bypass)
   e. LPCI Pump Start Time Delay - Normal Power

3. High Pressure Coolant Injection System

   a. Reactor Vessel Water Level - Low Low, Level 2
   b. Drywell Pressure - High
   c. Condensate Storage Tank Level - Low
   d. Suppression Pool Water Level - High
   e. Reactor Vessel Water Level - High, Level 8
   f. HPCI Pump Discharge Flow - Low (Bypass)

4. Automatic Depressurization System

   a. Reactor Vessel Water Level - Low Low Low, Level 1
   b. Drywell Pressure - High
   c. ADS Timer
   d. Core Spray Pump Discharge Pressure - High
   e. RHR LPCI Mode Pump Discharge Pressure - High
   f. Reactor Vessel Water Level - Low, Level 3
   g. ADS Drywell Pressure Bypass Timer

D. Bases Section 3/4.3.1 is revised to reference the General Electric (GE) Licensing Topical Reports (LTRs) which justify the above proposed changes to the ECCS actuation instrumentation.

E. The allowed out-of-service time (AOT) for surveillance testing specified in Note (a) to Table 3.3.5-1 is extended from 2 to 6 hours.

F. The AOTs for maintenance specified in Action Statements 50 through 52 of Table 3.3.5.1 are extended to 24 hours.

G. The channel functional test requirements specified in Table 4.3.5.1-1 are extended from monthly to quarterly for the following trip functions:

   1. Reactor Vessel Water Level - Low Low, Level 2
   2. Reactor Vessel Water Level - High, Level 8
   3. Condensate Storage Tank Level - Low
   4. Manual Initiation

H. Bases Section 3/4.3.5 is revised to reference the GE LTR which justifies the above proposed changes to the RCIC actuation instrumentation.

The proposed TS changes described above are consistent with the changes proposed and approved in the referenced GE documents and associated NRC safety evaluation reports (References 1 through 6) with one exception. The proposed wording relative to the maintenance AOTs in References 1 and 2 imply an allowance of 24 hours <u>before</u> taking the action of Technical Specification 3.3.3-1. This issue was addressed and revised marked up TS pages were provided to the NRC by GE in Reference 7. Our proposed changes are consistent with the wording contained in Reference 7.

II. <u>REASON FOR THE PROPOSED CHANGES</u>

The technical assessment of the proposed changes contained in the GE LTRs indicates a positive benefit and net improvement in overall plant safety. This conclusion was based upon the following factors:

A. Surveillance test activities have historically proven to be a significant source of inadvertent reactor scrams. Consequently, increased surveillance test intervals are expected to provide a decrease in unnecessary scrams thereby reducing unnecessary cycles on reactor equipment and unnecessary demands on safety systems. Additional safety benefit of reducing the number of unnecessary scrams is realized through a reduction in the number of potential precursor events to accident scenarios.

B. Test actuation of ECCS instrumentation can potentially place higher stress on equipment than standby operation and can lead to a higher failure rate. Therefore, a reduction in the number of test cycles is expected to have a positive effect on ECCS actuation instrumentation availability and improve overall plant safety.

C. The reduced test frequency reduces the diversion of plant personnel in performing unnecessary testing. This has a net effect of improving the efficiency of the plant operations and maintenance staff in conducting other tasks which have a higher significance on plant safety.

D. The short allowable out-of-service times (AOTs) that currently exist for ECCS instrumentation create the potential of increasing the risk of error during testing and repair. By providing more reasonable and more realistic times for testing and maintenance, the rate of human error will be lowered.

E. A reduction in the test frequency will increase overall equipment availability by reducing the potential for human error during testing and reducing the amount of time that equipment is unavailable due to testing.

F. Limiting Conditions of Operation containing insufficient AOTs can induce plant shutdowns thereby placing the plant in elevated states of risk during the shutdown and startup cycle. Although current PRAs have not explicitly calculated the cumulative risk caused by these operational cycles, this risk is estimated to be higher than the risk present during the AOT for ECCS instrumentation repair. Therefore, reducing the number of such shutdowns will contribute to improved safety.

