APR 01 1994

Docket Nos. 50-369, 50-370
License Nos. NPF-9, NPF-17
EA94-038

Duke Power Company
ATTN: Mr. T. C. McMeekin
Vice President
McGuire Site
12700 Hagers Ferry Road
Huntersville, NC 28078-8985

Gentlemen:

SUBJECT: ENFORCEMENT CONFERENCE SUMMARY - MCGUIRE UNITS 1 AND 2
NRC INSPECTION REPORT NOS. 50-369/93-32, 50-370/93-32, 50-369/93-33, 50-370/93-33, 50-369/94-04 AND 50-370/94-04

This refers to the followup of items identified during the Nuclear Regulatory Commission (NRC) Augmented Inspection Team (AIT) inspection conducted at your McGuire facility on December 29, 1993, through January 4, 1994. Our letter to you dated March 4, 1994, summarized six apparent violations, which were identified during followup inspections to the AIT.

An enforcement conference was held on March 21, 1994, in the NRC Region II office to discuss these apparent violations, the cause and safety significance, and to provide you the opportunity to point out any errors in the inspection report. A list of attendees, enforcement conference summary, and a copy of your enforcement conference handout are enclosed.

Your presentation provided additional information and clarification of the issues associated with the apparent violations and the items identified in our inspection reports. We are continuing our review of these apparent violations to determine the appropriate enforcement action.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice", a copy of this letter and its enclosures will be placed in the NRC Public Document Room.

Should you have any questions concerning this letter, please contact us.

Sincerely,

Orig signed by Jon R. Johnson

Jon R. Johnson, Acting Director
Division of Reactor Projects

Enclosures: See page 2

IE45

Enclosures:
1. List of Attendees
2. Meeting Summary
3. Licensee's Presentation

cc w/encls:
R. O. Sharpe
Compliance
Duke Power Company
12700 Hagers Ferry Road
Huntersville, NC 28078-8985

G. A. Copp
Licensing - EC050
Duke Power Company
P. O. Box 1006
Charlotte, NC 28201-1006

A. V. Carr, Esq.
Duke Power Company
422 South Church Street
Charlotte, NC 28242-0001

J. Michael McGarry, III, Esq.
Winston and Strawn
1400 L Street, NW
Washington, D. C. 20005

Dayne H. Brown, Director
Division of Radiation Protection
N. C. Department of Environment,
Health & Natural Resources
P. O. Box 27687
Raleigh, NC 27611-7687

County Manager of Mecklenburg County
720 East Fourth Street
Charlotte, NC 28202

T. Richard Puryear
Nuclear Technical Services Manager
Carolinas District
Westinghouse Electric Corporation
2709 Water Ridge Parkway, Ste. 430
Charlotte, NC 28217

cc w/encls: See page 3

cc w/encls: Continued
Dr. John M. Barry, Director
Mecklenburg County Department
of Environmental Protection
700 North Tryon Street
Charlotte, NC 28203

Karen E. Long
Assistant Attorney General
N. C. Department of Justice
P. O. Box 629
Raleigh, NC 27602

bcc w/encls:
V. Nerses, NRR
R. Watkins, RII
M. S. Lesser
Document Control Desk

NRC Resident Inspector
U.S. Nuclear Regulatory Commission
12700 Hagers Ferry Road
Huntersville, NC 28078-8985

*FOR PREVIOUS CONCURRENCE SEE ATTACHED

RII	RII	RII	RII	RII MWS
*WMiller	*MLesser	*CEvans	*BUryc	MSinkule
04/ /94	04/ /94	04/ /94	04/ /94	04/ /94 0331

cc w/encls: Continued
T. Richard Puryear
Nuclear Technical Services Manager
Carolinas District
Westinghouse Electric Corporation
2709 Water Ridge Parkway, Ste. 430
Charlotte, NC 28217

Dr. John M. Barry, Director
Mecklenburg County Department
of Environmental Protection
700 North Tryon Street
Charlotte, NC 28203

Karen E. Long
Assistant Attorney General
N. C. Department of Justice
P. O. Box 629
Raleigh, NC 27602

bcc w/encls:
V. Nerses, NRR
R. Watkins, RII
M. S. Lesser
Document Control Desk

NRC Resident Inspector
U.S. Nuclear Regulatory Commission
12700 Hagers Ferry Road
Huntersville, NC 28078-8985

RII	RII	RII	RII	RII
WHM	MSL	CBE		
WMiller	MLesser	CEvans	BUryc	MSinkule
~~04~~/30/94 03	~~04~~/31/94 3	~~04~~/31/94 03	~~04~~/31/94 03	04/ /94

ENCLOSURE 1

LIST OF ATTENDEES

U.S. Nuclear Regulatory Commission

S. D. Ebneter, Regional Administrator, Region II (RII)
J. R. Johnson, Acting Director, Division of Reactor Projects (DRP), RII
A. F. Gibson, Director, Division of Reactor Safety (DRS), RII
B. S. Mallett, Deputy Director, Division of Radiation Safety and Safeguards (DRSS), RII
D. B. Matthews. Director, Project Directorate II-3, Office of Nuclear Reactor Regulation (NRR)
V. Nerses, Senior Project Manager, Project Directorate II-3, NRR
M. S. Lesser, Acting Chief, Reactor Projects Branch 3, DRP, RII
B. Uryc, Acting Director, Enforcement and Investigation Coordination Staff, RII
A. M. Rubin, Regional Coordinator, Office of the Executive Director for Operations
P. L. Eng, Acting Chief, Technical Specification Branch, NRR
R. V. Jenkins, Electrical Engineer, Electrical Engineering Branch, NRR
C. F. Evans, Regional Counsel, RII
L. J. Watson, Acting Enforcement Specialist, RII
J. E. Beall, Enforcement Specialist, Office of Enforcement (By Phone)
G. F. Maxwell, Senior Resident Inspector, McGuire, DRP, RII
W. H. Miller, Project Engineer, DRP, RII
F. N. Wright, Senior Radiation Specialist, DRSS, RII

