UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W.
ATLANTA, GEORGIA 30323

Report Nos.: 50-369/85-03 and 50-370/85-03

Licensee: Duke Power Company
422 South Church Street
Charlotte, NC 28242

Docket Nos.: 50-369 and 50-370 License Nos.: NPF-9 and NPF-17

Facility Name: McGuire 1 and 2

Inspection Conducted: December 20, 1984 - January 20, 1985

Inspectors: C. W. Burger, for 5/2/85
W. Orders Date Signed

C. W. Burger, for 5/2/85
R. Pierson Date Signed

Approved by: H C Dance 5/3/85
H. C. Dance, Section Chief Date Signed
Division of Reactor Projects

SUMMARY

Scope: This routine, unannounced inspection entailed 276 inspector-hours on site in the areas of operations, safety verification, surveillance testing and maintenance activities.

Results: Of the four areas inspected, three violations were found in two areas (failure to follow operations procedures, paragraph 5; failure to perform surveillance, paragraph 9; failure to implement requirements of 3.0.3. paragraph 7).

REPORT DETAILS

1 Persons Contacted

Licensee Employees

*M. McIntosh, Station Manager
*T. McConnell, Superintendent of Technical Services
*G. Cage, Superintendent of Operations
*D. Rains, Superintendent of Maintenance
*L. Weaver, Superintendent of Station Services
*B. Travis, Operations Engineer
*D. Marquis, Performance Engineer
*R. White, Instrument and Electrical (IAE) Engineer
*J. Silver, Operations Engineer
*K. Reece, IAE Engineer
*N. McCraw, Compliance Engineer
*D. Tropp, Mechanical Maintenance

Other licensee employees contacted included technicians, operators, mechanics, security force members and office personnel.

*Attended exit interview

2. Exit Interview

The inspection scope and findings were summarized on January 22, 1985, with those persons indicated in Paragraph 1 above. The licensee was informed of the violations. The licensee acknowledged understanding of the concerns discussed but expressed philosophical differences concerning equipment operability which must be resolved. These differences of philosophy are currently under review. The licensee did not identify as proprietary any of the materials provided to or reviewed by the inspectors during this inspection.

3. Licensee Action on Previous Inspection Findings

Not inspected.

4. Unresolved Items

Unresolved items are matters about which more information is required to determine whether they are acceptable or may involve noncompliance or deviations. New unresolved items identified during this inspection are discussed in paragraphs 6, 7, and 11.

5. Plant Operations

The inspection staff reviewed plant operations during the report period, December 20, 1984 - January 20, 1985 to verify conformance with applicable regulatory requirements. Control room logs, shift supervisor logs, shift turnover records and equipment removal and restoration records were routinely perused. Interviews were conducted with plant operations, maintenance, chemistry, health physics, and performance personnel.

Activities within the control rooms were monitored during shifts and at shift changes. Actions and/or activities observed were conducted as prescribed in applicable station administrative directives. The complement of licensed personnel on each shift met or exceeded the minimum required by Technical Specifications (TSs)

Plant tours were taken throughout the reporting period on a systematic basis. The areas toured include but are not limited to the following:

Turbine Buildings
Auxiliary Buildings
Units 1 and 2, Electrical Equipment Rooms
Units 1 and 2, Cable Spreading Rooms
Station Yard Zone within the protected area

During the plant tours, ongoing activities, housekeeping, security, equipment status and radiation control practices were observed.

McGuire Unit 1 began the reporting period in Mode 3 preparing for Unit startup following a planned maintenance outage. On December 21, 1984, during pressurization of the Upper Head Injection (UHI) system, the UHI diaphragm was ruptured. Following completion of repairs to the system, unit pressurization was completed and reactor startup commenced. The unit reached criticality at 9:38 p.m. on December 25, 1984, was paralleled to the grid at 4:30 a.m. on the 26th. Power was increased to and maintained at 50% reactor power per grid demand, until December 31, 1984. Power was increased and subsequently reached 100% on January 1, 1985.

