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October 15, 2003

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

Subject: Duke Energy Corporation
Catawba Nuclear Station, Unit 1
Docket Number 50-413
Proposed Technical Specifications (TS) Amendment
TS 3.3.2, Engineered Safety Feature Actuation System (ESFAS) Instrumentation
TS 3.6.6, Containment Spray System

Reference: Letter from Duke Energy Corporation to NRC, dated October 9, 2003

Pursuant to 10 CFR 50.90, Duke Energy Corporation is requesting an exigent amendment to the Catawba Nuclear Station Unit 1 Facility Operating License and TS. This amendment applies to the subject TS sections indicated above. Specifically, the proposed amendment modifies the TS to allow, for a limited period of time, operation of Unit 1 with only one operable train of the Containment Spray System. It also extends the surveillance test interval associated with TS Surveillance Requirement (SR) 3.3.2.7 for a limited period of time. This proposed amendment will support the operation of Unit 1 until the End of Cycle 14 Refueling Outage. The Train 1B Containment Spray System heat exchanger is presently inoperable as a result of tube support baffle plate degradation. This degradation has led to the inability to maintain seismic qualification following certain seismic events. Apart from the seismic qualification issue, the inoperable heat exchanger is fully functional and able to perform its accident mitigation function. Catawba will replace this heat exchanger during the above cited outage. The extension of the surveillance test interval associated with SR 3.3.2.7 is necessary because performance of this SR would cause Train 1A of the Containment Spray System to be rendered inoperable, thereby

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placing Unit 1 in TS Limiting Condition for Operation (LCO) 3.0.3.

The proposed amendment adds temporary footnotes to the above TS in order to support operation of Unit 1 until the outage. The attached justification supports this proposed amendment.

Catawba is requesting that this proposed TS amendment be reviewed and approved by the NRC on an exigent basis. Currently, Unit 1 is operating under a Notice of Enforcement Discretion that was verbally granted by the NRC on October 8, 2003 at 2125 hours and expires on October 22, 2003 at 2125 hours.

This proposed amendment is categorized as a risk-informed TS amendment according to the guidance contained in Regulatory Guide 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications." In requesting this TS amendment on an exigent basis, Catawba informs the NRC that the exigent situation was not created by failure to take timely action. The degradation of the tube support baffle plates in the Containment Spray System Train 1B heat exchanger was discovered on October 6, 2003. The degradation was discovered during the process of installing inspection ports on the shell side of the heat exchanger.

The contents of this amendment request package are as follows:

Attachment 1 provides a marked copy of the affected TS pages for Catawba, showing the proposed changes. Attachment 2 contains the reprinted pages of the affected TS. Attachment 3 provides a description of the proposed changes and technical justification. Pursuant to 10 CFR 50.92, Attachment 4 documents the determination that the amendment contains No Significant Hazards Considerations. Pursuant to 10 CFR 51.22(c)(9), Attachment 5 provides the basis for the categorical exclusion from performing an Environmental Assessment/Impact Statement.

Implementation of this amendment to the Catawba Facility Operating License and TS will not impact the Catawba Updated Final Safety Analysis Report (UFSAR). Planned compensatory actions are described in Attachment 3. These actions will be implemented as soon as practical, and prior to the implementation of the amendment following NRC approval.

Duke Energy Corporation is requesting NRC review and approval of this proposed amendment prior to October 22, 2003 at 2125 hours as a result of the exigent situation surrounding the heat exchanger. Approval of this proposed amendment will prevent having to shut down the affected unit prior to the end of Cycle 14. As indicated in Regulatory Position C.1.1.3 of Regulatory Guide 1.177, this will reduce an unnecessary burden on Unit 1.

In accordance with administrative procedures and the Quality Assurance Program Topical Report, this proposed amendment has been previously reviewed and approved by the Catawba Plant Operations Review Committee and the Duke Energy Corporation Nuclear Safety Review Board.

Pursuant to 10 CFR 50.91, a copy of this proposed amendment is being sent to the appropriate State of South Carolina official.

Inquiries on this matter should be directed to L.J. Rudy at (803) 831-3084.

Very truly yours,

Dhiaa M. Jamil

LJR/s

Attachments

Dhiaa M. Jamil, affirms that he is the person who subscribed his name to the foregoing statement, and that all the matters and facts set forth herein are true and correct to the best of his knowledge.

Dhiaa M. Jamil, Site Vice President

Subscribed and sworn to me: 10-15-2003
Date

Nicky Standridge
Notary Public

My commission expires: 7-10-2012
Date

SEAL

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ATTACHMENT 1

MARKED-UP TECHNICAL SPECIFICATIONS PAGES FOR CATAWBA

SURVEILLANCE REQUIREMENTS

-----NOTE-----
Refer to Table 3.3.2-1 to determine which SRs apply for each ESFAS Function.

SURVEILLANCE		FREQUENCY
SR 3.3.2.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.2.2	Perform ACTUATION LOGIC TEST.	31 days on a STAGGERED TEST BASIS
SR 3.3.2.3	-----NOTE----- Final actuation of pumps or valves not required. ---------- Perform TADOT.	31 days
SR 3.3.2.4	Perform MASTER RELAY TEST.	31 days on a STAGGERED TEST BASIS
SR 3.3.2.5	Perform COT.	92 days
SR 3.3.2.6	Perform SLAVE RELAY TEST.	92 days
SR 3.3.2.7	Perform COT.	31 days*

(continued)

* INSERT

3.6 CONTAINMENT SYSTEMS

3.6.6 Containment Spray System

LCO 3.6.6 Two containment spray trains shall be OPERABLE*.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One containment spray train inoperable.	A.1 Restore containment spray train to OPERABLE status.	72 hours*
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 84 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.6.6.1 Verify each containment spray manual, power operated, and automatic valve in the flow path that is not locked, sealed, or otherwise secured in position is in the correct position.	31 days

(continued)

INSERT

~~*For each Unit, the Completion Time that Containment Spray System train 'A' can be inoperable, as specified by Required Action A.1 may be extended beyond the 72 hours up to 168 hours as part of the NSWS system upgrades. System upgrades include maintenance and modification activities associated with replacement of portions of the train 'A' NSWS piping via modification CE-71424. Upon completion of the pipe replacement and system restoration this footnote is no longer applicable.~~

INSERTS for TS 3.3.2 and TS 3.6.6

INSERT for TS 3.3.2, SR 3.3.2.7 Frequency:

For Unit 1 only, the Frequency of this SR may be extended from 31 days until 2400 hours on November 9, 2003. This allowance is only applicable to Table 3.3.2-1, Functions 9.a and 9.b, for Train A of the CPCS, insofar as it pertains to Containment Spray System equipment.