Duke Power Company

T. C. McMeekin, Site Vice President, McGuire Nuclear Station (MNS)
H. B. Barron, Manager, Nuclear Assessment, General Office
E. M. Geddie, Station Manager, MNS
R. A. Jones, Operations Superintendent, MNS
P. R. Herran, Engineering Manager, MNS
K. D. Thomas, Modifications Manager, MNS
D. A. Baxter, Operations Support Manager, MNS
R. B. Travis, Mechanical/Civil Equipment Engineering Manager, MNS
R. O. Sharpe, Compliance Manager, MNS
J. Lee, Senior Engineer, Nuclear Engineering, MNS

P. R. Pappas, Representative of Catawba Nuclear Station Owner (North Carolina EMC)

ENCLOSURE 2

ENFORCEMENT CONFERENCE SUMMARY

On March 21, 1994, representatives from Duke Power Company (DPC) met with the NRC in the Region II Office in Atlanta, Georgia to discuss the events surrounding the McGuire Unit 2 loss of offsite power and main steam isolation valve failure on December 27, 1993. The conclusions and findings of the special inspection conducted by the NRC Augmented Inspection Team (AIT) on December 29, 1993, through January 4, 1994 were also discussed, along with the results of the followup inspections.

Following opening remarks by Mr. S. D. Ebneter, Regional Administrator, Region II (RII), Mr. J. R. Johnson, Acting Director, Division of Reactor Projects, RII, identified the following apparent violations of NRC requirements which were identified during the inspections: inadequate maintenance and testing for main steam isolation valves; inadequate safety evaluation to review potential impact of turbine runback modification on protective relay coordination; failure to follow procedure to ensure steam line drain valves are closed; incorrect main steam system drawings which depicted fail-close valves as fail-open; failure to make complete and accurate notification to NRC of the event; and failure to define operating crew responsibilities for event oversight, EOP procedure reader, and NRC notification.

DPC gave a presentation, Enclosure 3, on the issues. An introduction to DPC's presentation was given by Mr. T. C. McMeekin, Vice President, McGuire Nuclear Station (MNS). Mr. E. M. Geddie, Station Manager, MNS, provided a description of the event, NRC notification, operating crew responsibilities, and procedure usage for steam line drain closure. Mr. P. R. Herran, Engineering Manager, MNS, gave a presentation on control room drawings, switchyard protective relay coordination, maintenance and testing of main steam isolation valves, and the status of long term corrective actions associated with a reduction of probability of safety injection on the loss of offsite power, root cause of the reactor trip, effects of the excessive cooldown of the reactor coolant system, and failure of the underhung switchyard insulator. Mr. H. B. Barron, Manager, Nuclear Assessment, Duke's General Office, gave a presentation on the effectiveness of Duke's Significant Events Investigation Team (SEIT) process. Closing remarks on Duke's presentation were given by Mr. McMeekin.

Following an open discussion, Mr. Johnson summarized Duke's presentation and closed the meeting by thanking DPC for an informative presentation which enhanced the NRC's understanding of the issue associated with this event.

ENCLOSURE 3

ENFORCEMENT CONFERENCE
DUKE POWER COMPANY
McGUIRE NUCLEAR STATION
UNIT 2

March 21, 1994

LOSS OF OFFSITE POWER

AGENDA

1.	Opening Remarks	T.C. McMeekin
2.	AIT Conclusions	T.C. McMeekin
3.	Event Description	E.M. Geddie
4.	Potential Violations/Root Cause/ Corrective Action/Safety Significance	
	• NRC Notification	E.M. Geddie
	• Operating Crew Responsibilities	E.M. Geddie
	• Procedure Usage for Steam Line Drain Closure	E.M. Geddie
	• Control Room Drawings	P.R. Herran
	• Switchyard Protective Relay Coordination	P.R. Herran
	• Maintenance and Testing of MSIV's	P.R. Herran
5.	Status of Other Long Term Corrective Actions	
	• Reduction of Probability of SI on LOOP	P.R. Herran
	• Root Cause of Reactor Trip	P.R. Herran
	• Reactor Coolant System Cooldown	P.R. Herran
	• Insulator Failure	P.R. Herran
	• SEIT Evaluation	H.B. Barron
6.	Closing Remarks	T.C. McMeekin

AIT CONCLUSIONS

- Ineffective design controls associated with equipment overcurrent protection schemes led to the Unit 2 loss of offsite power event.

- Ineffective maintenance and testing controls led to the failure of the B steam generator main steam isolation valve to fully close on demand.

- Controls over vendor information do not assure that vendor recommendations are readily available for reference and sufficiently evaluated in a timely manner.

- The Emergency Operating Procedures were effective in providing direction to mitigate the event and to safely bring the reactor plant to cold shutdown.

- The operators generally executed the procedures correctly and in a controlled manner. Excessive time was spent reviewing continuous action steps. Corrective actions regarding previous NRC concerns in this area were not effective. Some incorrect actions were taken without the use of appropriate references.

- The duties and responsibilities of senior reactor operators during emergencies were not clearly defined.

- Ineffective oversight regarding Control Room drawing revisions could lead to confusion and delays during an emergency.

- Ineffective oversight to assure proper notification of the NRC resulted in an inaccurate and incomplete report of the event within the required time frame.

- Corrective actions, regarding excessive cooldown and depressurization, from a previous loss of offsite power event were not effective in preventing recurrence.