McGuire Unit 2 began the reporting period operating at 100% power. At 6:29 a.m. on December 21, 1984, the unit tripped on lo-lo level in steam generator C due to a feedwater swing initiated from a loss of Channel II Vital instrument and Control Power. Details of this event are entailed elsewhere in this section. Recovery was initiated and the unit entered mode 2 at 11:21 p.m., with the reactor reaching criticality at 11:43 p.m. Power ascension was complicated by axial flux deviation penalty time accumulation. On December 23, 1984 while operating at 48% power, the unit experienced a loss of normal letdown when 2NV-1, the reactor coolant letdown isolation to the regenerative heat exchanger, failed closed. Excess letdown was established and power was reduced to 10^{-8} amps in the intermediate range. Excessive valve stem leak-off was noted from 2NV-1. The valve was isolated and repaired. Following completion of repairs, normal letdown was re-established and power ascension commenced. The unit was synchronized to the

grid at 2:27 a.m. on December 24, 1984 and power was subsequently increased to 100%. The unit was operated at or about 100% power until January 4, 1985 when a 50% load reject occurred due to the loss of the only remaining generator power circuit breaker from one of two station output step-up transformers. The other breaker had been previously tagged out for maintenance. Following recovery, power was increased to 100% and was maintained at or about 100% throughout the duration of the reporting period.

Details of the Unit 2 reactor trip from 100% power following loss of channel II, 120 Volt ac, Vital Instrument and Control Power, is described below. On December 21, 1984 Operations personnel were in the process of shutting down Unit 1, 120 Vac, Channel II, inverter (1EV1B) for preventive maintenance. Unit 1 was in mode 3. Operators had correctly applied the alternate supply power to the Unit 1 1EVIB manual transfer switch which would supply power to the vital loads on bus 1EKVB when 1EVIB was removed from service. The operators mistakenly actuated the Unit 2, 2EVIB manual transfer switch for bus 2EKVB, removing it from service without having the Unit 2 alternate supply power available to supply the Channel II instrument and control loads. The Unit 2 analog controllers for steam generator level, feedwater flow, and steam flow were selected to the Channel II instruments when power was lost to them. The feedwater transient following the loss of power to the controlling instrumentation ultimately resulted in a reactor trip due to lo-lo level in the C steam generator.

A Nuclear Control Operator and Nuclear Equipment Operator were to remove 1EVIB and 2EVIB from service to facilitate preventive maintenance on the inverters. The Nuclear Control Operator closed the breaker that provided an alternate ac source to the manual transfer switch for 1EVIB. The operators then went to inverters 1EVIB and 2EVIB, which are located beside each other, and turned the Manual Bypass Switch to "Alternate Source to Load" position on the Unit 2 2EVIB inverter which removed all incoming power. The operator had checked the "IN SYNC" indicator lamps on the inverter and transfer switch (one light on each) but presumed them to be burned out since they were not illuminated.

It is important to note that independent verification is required per Operations Procedure OP/O/A/6350/01A (Enclosure 4.2) which places the Manual Bypass Switch to the "Alternate Source to Load" position on the inverter. Removing 2EVIB from service without an alternate ac power supply resulted in the loss of 120 Vac to all the Unit 2 Channel II vital instrumentation and controls. The loss of power to the selected steam generator level control channels caused a feedwater swing, which ultimately resulted in a reactor trip as detailed above.

It is concluded that the root cause of the event was failure to follow the procedure steps as written and disregarding the equipment indication, namely the unlit "IN SYNC" lamp as well as failure to adequately implement independent verification when the operator turned the "Manual Bypass Switch for 2EVIB to the "Alternate Source to Load" position.

TS 6.8.1.a requires that written approved procedures be employed in the performance of surveillance tests in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978; more specifically procedures for startup, operation, and shutdown of safety-related electrical systems. Implicit in that requirement is the requirement that the procedure be properly implemented. This procedure was not adequately implemented and as such constitutes a violation of TS 6.8.1.a (370/85-03-01). A similar violation on inadequate use of procedures had been identified in Inspection Report Number 50-369/84-11, violation 369/84-11-03.