INSERT for TS 3.6.6, Required Action A.1 Completion Time:

For Unit 1 only, the stated Completion Time may be increased from 72 hours until 2400 hours on November 9, 2003. This allowance is only applicable to the Train 1B Containment Spray System heat exchanger tube support plate degradation, and is only applicable provided Train 1B of the Containment Spray System is otherwise OPERABLE.

ATTACHMENT 2

REPRINTED TECHNICAL SPECIFICATIONS PAGES FOR CATAWBA

SURVEILLANCE REQUIREMENTS

---NOTE---
Refer to Table 3.3.2-1 to determine which SRs apply for each ESFAS Function.

SURVEILLANCE		FREQUENCY
SR 3.3.2.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.2.2	Perform ACTUATION LOGIC TEST.	31 days on a STAGGERED TEST BASIS
SR 3.3.2.3	--------------------------------NOTE-------------------------------- Final actuation of pumps or valves not required. -- Perform TADOT.	31 days
SR 3.3.2.4	Perform MASTER RELAY TEST.	31 days on a STAGGERED TEST BASIS
SR 3.3.2.5	Perform COT.	92 days
SR 3.3.2.6	Perform SLAVE RELAY TEST.	92 days
SR 3.3.2.7	Perform COT.	31 days*

(continued)

*For Unit 1 only, the Frequency of this SR may be extended from 31 days until 2400 hours on November 9, 2003. This allowance is only applicable to Table 3.3.2-1, Functions 9.a and 9.b, for Train A of the CPCS, insofar as it pertains to Containment Spray System equipment.

3.6 CONTAINMENT SYSTEMS

3.6.6 Containment Spray System

LCO 3.6.6 Two containment spray trains shall be OPERABLE*.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One containment spray train inoperable.	A.1 Restore containment spray train to OPERABLE status.	72 hours*
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 84 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.6.1	Verify each containment spray manual, power operated, and automatic valve in the flow path that is not locked, sealed, or otherwise secured in position is in the correct position.	31 days

(continued)

* For Unit 1 only, the stated Completion Time may be increased from 72 hours until 2400 hours on November 9, 2003. This allowance is only applicable to the Train 1B Containment Spray System heat exchanger tube support plate degradation, and is only applicable provided Train 1B of the Containment Spray System is otherwise OPERABLE.

ATTACHMENT 3

BACKGROUND INFORMATION, DESCRIPTION OF PROPOSED CHANGES, AND TECHNICAL JUSTIFICATION

BACKGROUND INFORMATION

The Containment Spray System provides containment atmosphere cooling to limit post accident pressure and temperature in containment to less than the design values. Reduction of containment pressure, combined with the iodine removal capability of the spray, reduce the release of fission product radioactivity from containment to the environment, in the event of a Design Basis Accident (DBA). The Containment Spray System is designed to meet the requirements of 10 CFR 50, Appendix A, GDCs 2, 38, 39, 40, 41, 42, and 43.

The Containment Spray System consists of two separate trains of equal capacity, each capable of meeting the system design basis spray coverage. Each train includes a containment spray pump, one containment spray heat exchanger, spray headers, nozzles, valves, and piping. Each train is powered from a separate Engineered Safety Feature (ESF) bus. The Refueling Water Storage Tank (RWST) supplies borated water to the Containment Spray System during the injection phase of operation. In the recirculation mode of operation, containment spray pump suction is transferred from the RWST to the containment recirculation sump.

The diversion of a portion of the recirculation flow from each train of the Residual Heat Removal (RHR) System to additional redundant spray headers completes the Containment Spray System heat removal capability. Each RHR train is capable of supplying spray coverage, if required, to supplement the Containment Spray System.

The Containment Spray System and RHR System provide a spray of borated water into the upper containment volume to limit the containment pressure and temperature during a DBA. In the recirculation mode of operation, heat is removed from the containment sump water by the Containment Spray System and RHR heat exchangers. Each train of the Containment Spray System, supplemented by a train of RHR spray, provides adequate spray coverage to meet the system design requirements for containment heat removal.

The Containment Spray System is actuated either automatically by a containment pressure high-high signal or manually. An automatic actuation opens the containment spray pump discharge valves, starts the two containment spray pumps, and begins the spray phase. A manual actuation of the Containment Spray System requires the operator to actuate two separate train related switches on the main control board to begin the same sequence of two train

actuation. The spray phase continues until an RWST level low-low alarm is received. The low-low alarm for the RWST signals the operator to manually align the system to the recirculation mode. The Containment Spray System in the recirculation mode maintains an equilibrium temperature between the containment atmosphere and the recirculated sump water. Operation of the Containment Spray System in the recirculation mode is controlled by the operator in accordance with the emergency operating procedures.

The RHR spray operation is initiated manually, when required by the emergency operating procedures, after the Emergency Core Cooling System (ECCS) is operating in the recirculation mode. The RHR sprays are available to supplement the Containment Spray System, if required, in limiting containment pressure. This additional spray capacity would typically be used after the ice bed has been depleted and in the event that containment pressure rises above a predetermined limit. The Containment Spray System is an ESF system. It is designed to ensure that the heat removal capability required during the post accident period can be attained.

The Containment Spray System limits the temperature and pressure that could be expected following a DBA. Protection of containment integrity limits leakage of fission product radioactivity from containment to the environment.

The Containment Pressure Control System (CPCS) protects the containment from excessive depressurization by preventing inadvertent actuation or continuous operation of the Containment Spray and Containment Air Return Systems when containment pressure is at or less than the CPCS permissive setpoint. The control scheme of CPCS is comprised of eight independent control circuits (four per train), each having a separate and independent pressure transmitter and current alarm module. Each pressure transmitter monitors the containment pressure and provides input to its respective current alarm. The current alarms are set to inhibit or terminate Containment Spray and Containment Air Return Systems when containment pressure falls to or below 0.25 psig. The alarm modules switch back to the permissive state (allowing the systems to operate) when containment pressure is greater than or equal to 0.45 psig.

On October 6, 2003, during the process of installing inspection ports on the shell side of the Train 1B Containment Spray System heat exchanger, degradation was observed for the tube support baffle plates. The purpose of the baffle plates is to create turbulent flow of the shell

side fluid (nuclear service water). The baffle plates create a tortuous path through the shell side, increasing the velocity of the fluid. An increase in the velocity of the fluid results in an increase in heat transfer of the heat exchanger. The most significant finding was the loss of tube baffle plate ligament material on the outer and inner bundle periphery tube rows, which adversely affects the unsupported tube length. A video probe inspection within the bundle outer periphery rows at six baffle plate locations verified the presence of baffle plate ligament support at three to five rows deep on the shell outlet and at two rows deep on the shell inlet. The seismic capability of the heat exchanger was evaluated with the observed baffle plate degradation. The evaluation has indicated that the heat exchanger is incapable of maintaining its seismic qualification under all seismic conditions.