III. JUSTIFICATION FOR THE PROPOSED CHANGES

The generic GE analyses contained in References 1, 2, and 5 evaluated the effect of the proposed changes to the STIs and AOTs for the ECCS and RCIC actuation instrumentation and demonstrated that the water injection function (WIF) unavailability is insensitive to the proposed changes and that the change in WIF unavailability meets the established acceptance criterion. Section 1.0 of Reference 2 concluded that, from the standpoint of probabilistic considerations alone, it is apparent that the increases in the STIs and AOTs have little affect on plant safety. Furthermore, when the factors described in Section II of this submittal are considered, in addition to the water injection function failure

frequency, the overall effect on plant safety is judged to be an improvement.

References 4 and 6 concluded that the associated GE report provide an acceptable basis for extending STIs and AOTs for ECCS and RCIC actuation instrumentation; however, these NRC safety evaluation reports (SERs) also required that two issues be addressed to justify the applicability of the generic analysis to individual plants when specific facility Technical Specifications are considered for revision. These issues were: 1) confirmation of the applicability of the generic analyses to the specific plant and 2) confirmation that any increase in instrument drift due to the extended STIs is properly accounted for in the setpoint calculation methodology. The following discussion provides information to address these issues.

A. Confirmation of the Applicability of the Generic Analyses

Our confirmation of the applicability of the generic analyses to Hope Creek is based upon the following:

1. Appendix N of Reference 1 and Appendix B of Reference 2 identify Public Service Electric and Gas Company/Hope Creek as a participating utility/plant in the ECCS Technical Specification Improvement Analysis. PSE&G has maintained its participation and involvement on the BWR Owners' Group Technical Specification Improvement Committees thereby assuring that the development of these generic reports encompass the Hope Creek Generating Station.

2. PSE&G has extended the generic analysis completed by the BWR Owners' Group to Hope Creek by completing the required plant specific analysis. At the request of PSE&G, GE developed the plant specific report (Reference 8) included in Attachment 3 of this letter. The plant specific analysis identified those differences in ECCS system design, support systems, and instrumentation between Hope Creek and the generic plant which could affect ECCS system reliability and thereby impact the generic analyses contained in the subject GE LTR. The identified differences were analyzed and the plant specific report concluded that the generic analyses in the GE LTR are applicable to Hope Creek. Based on discussion with GE, this conclusion is applicable not only for ECCS, but also for RCIC. Since the plant specific report was issued in October 1990, we conducted a review and verified that there have been no modifications to the ECCS or RCIC systems since issuance of the report which would invalidate its conclusion.

B. Confirmation that Instrument Drift is Properly Considered

The NRC staff has provided guidance on addressing the issue of instrument drift in Reference 9. This guidance indicated that:

"...licensees need only confirm that the setpoint drift which could be expected under the extended STIs has been studied and

either (1) has been shown to remain within the existing allowance in the RPS and ESFAS instrument setpoint calculation or (2) that the allowance and setpoint have been adjusted to account for the additional expected drift."

In order to satisfy this requirement, PSE&G applied a two fold approach to the issue of instrument drift. This two fold approach involved the following:

1. The setpoint calculations for all instrumentation affected by the changes proposed in this amendment application were reviewed. Results of this review indicate that, in all cases, the loop (setpoint) drift calculation was based on an eighteen month interval; therefore, the proposed STI extensions from monthly to quarterly are well bounded by the existing setpoint calculations.

2. The second approach taken by PSE&G to evaluate the effects of instrument drift was to gather and review actual plant data in order to confirm the drift expectations of the setpoint calculations which are based on vendor supplied information. Plant data was gathered for the trip units that are affected by the changes proposed in this amendment application. The data for each trip unit consisted of the "as found" and "as left" trip setpoint settings over a twelve month period. The actual observed drift over the twelve month period, in all cases, was found to be conservatively bounded by the total loop allowance for a six month period. The results of this evaluation are documented in Reference 10 and are available for NRC staff review.

IV. SIGNIFICANT HAZARDS CONSIDERATION EVALUATION

PSE&G has, pursuant to 10 CFR 50.92, reviewed the proposed amendment to determine whether the request involves a significant hazards consideration. We have determined that operation of the Hope Creek Generating Station in accordance with the proposed changes:

1. **Will not involve a significant increase in the probability or consequences of an accident previously evaluated.**

   The proposed changes to the ECCS and RCIC actuation instrumentation were judged to potentially affect core damage frequency through their impact on the water injection function (WIF) failure frequency. The generic analyses contained in Licensing Topical Report (LTR) NEDC-30936P-A and LTR GENE-770-06-2-A assessed the impact of changing ECCS and RCIC surveillance test intervals (STIs) and allowed out-of-service times (AOTs) on the WIF failure frequency. The analyses contained in these LTRs demonstrate that the proposed changes have an insignificant effect on the WIF failure frequency, and when all contributing factors are considered, the net impact of the proposed changes is to improve plant safety. These generic analyses have been shown to be applicable to the HCGS as

indicated in Section III above. Since the proposed changes do not significantly affect the WIF failure frequency and have a beneficial impact on plant safety when all factors are considered, the proposed changes will not significantly increase the probability or consequences of a previously analyzed accident.

