Petitioner that would support the allegations that NU has harassed, intimidated, or discriminated against him, the NRC staff plans no further followup of the harassment and intimidation complaints. Based on the above, no further action is warranted.

III. Conclusion

On the basis of the above assessment, I have concluded that some of the Petitioner's concerns were substantiated and resulted in appropriate enforcement action. Other concerns were not substantiated. Therefore, no additional enforcement action is being taken in this matter.

The Petitioner's request for action pursuant to 10 CFR 2.206 is denied. As provided in 10 CFR 2.206(c), a copy of this Decision will be filed with the Secretary of the Commission for the Commission's review. This Decision will constitute the final action of the Commission 25 days after issuance unless the Commission, on its own motion, institutes review of the Decision in that time.

Dated at Rockville, Maryland, this 31st day of October 1996.

For the Nuclear Regulatory Commission.

Ashok C. Thadani,

*Acting Director, Office of Nuclear Reactor Regulation.*

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**BILLING CODE 7590–01–P**

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**[Docket Nos. 50–413 and 50–414]**

## Duke Power Company, et al.; Catawba Nuclear Station, Units 1 and 2; Issuance of Director's Decision Under 10 CFR 2.206

Notice is hereby given that the Director, Office of Nuclear Reactor Regulation, has taken action with regard to a Petition for action under 10 CFR 2.206 received from Mr. Charles Morris (Petitioner), dated February 13, 1996, as supplemented May 1, 1996, with regard to the Catawba Nuclear Station.

The Petitioner requested the NRC to suspend the operating licenses for the Catawba Nuclear Station and ''some ten other licensees with uncoordinated breakers'' (not specifically identified in his initial Petition) until the lack of circuit breaker coordination has been remedied. Mr. Morris also requested that enforcement conferences be held on these cases and that Catawba be defueled. Mr. Morris also asked that the NRC take enforcement action against Catawba for operating with a ''known safety deficiency of which they did not inform the NRC.''

The Director of the Office of Nuclear Reactor Regulation has denied the Petition. The reasons for this decision are explained in the ''Director's Decision Pursuant to 10 CFR 2.206'' (DD–96–14), the complete text of which follows this notice and which is available for public inspection at the Commission's Public Document Room, the Gelman Building, 2120 L Street, NW., Washington, DC, and at the local public document Room for the Catawba Nuclear Station located at the York County Library, 138 East Black Street, P.O. Box 10032, Rock Hill, South Carolina.

A copy of this Decision has been filed with the Secretary of the Commission for the Commission's review in accordance with 10 CFR 2.206(c) of the Commission's regulations. As provided by this regulation, this Decision will constitute the final action of the Commission 25 days after the date of issuance unless the Commission, on its own motion, institutes review of the Decision within that time.

Dated at Rockville, Maryland, this 10th day of October 1996.

For the Nuclear Regulatory Commission.

Frank J. Miraglia,

*Acting Director, Office of Nuclear Reactor Regulation.*

### Director's Decision Under 10 CFR 2.206

*I. Introduction*

On February 13, 1996, Mr. Charles Morris of Middletown, Maryland, filed a Petition with the U.S. Nuclear Regulatory Commission (NRC) pursuant to Title 10 of the Code of Federal Regulations, Section 2.206 (10 CFR 2.206). In the Petition, the Petitioner requested the NRC to suspend the operating licenses for the Catawba Nuclear Station and ''some ten other licensees with uncoordinated breakers'' (not specifically identified in his initial Petition) until the lack of circuit breaker coordination has been remedied. Mr. Morris also requested that enforcement conferences be held on these cases and that Catawba be defueled. Mr. Morris also asked that the NRC take enforcement action against Catawba for operating with a ''known safety deficiency of which they did not inform the NRC.'' This aspect will be addressed separately as stated in the April 2, 1996, letter to Mr. Morris. On May 1, 1996, Mr. Morris submitted an addendum to his Petition, providing a list of 14 cases involving 9 other nuclear power plants for which lack of protective device coordination had been identified as a concern by electrical distribution system functional inspection (EDSFI) teams; see Section II for information.

*II. Discussion*

During an EDSFI conducted by the NRC staff from January 13 to February 14, 1992, at the Catawba Nuclear Station, circuit breaker coordination deficiencies were identified for the 600-Vac essential motor control centers (MCCs) and the 125-Vdc system. This circuit breaker coordination issue was addressed in EDSFI Inspection Report 50–413, 414/92–01, dated March 18, 1992, as a deviation from a written commitment. Section 5.3.1 of the Institute of Electrical and Electronics Engineers (IEEE) Standard 308–1974, ''IEEE Standard Criteria for Class 1E Power Systems for Nuclear Power Generating Stations,'' stipulates that protective devices shall be provided to limit the degradation of Class 1E power systems. The Catawba Final Safety Analysis Report (FSAR) states that the system meets the requirements of this standard. The FSAR also states that the protective devices on the 600-Vac essential auxiliary power (EPE) system are set to achieve a selective tripping scheme so that a minimal amount of equipment is isolated for an adverse condition such as a fault.

Contrary to this IEEE Standard, however, the licensee's protective devices may not limit the degradation of the 125-Vdc vital instrumentation and control (I&C) power system distribution center and other main feeder circuit breakers. An analysis performed by the licensee showed that coordination did not exist for fault currents from 3500 amperes (A) up to the maximum fault current of 9500 A. A fault on the battery charger feeder cable could cause both the charger and the battery to be isolated from the remainder of the distribution system and loads.