DESCRIPTION OF PROPOSED CHANGES

TS 3.6.6 governs the Containment Spray System. The LCO requires two trains of the system to be operable in Modes 1, 2, 3, and 4. With one train of the Containment Spray System inoperable, Condition A allows continued unit operation for 72 hours. If the inoperable train is not restored to operable status within 72 hours, Condition B requires the unit to be in Mode 3 within 6 hours and in Mode 5 within 84 hours.

This amendment request proposes to modify the Condition A Completion Time of 72 hours via the addition of the following footnote: "For Unit 1 only, the stated Completion Time may be increased from 72 hours until 2400 hours on November 9, 2003. This allowance is only applicable to the Train 1B Containment Spray System heat exchanger tube support plate degradation, and is only applicable provided Train 1B of the Containment Spray System is otherwise OPERABLE." The extended period of inoperability is only allowed for the degradation of the Train 1B Containment Spray System heat exchanger tube support baffle plates. For any other causes of inoperability of Train 1B of the Containment Spray System, the standard 72-hour Completion Time of Condition A will continue to apply. For any other causes of inoperability of Train 1B of the Containment Spray System, the 72-hour Completion Time clock will be started upon discovery of the inoperability, consistent with the standard TS practice for the application of Completion Times.

TS 3.3.2, Table 3.3.2-1, "Engineered Safety Feature Actuation System Instrumentation," Function 9, governs the CPCS. The CPCS is required to be operable in Modes 1, 2, 3, and 4. Condition P applies to the CPCS. Condition P states that with one or more CPCS channel(s) inoperable, the affected supported system must be immediately declared inoperable. SR 3.3.2.7 is one of the SRs applicable to the CPCS. SR 3.3.2.7 is a Channel Operational Test (COT), which is required to be performed every 31 days.

In order to perform SR 3.3.2.7, it is necessary to render the affected CPCS channel inoperable. Train 1A of the CPCS requires its COT to be performed no later than November 2, 2003 (including the 25% grace time allowed by SR 3.0.2). Performance of the COT would therefore result in both trains of the Containment Spray System being inoperable, as a result of the application of Condition P to the inoperable CPCS channel. This would therefore cause Unit 1 to be in LCO 3.0.3. It is being requested that the surveillance test interval associated with SR 3.3.2.7 be extended until such time that it is no longer applicable due to Unit 1 being in the End of Cycle 14 Refueling Outage. SR 3.3.2.7 is therefore proposed to be modified by the following footnote: "For Unit 1 only, the Frequency of this SR may be extended from 31 days until 2400 hours on November 9, 2003. This allowance is only applicable to Table 3.3.2-1, Functions 9.a and 9.b, for Train A of the CPCS, insofar as it pertains to Containment Spray System equipment." At that time, Unit 1 will no longer be in the Modes of applicability of SR 3.3.2.7. Note that no relief is necessary or is being requested insofar as SR 3.3.2.7 pertains to Containment Air Return System equipment.

TECHNICAL JUSTIFICATION

Evaluation of Risk Impact

Relevant Sequences

The impact of the degraded baffle plates in the Train 1B Containment Spray System heat exchanger is to reduce the seismic capacity of the heat exchanger. If subjected to seismic accelerations greater than 0.01 g, the heat exchanger tubes are assumed to fail. In the event of a seismic event coincident with the need for containment sump recirculation to mitigate an accident, the Containment Spray System is assumed, absent action to isolate the heat exchanger, to pump the containment sump inventory into the

Nuclear Service Water System, eventually depleting the supply of water available for core cooling.

Some of the more significant assumptions in the analysis are:

1. The only impact on the capability of the Containment Spray System to perform its function is the reduction of seismic capability. Therefore, a change in Core Damage Frequency (CDF) only occurs if a seismic event occurs in conjunction with the need to mitigate an event.
2. The seismic capacity of the heat exchanger is assumed to be 0.01 g.
3. The heat exchanger function in the absence of a seismic event is unimpaired.
4. Failure to isolate the affected heat exchanger following a seismic event sufficiently strong to fail it results in a continuous loss of containment sump fluid and an eventual loss of recirculation. This event sequence is assumed to lead directly to core damage.
5. Isolation of the heat exchanger requires that the two Nuclear Service Water System motor operated valves that are on either side of the heat exchanger both be closed.
6. Failure to maintain long term containment heat removal results in the eventual loss of containment integrity. Containment failure is conservatively assumed to occur, such that the containment sump inventory is lost, leading to failure of recirculation and core damage.
7. The assumption of 30 days for applicability of the TS change is conservative.
8. The detection limit for seismic events is assumed to be 0.01 g. Any seismic event that can be detected is assumed to fail the heat exchanger.
9. No operability concerns exist for the Train 1A Containment Spray System.
10. It has been assumed that two trains of Residual Heat Removal System auxiliary spray are available. This assures independence between the two means of containment cooling.

The CDF analysis considers the following questions as top events in an event tree structure (see Figure 1) for conducting the analysis.

1. An initiating event requires containment sump recirculation for accident mitigation.
2. A detectable seismic event occurs.
3. The heat exchanger survives the seismic event.