McGuire LOOP 12/27/93

Sequence of Events

<u>12/27/93</u>	
22:06:31	Loss of 2B Busline due to insulator failure (T/G does not runback)
22:07:00	Loss of 2A Busline due to overcurrent
22:07:08	Unit 2 Rx trip on high flux rate/generates a T/G trip
22:07:18	2A and 2B D/G carrying ETA and ETB and starting to load
22:14:04	Pressurizer low pressure Safety Injection
22:14:05	B Steamline low pressure main steam isolation
22:14:11	2SM1, 2SM3 and 2SM7 indicate closed, 2SM-5 indicates not fully closed
22:22	Shift Supervisor turns over procedure reader responsibilities to another SRO
22:22	Declare Notification of Unusual Event
22:35	"Green Form" sent to state, counties and the NRC
22:36	Auxiliary Feedwater isolated to B S/G
22:40	Safety Injection reset and termination begun
23:42:03	Offsite power restored

<u>12/28/93</u>

00:10	Shift Supervisor decided to activate the TSC to aid in event recovery
00:32	Both emergency buses aligned to offsite power
01:10	TSC activated
01:13	2SM-83, 2SM-89, 2SM-95 and 2SM-101 were inadvertently opened
01:37	A reactor coolant pump was started and forced circulation was re-established
03:30	Began a cooldown of the NC System using S/G PORV
05:30	Recovered condenser vacuum to allow cooldown with steam dumps
06:22	Second offsite power source restored
10:15	Entered Mode 4, Hot Shutdown
12:55	Terminated Unusual Event

<u>12/29/93</u>

04:25	Entered Mode 5, Cold Shutdown

EVALUATION OF OPERATIONS CONCERNS

- Need to enhance delineation of operating crew's roles and responsibilities and continue to improve command and control.
  - Recognized prior to event
  - OMP was revised to include a section more clearly defining roles and responsibilities of the operating crew and command and control model. (Complete)
  - Soft skills assessment on the simulator and in the Control Room.
  - Operations Shift Manager leads the 7:00 status meeting.
  - Continue to evaluate further enhancements.

NRC NOTIFICATION

CONCERN

- NRC notification not done in accordance with procedure
  - wrong form
  - via fax not via ENS phone
- NRC was provided inaccurate follow-up information

NRC NOTIFICATION

DISCUSSION OF EVENTS

- Shift Supervisor delegates notification duties to the Unit 1 Senior Reactor Operator and the Shift Support Assistant

- Unit 1 Senior Reactor Operator initially helps Shift Support Assistant prepare the state and counties "green form" notification but then becomes involved in plant recovery activities.

- Shift Support Assistant faxes the state and counties "green form" to the NRC and considers the NRC notified

- NRC calls to get follow-up to "green form"

- On-call SRO arrives; receives a short, but incomplete briefing on plant status from the Unit 1 Supervisor and is asked to assume NRC communicator duties

- On-call SRO is asked to read the green form to the NRC over the ENS phone and answer NRC follow-up questions

- On-call SRO asks the Shift Support Assistant whether the NRC notification is complete and is told that it has been

- On-call SRO answers follow-up questions on the ENS phone. Some of the answers are incorrect.

NRC NOTIFICATION

ROOT CAUSE

- Insufficient follow-up by the Unit 1 SRO to ensure proper notification.

- Inappropriate action causing inaccurate information being given to the NRC on follow-up questions

NRC NOTIFICATION

CORRECTIVE ACTIONS

We recognize our responsibility to provide timely and accurate information to the NRC.

- Operations Management Procedure (OMP) 2-2, Shift Turnover, has been enhanced to designate an offsite communicator by name. (Complete)

- A training package has been completed by all SRO's on the OMP 2-2 change and restatement of management expectations. (Complete)

- Enhanced licensed operator requal to practice NRC notifications on the simulator and in the classroom. (Continuing)

- Emergency Plan Implementing Procedures are being upgraded to be more user-friendly. (Complete by April 29, 1994)

- Event will be covered in Segment 2 licensed requal. The corrective actions for the notification and inaccurate communications will be discussed. (Complete by April 12, 1994)

NRC NOTIFICATION

FACTORS TO CONSIDER

- Shift Supervisor did delegate notification duties to the Unit 1 Senior Reactor Operator and the Shift Support Assistant

- McGuire had made numerous NRC notifications in the past. Use of the wrong notification form or providing inaccurate information have not been problems in the past.

- Although the initial communication to the NRC was done on the wrong form, the communication contained all the necessary plant information and was done within 1 hour.

NRC NOTIFICATION

SAFETY SIGNIFICANCE

- None
  - The NRC notification was made within one hour of event classification.
  - The inaccurate information provided to the NRC was corrected by the TSC communicator.

OPERATING CREW RESPONSIBILITIES

CONCERN

- Duties of the facility licensee for emergency response are not unambiguously defined per 10CFR50.47.

OPERATING CREW RESPONSIBILITIES

DISCUSSION OF EVENT

- The Shift Supervisor was the Emergency Procedure reader for the initial 15 minutes

- The Shift Supervisor delegated notification duties to the Unit 1 Senior Reactor Operator and the Shift Support Assistant while the Shift Supervisor was the Emergency Procedure reader

- The notification to state and county agencies was appropriately made, the NRC notification was not made in accordance with procedure

OPERATING CREW RESPONSIBILITIES

ROOT CAUSE - NOT APPLICABLE

- Duties were defined in accordance with 10 CFR 50.47.

- However, this event revealed opportunities to improve procedural guidance and communication of management expectations regarding duties and responsibilities of the control room team.

OPERATING CREW RESPONSIBILITIES

CORRECTIVE ACTIONS

SHORT TERM

- Operations Management Procedure (OMP) 2-2, Shift Turnover, was enhanced to designate an offsite communicator by name. (Complete)

- A training package was issued to all SRO's on the OMP 2-2 change and restatement of management expectations. (Complete)

- Operations Management Procedure has been enhanced to include a section describing the control room team individual roles and responsibilities in more detail. The new section also describes the Command and Control model. (Complete)

- Operations manning philosophy for 1994 is to schedule 4 SROs on shift at all times. (Complete)

LONG TERM

- Clear expectations will be implemented (at all 3 Duke sites) with respect to the roles of on-duty SROs during an event.

OPERATING CREW RESPONSIBILITIES

FACTORS TO CONSIDER

- Various Duke Management Documents such as the Duke Nuclear Policy Manual, Operations Management Procedures and the Emergency Plan describe the responsibilities of the on-shift emergency response crew. These documents describe the responsibilities of the Shift Supervisor, the Shift Technical Advisor and the control room operating crew.