In addition, the outgoing feeder breakers for the 600-Vac essential MCCs have thermal elements and the incoming MCC breakers have instantaneous elements. The incoming breaker (supply breaker) and the feeder breakers at each of the 600-Vac MCCs were not coordinated for the maximum expected short-circuit current. A fault on any of the MCC outgoing feeders could cause the MCC incoming breakers to trip, resulting in a loss of the MCC.

Enclosed with the letter dated April 16, 1992, Duke Power Company (the licensee) provided a response to this deviation which stated that the 125-Vdc vital I&C power (EPL) system primarily uses molded-case circuit breakers in the 125-Vdc distribution centers and power panelboards for protection. The battery, main, and tie breakers are equipped only with adjustable magnetic trip units. The battery charger breaker is a thermal magnetic type with an adjustable magnetic trip setting. The rest of the breakers are of a non-adjustable thermal magnetic type.

The licensee's response concluded that this design was acceptable for the following reasons:

1. The EPL system is not a shared system between the two Catawba units; thus, a postulated fault in the EPL system of one unit will not affect the opposite unit.

2. The EPL system for each unit is composed of two completely redundant and separate trains, each consisting of two load channels for a total of four load channels per unit. A postulated fault would, at worst, disable two load channels of the same train, yet the redundant train would remain unaffected.

3. Selected loads such as the diesel load sequencer, essential switchgear and load center controls, and auxiliary feedwater pump turbine controls are not only fed by the EPL system, but are auctioneered with the 125-Vdc diesel auxiliary power (EPQ) system. As a result, if the EPL system was unable to feed these loads, the EPQ system would supply them without interruption. Further, a fault on the EPL system will not affect the EPQ system or vice versa.

The licensee's response further states that the incoming 600-Vac breakers were incorporated in the design to provide a means of local isolation for the 600-Vac Class 1E MCCs. The licensee deemed acceptable the use of circuit breakers having a continuous rating equal to the MCC incoming rating and their instantaneous trip settings at maximum, 10 times their continuous rating.

In the response to the deviation, the licensee committed to perform a detailed study to identify acceptable methods to achieve improved protective device coordination within the EPL system and to evaluate the feasibility of eliminating the incoming 600-Vac MCC breakers. The licensee committed to either update the FSAR to justify the deviation from the IEEE Standard 308–1974 or to modify the system to meet this IEEE standard. Subsequent to completing the detailed study and evaluating the feasibility of making system modifications, the licensee proposed modifying the FSAR.

## Deterministic Analysis

To review and evaluate the lack of circuit breaker coordination in the Catawba EPL and EPE circuits, the staff requested the licensee to provide additional information. The licensee's response of March 2, 1994, addressed fault types, fault locations, breakers that are coordinated and breakers that are not coordinated, the impact of the upstream breaker opening, and the safety significance of the loss of a train. The staff also requested additional information regarding the 2-kV-rated interlocking armored cabling; the operating history of faults; the measures provided to detect, locate, and correct faults; and related criteria and practices incorporated to ensure continued system functional performance. The licensee's responses to these requests were enclosed in its letter to the NRC of May 17, 1996.

### *125-Vdc Vital EPL System*

The EPL system is an ungrounded system and therefore can remain operational for a single postulated fault of either positive-to-ground or negative-to-ground. In order to render the system inoperable, postulated faults would have to be either a simultaneous positive-to-ground and negative-to-ground fault or a double-line (positive-to-negative) fault. The former type of fault requires that two failures occur, which is beyond the design basis for the plant. The occurrence of a single line-to-ground fault will not affect the functional capability of the power system. However, upon the occurrence of such a fault, a ground fault detector will alert the control room operator by way of an annunciator and a computer alarm. A program that seeks to maintain a dark control room annunciator board promptly addresses ground faults. The latter type of fault is thought to be unlikely in view of a study performed with information obtained from the Nuclear Plant Reliability Database System (NPRDS) and the Catawba probabilistic risk assessment (PRA). The licensee analyzed failures at Catawba since 1985 and all U.S. plants since 1990. Three reported cases were found in which a double-line fault occurred on a direct current system. One case that occurred at Catawba involved a shorted lamp holder and was attributed to improper installation during maintenance. The two other cases occurred at nuclear plants operated by other utilities and involved component failures within battery chargers; in both of these other cases, the plant status was not affected. No cases were reported that involved double-line faults attributed to cable faults. In addition, no faults of the types that could challenge the EPL system were identified in the NPRDS.