4. The heat exchanger is isolated by the operators.
5. Long term containment heat removal succeeds.

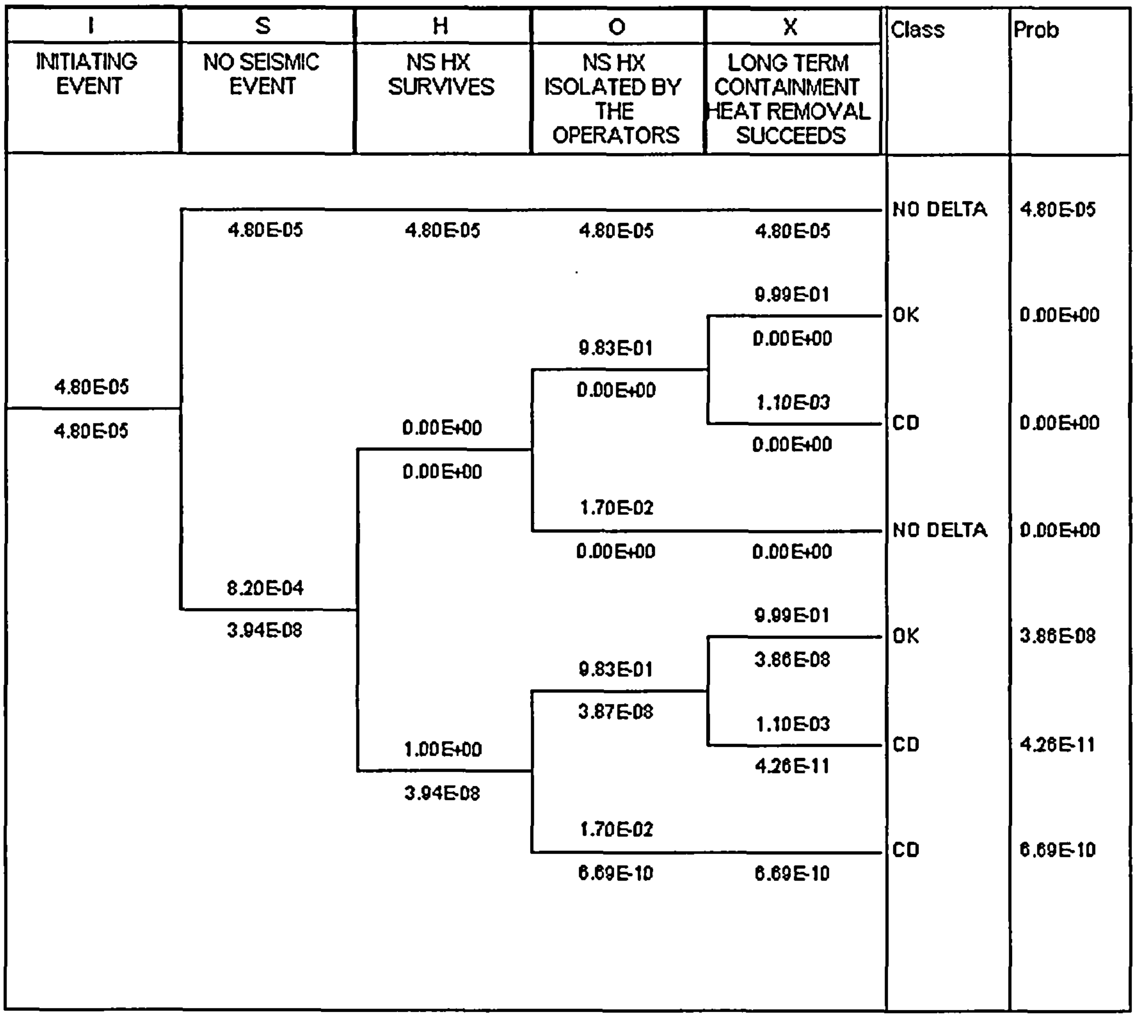

Figure 1

There are two general categories of sequences that are assumed to proceed to core damage. First, in conjunction with an initiating event, a seismic event occurs which is of sufficient magnitude to fail the heat exchanger tubes. Failure to isolate the faulted heat exchanger is assumed to result in core damage as a result of eventual depletion of the recirculation fluid. Second, in conjunction with an initiating event, a seismic event occurs. If the heat exchanger is successfully isolated or does not fail, and if there is a subsequent failure of long term heat removal, it is assumed that there is an eventual overpressure failure of the containment. The containment failure is then assumed to result in core damage as a result of eventual depletion of the recirculation fluid. This loss of fluid might occur as a result of leakage from containment if the failure is

underwater, or it might occur due to boiling in the core and loss of steam through the failure. No credit has been taken for preventing containment failure by actions such as venting containment or refilling the RWST as a means to attempt a perpetual injection.

Initiating Event

The Catawba Probabilistic Risk Assessment (PRA) model has been used to estimate the frequency of initiating events that would demand containment sump recirculation. The frequency is found to be approximately 5.3E-04/year. This frequency is dominated by loss of coolant accidents and transients that require feed and bleed following a loss of secondary side heat removal. This annual frequency converts to a probability of 4.8E-05.

Seismic Event Does Not Occur

This event addresses the occurrence of a seismic event during a 30-day period. From Figure 3.2-1 of the Catawba Individual Plant Examination (IPE) submittal (PRA Revision 1), the frequency of occurrence of an earthquake that exceeds 0.01 g is approximately 1.0E-02/yr. Therefore, the probability over a 30-day period is 8.2E-04.

Event S = 1 - 8.2E-04 = 0.99918

Containment Spray System Heat Exchanger Survives

Success of this event is the maintenance of functional integrity for the affected heat exchanger. This probability is conditional on the occurrence of a seismic event.

The seismic capacity of the heat exchanger is assumed to be 0.01 g. Seismic events of this magnitude have a frequency of exceedance of approximately 1.0E-02/yr.

This event is quantified from the ratio of the frequency of exceedance for the capacity of the heat exchanger to the frequency of occurrence of a seismic event. This is the conditional probability of failure of the heat exchanger. The probability for event H is the complement of this conditional failure probability.

Event H = 1 - 1.0E-02 / 1.0E-02 = 0.0

Should the capacity of the heat exchanger be determined to be above 0.01 g, this would provide a conditional probability of survival that is non-zero for this analysis.

Containment Spray System Heat Exchanger Isolated by the Operators

Success for this event is isolation of the Nuclear Service Water System flow to the heat exchanger so that leakage of recirculated fluid cannot enter the Nuclear Service Water System and be lost from the containment sump. Continued leakage would eventually deplete the containment sump inventory and would result in a loss of recirculation.

The Nuclear Service Water System supply to the heat exchanger is isolated by a motor operated valve on each side of the heat exchanger. It is assumed that both valves must close (failure of either results in failure to isolate). The probability that either of the two valves fails to close is estimated as twice the motor operated valve failure probability of 3.5E-03/demand.

Plant procedures are to be revised to require isolation of the heat exchanger following an indicated seismic event. This is a straightforward action that can be accomplished from the control room. In the Catawba PRA, the human error probability for "Operators Fail to Establish High Pressure Recirculation" is quantified at 4.5E-03. Both this action and the heat exchanger isolation action are proceduralized, can be accomplished from the control room, and are called for following an alarm or other indication. From this comparison, a human error probability of 0.01 is assumed for the operator actions required to isolate the heat exchanger. While the heat exchanger isolation action is likely to be simpler than aligning high pressure recirculation, the action is new. The assumed value is judged to be conservative.