6. Open Valve Control Breakers

During an operator control board surveillance on January 3, 1985, a Nuclear Control Operator noticed that the position indication lamps for Nuclear Service Water (NSW) valves 2RN 43 and 2RN64 were not illuminated. It was subsequently determined that the breakers for these valves, 2EMXA-R11D and 2EMXA-R9A respectively, were open. The breakers were last verified shut on December 26 and 27, 1984 when PT/2/A/4200/28, Slave Relay Test, was performed. It is reasonable to assume that the breakers were somehow opened after this verification.

A licensee survey did not reveal an activity which could have precipitated placing the breakers in the incorrect position.

NSW valves 2RN43A and 2RN64A are the essential train 2B to nonessential header isolation and AB non-essential return isolation valves respectively. Both valves close on a Train A safety injection signal and blackout signal with 2RN43A closing with a safety injection signal from Train A of either unit. Without power to the valves they would not have closed on an initiating safety signal. However both valves are in series with B train operated valves which were operable.

In another instance, on November 14, 1984, a Nuclear Control Operator noted that the control board open light for 1NV-7B, the outside containment isolation valve for the normal letdown line, was not lit. It was subsequently determined that the valve's power breaker 1EMXB-2F10 was open. The valve had last been determined operable on October 24, 1984 when PT/1/A/4200/02A, monthly Containment Integrity Verification, was performed. A licensee survey failed to determine how or why the breaker was open.

The valve 1NV-7B is designed to close on a containment isolation signal. With power removed from the valve, it was not capable of performing its safety function. The inside containment isolation valves 1NV-457A, 1NV-458A and 1NV-459A were operable during this time period. The safety implication of breakers being inexplicably out of position is cause for concern. The resident inspection staff will continue to evaluate these incidents. Pending completion of this evaluation and the completion of the licensee's investigation, this will be carried as an Unresolved Item. (369/85-03-01).

7. Loss of Control Room Ventilation

On June 4, 1984, both McGuire units were operating at 100% power when at 8:02 p.m., the train B chiller of control area ventilation (VC) tripped, due to what was subsequently found to be low oil level. Train A of VC had been taken out-of-service at 6:56 a.m. that morning for maintenance on the air handling unit. When the B chiller tripped, the control room complex was without an operable train of VC. The inoperability of both trains of VC, while a unit is on-line, is prohibited by TS 3.7.6. At 10:05 p.m. the control operators started to reduce power on Units 1 and 2 as required by TS 3.0.3.

At approximately 10:30 p.m., five gallons of oil were added to the B chiller and the chiller restarted. With VC Train B then operable, the control operators stopped reducing power with each unit having reached 97% power. Train B of VC was declared operable at 10:55 p.m. The units were returned to 100% power at 11:12 p.m.

A detailed review of Licensee Event Report (LER) 50-369/84-18, the LER associated with the above event, revealed two areas of concern as described below.

It has been the history at McGuire that when VC is lost and the control room temperature increases to the 85-90°F range, certain of the solid state electronic equipment located in cabinets in the control room complex, associated with safety systems control and engineered safety features, behave erratically. This was the case on June 4, 1984.

As detailed in the Unit 1 Reactor Operator logbook Volume 21, page 130; at 9:45 p.m. (this is 43 minutes after loosing the B VC chiller) "C loop Tavg started failing high. Think problem due to control room chiller malfunction"; at 9:21 p.m. "the pressurizer level program fluctuating due to temperature in control room". This information concerning the effects that VC inoperability had on other safety-related equipment, i.e. safety significant impact, was not delineated in the LER. This deficiency was brought to licensee management attention on January 22, 1985.