OPERATING CREW RESPONSIBILITIES

FACTORS TO CONSIDER (CONTINUED)

- Control Room staffing during the start of the event exceeded McGuire Technical Specification and McGuire Emergency Plan staffing requirements

Tech Specs	Emer Plan	Actual	1994
1 Shift Supv	1 Shift Supv	1 Shift Supv	1 Shift Supv
1 addt. SRO	1 addt. SRO	2 addt. SROs	3 addt. SROs
1 STA	1 STA	1 STA	1 STA
3 ROs	2 ROs	4 ROs	4 ROs

- The Shift Supervisor also called in an additional SRO and 2 RO's

OPERATING CREW RESPONSIBILITIES

FACTORS TO CONSIDER (CONTINUED)

- Operations recognized a need to enhance guidance on control room personnel guidance and was developing this enhanced guidance prior to the event.

- All Operations licensed operators and non-licensed operators are trained on Emergency Plan responsibilities annually. Each shift goes through a drill each year.

- The Assistant Shift Supervisors understood that they needed to report to the Control Room and that one of them needed to relieve the Shift Supervisor from reading duty.

- McGuire has numerous ongoing improvement projects. (eg. OMP Enhancement For Useability and Guidance, Increase Management Involvement in Simulator Training, Soft Skills Assessment of Crews on the Simulator and in the Control Room)

- The Shift Supervisor oversight was adequate during the event.

  - Activated the TSC and OSC

  - Called in additional resources

  - Mitigated event

  - Ensured Control Room crew correctly diagnosed event and correctly implemented EOPs.

OPERATING CREW RESPONSIBILITIES

SAFETY SIGNIFICANCE

- None
  - The health and safety of the public was maintained
  - The plant was maintained in a safe condition
  - The Shift Supervisor's command and control was adequate

PROCEDURE USAGE FOR STEAM LINE DRAIN CLOSURE

CONCERN

- Incorrect actions were taken by Operations which inadvertently opened four containment isolation valves.

PROCEDURE USAGE FOR STEAM LINE DRAIN CLOSURE

DISCUSSION OF THE EVENT

DESCRIPTION OF THE EQUIPMENT

- 2SM–83, 2SM–89, 2SM–95 and 2SM–101 are 4 of 20 steam line drain valves
- These 4 are upstream of the MSIVs
- Designed to automatically remove moisture from low points in the main steam lines
- Two inch, air operated valves
- All 20 steam line drain valves fail open on Unit 1
- The 16 steam line drain valves downstream of the MSIVs fail open and the 4 upstream fail closed on Unit 2
- Although classified as containment isolation valves, these 4 valves received no signals and are not required to close under accident conditions, the accident analysis takes no credit for their position

PROCEDURE USAGE FOR STEAM LINE DRAIN CLOSURE

SEQUENCE OF EVENTS

- Performance of EP/01, Reactor Trip or Safety Injection, step 12 requires a check of NC System heat removal

- Substep "e" requires that operator check "NC Loop Tavg – STABLE OR TRENDING TO 557°F." It was not.

- The Response Not Obtained (RNO) requires the operators ensure the steam dumps and S/G PORVs are closed, and the MSR are reset. This was all true.

- The RNO requires the operators close 2SM–15 (Main Steam to 2nd Stg Rhtrs) if any MSIV is open. 2SM–5 was not fully closed. An NLO was dispatched to locally close 2SM–15.

- The RNO requires the operator select "CLOSE" for 2SM–83, 2SM–89, 2SM–95 and 2SM–101. The operators did this and received no confirmatory indication.

- The control room staff recalled one of the units had modified these valves to fail closed. They could not remember which unit.

- As a result of (1) a lack of confirmatory indication, (2) continued NC system cooldown, and (3) past practice and experience with these valves, the control room staff dispatched an NLO to locally close the four valves shut.

PROCEDURE USAGE FOR STEAM LINE DRAIN CLOSURE

DISCUSSION OF THE EVENT

SEQUENCE OF EVENTS - Continued

- The dispatched NLO returned and reported the local actuator had been removed from the valves and he had not been able to locally close them. He further reported the lines downstream felt hot.
- The STA, acting at the direction of the Shift Supervisor, instructed the shift IAE technicians to assure that 2SM-83, 2SM-89, 2SM-95 and 2SM-101 were closed.
- The IAE technicians pulled the appropriate drawings from the IAE file room. They did not take note of the NSM stamp on the drawing.
- The IAE technicians determined that the four valves failed open and how they should air jumper the valves shut.
- IAE technicians informed the control room staff that air jumpers would be used to close the valves. The control room staff gave them clearance to do the work.
- IAE technicians placed the air jumpers at ≈0115 hours and reported the completion of their work to the control room staff.
- The control room staff and the IAE technicians believed they had closed the four valves.
- 2SM-83, 2SM-89, 2SM-95 and 2SM-101 remained jumpered open until 12/30/93.

PROCEDURE USAGE FOR STEAM LINE DRAIN CLOSURE

ROOT CAUSE

- 2SM–83, 2SM–89, 2SM–95 and 2SM–101 were inadvertently opened as a result of inappropriate action on the part of the IAE technician.

PROCEDURE USAGE FOR STEAM LINE DRAIN CLOSURE

CORRECTIVE ACTIONS

- All IAE personnel were counseled on the importance of attention to detail and the proper use of drawings. (Complete)
- All IAE personnel were trained on the proper use of drawings and how drawing use impacted this event. (Complete)
- The Work Control Center will provide more structure for work planning and execution. (Complete)

PROCEDURE USAGE FOR STEAM LINE DRAIN CLOSURE

FACTORS TO CONSIDER

UNIT DIFFERENCES CREATED DOUBTS FOR OPERATORS

- On Unit 1, all 20 of the steam line drain valves fail open on loss of electrical power
- On Unit 2, only the 4 steam line drain valves upstream of the MSIVs fail closed on loss of electrical power (this mod was recently completed during the summer refueling outage)
- Unit 1's emergency procedures require the operators to gag these valves shut if the position indication lights are not lit.
- Unit 2's emergency procedures assume the valves have failed closed and make no reference to the indication lights.
- Simulator training is conducted using Unit 1 procedures.