Event O = 1 - (2 x 3.5E-03 + 0.01) = 0.983

Long Term Containment Heat Removal Succeeds

Success for this event is continued operation of the remaining train of the Containment Spray System or of auxiliary containment spray via the Residual Heat Removal System. Because both Residual Heat Removal System trains will remain available, and Train 1A of the Containment Spray System and Train 1B of the Residual Heat Removal System are independent of each other, the loss of both the Containment Spray System and the Residual Heat Removal System auxiliary spray can be considered to be two independent failures. A 30-day mission time is assumed for the time dependent

failures. The long term loss of the Containment Spray System is estimated as follows:

- Demand failures are ignored as they are small compared to time dependent failure over a 30-day period.
- When drawing from the containment sump, there are two series motor operated valves on the suction side and two parallel motor operated valves on the discharge side of a pump. It is assumed that a transfer of any one valve will result in system failure (this is likely conservative for the parallel valves).
- It is noted that the assumption of the full 30 days is a conservative assumption.

Failure of the Containment Spray System = [4 x 3.7E-07/hr (motor operated valve transfers) + 2.39E-05/hr (Containment Spray System pump fails to run)] x 24 hr/day x 30 days = 1.8E-02.

It has been demonstrated that one Residual Heat Removal System train supplying auxiliary spray is adequate to control containment pressure well below the level at which the probability of containment failure becomes non-trivial. The Residual Heat Removal System auxiliary spray function is similarly modeled with two check valves, two motor operated valves, and a pump.

Residual Heat Removal System Auxiliary Spray = [2 x 4.5E-07/hr (check valve transfers) + 2 x 3.7E-07/hr (motor operated valve transfers) + 8.35E-05/hr (Residual Heat Removal System pump fails to run)] x 24 hr/day x 30 days = 6.1E-02.

Event X = 1 - (1.8E-02 x 6.1E-02) = 1 - 1.1E-03 = 0.9989

Results

The event tree identifies each end point as either CD (core damage), OK (no core damage), or NO DELTA (sequences where the Containment Spray System heat exchanger function is unimpaired and the reduced seismic capacity of the heat exchanger has no impact on risk). These NO DELTA sequences result when there is no seismic event or the seismic event does not result in heat exchanger failure and the operators leave the heat exchanger in service.

The sum of the core damage end points is approximately 7.1E-10. This is the core damage probability over the 30-day period with the heat exchanger assumed to have the reduced

seismic capacity. This is therefore the Incremental Conditional Core Damage Probability (ICCDP) required by Regulatory Guide 1.177.

The risk of similar accidents (loss of containment sump recirculation due to loss of heat exchanger integrity in a seismic event) is not currently modeled in the Catawba seismic CDF analysis. The seismic core damage risk for Catawba has been evaluated to be approximately 8.5E-06/year, and is dominated by station blackout events. The base case CDF associated with accidents as analyzed here is assumed to be negligible given that the seismic capacity of the heat exchanger is high under normal conditions. The ΔCDF is assumed to be numerically equal to the ICCDP estimated above at 7.1E-10/RY.

Approximately 94% (6.7E-10) of the ICCDP involves sequences with core damage and an intact containment. These sequences all have AC power available and therefore are expected to have the hydrogen igniters available. Per NUREG/CR-6595, "An Approach for Estimating the Frequencies of Various Containment Failure Modes and Bypass Events," the conditional probability of early containment failure for sequences with the igniters available is no higher than 0.05 (high pressure case). Consequently, the contribution to Incremental Conditional Large Early Release Probability (ICLERP) from these sequences should be less than 3.4E-11. The remaining 6% (4.3E-11) involves core damage after containment failure. These are assumed to contribute directly to the ICLERP. The total ICLERP is estimated to be 7.7E-11. Likewise the change in Large Early Release Frequency (ΔLERF) is estimated to be 7.7E-11/RY. Both results are well below the Regulatory Guide 1.177 acceptance criteria.

Impact of Missed CPCS COT

The impact of missing the COT on Train 1A of the CPCS is judged to be less than would be expected by making Train 1A of the Containment Spray System inoperable to perform the surveillance. From a best estimate point of view, the decrease in reliability of the CPCS over a 7-day period is negligible.

In the unlikely event that the channel is failed, there is more than sufficient time to put the train of Containment Spray System in service (local actuation of components if needed) prior to a loss of containment integrity. Several hours would be required to melt the ice and pressurize containment to a pressure that would challenge containment

integrity. Auxiliary containment spray from the Residual Heat Removal System must also fail in order to create a challenge to containment integrity as a result of steam overpressurization.

Conclusion

The risk significance of the temporary TS change has been evaluated and compared to the acceptance criteria of Regulatory Guide 1.177. The risk results were found to be well below the acceptance criteria. Operation for as much as 30 days with the degraded seismic capacity of the Train 1B Containment Spray System heat exchanger does not represent a significant risk to the health and safety of the public.

Avoidance of Risk Significant Plant Configurations

Train 1A of the Containment Spray System and two trains of the Residual Heat Removal System auxiliary spray are important functions for mitigating the effects of the degraded heat exchanger. These functions should remain available for the duration of the proposed amendment.

Risk Informed Configuration Risk Management

10 CFR 50.65(a)(4), Regulatory Guide 1.182, "Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants," and NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," require that prior to performing maintenance activities, risk assessments shall be performed to assess and manage the increase in risk that may result from proposed maintenance activities. These requirements are applicable for all plant modes. NUMARC 91-06, "Guidelines for Industry Actions to Assess Shutdown Management," requires utilities to assess and manage the risks that occur during the performance of outages.

Duke Energy Corporation has several Work Process Manual procedures and Nuclear System Directives that are in place at Catawba to ensure the requirements of the Maintenance Rule are implemented. The key documents are as follows:

- Nuclear System Directive 415, "Operational Risk Management (Modes 1-3) per 10 CFR 50.65 (a.4)," Revision 1, April 2002.
- Nuclear System Directive 403, "Shutdown Risk Management (Modes 4, 5, 6, and No-Mode) per 10 CFR 50.65 (a.4)," Revision 11, December 2002.

- Work Process Manual, WPM-609, "Innage Risk Assessment Utilizing ORAM-SENTINEL," Revision 7, December 2002.
- Work Process Manual, WPM-608, "Outage Risk Assessment Utilizing ORAM-SENTINEL," Revision 6, July 2002.

The documents listed above are used to address the Maintenance Rule requirement and the on-line (and off-line) Maintenance Policy requirement to control the safety impact of combinations of equipment removed from service. They assure that the risk associated with the various plant configurations planned during at power or shutdown conditions is assessed prior to entry into these configurations and appropriately managed while the plant is in these various configurations. More specifically, the Nuclear System Directives address the process, define the program, and state individual group responsibilities to ensure compliance with the Maintenance Rule.