The licensee's circuit breaker coordination analysis for the EPL system postulates faults at selected locations within the system. The analysis was performed in accordance with the guidelines of IEEE Standard 946–1993, ''IEEE Recommended Practice for the Design of DC Auxiliary Power Systems for Generating Stations,'' and included EPL system load groups A and D for both units. These two load groups for both units were analyzed since the 125-Vdc vital batteries associated with them are capable of producing the highest fault current. The coordination analysis postulates faults at nine locations within each of the four EPL load groups. These locations are as follows: (1) Battery charger output; (2) auctioneering diode assembly input; (3) inverter input; (4) auctioneered distribution center bus; (5) load end of 4160-Vac essential switchgear control power feeder breaker and first termination point of associated feeder cable; (6) load end of 600-Vac essential load center control power feeder breaker and first termination point of associated feeder cable; (7) load end of diesel generator load sequencer control power feeder breaker and first termination point of associated feeder cable; (8) power panelboard bus; and (9) load end of the largest breaker used in a power panelboard and the first termination point of the associated feeder cable. These fault locations were chosen to represent a broad cross-section of possible fault locations. At these locations, calculated fault currents for the two A load groups (one A load group per unit) and the two B load groups are very similar, as may be expected since the two units are very similar. The analysis results also show that for faults at locations (2) and (4), the breakers are fully coordinated, while for faults at locations (5), (6), (7), and (9), the breakers are partially coordinated. For postulated faults at locations (1), (3), and (8), the breakers are not coordinated. In the analysis, full breaker coordination is considered to exist if the breaker nearest the fault clears without operating (opening) any upstream breakers, or if the consequences of operating an upstream breaker are no more severe than those associated with operating the breaker nearest the fault. Partial coordination is considered to exist if some of the upstream breakers, except the battery breaker or the load center incoming breaker, could operate before the breaker nearest the fault clears. For those cases in which either the battery compartment breaker or the load center breaker could operate before the breaker nearest the fault operates, coordination is considered not to exist. If an upstream breaker, such as the load center incoming breaker, operates before the breaker nearest the fault opens, one of the four EPL system load centers would be lost.

The EPL circuit breaker coordination analysis neglects cable faults and credits cable resistances in the fault current calculations. The cabling used in the system is 2-kV-rated interlocking armored cable. This cabling has the same construction as non-armored cable, except that a steel armor covering is applied around the entire outer circumference. This interlocked steel outer covering protects the cable from damage or degradation during loading, unloading, transporting, installation, and while in service at the plant. The cabling was purchased with an insulation system rated at 2000 Vac. The cable conductors were high-potential tested underwater and spark tested at the factory with values required by standards for 2-kV cable. The low voltage of the EPL system does not produce internal ionization or corona that would cause an internal flashover or failure between conductors within the armored cable. Further, the cable insulation system has a greater thickness than the insulation system of standard 600-Vac rated cable and therefore provides higher dielectric capability, enhanced physical protection, and added margin for aging considerations.

In addition, the licensee had an interlocked armored cable fault test performed at the High Power Laboratory of the Westinghouse Electric Corporation. This test did not result in any additional shorts between conductors within the multiconductor cable. Similar interlocking armored cabling is used at the Oconee Nuclear Station, which has an inservice cable monitoring program. For this program, six cable samples were installed inside one of the containment buildings. At 5-year intervals, a 5-foot segment is removed from each cable sample for testing. This testing measures, documents, and trends the mechanical and electrical properties of the cable. Past test results from this program collectively show that cable samples are in good physical condition after 20 years in a reactor building environment. The installed interlocking armored cabling at Catawba is identical or superior to the cable that is installed at Oconee. A similar monitoring program to evaluate and trend cable problems has been in place at Catawba since January 1995. The purpose of this program is to evaluate and record problems or malfunctions of plant cables and, if an adverse trend develops, take corrective actions to address the problem. Deficiencies that would be reported as a result of this program include short circuits, insulation damage, and problems with cable terminations and splices. Since cabling of the same basic specifications and ratings is used in both safety and nonsafety applications at Catawba, all plant cabling is included in the scope of this trending program. Data on failures or problems with cables are collected at the end of each quarter; since January 1995 there has only been one failure.

Neither of the Catawba units has ever experienced a single line-to-ground fault that caused the EPL system to become inoperable. As noted previously, this result is due in part to the ungrounded system design. A complete review of the EPL system work order history revealed that five ground faults have been experienced in the last 5 years. Each of these faults resulted in an alarm both locally and in the control room and was caused by solenoid valve problems. Three cases involved failed solenoid valve components, and the other two cases involved water intrusion into solenoids, which was subsequently corrected. Because of the intermittent nature and high resistance of these faults, it sometimes took an extensive amount of time to specifically locate and correct the ground fault. However, none of these faults caused the EPL system to become functionally inoperable. The licensee has implemented additional measures to aggressively locate and correct ground faults that may occur in the future. These measures include the procurement of an advanced ground-locating device that will allow ground faults of a high-resistance nature to be located more readily. The EPL system work order history search also revealed that only one ground fault detector has failed during the last 5 years. Because the original ground detector was no longer available from the manufacturer, a substitute part had to be located and an evaluation performed to verify its acceptability for use in the application. As a result, it took longer than normal to restore the unit to service. However, the EPL system is checked weekly in accordance with an administrative procedure for ground faults by way of another method that is independent of the ground detector system. Thus, in the unlikely event of a ground fault detector failure, a ground would very likely be detected by way of the independent alternate means before a fault-related problem developed.

To ensure continued functional performance of the EPL system, the following additional criteria and practices are in place at Catawba. Only a minimal amount of cable splicing is permitted, and no cable splicing is allowed in raceways. Safety-related cables routed underground are installed in conduit or cable trenches, and are not directly buried in the earth. Cable ampacities used for cables are based on 70 percent of the standard industry ampacity ratings. Further, for the EPL system, higher rated voltage (2000 Vac versus 125 Vac) cable is used with the steel interlocking armor jacket to provide additional physical protection.