THE POSITION OF THESE VALVES WAS NOT A TOP PRIORITY

- The unit had lost offsite power, tripped, safety injected, and was experiencing a faster than desired cooldown.
- 2SM-5 had not fully closed and was the primary reason for the continued cooldown. Attempting to close this valve was a top priority.
- Restoration of offsite power was a top priority.
- Maintaining our ability to dump heat was a top priority with the loss of condenser vacuum.

PROCEDURE USAGE FOR STEAM LINE DRAIN CLOSURE

SAFETY SIGNIFICANCE

- The safety significance of inadvertently opening 2SM-83, 2SM-89, 2SM-95 and 2SM-101 was minimal.

- The valves were opened almost 3 hours into the event. Actions had already been taken to stabilize the plant and restore conditions to normal.

- The B S/G was being blown down through 2SM-5 and sixteen failed open steam line drains to the condenser.

- The resulting impact was so minimal that it was not observed by the Control Room staff.

CONTROL ROOM DRAWINGS

CONCERN

- A Flow Diagram depicted Fail Closed Valves as Fail Open, which does not meet the requirements of 10 CFR 50, Appendix B, Criterion VI.

- Final as–built drawings were not issued in a timely manner.

CONTROL ROOM DRAWINGS

DISCUSSION OF EVENTS

- Modification MG-22401, Modify Main Steam Drain Isolation Valves To Fail Close On Loss Of Air, was completed on August 31, 1993.

- Interim as-built drawing:

  - By procedure, modification stamps placed on drawings to indicate configuration change.

  - By procedure, Operations reviewed modification for significant changes to be redmarked on Control Room drawings.

  - Changes were not considered to be operationally significant and Control Room drawings were not redmarked.

- The permanent as-built drawing was not issued within the prescribed 75 days due to a backlog from the outage.

- These drawings were not referenced during the LOOP event.

CONTROL ROOM DRAWINGS

ROOT CAUSE - NOT APPLICABLE

- These drawings were handled in conformance with the established document control program.

  However, Duke agrees that the past redmarking procedure was not optimum, and therefore has amended the program as described in Corrective Actions.

- As-built drawings should be completed within 75 days; however, interim as-built drawings were available.

CONTROL ROOM DRAWINGS

CORRECTIVE ACTIONS

SHORT TERM

- Control Room flow diagrams and one-line diagrams were fully redmarked prior to restart to reflect all configuration changes. (Complete)

- Effective March 15, 1994, Engineering assumed responsibility for redmarking Control Room flow diagrams and one-line diagrams for all modifications. (Complete)

LONG TERM

- A final as-built drawing for all Control Room flow diagrams and one-line diagrams will be issued prior to the affected systems/components being returned to service. In rare circumstances when this is not possible, Engineering will perform full redmarking of the Control Room flow diagrams and one-line diagrams as stated above. (Complete by end of 1EOC9)

CONTROL ROOM DRAWINGS

SAFETY SIGNIFICANCE

There is minimal safety significance due to the as-built status of this drawing.

SWITCHYARD PROTECTIVE RELAY COORDINATION

CONCERNS

- The 10 CFR 50.59 Evaluation for the modification changing the runback rate to 3 minutes did not consider the effect on switchyard relaying which constitutes an Unreviewed Safety Question.

- Another modification adding relaying to the MSU Transformers was an additional opportunity to improve relaying coordination.

SWITCHYARD PROTECTIVE RELAY COORDINATION

DESCRIPTION OF THE EQUIPMENT

- McGuire's offsite power scurces utilize depth of design with two immediate access buslines which do not require bus transfer schemes on unit trips to maintain offsite power.

- The original design depended on a 56% turbine runback in 15 seconds on loss of one busline to remove an overcurrent condition on the remaining busline.

SWITCHYARD PROTECTIVE RELAY COORDINATION

DISCUSSION OF EVENTS

- 1985 – Loss of Offsite Power Task Force recommended a number of enhancements to improve reliability of offsite power.

- 1987 – NSM MG 22004 replaced a portion of turbine controls with the DEH System to improve response time. A new three–minute runback capability was provided in this system but not placed in service.

- 1989 – two of the recommendations of the Loss of Offsite Power Task Force were implemented:

  MG 22017 (1/89) – Added overcurrent relaying to supervise a three–minute runback to protect the main step up transformers and isolated phase bus.

  MG 22236 (4/89) – Provided redundant switchyard breaker status input to the runback circuit and provided runback with loss of busline tie to the grid to enhance reliability. The field inputs were moved to the three– minute runback circuit.

  The same team designed both modifications and was under the impression that the three–minute runback was an existing and analyzed plant function.

- 1991 – Unit 2 experienced a busline trip which initiated a successful runback and maintained offsite power through the second busline.

- 1993 – in the LOOP event, the switchyard protective relaying cleared the second offsite power source upon failure of the turbine runback system.

SWITCHYARD PROTECTIVE RELAY COORDINATION

ROOT CAUSE

Inadequate research into the design basis and licensing (FSAR) documentation for both the modification design and the 10 CFR 50.59 evaluation.

SWITCHYARD PROTECTIVE RELAY COORDINATION

CORRECTIVE ACTIONS

IMMEDIATE

- Blocked busline overcurrent relays, thereby removing the dependency on a turbine runback. (Complete)
- Study of Generator, Busline, and Switchyard Relaying Related to Independence of Offsite Power. (Complete)
- Screened past modifications for potential relaying impact on offsite power availability. (Complete)

LONG TERM

- Conduct a Self-Initiated Technical Audit of the McGuire Power Distribution System. (Complete by 12/94)
- Expand the Design Basis Documentation program to include an Offsite Power DBD. (Complete by 12/95)
- Modify the Electrical Modification Checklist to address enabling existing system features. (Complete 7/94)
- Review lessons-learned with appropriate Engineering personnel of McGuire, Catawba, and Oconee. (Complete 7/94)

MODIFICATION PROCESS ENHANCEMENTS

- In 1992, began using an "on site" modification team to improve communications and design reviews.
- As of December, 1993, the Engineering Staff has completed McGuire Systems training.
- In 1994, the McGuire system engineers will develop the scope of the modifications.