The Work Process Manual procedures provide a consistent process for utilizing the computerized software assessment tool, ORAM-SENTINEL, which manages the risk associated with equipment inoperability. ORAM-SENTINEL is a Windows based computer program designed by the Electric Power Research Institute as a tool for plant personnel to use to analyze and manage the risk associated with all risk significant work activities, including assessment of combinations of equipment removed from service. It is independent of the requirements of TS and Selected Licensee Commitments.

The ORAM-SENTINEL models for Catawba are based on a "blended" approach of probabilistic (the full at power PRA models are utilized) and traditional deterministic approaches. The results of the risk assessment include a prioritized listing of equipment to return to service, a prioritized listing of equipment to remain in service, and potential contingency considerations.

Additionally, prior to the release of work for execution, Operations personnel must consider the effects of severe weather and grid instabilities on plant operation. This qualitative evaluation is inherent of the duties of the Work Control Center Senior Reactor Operator. Responses to actual plant risk due to severe weather or grid instabilities are programmatically incorporated into applicable plant emergency or response procedures.

PRA Quality

Duke Energy Corporation periodically evaluates changes to the plant with respect to the assumptions and modeling in

the Catawba PRA. The original Catawba PRA was initiated in July 1984 by Duke Power Company assisted by several outside contractors who performed specialized subtasks. It was a full scope Level 3 PRA with internal and external events. A peer review sponsored by the Electric Power Research Institute was conducted after completion of the draft report. The study was published in an internal Duke Power Company report in 1987 as Revision 0 to the PRA.

On November 23, 1988, the NRC issued Generic Letter 88-20, "Individual Plant Examination for Severe Accident Vulnerabilities," which requested that licensees conduct an Individual Plant Examination (IPE) in order to identify potential severe accident vulnerabilities at their plants. The Catawba response to Generic Letter 88-20 was provided by letter dated September 10, 1992. Catawba's response included an updated Catawba PRA (Revision 1) study.

The Catawba PRA Revision 1 study and the IPE process resulted in a comprehensive, systematic examination of Catawba with regard to potential severe accidents. The Catawba study was again a full scope, Level 3 PRA with analysis of both the internal and external events. This examination identified the most likely severe accident sequences, both internally and externally induced, with quantitative perspectives on likelihood and fission product release potential. The results of the study prompted changes in equipment, plant configuration, and enhancements in plant procedures to reduce vulnerability of the plant to some accident sequences of concern.

By letter dated June 7, 1994, the NRC provided a Safety Evaluation of the internal events portion of the above Catawba IPE submittal. The conclusion of the NRC letter (page 16) states:

"The staff finds the licensee's IPE submittal for internal events including internal flooding essentially complete, with the level of detail consistent with the information requested in NUREG-1335. Based on the review of the submittal and the associated supporting information, the staff finds reasonable the licensee's IPE conclusion that no fundamental weakness or severe accident vulnerabilities exist at Catawba."

In response to Generic Letter 88-20, Supplement 4, Duke Power Company completed an Individual Plant Examination of External Events (IPEEE) for severe accidents. This IPEEE was submitted to the NRC by letter dated June 21, 1994. The report contained a summary of the methods, results, and

conclusions of the Catawba IPEEE program. The IPEEE process and supporting Catawba PRA included a comprehensive, systematic examination of severe accident potential resulting from external initiating events. By letter dated April 12, 1999, the NRC provided an evaluation of the IPEEE submittal. The conclusion of the NRC letter (page 6) states:

"The staff finds the licensee's IPEEE submittal is complete with regard to the information requested by Supplement 4 to GL 88-20 (and associated guidance in NUREG-1407), and the IPEEE results are reasonable given the Catawba design, operation, and history. Therefore, the staff concludes that the licensee's IPEEE process is capable of identifying the most likely severe accidents and severe accident vulnerabilities, and therefore, that the Catawba IPEEE has met the intent of Supplement 4 to GL 88-20."

In 1996, Catawba initiated Revision 2 of the 1992 IPE and provided the results to the NRC in 1998. Since the initial completion of Revision 2, there have been subsequent minor revisions. The current revision is designated Revision 2c and incorporates changes to the model to reflect both plant modifications (e.g., reactor coolant pump seal upgrades) as well as PRA model enhancements.

Currently, Revision 3 of the Catawba PRA is underway. This update is a comprehensive revision to the PRA models and associated documentation. The Level 1 portion of the update, CDF estimation, is expected to be completed in late 2003. The objectives of this update are as follows:

- To ensure the models comprising the PRA accurately reflect the current plant, including its physical configurations, operating procedures, maintenance practices, etc.

- To review recent operating experience with respect to updating the frequency of plant transients, failure rates, and maintenance unavailability data.

- To correct items identified as errors and implement PRA enhancements as needed.

- To address areas for improvement identified in the recent Catawba PRA Peer Review.

- To utilize updated Common Cause Analysis data and Human Reliability Analysis data.

PRA maintenance encompasses the identification and evaluation of new information into the PRA and typically involves minor modifications to the plant model. PRA maintenance and updates, as well as guidance for developing PRA data and evaluation of plant modifications, are governed by workplace procedures.

Approved workplace procedures address the quality assurance of the PRA. One way the quality assurance of the PRA is ensured is by maintaining a set of system notebooks on each of the PRA systems. Each system PRA analyst is responsible for updating a specific system model. This update consists of a comprehensive review of the system, including drawings and plant modifications made since the last update, as well as implementation of any PRA change notices that may exist on the system. The analyst's primary focal point is with the system engineer at the site. The system engineer provides information for the update as needed. The analyst will review the PRA model with the system engineer and as necessary, conduct a system walkdown with the system engineer.

The system notebooks contain, but are not limited to, documentation on system design, testing and maintenance practices, success criteria, assumptions, descriptions of the reliability data, as well as the results of the quantification. The system notebooks are reviewed and signed off by a second independent person and are approved by the manager of the group.

When any change to the PRA is identified, the same three signature process of identification, review, and approval is utilized to ensure that the change is valid and that it receives the proper priority.

In January 2001, an enhanced manual configuration control process was implemented to more effectively track, evaluate, and implement PRA changes to better ensure the PRA reflects the as built, as operated plant. This process was further enhanced in July 2002 with the implementation of an electronic PRA change tracking tool.

Peer Review Process

Between March 18-22, 2002, Catawba participated in the Westinghouse Owners Group (WOG) PRA Certification Program. This review followed a process that was originally developed and used by the Boiling Water Reactor Owners Group (BWROG) and subsequently broadened to be an industry applicable

process through the Nuclear Energy Institute (NEI) Risk Applications Task Force. The resulting industry document, NEI-00-02, "Probabilistic Risk Assessment (PRA) Peer Review Process Guideline," describes the overall PRA peer review process. The Certification/Peer Review process is also linked to the ASME PRA Standard, ASME RA-S-2002, "Standard for Probabilistic Risk Assessment for Nuclear Power Plant Applications."