Although the EPL system analysis described above demonstrates that full circuit breaker coordination does not exist for all postulated faults, this fact has no significance for the operational capabilities of the system because the faults that result in lack of breaker coordination are limited. These faults are limited in both type (doubled-sided, solid, low resistance ones) and location (postulating such faults at many locations does not result in a lack of breaker coordination). Monitoring by ground fault detectors further limits such faults since this activity minimizes the potential for bigger problems, such as positive-to-negative faults. In the event that such a fault does result in the loss of an EPL load distribution center, an independent and redundant EPL load distribution center is provided to supply safety-related loads. Further, should a fault-induced transient occur as a result of the loss of one of the two plant transient-inducing EPL load distribution centers, the plant can be safely shut down using only the loads powered from either one of the two EPQ system auctioneered distribution centers. In addition, the safety significance of the loss of one EPL load group is analyzed in the Catawba FSAR. This analysis includes the loss of an EPL load group as a result of any postulated cause. Thus, the loss of an EPL load group as a result of any cause (faults or any other cause) is within the licensing basis (i.e., analyzed in the FSAR) for Catawba Units 1 and 2.

*600–Vac EPE System*

The licensee also provided additional information on the lack of breaker coordination in the EPE system. This additional information included the analysis performed for the EPE system, fault locations, identification of the breakers that are coordinated and those that are not, the impact of upstream breakers opening, the significance of taking out an EPE train, and measures taken to prevent degrading the installed equipment during modification and maintenance work activities.

The fault current analysis for the EPE system was performed in accordance with the guidelines in IEEE Standard 141–1986, ''IEEE Recommended

Practice for Electric Power Distribution for Industrial Plants.'' For each 600–Vac essential MCC, all load breakers and cables were reviewed to determine which circuit can produce the highest fault current. For each MCC, a coordination evaluation was performed for the worst-case feeder (load) breaker and the incoming (supply) breaker. In this analysis, the feeder breaker fault is modeled at the load or at the first cable termination outside the MCC. For the fault current analysis, the normal load current for all nonfaulted feeder breaker loads is added to the feeder breaker fault current to establish the total current experienced by the incoming breaker during the fault. Also, in this analysis, the feeder breaker fault current is obtained by adding the fault contribution from the incoming breaker and the fault contribution from the large motor loads connected to the bus. The fault currents were determined for both the normal and accident cases. The normal operation case produces the highest postulated fault current and, as such, is used throughout the analysis. The postulated faults in the analysis are three-phase, bolted faults, and all fault currents and load currents are based on the highest bus voltage for the normal operating case.

Fault locations for the Unit 1 Train A and B EPE MCC circuits were established. The Unit 2 Train A and B circuits are similar. Based on the unlikely occurrence of bus faults and/or breaker faults at Catawba, faults were not postulated on the output of the feeder breaker. In addition, because of the 2–kV–rated interlocked armor cable protection and the fact that no faults have occurred on any such cable in service at any of the Duke Power nuclear plants, faults were not postulated along the routes of the cable. Further, the fault current calculations credit cable impedances and postulate faults at the input terminals of the load or at the first cable termination after the cable leaves the MCCs. The 2–kV–rated interlocking armored cabling used in the EPE system is the same as that used in the EPL system. Thus, the cable analysis information previously mentioned for the EPL system is applicable to the EPE system.

The Unit 1 EPE system includes 11 MCCs. Analysis shows that for 10 of these MCCs, the incoming breakers are coordinated for the worst-case postulated fault at the first cable termination outside the MCC. The remaining MCC is provided with two incoming breakers, which can be powered from either a Unit 1 or a Unit 2 load center. The two incoming breakers supplying this MCC are not fully coordinated for a fault at the worst-case load, which is a control room ventilation system air-handling unit. This unit is connected with a 250 MCM cable that is 100 feet long. The other loads powered by this MCC are fed from smaller breakers and cables with lower maximum fault current and thus are coordinated with the incoming breakers.

The two incoming breakers for the one MCC are mechanically interlocked such that one breaker is always locked in the open position. If the incoming breaker in service to this MCC trips to clear a fault, power is lost to some Train A control room ventilation system and nuclear service water system loads. An important function associated with these systems is maintaining pressurization of the control room. If this MCC is deenergized under nonaccident conditions, control room pressurization decreases until the operators manually transfer the system to Train B. This result is not viewed any differently than the result of losing the pressurizing fan alone and has little impact. If the MCC is deenergized under accident conditions, the design is such that pressurization is reestablished automatically from Train B, and this situation has little impact.

To ensure continued fault-free functional operation of the EPE system, modifications and maintenance work are controlled by station procedures. The Catawba inspection and maintenance procedure for MCC breakers addresses much of the work related to the EPE MCCs. This procedure, along with other station procedures, provides strict controls on any changes from the normal system configuration, such as placement of grounding jumpers or test alignments. These types of configuration changes are documented on a circuit alteration/ restoration log sheet attached to the procedure. Before the work can be closed out and the equipment reenergized, the proper steps in the restoration section of the procedure must be completed and verified by an independent technician. Typical restoration activities performed at the completion of maintenance work on EPE MCC feeders include removing all test equipment and verifying that the MCC compartment is wired according to the latest wiring diagram. If required, motor phase rotation testing would also be performed. If the feeder breaker has been removed or replaced, a thermography test of the energized breaker will be conducted. Additional specified functional verification requirements, such as verifying proper full-speed operation and normal pressure and flow parameters, may be performed, depending on the type of equipment involved with the work. In addition, the test requirements section of the inspection and maintenance procedure for MCC breakers specifies that megger testing of the load is to be performed if a fault is suspected. The procedure signoff sheet includes a section for recording such megger readings.