On January 1, 1984, 10 CFR 50.73 became effective. 10 CFR 50.73(b) requires in part that an LER contain a clear, specific narrative description of the event so that knowledgeable readers conversant with the design of commercial nuclear power plants can understand the "complete event". Further, it is required that the failure mode mechanism and "effect" of each failed component be delineated. Moreover, it is required that an assessment of the safety "consequences" and "implications" be entailed. The only reference made in the LER associated with possible safety significant impact was one statement on page 3 of 3 of the LER text. The statement is simply. "The trip of train B chiller while the other train was down for repair caused a loss of all cooling for the control room area, resulting in an increase of temperatures in the control room. This could have eventually resulted in electronic equipment failure and/or reactor trip."

A second area of concern involves the inoperability of the VC equipment. TS 3/4.7.6 requires that two independent Control Area Ventilation Systems (VC) be operable in all modes. With one Control Area Ventilation System inoperable, the inoperable system must be restored within 7 days or the reactor must be shutdown. With both VC systems inoperable the exigencies of TS 3.0.3 became applicable. TS 3.0.3 requires that when a Limiting Condition for Operation is not met (3/4.7.6 above) within 1 hour action shall be initiated to place the unit in a mode in which the specification does not apply.

A review of the design and function of the VC system as detailed in the McGuire FSAR Section 6.4.1, pages 6.4-1, 2, 3, revealed that the Control Area Ventilation and Air Conditioning Systems are designed to maintain the environment in the Control Room, Control Room Area and Switchgear Room within acceptable limits for the operation of "unit controls", for maintenance and testing of the controls as required and for uninterrupted safe occupancy of the room during post-accident shutdown.

Two 100 percent Safety Class 3 redundant air handling systems are provided for the Control Room, two 100 percent Safety Class 3 redundant air handling systems are provided for the switchgear rooms, and two 100 percent Safety Class 3 redundant air handling systems are provided for the Control Room Area (Equipment Rooms, Cable Room, Battery Room, MCC Room, etc.).

The Safety Class 3 air handling units for the Control Room, Control Room Area and Switchgear Rooms are supplied with chilled water by two 100 percent Safety Class 3 redundant chilled water systems, each with one 75 percent capacity chiller and one 100 percent chilled water pump. The air conditioning is designed to maintain the Control Room at approximately 75°F.

A review of reactor operator logbook entries and alarm typer printout for the date in question revealed that contrary to the information relayed in the LER, the B chiller had tripped at 8:02 p.m., not 9:00 p.m. Discussions held with licensee operations and maintenance staff revealed that there were two attempts to restart the chiller; the first at 8:34 p.m. at which time the chiller ran for 3 minutes tripping again at 8:37 p.m.; the second attempt occurred at 9:02 p.m. at which time the chiller would not start. It was after this second attempt to restart the chiller that the licensee declared B train of VC inoperable and entered TS 3.0.3. at 9:05 p.m. Subsequent to entering 3.0.3, it wasn't until 10:05 p.m. that the licensee began reducing power on the units as the requirements of 3.0.3 stipulate.

Having reviewed the design and function of the VC system as detailed in the FSAR as previously delineated above and considering the definition of operable detailed in the TS it appears that on June 4, 1984, at 8:02 p.m. when train B of VC tripped, it should have been considered inoperable. It was subsequently verified to be inoperable by the two start attempts. Thus, McGuire Units 1 and 2 should have entered TS 3.0.3 at 8:02 p.m. Further, as also required by TS 3.0.3, the units should have started power reduction at 9:02 p.m.; this did not occur until 10:05 p.m. It is therefore concluded

that both McGuire Units 1 and 2 were in violation of those requirements on the dates and times specified above.

Further, in as much as certain safety-related components inherent in the control and safe operation of the facility were apparently unstable, as is detailed above, it appears that the conservative approach would have beer to begin a controlled power descent.

Summary:

1. LER 50-369/84-18 appears to be inadequate in that,

   a. the times reported in the LER regarding equipment operability are incorrect, and

   b. there is no discussion in the LER regarding the effects of loss of VC and elevated control room temperature on safety-related electronic equipment located therein.