NEI has developed draft guidance for self assessments to address the use of industry peer review results in demonstrating conformance with the ASME PRA standard. This guidance supplements, and is expected to ultimately become part of, NEI-00-02. The guidance is intended to support development of NRC draft Regulatory Guide DG-1122, "Determining Technical Adequacy of PRA Results for Risk-Informed Activities," which will endorse the ASME standard and discuss the industry peer review process as a means of addressing the requirements of the standard.

The objective of the PRA Peer Review Process is to provide a method for establishing the technical quality and adequacy of a PRA for a range of potential risk informed plant applications for which the PRA may be used. The PRA Peer Review Process employs a team of PRA and system analysts, who possess significant expertise in PRA development and PRA applications. The team uses checklists to evaluate the scope, comprehensiveness, completeness, and fidelity of the PRA being reviewed. One of the key parts of the review is an assessment of the maintenance and update process to ensure the PRA reflects the as built plant.

The review team for the Catawba PRA Peer Review consisted of six members. Three of the members were PRA personnel from other utilities. The remaining three were industry consultants. Reviewer independence was maintained by assuring that none of the six individuals had any involvement in the development of the Catawba PRA or IPE.

A summary of some of the Catawba PRA strengths and recommended areas for improvement from the peer review are as follows:

Strengths

- Aggressive response to past PRA peer reviews
- Knowledgeable personnel
- Culture of continuous improvement
- Documentation of final results and analyses

- Good capture of plant experience into the model
- Rigorous Level 2 and 3 PRA

Recommended Areas for Improvement

- Limited comparison to other plant/utilities' PRAs for results and techniques
- Better documentation of bases for success criteria and Human Reliability Analysis timing
- More focus on realism vs. conservatism in models
- More attention to eliminating old documentation and modeling assumptions/simplifications
- Consider more efficient methods to streamline recovery/post processing process

Based on the PRA peer review report, the Catawba PRA received no Fact and Observations (F&O) with the significance level of "A" and 32 F&O with the significance level of "B". The "B" findings have been reviewed and prioritized for incorporation into the PRA. Some of the "B" findings have already been resolved during the normal PRA update process for Revision 3 of the PRA which is in progress. Since the PRA peer review was conducted after the initiation of the PRA Revision 3 update, some of the peer review items will not be resolved in PRA Revision 3. It is expected that all of the items will be resolved and incorporated no later than Revision 4 of the PRA.

All of the peer review F&O were reviewed with respect to the impact on the PRA and all were determined to be insignificant with respect to the current application.

PRA Model

The Catawba PRA is a full scope PRA including both internal and external events. In this analysis the Catawba PRA has been used to evaluate the frequency of accidents important to the evaluation. The model includes the necessary initiating events (e.g., loss of coolant accidents, transients) necessary to accomplish this objective. The previous reviews of the Catawba PRA, NRC and peer reviews, have not identified deficiencies related to the scope of initiating events considered.

The Catawba PRA includes models for those systems needed to estimate core damage frequency. These include all of the major support systems (e.g., AC power, service water, component cooling, instrument air) as well as the mitigating systems (e.g., emergency core cooling). These systems are

modeled down to the component level, pumps, valves, and heat exchangers. This level of detail is sufficient for this application.

The current version of the Catawba PRA retains the assumption that the reactor coolant pump seal packages have the old low temperature o-ring material. All but one seal in one reactor coolant pump have been replaced with seal packages containing the high temperature o-rings. This represents a conservatism in this analysis, but is judged to have an insignificant impact.

Sensitivity and Uncertainty

A number of conservative assumptions have been made in the development of this analysis. Some examples are:

- A 30-day exposure applied to the initiating event frequency, the probability of a seismic event, and the failure probability for the containment spray function
- No credit for two trains of Residual Heat Removal System auxiliary spray
- Assuming that a late containment overpressurization would lead to loss of containment sump recirculation
- No credit for preventing containment overpressure given failure of long term heat removal

Given the large margin (three to four orders of magnitude) between the estimated risk parameters and the Regulatory Guide 1.177 acceptance criteria, the likelihood that the uncertainties could drive the results above the acceptance criteria is judged to be insignificant.

Traditional Engineering Considerations

The Train 1B Containment Spray System heat exchanger was reanalyzed assuming no baffle plates are present within the tube bundle. This assumption effectively doubles the flow area within the shell side of the heat exchanger. The reanalysis showed that the heat exchanger would continue to create the required values of the product of U (overall heat transfer coefficient) and A (heat transfer surface area) that are assumed in the Catawba containment peak pressure analysis, as long as: 1) the heat exchanger fouling factor remains below 0.0045 hr ft^2 °F/BTU, 2) nuclear service water essential header temperature remains below 100°F, and 3) nuclear service water flow to the heat exchanger is at least 2200 gpm. The test data from the most recent Train 1B Containment Spray System heat exchanger heat capacity test

on September 18, 2003 indicated an instrument error adjusted fouling factor of 0.0037 hr ft^2 °F/BTU. The data was reevaluated with the revised shell side flow area and the instrument error adjusted fouling factor was determined to be 0.0036 hr ft^2 °F/BTU. The degradation of the baffle plates would result in a lower shell side pressure drop. Inspections indicate partial baffle plate loss and large tubercles, so an accurate prediction of pressure drop would be difficult.

The loads expected to be experienced by the heat exchanger during a loss of coolant accident have been evaluated. The evaluation indicated that the current status of the heat exchanger would result in it being able to withstand these loads and perform the design requirements for a loss of coolant accident.

The integrity of the heat exchanger tubes has been verified by hydrostatic testing performed on 100% of the non-plugged tubes. The tubes were hydrotested at a pressure of 1800 psig. The potential for damage to heat exchanger tubes from flow induced vibration under test and post accident service conditions has been evaluated as follows.

Degraded tube bundle structural response to Nuclear Service Water System flow conditions has been evaluated for flow rates between 2200 gpm and 3000 gpm assuming the absence of all segmental baffle plates. The conclusion of this evaluation is that the level of tube vibration/interaction over this range of flow rate is not sufficient to cause damage to the tubes for up to a 10-day Containment Spray System post accident mission time. These results are consistent with the tube integrity testing results (i.e., eddy current testing performed in April/May 2002 and hydrostatic tube leakage testing performed in October 2003), which show all tubes not currently plugged to be leak tight. The tube integrity testing results indicate no tube damage has occurred despite being periodically subjected to Nuclear Service Water System flow rates in the range of 1800 gpm to 4400 gpm for over 250 hours over the last two years under similar degraded segmental baffle plate conditions as currently known to exist.