The licensee's March 2, 1994 analysis indicated that selected circuit breakers associated with certain EPE MCCs are not coordinated for postulated faults. However, the technical significance of this fact is low, which is due, in part, to such faults being limited in both type (bolted low-impedance faults) and location (postulating such faults in many EPE system locations does not result in lack of breaker coordination). Assurance that such faults are limited is further established by the positive test results obtained for the interlocking armored cabling and the strict adherence to maintenance procedures. In addition, an analysis of the loads powered by each of the 11 600–Vac EPE system MCCs indicates that loss of power to any one of these MCCs because of a fault or for any other reason would not directly result in a reactor transient. Further, Trains A and B of the EPE system are redundant and, as such, loss of functions from any MCC is backed up by the redundant MCC of the other train. Finally, each MCC is provided with a control room alarm for loss of power to facilitate restoration of equipment in a timely manner by operator actions.

## Probabilistic Risk Assessment

To further supplement the deterministic engineering analysis results, the staff requested the licensee to consider using PRA techniques to better understand the likelihood and impact of the lack of breaker coordination in the Catawba EPL and EPE systems. The licensee responded in the attachments to a letter dated December 29, 1994, by addressing EPL and EPE system uncoordinated breakers within a PRA framework. Following the review of the submitted PRA information, the staff requested by letter dated April 30, 1996, that the licensee specifically address the uncoordinated breaker issue including the (1) initiating event (IE) frequency; (2) conditional impact of the IE on plant operation; (3) ability to recover from an uncoordinated breaker event; and (4) recovery by way of the standby shutdown facility (SSF). The licensee provided this additional PRA information in the enclosures to a letter dated May 17, 1996. The paragraphs below discuss the PRA and the lack of breaker coordination in the EPL and EPE systems.

*125–Vdc EPL System*

In the Catawba PRA, the licensee identified a ''Loss of Vital Instrumentation and Control'' as an initiator-coded T14. With uncoordinated breakers, some line-to-line electrical faults in the 125–Vdc feeders could cause both the loss of a vital I&C power distribution center (T14 initiator) and a subsequent turbine trip and reactor trip.

In Calculation CNC–1535.00–00–0007 enclosed in its December 29, 1994, letter, the licensee established the frequency of the T14 initiating event at 5E–02 per year. This value had also been used in the Catawba PRA, which supported the licensee's individual plant examination (IPE). The IE frequency had been based on the operational experience of one event in 20 reactor-years of operation at the combined Catawba and McGuire units (four units) from 1987 to 1991. The event involved manual tripping of a 125–Vdc vital I&C power distribution center at the McGuire station in 1987. In response to this event, the NRC issued Information Notice 88–45, ''Problems in Protective Relay and Circuit Breaker Coordination.'' Because no other T14 IE occurred since that timeframe, the actual IE frequency would be lower.

In order to establish the fraction of the T14 initiator event frequency that could be associated with breaker miscoordination, the licensee performed an NPRDS search for all dc line-to-line faults. The data search included all U.S. nuclear plants from 1990 (Catawba since 1985) to the present. The NPRDS search identified only one such fault at Catawba and three faults at all U.S. plants. In recognition of the fact that the results of NPRDS searches are dependent on the search commands, the staff requested the Oak Ridge National Laboratory (ORNL) to perform a similar search. ORNL obtained the same results as did the licensee for the Duke Power plants. However, ORNL found a slightly higher rate for the other U.S. plants. In no case did cable failure(s) result in a line-to-line fault or a plant trip.

In order to estimate (bound) the contribution of a cable fault to the T14 initiator event frequency, the licensee assumed that one cable fault occurred out of a combined 46 years of reactor operation at the Catawba and the McGuire units. This assumption resulted in a cable fault frequency of 2E–02 per unit-year. Catawba Unit 1 has about 18,500 cables and about 30 feeders per 125–Vdc vital distribution center. From these data, cable faults causing loss of a single distribution center have an IE frequency of 3E–05 per year ((2E–02)(30)/18,500 = 3E–05 per year). A second (somewhat higher) estimate was obtained by using the IEEE Standard 500–1984, ''IEEE Guide to the Collection and Presentation of Electrical, Electronic, Sensing Component, and Mechanical Equipment Reliability Data for Nuclear-Power Generating Stations,'' which specifies a composite cable failure rate of 7.54E–06 per hour per plant for power, control, and signal cables combined. Line-to-line cable failure rate is a small fraction of this rate. With this cable failure rate, the failure rate of a single distribution center is 1E–04 per year ((7.54E–06)(8760)(30)/18,500 = 1E–04 per year).

The Catawba PRA used a generic value for bus fault probability of 2E–03 per year, where the term bus fault includes distribution center or panel faults, cable faults, and terminal faults. Although this IE is only 4 percent of the T14 initiator frequency, it is obviously higher than the probability figures derived from plant operational experience and IEEE 500–1984 data (i.e., the cable fault contribution was 5 percent of the bus fault probability using IEEE data, and 1.5 percent using operational experience). On the basis of this rationale, the staff concluded that the cable fault contribution was bounded by the distribution center fault probability used in the Catawba PRA.