2. **Will not create the possibility of a new or different kind of accident from any accident previously evaluated.**

   Increasing the AOTs and STIs for the ECCS and RCIC instrumentation does not alter the function of the emergency core cooling system (ECCS) or reactor core isolation cooling system (RCIC) nor involve any type of plant modification. Additionally, no new modes of plant operation are involved with these changes. The proposed changes therefore will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. **Will not involve a significant reduction in a margin of safety.**

   The proposed changes to the ECCS and RCIC actuation instrumentation were judged to potentially affect core damage frequency through their impact on the WIF failure frequency. As requested by the BWR Owners' Group, GE performed analyses to evaluate the effect of the proposed changes on the WIF failure frequency. The NRC staff has reviewed and approved the generic study contained in LTRs NEDC-30936P-A and GENE-770-06-2-A and has concurred with the BWR Owners' Group that the proposed changes do not significantly affect the WIF failure frequency. Furthermore, the overall level of plant safety will be improved by the proposed changes as indicated in Section II above. A plant specific evaluation was conducted for HCGS, as indicated in Section III above, which demonstrated applicability of the generic conclusions to HCGS. It can therefore be concluded that the proposed changes will not significantly reduce a margin of safety.

V. CONCLUSION

As discussed above, PSE&G has concluded that the proposed changes to the Technical Specifications do not involve a significant hazards consideration since the changes: (i) do not involve a significant increase in the probability or consequences of an accident previously evaluated, (ii) do not create the possibility of a new or different kind of accident from any accident previously evaluated, and (iii) do not involve a significant reduction in a margin of safety.

Finally, PSE&G has addressed the two issues, discussed in Item III above, which the NRC staff indicated are necessary in order to implement the generic Technical Specification changes identified in NEDC-30936P-A and GENE-770-06-2-A on a plant-specific basis. The information provided in the proprietary report contained in Attachment 3 addresses the HCGS differences from the generic analysis and when applied with the conclusions contained in NEDC-30936P-A and GENE-770-06-2-A, justifies the proposed changes.

VI. REFERENCES

1. NEDC-30936P-A, "BWR Owners' Group Technical Specification Improvement Methodology (With Demonstration for BWR ECCS Actuation Instrumentation) Part 1", dated December 1988

2. NEDC-30936P-A, "BWR Owners' Group Technical Specification Improvement Methodology (With Demonstration for BWR ECCS Actuation Instrumentation) Part 2", dated December 1988

3. Letter from A. C. Thadani (NRR) to D. N. Grace (BWROG) dated December 9, 1988 (transmits NRC safety evaluation report for NEDC-30936P-A Part 1

4. Letter from C. E. Rossi (NRR) to D. N. Grace (BWROG) dated December 9, 1988 (transmits NRC safety evaluation report for NEDC-30936P-A Part 2)

5. GENE-770-06-2-A, "Addendum to Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications", dated December 1992

6. Letter from C. E. Rossi (NRR) to G. J. Beck (BWROG) dated September 13, 1991 (transmits NRC safety evaluation report for GENE-770-06-2-A relative to RCIC Instrumentation)

7. GE Document No. OG90-319-32D, letter from W. P. Sullivan (GE) to USNRC, "Clarification of Technical Specification Changes Given in ECCS Actuation Instrumentation Analysis", dated March 22, 1990

8. GE Document No. RE-019, Revision 1; "Clarification of Technical Specification Improvement Analysis for the Emergency Core Cooling System Actuation Instrumentation for Hope Creek Generating Station", dated October 1990

9. Letter from C. E. Rossi (NRR) to R. F. Janecek (BWROG), "Staff Guidance for Licensee Determination that the Drift Characteristics for Instrumentation Used in RPS Channels are Bounded by NEDC-30851P Assumptions When the Functional Test Interval is Extended from Monthly to Quarterly", dated April 27, 1988