SWITCHYARD PROTECTIVE RELAY COORDINATION

FACTORS TO CONSIDER

MODIFICATION SCOPE DEVELOPMENT

- There was a misunderstanding in the scope development that the three minute runback was an existing and analyzed function.

- The modification did not create the three-minute turbine runback, but simply provided an input to the DEH.

SWITCHYARD PROTECTIVE RELAY COORDINATION

SAFETY SIGNIFICANCE

Offsite power could have been restored by either of the following methods:

- The ability to immediately reclose the remaining busline upon loss of a busline and supply the total safety and non- safety plant loads.

- The availability of two additional offsite power sources for the emergency power system through alignment to the other unit using Procedure EOP 09, Loss Of All AC Power or AOP 07, Blackout.

The relaying coordination issue would not result in unavailability of offsite power for a significant period of time.

MAINTENANCE AND TESTING OF MSIV's

CONCERN

- 2 SM–5 on B Steam Generator did not fully close on MSI signal

- 2 SM–7 on A Steam Generator experienced some minor binding.

- Maintenance procedure did not specify clearances for yoke rods and yoke rod guides.

- Test procedures did not require the valve to be tested at normal operating conditions – full temperature and pressure.

- Several opportunities existed to incorporate vendor information into station procedures.

MAINTENANCE AND TESTING OF MSIV's

DISCUSSION OF EVENT

- September 1980: Du-ng the second hot functional test, it was found that three of the MSIVs would not fully close. After active involvement with the manufacturer, the station, and Design Engineering, the cause of the failure could not be determined. As a result, an air to close feature similar to the type the manufacturer supplies with BWR MSIVs was installed on both units 1 and 2.

- May 1981: Manufacturer sent a letter to Duke describing setting valve Yoke Rod Guides while at operating temperature and specifying a clearance value.

- July 1983: Generic Letter 83-28. Duke enhanced OEP Program to include Vendor Information Letters.

- September 1989: It was discovered (ref. PIR 0-M89-0239) that components installed in the air to close feature had not been seismically and/or environmentally qualified.

- March 1992: The valves were tested (cold) to see if they could meet the 8 second closing requirement without the need of the air to close feature. The valves passed this test and the air to close feature was removed.

- April 1992: The vendor manual revision requested by Duke was received. The manual revision and subsequent changes made to it by the manufacturer were considered incomplete by Duke, which resulted in several exchanges of the information. The vendor manual had therefore not been adopted at the time of the LOOP event.

MAINTENANCE AND TESTING OF MSIV's

DISCUSSION OF EVENT (CONTINUED)

- During the LOOP event, 2SM-5 was found 1-2 inches off its seat. Upon loosening one yoke rod guide, the valve fully closed.

- After cooldown from LOOP event, all four MSIVs were found fully closed.

- Transient evaluation showed that there may have been some leakage past 2SM-7 during the event but that its safety functions were performed.

  - All four MSIV yoke rod guides were adjusted during the outage, and the valves were successfully stroked cold.

  - During hot testing, 2SM-7 pilot valve did not fully close.

  - Yoke rod guide adjustments were made on all four MSIVs and all were successfully stroked hot.

MAINTENANCE AND TESTING OF MSIV's

ROOT CAUSE

- Vendor recommendations not incorporated into plant procedures.

MAINTENANCE AND TESTING OF MSIV's

CORRECTIVE ACTIONS

SHORT TERM

MSIV

- Incorporated vendor recommendations into maintenance and testing procedures.

- Tested MSIV's hot on both units

- Shared event with the industry

  - Nuclear Network Message to alert others doing cold testing of MSIVs

  - Presentation on the event at the 2/23/94 WOG Operations Subgroup meeting.

VENDOR INFORMATION

- Reviewed OEP program for outstanding Vendor Information Letters (VIL).

- Polled entire Engineering staff for outstanding vendor information not incorporated into station procedures.

MAINTENANCE AND TESTING OF MSIV's

CORRECTIVE ACTIONS

LONG TERM

- OEP program has been enhanced requiring a PIP (Problem Identification Process) to be initiated with each VIL. – Complete.

- Establish an equipment and system testing policy that appropriately considers risk versus benefit to overall plant safety. If test is not conducted at desired conditions, identify additional actions or analysis needed. Policy is being jointly developed by MNS, ONS and CNS. – Phase I, 5/94

- The new engineering organization stream lines handling of vendor manuals. Vendor manuals now go directly from the vendor to the plant equipment engineer. – 4/94

- Enhance equipment sponsor expectations for vendor documents in the Engineering Documents Manual. – 5/94

MAINTENANCE AND TESTING OF MSIV's

FACTORS TO CONSIDER

- A decision was made in the early 1980's on hot testing of MSIV's. The risk of an inadvertent SI (on steam pressure negative rate while cycling valve) was given greater priority than testing MSIV at full temperature and pressure.

- The MSIV's have historically tested successfully in meeting the periodic testing requirements of Tech Specs and ASME code requirements. Testing was done in cold condition.