Unit 1 has six 125-Vdc load distribution centers: 1EDA, 1EDB, 1EDC, 1EDD, 1EDE, and 1EDF. The licensee evaluated the plant response on loss of power for each of the Unit 1 distribution centers. The Unit 2 system is similar to Unit 1, and the evaluation for Unit 1 is applicable to Unit 2.

The licensee's evaluation indicates that a loss of power at 1EDB or 1EDC would result in a loss of a vital I&C power 120-Vac inverter, one solid-state protection system (SSPS) channel, one nuclear instrumentation channel, and a process protection channel. A loss of power at 1EDA or 1EDD would result in similar channel losses, plus a loss of power to process control for associated pressurizer power-operated relief valves (PORVs), to control solenoids for certain main steam isolation valves, and to control solenoids for attendant main feedwater control valves. However, except for the loss of the PORVs, a loss of any of these four distribution centers would not significantly impact the plant's accident mitigation capability. Loss of one channel of the SSPS, process protection channels, main steam isolation valves, and main feedwater control valves would not preclude mitigation unless there were additional faults.

Distribution center 1EDE or 1EDF provides control power for safety equipment. The licensee's breaker coordination analysis indicates that the other four distribution centers lack full coordination. Distribution center 1EDE is powered by two power supplies that are auctioneered. One of these auctioneered power supplies is from 1EDA, and the other is from one of the trains of the 125-Vdc EPQ system. Similarly, 1EDF is powered by two power supplies that are auctioneered. One of these auctioneered power supplies is from 1EDD and the other is from the other train of the 125-Vdc EPQ system. Thus, even though distribution centers 1EDE and 1EDF may be fed from uncoordinated distribution centers 1EDA and 1EDD, respectively, in the event of loss of 1EDA or 1EDD, the distribution centers 1EDE or 1EDF will continue to be powered by the alternate power source. Further, a loss of power at 1EDE or 1EDF would not result in a plant transient and thus would not result in an immediate need for mitigating systems, although the resulting loss of control power to equipment would require resolution within the specified time period of the applicable Technical Specifications Action Statement.

In addition to redundant mitigation capability, Catawba is provided with a manually activated SSF. The SSF is an independent structure with its own ac and dc power supplies, instrumentation, and reactor coolant makeup pump. Upon loss of normal ac or dc power, the SSF can be used to remove core decay heat and provide reactor coolant pump seal protection if the event leads to the loss of all plant-side safety systems. The SSF reduces the contribution of the T14 initiators by more than an order of magnitude, resulting in a total contribution of 6.7E–08 per reactor-year, or less than 0.1 percent to the total core damage frequency (CDF).

Using a T14 IE frequency of 5E–02 per year, the licensee derived a total CDF of 7.76E–05 per year in the Catawba IPE. Applying information from the IEEE standard for cable fault frequency to the four distribution centers lacking full coordination, which is a subset of the T14 initiator, reveals that the contribution to the total CDF from the loss of a 125-Vdc load distribution center is less than 1E–09 per reactor-year. The licensee also performed a sensitivity study by changing the T14 IE frequency from 5E–02 per year to 1.0 per year. The total CDF changed by 1.55 percent (i.e., the total CDF changed from 7.76E–05 per year to 7.88E–05 per year).

The sensitivity study indicates that any increase in the CDF from a lack of breaker coordination would be small.

*600-Vac EPE System*

As previously mentioned in this report, the licensee's breaker coordination study indicates that out of 11 MCCs in the EPE system, only 1 MCC, 1EMXG, is uncoordinated. This calculation, however, excluded all cable faults from the 600-Vac EPE system MCCs to the first cable termination on the basis that the occurrence of severe cable faults was of low probability. The licensee states that no severe cable faults have been reported in its seven nuclear plants, which have a combined operational experience of 120 reactor-years. On the basis of the IEEE Standard 500–1984 data of 4.8 failures per million hours per plant for power cables, the licensee calculated that a typical plant with 18,500 cables had a probability of a cable failure of 2.3E–06 per year per cable, and the probability of an MCC loss as a result of cable failure is 7E–05 per year for a typical MCC with 30 feeders.

In the Catawba PRA, loss of a 600–Vac MCC is addressed through its plant response characteristics (mission time) because the loss of an MCC does not cause a reactor transient. The Catawba PRA study identified a probability of loss of a 600–Vac MCC as 1.5E–04 for a 24-hour mission time, and the contribution of cable faults to this mission time as 5E–07. Therefore, the Catawba PRA indicates that cable faults did not have any significant impact on the overall MCC failure probability calculated in the PRA.

The licensee's study revealed that a loss of any of the 11 600–Vac EPE system MCCs would not directly lead to a reactor trip. In a review of the 600–Vac EPE system MCC loads, the staff arrived at the same conclusion. Although such an MCC loss would not result in a reactor transient, it would render one train of safety systems inoperable and would require entry into applicable limiting conditions of operation defined in the Technical Specifications. However, a loss of any MCC would only affect one train, and the redundant train would be available for accident mitigation.

The licensee did not provide an analysis of the effect of SSF availability on the CDF from the loss of a 600–Vac MCC. The SSF response for the 600–Vac EPE system is expected to be similar to that previously explained herein for the EPL system.