10. PSE&G Internal Memorandum ELE-92-0667 from Robert Sandy, Hope Creek I&C, to C. Manges, Nuclear Licensing, dated December 9, 1992

ATTACHMENT 2

TECHNICAL SPECIFICATION PAGES WITH PEN AND INK CHANGES

LICENSE AMENDMENT APPLICATION 93-02, NLR-N93014
STI/AOT EXTENSIONS FOR ECCS AND RCIC ACTUATION INSTRUMENTATION
FACILITY OPERATING LICENSE NPF-57
HOPE CREEK GENERATING STATION
DOCKET NO. 50-354

The following Technical Specifications have been revised to reflect the proposed changes:

Technical Specification	Page
Table 3.3.3-1	3/4 3-34 3/4 3-35
Table 4.3.3.1-1	3/4 3-39 3/4 3-40
3/4.3.3 Bases	B 3/4 3-2
Table 3.3.5-1	3/4 3-52 3/4 3-53
Table 4.3.5.1-1	3/4 3-55
3/4.3.5 Bases	B 3/4 3-4

TABLE 3.3.3-1 (Cont'd)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP FUNCTION(a)	APPLICABLE OPERATIONAL CONDITIONS	ACTION
4. AUTOMATIC DEPRESSURIZATION SYSTEM##			
e. RHR LPCI Mode Pump Discharge Pressure - High (Permissive)	2/pump	1, 2, 3	31
f. Reactor Vessel Water Level - Low, Level 3 (Permissive)	2	1, 2, 3	31
g. ADS Drywell Pressure Bypass Timer	4	1, 2, 3	31
h. ADS Manual Inhibit Switch	2	1, 2, 3	31
i. Manual Initiation	4	1, 2, 3	33

	TOTAL NO OF CHANNELS(h)	CHANNELS TO TRIP(h)	MINIMUM CHANNELS OPERABLE(h)	APPLICABLE OPERATIONAL CONDITIONS	ACTION
5. LOSS OF POWER					
1. 4.16 kv Emergency Bus Under-voltage (Loss of Voltage)	4/bus	2/bus	3/bus	1, 2, 3, 4**, 5**	36
2. 4.16 kv Emergency Bus Under-voltage (Degraded Voltage)	2/source/ bus	2/source/ bus	2/source/ bus	1, 2, 3, 4**, 5**	36

(a) A channel may be placed in an inoperable status for up to ~~2~~ 6 hours for required surveillance without placing the trip system in the tripped condition provided at least one OPERABLE channel in the same trip system is monitoring that parameter.

(b) Also actuates the associated emergency diesel generators.

(c) One trip system. Provides signal to HPCI pump suction valve only.

(d) Provides a signal to trip HPCI pump turbine only.

(e) In divisions 1 and 2, the two sensors are associated with each pump and valve combination. In divisions 3 and 4, the two sensors are associated with each pump only.

(f) Division 1 and 2 only.

(g) In divisions 1 and 2, manual initiation is associated with each pump and valve combination; in divisions 3 and 4, manual initiation is associated with each pump only.

(h) Each voltage detector is a channel.

(i) Start time delay is applicable to LPCI Pump C and D only.

* When the system is required to be OPERABLE per Specification 3.5.2.

** Required when ESF equipment is required to be OPERABLE.

Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 200 psig.

Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 100 psig.

TABLE 3.3.3-1 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

ACTION

ACTION 30 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement:

a. With one channel inoperable, place the inoperable channel in the tripped condition within ~~one hour~~ 24 hours or declare the associated system inoperable.

b. With more than one channel inoperable, declare the associated system inoperable.

ACTION 31 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, declare the associated ECCS inoperable within 24 hours.

ACTION 32 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, place the inoperable channel in the tripped condition within ~~one hour~~ 24 hours.

ACTION 33 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, restore the inoperable channel to OPERABLE status within ~~8~~ 24 hours or declare the associated ECCS inoperable.

ACTION 34 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement:

a. For one channel inoperable, place the inoperable channel in the tripped condition within ~~1 hour~~ 24 hours or declare the HPCI system inoperable.

b. With more than one channel inoperable, declare the HPCI system inoperable.

ACTION 35 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, place at least one inoperable channel in the tripped condition within 24 hours ~~one hour~~ or declare the HPCI system inoperable.