MAINTENANCE AND TESTING OF MSIV's

SAFETY SIGNIFICANCE

The safety functions of the MSIVs are to limit:

- Reactivity inserted by cooldown in a steam line break to limit fuel failures due to DNB
- Mass and energy released into containment during a steam line break to limit peak containment pressure
- Mass and energy released into containment during a steam line break to limit peak containment temperature
- The release of radioactivity to the environment

Conclusions about the ability of the MSIV to perform these safety functions:

- Although a specific analysis has not been performed, there is a significant chance that fuel failures due to DNB would continue to be avoided; if not, fuel failures would be limited to 5%
- The blowdown of two SGs will not release enough energy to completely melt the ice condenser inventory; therefore, large LOCA remains bounding from a peak pressure standpoint
- Although the cooling from the increased ice condenser drain flow might not completely offset the heating from the additional steam releases, there is margin between the existing peak temperature analysis result and the lowest relevant equipment qualification limit
- For this event, there were no significant radiological releases

  Licensing Basis Events will be reevaluated with replacement steam generators

REDUCTION OF PROBABILITY OF SI ON LOOP

CONCERN

- Main Steam Isolation (MSI) and SI occurred approximately 7 minutes after LOOP
- LOOP Safety Analysis does not address over cooling

REDUCTION OF PROBABILITY OF SI ON LOOP

DISCUSSION OF EVENT

- Primary cooldown and secondary pressure decrease due to:
  - No RCP heat input
  - Steam loads from fail-open non-safety steam drains
  - Steam load to the turbine driven aux feed pump
  - Feedwater flow from both the motor driven and turbine driven aux feedwater pumps

- Operators reviewed items on foldout page:
  - SI criteria
  - Natural circ criteria

  and were at step to control cooldown when MSI/SI occurred

REDUCTION OF PROBABILITY OF SI ON LOOP

CORRECTIVE ACTION

- Implement Project: "Decrease MSI/SI Probability after LOOP"
- Project goal: Assure plant response provides adequate time for operator action, and operator response is timely and effective, to prevent MSI/SI after LOOP
- Modifications prior to next operating cycle:
  - Complete modification to steam drains upstream of MSIVs (Unit 1)
  - Modify steam drains down stream of MSIVs to fail–close on LOOP
- Above modifications sufficient for project goal; evaluation of potential change in turbine driven AFW pump start logic in progress (would require TS change)
- Operator training package issued, training will be complete by 4/12/94
  - Enhanced use of foldout page
  - Promptly controlling cooldown after LOOP by throttling AFW and closing MSIVs
- Emergency Procedure changes include
  - Guidance to use Tcold versus Tavg on LOOP
  - Revised handling of foldout page (complete)

REDUCTION OF PROBABILITY OF SI ON LOOP

FACTORS TO CONSIDER

- PWRs are subject to over cooling on Loss of Power
- Cooldown and MSI/SI have no impact upon LOOP accident analysis
- More limiting over cooling events are analyzed in the FSAR
- Previous McGuire LOOP events showed over cooling due to steam loads and AFW, with successful operator action to stabilize the plant. SI occurred in one previous event.

ROOT CAUSE OF REACTOR TRIP

ISSUE

- Event data has raised the possibility that the High Flux Rate Trip occurred due to a voltage transient.

ACTIONS

- An engineering study has been initiated consisting of the following activities:
  - Investigate the alignment of the AC power source to the NIS system.
  - Investigate the configuration of the instrument grounding and equipment isolation.
  - Evaluate the possibility of an electrical transient occurring due to a full load rejection.
  - Investigate whether any other plant equipment was similarly affected.

SCHEDULE

- The study will be completed by 5/1/94. Recommendations will then be reviewed and selected for implementation.

SIGNIFICANCE

- This is not a safety or reliability issue.

COOLDOWN LIMITS

ISSUES

- Exceeded LCO on Reactor Coolant System maximum cooldown rate as specified in Technical Specification (TS).
- Maximum Cooldown rate per TS: 100 degrees F/Hr.
- Actual Cooldown Cold Leg B Loop: 140 degrees F/Hr.

ACTIONS

PRIOR TO RESTART

- Satisfy TS Acticn Statement - Perform an Engineering Evaluation to determine the effects of the out-of-limit condition on the structural integrity of the Reactor Coolant System.
  - Reactor Vessel
  - Reactor Piping
  - Steam Generator

POST RESTART

- None

INSULATOR FAILURE

- Duke's metallurgy lab completed the determination of the cause of the failure of the underhung multicone insulator on 1/1/94.
- Evaluated impact for failures of other insulators in switchyard and determined busline bay areas were critical on 2/25/94.
- NGD/PDD Switchyard Interface Agreement was approved on 3/4/94 and implementation planning is now underway.
  - Switchyard work will be performed by Generation Services and documented in the Work Management System.
  - Formal switchyard maintenance procedures will be established.
  - A Switchyard Oversight Committee will be established to share information and review issues in respect to unit availability between the Power Delivery Engineering and Site Engineering Groups.
  - Extend the Operating Experience Program to PDD for switchyard issues.
- An initial description of the problem was sent out via Nuclear Network on 12/31/93. Insulators that did not fail are undergoing test in Duke's metallurgy lab and at the vendor's facility. Results of this test will be known 4/94 and shared with the industry.
- Switchyard and busline insulators will be reinspected and suspect insulators replaced during upcoming outages (Unit 1, 8/94 and Unit 2, 12/94)

EFFECTIVENESS OF SIGNIFICANT EVENT INVESTIGATION TEAM (SEIT) PROCESS

- Results of AIT and SEIT not identical – processes differ

- Process improves with each opportunity

- MNS LOOP SEIT considered to be best to date

- Effectively supported site management in directing recovery and restart process

THINGS THAT WENT WELL DURING THE LOOP EVENT

1. Offsite power from busline 2A was available. Offsite power was not reestablished immediately because emergency power was available and the operators had higher priorities.

2. Both emergency diesel generators functioned perfectly. They came up to speed and all loads sequenced on as designed.

3. The decision of the Shift Supervisor to activate the TSC and OSC - this is not required nor normally done for an Unusual Event. This was a very sound judgment call by the Shift Supervisor. The procedure cannot cover every scenario and this decision was a significant help in addressing a challenging situation.

4. The decision to call in an additional SRO and two additional ROs was also very appropriate. Although MNS staffing exceeds the licensing requirements by a noticeable margin, a challenging event quickly uses available resources.

5. The overall handling of the event by the Operations Shift Team from a plant perspective (less the NRC reporting and SM drains). The plant was shut down and cooled down in a safe and timely manner. Hundreds of procedure steps were adhered to properly and the plant was placed in safe condition without damage to equipment or injury to personnel.