2. On June 4, 1984, both McGuire Units 1 and 2 appear to have operated for sixty-three minutes (9:02 p.m. until 10:05 p.m.) in Violation of the requirements of TS 3.0.3.

Conclusion:

a. 10 CFR 50.73(b) requires that LER's contain a clear, specific narrative description of the event so that knowledgeable readers conversant with the design of commercial nuclear, power plants can understand the "complete event". Further, it is required that the failure mode mechanism and "effect" of each failed component be delineated. Moreover, it is required that an assessment of the safety "consequences" and "implications" be entailed.

   LER 50-369/84-18, was inadequate in that it was not possible to understand the "complete event" from reading the LER; the effects of the event were not detailed; nor were the safety consequences or safety implications detailed. The licensee has committed to supplementing LER 84-18. Pending review of this supplemental report, this concern will be maintained as Unresolved (369/85-03-02).

b. TS 3/4.7.6 requires that two independent Control Area Ventilation Systems (VC) be operable in all modes. With one Control Area Ventilation System inoperable, the inoperable system must be restored within 7 days or the reactor must be shutdown. With both VC systems inoperable, the exigencies of TS 3.0.3 become applicable. TS 3.0.3 requires that when a Limiting Condition for Operation is not met (3/4.7.6 above) within 1 hour, action shall be initiated to place the unit in a mode in which the specification does not apply.

Contrary to the requirements of TS 3.0.3 on June 4, 1984 at 8:02 p.m., train B of VC tripped placing both McGuire Units 1 and 2 in the exigencies of 3.0.3, though no action was taken to place the units in a mode in which TS 3.7.6 was not applicable until 10:05 p.m. The above described event constitutes a Violation of those requirements (369/85-03-03, 370/85-03-02).

8. Surveillance Testing

The surveillance tests categorized below were analyzed and/or witnessed by the inspector to ascertain procedural and performance adequacy.

The completed test procedures examined were analyzed for embodiment of the necessary test prerequisites, preparation, instructions, acceptance criteria, and sufficiency of technical content.

The selected tests witnessed were examined to ascertain that current written approved procedures were available and in use, that test equipment in use was calibrated, that test prerequisites were met, system restoration completed and test results were adequate.

The selected procedures perused attested conformance with applicable TSs and procedural requirements, they appeared to have received the required administrative review and they apparently were performed within the surveillance frequency specified. However, two cases of missed surveillances are detailed elsewhere in this report.

Procedure	Title
PT/0/A/4600/05A	Radiation Monitor System Operational Tests
PT/1/A/4600/03A	Semi-Daily Surveillance Items
PT/1/A/4700/10	Shift Turnover Verification
PT/1/A/4150/01B	Reactor Coolant Leakage Calculation
PT/2/A/4600/03A	Semi-Daily Surveillance Items
PT/2/A/4700/10	Shift Turnover Verification
PT/1/A/4200/28	Slave Relay Test; Train "B" Feedwater Isolation
PT/2/A/4400/02C	Nuclear Service Water Valve Verification

9. Missed Surveillances

On December 29, 1984, a surveillance required by TS 4.11.2.6 for gas storage tanks was not performed. This TS surveillance requires that the quantity of radioactive material contained in each gas storage tank be determined to be less than or equal to 49,000 curies noble gas (considered as Xe-133) at least once per 24 hours when radioactive materials are being added to the tank.

The missed surveillance was realized when the daily surveillance was being performed on December 30, 1984. The surveillance was performed as required on December 28 and December 30, 1984. In both cases the surveillances were within TS limits. The surveillance was missed due to an administrative

oversight. Subsequently the administrative review was revised in an effort to prevent recurrence.

On January 15, 1985, the licensee determined that the Diesel Generator 1A Fuel Transfer Pump surveillance required per TS 4.0.5 was not performed within its required interval. Technical Specification 4.0.5 delineates Surveillance Requirements for inservice inspection and testing of ASME Code Class 1, 2 and 3 components. Technical Specification 4.0.5 stipulates that the required frequencies for performing inservice inspection and testing shall be in accordance with Technical Specification 4.0.2.