ACTION 36 - With the number of OPERABLE channels one less than the Total Number of Channels, place the inoperable channel in the tripped condition within 1 hour; operation may then continue until performance of the next required CHANNEL FUNCTIONAL TEST.

ACITON 37 - With the number of OPERABLE channels less than required by the Minimum OPERABLE channels per Trip Function requirement, open the minimum flow bypass valve within one hour. Restore the inoperable channel to OPERABLE status within 7 days or declare the associated ECCS inoperable.

TABLE 4.3.3.1-1

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. CORE SPRAY SYSTEM				
a. Reactor Vessel Water Level - Low Low Low, Level 1	S	~~M~~ Q	R	1, 2, 3, 4*, 5*
b. Drywell Pressure - High	S	~~M~~ Q	R	1, 2, 3
c. Reactor Vessel Pressure - Low	S	~~M~~ Q	R	1, 2, 3, 4*, 5*
d. Core Spray Pump Discharge Flow - Low (Bypass)	S	~~M~~ Q	R	1, 2, 3, 4*, 5*
e. Core Spray Pump Start Time Delay - Normal Power	NA	~~M~~ Q	R	1, 2, 3, 4*, 5*
f. Core Spray Pump Start Time Delay - Emergency Power	NA	~~M~~ Q	R	1, 2, 3, 4*, 5*
g. Manual Initiation	NA	R	NA	1, 2, 3, 4*, 5*
2. LOW PRESSURE COOLANT INJECTION MODE OF RHR SYSTEM				
a. Reactor Vessel Water Level - Low Low Low, Level 1	S	~~M~~ Q	R	1, 2, 3, 4*, 5*
b. Drywell Pressure - High	S	~~M~~ Q	R	1, 2, 3
c. Reactor Vessel Pressure - Low (Permissive)	S	~~M~~ Q	R	1, 2, 3, 4*, 5*
d. LPCI Pump Discharge FLow - Low (Bypass)	S	~~M~~ Q	R	1, 2, 3, 4*, 5*
e. LPCI Pump Start Time Delay - Normal Power	NA	~~M~~ Q	R	1, 2, 3, 4*, 5*
f. Manual Initiation	NA	R	NA	1, 2, 3, 4*, 5*
3. HIGH PRESSURE COOLANT INJECTION SYSTEM#				
a. Reactor Vessel Water Level - Low Low, Level 2	S	~~M~~ Q	R	1, 2, 3
b. Drywell Pressure - High	S	~~M~~ Q	R	1, 2, 3
c. Condensate Storage Tank Level - Low	S	~~M~~ Q	R	1, 2, 3
d. Suppression Pool Water Level - High	S	~~M~~ Q	R	1, 2, 3
e. Reactor Vessel Water Level - High, Level 8	S	~~M~~ Q	R	1, 2, 3
f. HPCI Pump Discharge FLow - Low (Bypass)	S	~~M~~ Q	R	1, 2, 3
g. Manual Initiation	NA	R	NA	1, 2, 3

TABLE 4.3.3.1-1 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
4. AUTOMATIC DEPRESSURIZATION SYSTEM##				
a. Reactor Vessel Water Level - Low Low Low, Level 1	S	~~M~~ Q	R	1, 2, 3
b. Drywell Pressure - High	S	~~M~~ Q	R	1, 2, 3
c. ADS Timer	NA	~~M~~ Q	Q	1, 2, 3
d. Core Spray Pump Discharge Pressure - High	S	~~M~~ Q	R	1, 2, 3
e. RHR LPCI Mode Pump Discharge Pressure - High	S	~~M~~ Q	R	1, 2, 3
f. Reactor Vessel Water Level - Low, Level 3	S	~~M~~ Q	R	1, 2, 3
g. ADS Drywell Pressure Bypass Timer	NA	~~M~~ Q	Q	1, 2, 3
h. ADS Manual Inhibit Switch	NA	R	NA	1, 2, 3
i. Manual Initiation	NA	R	NA	1, 2, 3
5. LOSS OF POWER				
a. 4.16 kv Emergency Bus Undervoltage (Loss of Voltage)	NA	NA	R	1, 2, 3, 4**, 5**
b. 4.16 kv Emergency Bus Undervoltage (Degraded Voltage)	S	M	R	1, 2, 3, 4**, 5**

* When the system is required to be OPERABLE per Specification 3.5.2.
** Required OPERABLE when ESF equipment is required to be OPERABLE.
# Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 200 psig.
Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 100 psig.