6. The TSC/OSC response to the event was handled well. An important contribution the TSC made was the decision not to fill the B S/G with cold auxiliary feedwater. This could have thermally shocked the tubes. Field monitoring teams were dispatched as a conservative action.

7. The decision of the Emergency Coordinator early in the event to develop a "Recovery Team" and charter for that team. This significantly enhanced a timely and efficient event recovery.

8. The decision to initiate a SEIT and dispatch that day enhanced a timely, thorough event recovery plan.

NRC INSPECTION REPORTS 50-369/93-33 AND 50-370/93-33
LICENSEE COMMENTS

1. In the executive summary item 5, the report says "Corrective actions regarding previous NRC concerns in this area have not been effective". This concern was directed at an initial license class exam.

2. In the executive summary item 6, the report says "The duties and responsibilities of senior reactor operators during emergencies were not clearly and formally defined". It is our position that these responsibilities were defined and understood by the operators. We do agree, however, that the execution of them in this case was not without some problems and we are addressing those.

3. On page 2 of the report, in the third paragraph, it says that "--- the Pressurizer Relief Tank (PRT) was overpressurized, actuating the tank's rupture disk". This seems to imply this was unexpected when in fact the PRT functioned as designed.

4. On page 4 of the report, the entry for 10:07:20 says "All RCS pumps tripped due to loss of power". In fact, the RCS pumps lost power at 10:07:08 when all normal power was lost.

5. On page 9 of the report in the 7th paragraph of section 2.3.2, it says "Due to post trip recorder problems, auxiliary feedwater flow to each steam generator above 300 gpm was not recorded ---". In fact, 300 gpm is the maximum range of this instrumentation as it is designed and there was no problem as it functioned as designed.

6. On page 9 of the report in the first paragraph of section 2.3.3, it says "The PRT is located in lower containment and has a rupture disk which actuates at 100 psig". In fact, the PRT has two rupture disks.

7. On page 9 of the report in the first paragraph of section 2.3.3, it says "Based upon the B RCS cold leg exceeding 100 degrees cooldown, the procedure directed the operators to lower RCS pressure in order to limit the differential pressure across the tubes of B steam generator (which was Anticipated to go dry) to less than 1600 psid". The procedures do not base the 1600 psid limit on having exceeded the 100 degree/hr cooldown rate.

8. On page 10 of the report in the first paragraph of section 2.3.3, it says "The PRT rupture disk actuated at 11:26 p.m. when tank pressure exceeded 100 psig". In fact, the maximum pressure in the PRT prior to actuation of the rupture disks was approximately 60 psig.

9. On page 12 of the report in ~~the first paragraph~~ of section 3.3, it says "Structural failure of the electrical insulator caused a phase to phase fault". The fault was a single open phase fault.

10. On page 13 of the report in the 8th paragraph of section 3.3 it says "This made the operability of redundant offsite power paths unnecessarily reliant upon a functional turbine runback and was the root cause for the loss of offsite power event". We disagree with this conclusion in that the root cause of the loss of offsite power event was the failure of the turbine runback circuit to function.

11. On page 18 of the report in the third paragraph of section 4.4 it says "--- appears in part to randomly rely on perceived problems with the manual". We disagree with the word "randomly".

12. On page 18 of the report in the second paragraph of section 5.1 it says"After a reactor trip, the operators implement the EOP's by first reviewing the 'fold out' page of the EOP". This is not correct in that the operators perform the first five immediate actions of the EOP for reactor trip or safety injection, then implement the CSF's due to transition from EP/01, then go to EP/1.3 and review the foldout page.

13. On page 21 of the report in the second paragraph of section 5.2, there is a typo in that the words "expected that another SRO will assume the CRSO duties, at some point later" are repeated.

14. On page 21 of the report in the third paragraph of section 5.2 it says "It is questionable whether the SS was able to effectively maintain an overview of the event while actively responding to the event as the procedure reader". While we agree this may not be optimum, we do not consider this to be unacceptable for 15 minutes.

15. On page 22 of the report in the third paragraph of section 5.3 it says "However the control room operators assumed the valves failed open on loss of power ---". In fact, the operators did not assume this. They could not remember the failure mode and decided to insure the valves were closed.

16. On page 23 of the report in the 4th paragraph of section 5.3 it says "However the operators did not refer to drawings or other references prior to taking the actions". Since the operators had asked IAE to insure the valves were closed, the operators had no reason to refer to the drawings and took the appropriate action by deferring this task to IAE so they could focus on other plant concerns.

17. On page 24 of the report in the 4th paragraph of section 5.4 it says "The team determined that the NRC had a previous finding during an operator license examination (Examination report 50-369/92-301 dated January 12, 1993) regarding the review of foldout pages". This was directed at an initial license class.

18, On page 24 of the report in the 4th paragraph of section 5.5 it says "These action were at their own initiative, without procedural direction ---". In this situation, the operator's actions were appropriate. Procedures do not prevent local actions.

19. On page 22 of the report in the 6th paragraph of section 6.5 it says "--- nor did the SS clearly delegate someone to do so". We disagree with this in that the SS in fact instructed the Unit 1 SRO to do the notifications.

20. On page 29 of the report in the first paragraph of section 6.6 it says "Lack of oversight regarding the quality of Control Room Vital to Operation ---". We disagree with this statement in that in fact our existing program did provide oversight and the drawings were red-marked in accordance with our program.

21. On page 29 of the report in the third paragraph of section 6.6 it says "Inadequate oversight to assure proper NRC notification and lack of clear assignment ---". It is our position that these responsibilities were defined and understood by the operators. We do agree, however, that the execution of them in this case was not without some problems and we are addressing those.

22. On page 31 of the report in the 5th paragraph of section 8.0 it says "The SEIT actually considered that turnover of this duty should have been delayed until a crew briefing was conducted prior to event diagnosis". The SEIT said that it may have been more effective had the SS kept these duties until the briefing was conducted after event diagnosis and prior to transition to another procedure.