Technical Specification 4.0.2b states that the maximum combined time of three consecutive surveillance intervals for quarterly surveillance is 3.25 times the stated surveillance interval. PT/1/A/4350/17A, Diesel Generator 1A Fuel Oil Transfer Pump Performance Test, was performed on March 20, 1984, July 9, 1984, October 3, 1984 and January 15, 1985. The maximum allowed combined time for PT/1/A/4350/17 was 299 days (92 x 3.25). The actual combined time for the last three consecutive surveillance intervals was 301 days.

This surveillance is routinely performed after or concurrently with performance of an operability test on the associated diesel generator. However, the test engineer responsible for the performance of the surveillance relied on memory for scheduling. The missed surveillance was found by a Preventive Maintenance Periodic Test (PMPT) Program Review. Corrective action included ensuring that the requirement was properly listed on the Test Schedule. In both cases above, administrative oversight coupled with personal error contributed to the missed surveillances.

In as much as a review of licensee enforcement history revealed no other missed surveillances, within the past 6 months, the enforcement flexibility allowed by 10 CFR 2 Appendix C was employed for the first case detailed herein. However, the second case negates the flexibilities allowed. The later event constitutes a violation (369/85-03-04).

10. Maintenance Observations

The maintenance activities categorized below were analyzed and/or witnessed by the resident inspection staff to ascertain procedural and performance adequacy. The completed procedures examined were analyzed for embodiment of the necessary prerequisites, preparation, instruction, acceptance criteria and sufficiency of technical detail. Where applicable, the selected activities witnessed were examined to ascertain that current written approved procedures were available and in use, that prerequisites were met, equipment restoration completed and maintenance results were adequate. The selected work requests/maintenance packages perused attested conformance with applicable TSs and procedural requirements and appeared to have received the required administrative review. A number of the work requests reviewed were analyzed to clear outstanding LER's.

Work Request	Equipment
WR 85848	Investigate and repair blocking relay K 801 for Train "B" feedwater isolation
WR 113101	Repair zone #87 smoke detector
WR 113322	Investigate and repair problems with various fire zones
WR 113494	Investigate and repair reasons for fire alarm on zone 177
WR 113359	Investigate and repair fire zone Z149, Z173, Z175, Z176, Z177
WR 113499	Investigate and repair fire zone 102
WR 113133	Adjust setpoint on 2SV-20"A" main steam line code safety
WR 113096	Investigate cause of fire alarm
WR 53331	Provide assistance for main steam safety valve setpoint test

11. Modification of Control Room Panels

On January 18, 1985 during a control room tour, the inspector noted ongoing modifications of the main control panels. The modifications involved a "temporary modifications" to fix-mount 6 (3 per unit) video monitors to the vertical sections of the control panels. Heretofore, the monitors had simply been sitting in trays but not "seismically mounted".

A review of the Nuclear Station Modification (NSM) which installed these monitors in April 1984, revealed that the "Description of Work Requested" on both the NSM's required that the monitors be seismically mounted. Interviews with licensee personnel revealed that the "seismic" mounting of the monitors involved welding which was postponed until a convenient outage. The temporary modifications, discussed above, simply bolted the bottom of the monitors to the tray to keep them from falling onto equipment below in the case of a seismic event.

Inspection of this event is not complete; therefore, this issue will be maintained as an unresolved item pending the fruition of the analysis. (369/85-03-05)

12. Open Items Review

The following items were reviewed in order to determine the adequacy of corrective actions, the implications as they pertain to safety of operations, the applicable reporting requirements, and licensee review of the event. Based upon the results of this review, the items are herewith closed.

Unit 1, Docket 50-369	Unit 2, Docket 50-370
LER 83-07	LER 83-12
LER 84-30	LER 83-13
LER 84-25	LER 83-22
LER 83-31	
LER 83-35	
LER 83-36	

In addition LERs 369/84-28, 369/84-29 and 370/84-32 were reviewed and will be held open until completion of corrective action.