TABLE 3.3.5-1

REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP FUNCTION[(a)]	ACTION
a. Reactor Vessel Water Level - Low Low, Level 2	4[(b)]	50
b. Reactor Vessel Water Level - High, Level 8	4[(b)]	50
c. Condensate Storage Tank Water Level - Low[(e)]	2[(c)]	51
d. Manual Initiation	1[(d)]	52

(a) A channel may be placed in an inoperable status for up to ~~2~~ 6 hours for required surveillance without placing the trip system in the tripped condition provided all other channels monitoring that parameter are OPERABLE.
(b) One trip system with one-out-of-two twice logic.
(c) One trip system with one-out-of-two logic.
(d) One trip system with one channel.
(e) Initiates RCIC suction switchover from the condensate storage tank to the torus.

TABLE 3.3.5-1 (Continued)

REACTOR CORE ISOLATION COOLING SYSTEM

ACTUATION INSTRUMENTATION

ACTION 50 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement:

a. With one channel inoperable, place the inoperable channel in the tripped condition within ~~1 hour~~ 24 hours or declare the RCIC system inoperable.

b. With more than one channel inoperable, declare the RCIC system inoperable.

ACTION 51 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, place at least one inoperable channel in the tripped condition within ~~one hour~~ 24 hours or declare the RCIC system inoperable.

ACTION 52 - With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels per Trip Function requirement, restore the inoperable channel to OPERABLE status within ~~8 hours~~ 24 hours or declare the RCIC system inoperable.

TABLE 4.3.5.1-1

REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNITS	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION
a. Reactor Vessel Water Level - Low Low, Level 2	S	~~M~~ Q	R
b. Reactor Vessel Water Level - High, Level 8	S	~~M~~ Q	R
c. Condensate Storage Tank Level - Low	NA	~~M~~ Q	R
d. Manual Initiation	NA	Q ~~M~~(a)	NA

(a) Manual initiation switches shall be tested at least once per 18 months during shutdown. All other circuitry associated with manual initiation shall receive a CHANNEL FUNCTIONAL TEST at least once per ~~31~~ 92 days as part of circuitry required to be tested for automatic system actuation.

3/4.3.2 ISOLATION ACTUATION INSTRUMENTATION

This specification ensures the effectiveness of the instrumentation used to mitigate the consequences of accidents by prescribing the OPERABILITY trip setpoints and response times for isolation of the reactor systems. When necessary, one channel may be inoperable for brief intervals to conduct required surveillance. Some of the trip settings may have tolerances explicitly stated where both the high and low values are critical and may have a substantial effect on safety. The setpoints of other instrumentation, where only the high or low end of the setting have a direct bearing on safety, are established at a level away from the normal operating range to prevent inadvertent actuation of the systems involved.

Except for the MSIVs, the safety analysis does not address individual sensor response times or the response times of the logic systems to which the sensors are connected. For D.C. operated valves, a 3 second delay is assumed before the valve starts to move. For A.C. operated valves, it is assumed that the A.C. power supply is lost and is restored by startup of the emergency diesel generators. In this event, a time of 13 seconds is assumed before the valve starts to move. In addition to the pipe break, the failure of the D.C. operated valve is assumed; thus the signal delay (sensor response) is concurrent with the 10 second diesel startup. The safety analysis considers an allowable inventory loss in each case which in turn determines the valve speed in conjunction with the 13 second delay. It follows that checking the valve speeds and the 13 second time for emergency power establishment will establish the response time for the isolation functions.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

The emergency core cooling system actuation instrumentation is provided to initiate actions to mitigate the consequences of accidents that are beyond the ability of the operator to control. This specification provides the OPERABILITY requirements, trip setpoints and response times that will ensure effectiveness of the systems to provide the design protection. INSERT I Although the instruments are listed by system, in some cases the same instrument may be used to send the actuation signal to more than one system at the same time.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.5 REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION

The reactor core isolation cooling system actuation instrumentation is provided to initiate actions to assure adequate core cooling in the event of reactor isolation from its primary heat sink and the loss of feedwater flow to the reactor vessel. INSERT 2

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.6 CONTROL ROD BLOCK INSTRUMENTATION