In Calculation CNC–1535.00–00–0007, enclosed with the licensee's letter of December 29, 1994, the licensee indicated that on the basis of the Catawba PRA, the MCC 1EMXG had a failure probability of 1.4E–04 for a 24-hour mission time. Within this MCC, only one breaker feeding a control room air-handling unit lacked coordination with its upstream breaker. With this uncoordinated breaker, the MCC failure rate would increase by 1E–06 for a 24-hour mission time, or the impact would be approximately two orders of magnitude less than the total MCC failure probability. The licensee's sensitivity study provided in Calculation CNC–1535.00–00–0007 indicates that even if the failure rate of the uncoordinated MCC 1EMXG were increased by an order of magnitude from 1E–06 to 1E–05, the resulting failure probability for the MCC 1EMXG would increase by only 7.1 percent.

On the basis of these considerations, the staff concluded that the lack of breaker coordination in the EPE system has a negligible impact on the MCC failure probability as calculated in the Catawba IPE.

Full circuit breaker coordination is a desirable design feature for ac and dc power distribution systems in a nuclear plant since it assists in minimizing equipment losses if electrical faults occur. The staff has reviewed the licensee's submittals addressing the lack of full circuit breaker coordination within the 125–Vdc EPL and 600–Vac EPE systems. The licensee's circuit breaker coordination analysis shows that the Catawba EPL and EPE systems lack full breaker coordination. However, the faults that must occur to cause a lack of breaker coordination in these systems are limited by type and location. Such faults have a low probability of occurrence because the interlocking armored cabling is unlikely to develop such faults. Further, ongoing measures, such as ground fault detection, incorporating design criteria and practices, and strict adherence to modification and maintenance procedures, tend to minimize the likelihood of the occurrence of faults within the EPL and EPE systems that would result in miscoordinated breakers. Plant operational experience and IEEE Standard 500–1984 data indicate that line-to-line faults are of low probability. The probability of a line-to-line fault is 2E–02 per year and the probability of loss of a 125–Vdc distribution center is 1E–04 per year. In the 600–Vac EPE MCCs, the licensee has never experienced any severe cable fault in 120 reactor-years of operation of the seven Duke Power nuclear plants. The IEEE Standard 500–1984 data indicate a probability of a cable failure of 4.2E–02 per year and a corresponding probability of a loss of an MCC resulting from cable failure of 7E–05 per year. These results further support assumptions used in the licensee's breaker coordination analysis. However, in the unlikely event that such faults should occur in an EPL or EPE system train, a redundant and separate train is provided to perform the safety function.

The Catawba SSF reduces the impact on CDF of a loss of either one of two 125–Vdc distribution centers by more than an order of magnitude. Similar results would be expected for the 600–Vac EPE MCCs. In addition, a calculation by the licensee indicates that increasing the T14 IE frequency from 5E–02 per year to 1.0 per year would increase the total CDF by 1.55 percent from 7.76E–06 per year to 7.88E–05 per year. A similar calculation for the 600–Vac MCCs indicates that with lack of breaker coordination, the failure probability of the worst-case MCC would rise from 1.4E–04 per 24-hour mission time by 1E–06 per 24-hour mission time. The licensee's sensitivity study indicates that when the failure rate of the worst-case uncoordinated MCC was increased from 1E–06 to 1E–05, the resulting failure probability of the MCC would increase by 7.1 percent. Thus, the lack of circuit breaker coordination in the Catawba 125–Vdc EPL and 600–Vac EPE systems has a negligible impact on the CDF.

On the basis of this information, the staff concludes that the licensee has documented adequate technical justification for the lack of breaker coordination in the Catawba 125–Vdc EPL and the 600–Vac EPE systems. Accordingly, the staff concludes that there is no basis to suspend the Catawba operating licenses. The staff will pursue separately the requirement for the licensee to bring the FSAR into conformance with the as-built plant.

Lack of Protective Device Coordination at Other Nuclear Plants

As previously indicated in the introduction section of this Decision, the Petitioner submitted an addendum to his Petition on May 1, 1996. This addendum included a list of 14 cases, involving 9 other nuclear power plants, in which lack of protective device coordination was identified as a concern by EDSFI teams. These 14 cases were addressed by way of the NRC's inspection report item closeout process. As documented in the publicly available closeout inspection reports, these cases were resolved by (1) additional calculations and analyses showing that protective device coordination exists, and/or (2) plant hardware modifications such as replacement circuit breakers or fuses. The following list identifies each of these 14 cases by an EDSFI inspection follow-up item (IFI) number and the publicly available inspection report in which the lack of protective device coordination issue was closed out.

| Plant name | EDSFI IFI No. | Report date | Closeout inspection report | Report date |
|---|---|---|---|---|
| 1. Oyster Creek | 219/92–80–11 | 7/9/92 | 94–01 | 3/10/94 |
| 2. Nine Mile Point 1 | 220/91–80–07 | 1/10/92 | 94–20 | 11/4/94 |
| 3. Nine Mile Point 1 | 220/91–80–07A | 1/10/92 | 94–20 | 11/4/94 |
| 4. Nine Mile Point 1 | 220/91–80–07B | 1/10/92 | 94–20 | 11/4/94 |
| 5. Nine Mile Point 1 | 220/91–80–07C | 1/10/92 | 94–20 | 11/4/94 |
| 6. Dresden | 237/91–201–05 | 9/20/91 | 92–21 | 10/8/92 |
| 7. Quad Cities | 254/91011–09A | 6/24/91 | 94–26 | 12/5/94 |
| 8. Quad Cities | 254/91011–9B | 6/24/91 | 94–26 | 12/5/94 |
| 9. Quad Cities | 254/91011–9C | 6/24/91 | 94–26 | 12/5/94 |
| 10. Hatch | 321/91–202–07 | 8/22/91 | 93–19 | 11/2/93 |
| 11. McGuire | 369/91–09–01 | 2/19/91 | 94–20 | 10/12/94 |
| 12. Fort Calhoun | 285/91–01–03 | 5/20/91 | 92–30 | 12/31/92 |
| 13. WNP2 | 397/92–01–20 | 5/5/92 | 93–16 | 6/4/93 |
| 14. Beaver Valley 2 | 412/91–80–02 | 4/1/92 | 93–27 | 1/24/94 |