Degraded tube bundle structural response to seismic acceleration up to at least 0.01 g has been evaluated assuming the absence of all segmental baffle plates. The conclusion of this evaluation is that the tube bundle can withstand this level of acceleration without sustaining damage to the tubes. Compensatory actions will be established to limit Nuclear Service Water System flow rate

to between 2200 gpm and 3000 gpm and to isolate the heat exchanger following a seismic event with an acceleration greater than 0.01 g. The degraded heat exchanger will be replaced during the upcoming End of Cycle 14 Refueling Outage.

Compensatory Actions

In order to preserve defense in depth capability and to enhance the overall plant safety margin, the following compensatory actions will be implemented in conjunction with this proposed amendment:

- If a seismic event with an acceleration greater than 0.01 g were to occur prior to the end of Cycle 14, Operations will isolate the Train 1B Containment Spray System heat exchanger.
- Nuclear Service Water System flow rate to the Train 1B Containment Spray System heat exchanger will be procedurally limited to between 2200 gpm and 3000 gpm.
- The Core Damage Frequency (CDF) at Catawba is dominated by the risk from the turbine building flood initiator. This risk will be mitigated by controlling the work performed on associated systems and by increased turbine building rounds on Unit 1 and Unit 2 by Operations while the Train 1B Containment Spray System heat exchanger is inoperable due to the seismic concern. This will reduce the likelihood of this initiator below the random occurrence rate. This compensatory action includes no discretionary maintenance performed on the Unit 1 or Unit 2 Condenser Circulating Water System and the cooling towers that would increase the probability of a turbine building flood. This compensatory action results in a reduction in risk.
- A control room operator will be assigned to control the Unit 1 auxiliary feedwater flow control valves in the event that flow control is lost following a loss of offsite power on Unit 1. Continuing to use steam generators to remove heat from the core and to provide steam to the turbine driven auxiliary feedwater pump is preferable to shutdown cooling, as the turbine driven auxiliary feedwater pump provides the capability to mitigate a station blackout in conjunction with the Standby Shutdown System. One of the more important operator actions identified in the Catawba PRA is manually throttling auxiliary feedwater flow to the steam generators following a turbine building flood or a loss of offsite power. Improved operator awareness

of the importance of this action and improved operator response to these events results in a reduction in risk over that identified in the PRA.

- No maintenance will be performed which results in inoperability of Train 1A of the Containment Spray System or its support systems. These support systems include the Nuclear Service Water System, the Component Cooling Water System, and diesel generator 1A. Catawba does plan to perform maintenance and testing of diesel generator 1B prior to the end of Cycle 14. That portion of SR 3.3.2.7 for Train 1A of the CPCS, insofar as it pertains to Containment Air Return System equipment, will be performed as required prior to the expiration of its surveillance interval on November 2, 2003.
- No discretionary maintenance will be performed on either train of the Residual Heat Removal System or its support systems. These support systems include the Nuclear Service Water System, the Component Cooling Water System, and diesel generator 1A. Catawba does plan to perform maintenance and testing of diesel generator 1B prior to the end of Cycle 14. This compensatory action will reduce the risk impact of late releases due to small and medium loss of coolant accidents.
- No discretionary maintenance will be performed on the Instrument Air System. This compensatory action will reduce the risk impact of late releases due to a loss of instrument air.
- Operations completed training for shift operators concerning the importance of operator actions due to failure to swap to high pressure recirculation and failure to cross connect offsite power via SATA/SATB following a loss of all AC power. This included the importance of these actions and a review of the procedure actions to be taken.

<u>Compliance with Current Regulations</u>

This proposed amendment is consistent with all applicable NRC regulations, orders, and license conditions for Catawba. No exemptions to any of these items are required in conjunction with this proposed amendment. In addition, this proposed amendment has no impact concerning any previous Catawba commitments.

ATTACHMENT 4

NO SIGNIFICANT HAZARDS CONSIDERATION DETERMINATION

The following discussion is a summary of the evaluation of the changes contained in this proposed amendment against the 10 CFR 50.92(c) requirements to demonstrate that all three standards are satisfied. A no significant hazards consideration is indicated if operation of the facility in accordance with the proposed amendment would not:

1. Involve a significant increase in the probability or consequences of an accident previously evaluated, or

2. Create the possibility of a new or different kind of accident from any accident previously evaluated, or

3. Involve a significant reduction in a margin of safety.

First Standard

The proposed amendment will not involve a significant increase in the probability or consequences of an accident previously evaluated. Granting of this amendment will have no effect on accident probabilities, since the Containment Spray System is not considered accident initiating equipment and no physical changes are being made to the plant which would impact accident probabilities. Granting of this amendment would not result in any adverse impact from the standpoint of availability or reliability of the Containment Spray System trains. Also, this proposed amendment was evaluated and found to be acceptable from a risk standpoint. Therefore, there will be no significant increase in any accident consequences.

Second Standard

The proposed amendment will not create the possibility of a new or different kind of accident from any accident previously evaluated. No new accident causal mechanisms are created as a result of the NRC granting of this amendment. No changes are being made to the plant which will introduce any new accident causal mechanisms.

Third Standard

The proposed amendment will not involve a significant reduction in a margin of safety. Margin of safety is related to the confidence in the ability of the fission product barriers to perform their design functions during and following an accident situation. These barriers include the fuel cladding, the Reactor Coolant System, and the containment. The granting of this amendment by the NRC will not degrade the performance of these fission product

barriers. No safety margins will be impacted. The risk implications of this proposed amendment were evaluated and found to be acceptable.

Based upon the preceding discussion, Duke Energy Corporation has concluded that the proposed amendment does not involve a significant hazards consideration.

ATTACHMENT 5

ENVIRONMENTAL ANALYSIS

Pursuant to 10 CFR 51.22(b), an evaluation of this license amendment request has been performed to determine whether or not it meets the criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9) of the regulations.

Implementation of this amendment will have no adverse impact upon the Catawba units; neither will it contribute to any additional quantity or type of effluent being available for adverse environmental impact or personnel exposure.

It has been determined there is:

1. No significant hazards consideration,

2. No significant change in the types, or significant increase in the amounts, of any effluents that may be released offsite, and

3. No significant increase in individual or cumulative occupational radiation exposures involved.

Therefore, this amendment to the Catawba TS meets the criteria of 10 CFR 51.22(c)(9) for categorical exclusion from an environmental impact statement.