The control rod block functions are provided consistent with the requirements of the specifications in Section 3/4.1.4, Control Rod Program Controls and Section 3/4.2 Power Distribution Limits and Section 3/4.3 Instrumentation. The trip logic is arranged so that a trip in any one of the inputs will result in a control rod block.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.7 MONITORING INSTRUMENTATION

3/4.3.7.1 RADIATION MONITORING INSTRUMENTATION

The OPERABILITY of the radiation monitoring instrumentation ensures that; (1) the radiation levels are continually measured in the areas served by the individual channels, and (2) the alarm or automatic action is initiated when the radiation level trip setpoint is exceeded; and (3) sufficient information is available on selected plant parameters to monitor and assess these variables following an accident. This capability is consistent with 10 CFR Part 50, Appendix A, General Design Criteria 19, 41, 60, 61, 63 and 64.

3.4.3.7.2 SEISMIC MONITORING INSTRUMENTATION

The OPERABILITY of the seismic monitoring instrumentation ensures that sufficient capability is available to promptly determine the magnitude of a seismic event and evaluate the response of those features important to safety. This capability is required to permit comparison of the measured response to that used in the design basis for the unit. This instrumentation is consistent with the recommendations of Regulatory Guide 1.12 "Instrumentation for Earthquakes," April 1974

3/4.3.7.3 METEOROLOGICAL MONITORING INSTRUMENTATION

The OPERABILITY of the meteorological monitoring instrumentation ensures that sufficient meteorological data is available for estimating potential radiation doses to the public as a result of routine or accidental release of

Insert 1

Specified surveillance intervals and surveillance and maintenance outage times have been determined in accordance with NEDC-30936P-A, "BWR Owners' Group Technical Specification Improvement Methodology (With Demonstration for BWR ECCS Actuation Instrumentation)", Parts 1 and 2. The safety evaluation reports documenting NRC approval of NEDC-30936P-A are contained in letters to D. N. Grace from A. C. Thadani (Part 1) and C. E. Rossi (Part 2) dated December 9, 1988.

Insert 2

Specified surveillance intervals and surveillance and maintenance outage times have been determined in accordance with NEDC-30936P-A, "BWR Owners' Group Technical Specification Improvement Methodology (With Demonstration for BWR ECCS Actuation Instrumentation)", Parts 1 and 2 and GENE-770-06-2-A, "Addendum to Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications". The safety evaluation reports documenting NRC approval of NEDC-30936P-A and GENE-770-06-2-A are contained in letters to D. N. Grace from A. C. Thadani dated December 9, 1988 (Part 1), D. N. Grace to C. E. Rossi dated December 9, 1988 (Part 2), and G. J. Beck from C. E. Rossi dated September 13, 1991.

ATTACHMENT 3

PLANT SPECIFIC REPORT FOR HOPE CREEK GENERATING STATION

LICENSE AMENDMENT APPLICATION 93-02, NLR-N93014
STI/AOT EXTENSIONS FOR ECCS AND RCIC ACTUATION INSTRUMENTATION
FACILITY OPERATING LICENSE NPF-57
HOPE CREEK GENERATING STATION
DOCKET NO. 50-354

General Electric Company

AFFIDAVIT

I, Robert C. Mitchell, being duly sworn, depose and state as follows:

(1) I am Manager, Safety and Communications, General Electric Company ("GE") and have been delegated the function of reviewing the information described in paragraph 2 which is sought to be withheld, and have been authorized to apply for its withholding.

(2) The information sought to be withheld is contained in the document: *Technical Specification Improvement Analysis for the Emergency Core Cooling System Actuation Instrumentation for Hope Creek Generating Station*, RE-018, Rev. 1, October 1990. This information is delineated by brackets around the specific material.

(3) In making this application for withholding of proprietary information of which it is the owner, GE relies upon the exemption from disclosure set forth in the Freedom of Information Act ("FOIA"), 5 USC Sec. 552(b)(4), and the Trade Secrets Act, 18 USC Sec. 1905, and NRC regulations 10 CFR 9.17(a)(4), 2.790(a)(4), and 2.790(d)(1) for "trade secrets and commercial or financial information obtained from a person and privileged or confidential" (Exemption 4). The material for which exemption from disclosure is here sought is all "confidential commercial information", and some portions also qualify under the narrower definition of "trade secret", within the meanings assigned to those terms for purposes of FOIA Exemption 4 in, respectively, Critical Mass Energy Project v. Nuclear Regulatory Commission, 975F2d871 (DC Cir. 1992), and Public Citizen Health Research Group v. FDA, 704F2d1280 (DC Cir. 1983).