## III. Conclusion

The institution of proceedings in response to a request pursuant to 10 CFR 2.206 is appropriate only when substantial health and safety issues have been raised. See *Consolidated Edison Co. of New York* (Indian Point, Units 1, 2, and 3), CLI–75–8, 2 NRC 173, 176 (1975), and *Washington Public Power Supply System* (WPPSS Nuclear Project No. 2), DD–84–7, 19 NRC 899, 923 (1984). This standard has been applied to the concerns raised by the Petitioner to determine if the action he requested is warranted, and the NRC staff finds no basis for taking such actions. Rather, as previously explained herein, the NRC staff believes that the Petitioner has not raised any substantial health and safety issues. Accordingly, the Petitioner's request for action pursuant to 10 CFR 2.206, as specifically stated in his letter of February 13, 1996, and supplemented by a letter dated May 1, 1996, is denied.

A copy of this Director's Decision will be filed with the Secretary of the Commission for the Commission's review in accordance with 10 CFR 2.206(c). This Decision will become the final action of the Commission 25 days after issuance unless the Commission, on its own motion, institutes review of the Decision within that time.

Dated at Rockville, Maryland, this 10th day of October 1996.

For the Nuclear Regulatory Commission.

Frank J. Miraglia,

*Acting Director, Office of Nuclear Reactor Regulation.*

[FR Doc. 96–28736 Filed 11–7–96; 8:45 am]

**BILLING CODE 7590–01–P**

**[Docket No. 50–245, License No. DPR–21]**

## Northeast Utilities, Millstone Nuclear Power Station, Unit 1; Issuance of Director's Decision Under 10 CFR 2.206

Notice is hereby given that the Acting Director, Office of Nuclear Reactor Regulation, has taken action with regard to a Petition dated December 30, 1994, by Mr. Anthony J. Ross (Petition for action under 10 CFR 2.206). The Petition pertains to Millstone Nuclear Power Station, Unit 1.

In the Petition, the Petitioner asserted that (1) the licensee does not adequately control work and procedure compliance at Millstone, as evidenced by the use of standard commercial-grade lugs in a gas turbine fuel forwarding pump and motor that are quality assurance (QA) subsystems of the emergency gas turbine generator and which had apparently been crimped using diagonal pliers; improper Raychem splices, cable bend radius, and connections in the connection boxes of major safety-related QA equipment; and installation of non-QA lugs and improperly performed crimping in fire protection QA emergency lights and (2) the Petitioner was subjected to ridicule by the gas turbine system engineer for raising concerns regarding the lugs on the gas turbine fuel forwarding pump and motor. The Petitioner requested that the U.S. Nuclear Regulatory Commission (NRC) (1) ''force'' Northeast Utilities (NU) to review all existing work orders for the past 10 or 12 years, with NRC oversight, to ensure that quality assurance motor and connection work does not have certain deficiencies; (2) assess a Severity Level I violation against NU and its managers for apparent violations of 10 CFR 50.7 and a Severity Level III violation against a gas turbine system engineer at Millstone for his apparent violation of 10 CFR 50.7 and NU's ''Code of Conduct and Ethics;'' and (3) institute sanctions against the system engineer and NU and its managers for engaging in deliberate misconduct in violation of 10 CFR 50.5.

The Acting Director of the Office of Nuclear Reactor Regulation has determined to deny the Petition. The reasons for this denial are explained in the ''Director's Decision Pursuant to 10 CFR 2.206'' (DD–96–17), the complete text of which follows this notice and is available for public inspection at the Commission's Public Document Room, the Gelman Building, 2120 L Street, NW., Washington, DC, and at the local public document room located at the Learning Resources Center, Three Rivers Community-Technical College, 574 New London Turnpike, Norwich, Connecticut, and at the temporary local public document room located at the Waterford Library, ATTN: Vince Juliano, 49 Rope Ferry Road, Waterford, Connecticut.

A copy of the Decision will be filed with the Secretary of the Commission for the Commission's review in accordance with 10 CFR 2.206(c) of the Commission's regulations. As provided by this regulation, the Decision will constitute the final action of the Commission 25 days after the date of issuance unless the Commission, on its own motion, institutes a review of the Decision in that time.

Dated at Rockville, Maryland, this 31st day of October 1996.

For the Nuclear Regulatory Commission.

Ashok C. Thadani,

*Acting Director, Office of Nuclear Reactor Regulation.*

[DD–96–17]

## I. Introduction

On December 30, 1994, Mr. Anthony J. Ross (Petitioner) filed a Petition with