13. Enforcement Conference

An Enforcement Conference was held at Region II's request in the NRC Region II Office on March 26, 1985, to discuss the inoperability of the Control Area Ventilation System Chiller at McGuire Nuclear Station. The following personnel were in attendance.

a. Duke Power Company

G. Vaughn, General Manager Nuclear Stations
M. D. McIntosh, General Manager Nuclear Support
T. L. McConnell, Manager, McGuire
M. S. Tuckman, Manager, Oconee
E. O. McCraw, Compliance Engineer - McGuire
G. W. Cage, Superintendent of Operations - McGuire
N. Rutherford, System Engineer. Licensing
D. J. Rains, Superintendent of Maintenance
T. P. Harrall, Duke/Design Engineer/Electrical
T. E. Carroll, HP Supervisor, Oconee

Nuclear Regulatory Commission

J. Nelson Grace, Regional Administrator
R. D. Walker, Director, Division of Reactor Projects
P. R. Bemis, Director, Reactor Safety
V. L. Brownlee, Chief, Reactor Projects Branch 2, RII
H. Nicolaras, Oconee Project Manager/NRC/NRR
M. Chinamal, AEOD
J. M. Puckett, Acting Director, EICS, Region II, NRC
H. C. Dance, Section Chief, DRP
W. T. Orders, Senior Resident, McGuire
J. C. Bryant, Senior Resident Inspector, Oconee
K. Sasser, Oconee, Resident Inspector
C. W. Burger, Project Engineer, DRP

b. Event Discussion

The NRC staff opened the discussions concerning the inoperability of the control area ventilation system chiller with the Region II perception of the event including the concern of allowing the control room temperature to increase to the point where instrumentation failures occurred. Duke Power Company (DPC) provided a description of the sequence of events, corrective action and safety significance. The meeting summary notes are described below. The event details are discussed in item 7 of this report and the meeting handouts which are attached.

(1) Sequence of Events

DPC described the sequence of events on June 4, 1984 when both units were operating at 100% power. Train A of the Control Room Area Ventilation Chiller (VC) was declared inoperable for replacement of a bearing in the air handling unit. The Train B VC chiller tripped causing the VC to be inoperable. Train B VC chiller was restarted but tripped again on low oil level. The subsequent increasing control room temperature probably could cause increased random instrumentation failures. DPC began reducing power on both units. Oil was added to the Train B chiller and was successfully restarted. Train B of VC declared operable.

(2) DPC Corrective Action

- Control Room thermostats locked to prevent adjustments
- Change of operating procedure to allow cross connection of components in each train
- Increased surveillance frequency
- Rebalanced supply distribution in Control Room to increase air flow to instrument cabinet area
- Develop abnormal procedures as guidance to operation personnel including action plan to handle loss of control room ventilation
- Develop present operating practice on safety related required TS equipment as follows:

  Any clearly defined rotating equipment is declared inoperable as soon as we find it tripped or as soon as we identify it inoperable for any other reason.

(3) Safety Significance

Rack temperature effects were considered in the McGuire setpoint methodology study which determined the margin between protection system trip setpoints and safety limits assumed in the accident analysis.

Westinghouse performed a test by subjecting a 7300 PCS cabinet, as in normal operation, to a 120°F ambient environment for 12 hours. No card failures occurred.

The McGuire incident caused only 90°F ambient temperatures for approximately one hour with no degradation of protection system performance.

(4) Summary and Comments

The NRC expressed concern that the chiller was not declared inoperable sooner, that the 120°F TS is non conservative and that the control room temperature was allowed to escalate to the point where instrument failures began to occur before action was taken to place both units in Hot Standby.

DPC stated that the operability of the VC chillers is now the same as other safety related componets, that DPC is concerned about control room instrum ntation and that DPC is not basing operation on the 120°F TS limit. Subsequent to the meeting additional administrative controls were announced on elevated temperature in the control room.