(4) Some examples of categories of information which fit into the definition of proprietary information are:

a. Information that discloses a process, method, or apparatus, including supporting data and analyses, where prevention of its use by General Electric's competitors without license from General Electric constitutes a competitive economic advantage over other companies;

b. Information which, if used by a competitor, would reduce his expenditure of resources or improve his competitive position in the design, manufacture, shipment, installation, assurance of quality, or licensing of a similar product;

c. Information which reveals cost or price information, production capacities, budget levels, or commercial strategies of General Electric, its customers, or its suppliers;

d. Information which reveals aspects of past, present, or future General Electric customer-funded development plans and programs, of potential commercial value to General Electric;

e. Information which discloses patentable subject matter for which it may be desirable to obtain patent protection.

(5) The information sought to be withheld is being submitted to NRC in confidence. The information is of a sort customarily held in confidence by GE, and is in fact so held. Its initial designation as proprietary information, and the subsequent steps taken to prevent its unauthorized disclosure, are as set forth in (6) and (7) following. The information sought to be withheld has, to the best of my knowledge and belief, consistently been held in confidence by GE, no public disclosure has been made, and it is not available in public sources. All disclosures to third parties including any required transmittals to NRC, have been made, or must be made, pursuant to regulatory provisions or proprietary agreements which provide for maintenance of the information in confidence.

(6) Initial approval of proprietary treatment of a document is made by the manager of the originating component, the person most likely to be acquainted with the value and sensitivity of the information in relation to industry knowledge. Access to such documents within GE is limited on a "need to know" basis.

(7) The procedure for approval of external release of such a document typically requires review by the staff manager, project manager, principal scientist or other equivalent authority, by the manager of the cognizant marketing function (or his delegate), and by the Legal Operation, for technical content, competitive effect, and determination of the accuracy of the proprietary designation. Disclosures outside GE are limited to regulatory bodies, customers, and potential customers, and their agents, suppliers, and licensees, and others with a legitimate need for the information, and then only in accordance with appropriate regulatory provisions or proprietary agreements.

(8) The information identified in paragraph (2) is classified as proprietary because it would provide other parties, including competitors, with valuable information regarding the application of reliability based methodology to BWR instrumentation. A substantial effort has been expended by General Electric to develop this information in support of the BWR Owners' Group Technical Specifications Improvement Program. This information is considered to be proprietary for the reasons set forth in both paragraphs 4.b and 4.d, above.

(9) Public disclosure of the information sought to be withheld is likely to cause substantial harm to GE's competitive position and foreclose or reduce the availability of profit-making opportunities. The information is part of GE's comprehensive BWR technology base, and its commercial value extends beyond the original development cost. The value of the technology base goes beyond the extensive physical database and analytical methodology and includes development of the expertise to determine and apply the appropriate evaluation process. In addition, the technology base includes the value derived from providing analyses done with

NRC-approved methods.

The research, development, engineering, analytical, and NRC review costs comprise a substantial investment of time and money by GE.

The precise value of the expertise to devise an evaluation process and apply the correct analytical methodology is difficult to quantify, but it clearly is substantial.

The value of this information to GE would be lost if the information were disclosed to the public. Making such information available to competitors without their having been required to undertake a similar expenditure of resources would unfairly provide competitors with a windfall, and deprive GE of the opportunity to exercise its competitive advantage to seek an adequate return on its large investment in developing these very valuable analytical tools.

STATE OF CALIFORNIA)
COUNTY OF SANTA CLARA) ss:

Robert C. Mitchell, being duly sworn, deposes and says:

That he has read the foregoing affidavit and the matters stated therein are true and correct to the best of his knowledge, information, and belief.

Executed at San Jose, California, this 3RD day of MARCH 1993.

Robert C. Mitchell

Robert C. Mitchell
General Electric Company

Subscribed and sworn before me this 3Rd day of March 1993.

OFFICIAL SEAL
PAULA F. HUSSEY
NOTARY PUBLIC - CALIFORNIA
SANTA CLARA COUNTY
My comm. expires APR 5, 1994

Paula F. Hussey

Notary Public, State of California