UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

April 28, 1988

MEMORANDUM FOR: Steven Varga, Director
Division of Reactor Projects - I/II, NRR

Lawrence Shao, Director
Division of Engineering and Systems Technology, NRR

Jack W. Roe, Director
Division of Licensee Performance and Quality Evaluation, NRR

Charles E. Rossi, Director
Division of Operational Events Assessment, NRR

FROM: James H. Sniezek, Deputy Director
Office of Nuclear Reactor Regulation

SUBJECT: ASSIGNMENTS FOR NRR ACTIONS RESULTING FROM DIAGNOSTIC EVALUATION TEAM REPORT FOR MCGUIRE NUCLEAR STATION (TACS 67915/67916)

In the enclosed memorandum dated April 6, 1988, the EDO identified and assigned to NRR, Region II and AEOD responsibility for generic and plant-specific actions resulting from the diagnostic evaluation at the McGuire Nuclear Station. Specific items for NRR action are listed in Enclosure 1 of the EDO's memorandum. I request that DRP assume responsibility for coordination of the items assigned to NRR, including integration with Region II and AEOD on assigned items as appropriate, and tracking the status of each NRR item through final resolution. Any additional NRR action items as may be identified from ongoing reviews of the subject report should be referred to DRP for further consideration and assignment. The McGuire Project Manager, Darl Hood (FTS 492-1442), is designated the lead contact for NRR actions.

The following assignments and schedules are made for NRR actions as identified as Staff Actions Required, Enclosure 1 to the EDO's memorandum. In view of the significance of these items, every effort should be made to complete these assignments on or before these specified schedules. Contact Darl if the schedules can be improved or cannot be met.

CONTACT: Darl S. Hood, NRR
(49-21442)

Item No.	Responsible NRR Division/ AD/Branch Staff	Schedule
1.(a)	L. Shao J. Richardson T. Marsh	12/2/88
1.(c)	L. Shao J. Richardson T. Marsh	5/31/88
2.	L. Shao J. Richardson T. Marsh (with support from C. Rossi/C. Berlinger as needed)	5/31/88
3.(b)	L. Shao J. Richardson T. Marsh	7/15/88
4.(a)	J. Roe T. Gody	5/31/88
4.(b)	J. Roe T. Gody	6/17/88
6.	S. Varga G. Lainas D. Hood	As requested by RII

With respect to Enclosure 2 of the EDO's memorandum, areas of suggested follow-up, the only item identified for NRR action is item 2 regarding Duke's weaknesses relative to 10 CFR 50.59 evaluations. The action for this item will be the PM's as part of his review of licensee evaluations.

By June 1, 1988, please provide DRP with a written summary of the status of your above assigned items plus any that may be additionally identified. The specific milestones leading to resolution of each item should be identified and scheduled. Any changes to the above final completion dates should be noted and justified. Darl will compile your inputs for the first summary requested by the EDO by June 6, 1988. Progress and periodic updating will be monitored through WITS. Additionally, your input for a 6-months written status report to the EDO regarding disposition and anticipated actions for uncompleted items should be provided to Darl by September 20, 1988.

Also attached is the EDO's transmittal letter of April 8, 1988, to Duke Power Company requesting their written response to Section 2 of the subject report as soon as appropriate. In the interim, if specific information is needed from Duke, contact Darl.

APR 28 1988

This effort should be charged to TACS 67915/67916 except where previous TACS (e.g., for IST reviews) exist.

Original signed by
James H. Sniezek

James H. Sniezek
Deputy Director
Office of Nuclear Reactor Regulation

CONTACT: D. Hood
49-21442

Enclosures:
As stated

cc: F. Miraglia
J. Nelson Grace
E. Jordan
R. L. Spessard

DISTRIBUTION:

Docket File	McGuire Reading
NRC PDR (w/incoming)	PDII-3 Reading
MRood	DMatthews
DHood	GLainas
JSniezek	DMossburg, PMAS
TMarsh	JRichardson
CBerlinger	HRegan

*SEE PREVIOUS PAGE FOR CONCURRENCE

LA:PDII-3*	PM:PDII-3*	D:PDII-3*	ADR2/DRPR:NRR*	D:DRP/NRR*
MRood	DHood:pw	DMatthews	GLainas	SVarga
04/25/88	04/25/88	04/25/88	04/25/88	04/25/88
AD:PNRR	DDNRR/NRR			
FMiraglia	JSniezek			
4/ /88	/ /88			

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

APR 06 1988

Action: Develop ~~staff~~ assignment memo including appropriate dates for my signature. JHS 4/8
shoot for 4/19 completion JZ
talk w/ Serio

MEMORANDUM FOR: Thomas E. Murley, Director
Office of Nuclear Reactor Regulation

J. Nelson Grace, Regional Administrator
Region II

Edward L. Jordan, Director
Office for Analysis and Evaluation
of Operational Data

FROM: Victor Stello, Jr.
Executive Director for Operations

SUBJECT: STAFF ACTIONS RESULTING FROM THE DIAGNOSTIC EVALUATION TEAM REPORT FOR MCGUIRE NUCLEAR STATION

An advance copy of the subject report was transmitted to you by memorandum dated March 8, 1988 from Edward L. Jordan, Director, AEOD. The report documents the diagnostic evaluation team efforts to identify performance strengths, deficiencies and causes, together with the findings and conclusions which form the basis for follow-up actions.

The purpose of this memorandum is to identify and assign staff responsibility for generic and plant-specific actions resulting from the diagnostic evaluation at the McGuire Nuclear Station. You are requested to review the subject report and the enclosures. You should determine the actions necessary to resolve each of the recommended actions in your area of responsibility and, where appropriate, identify additional staff actions or revisions to the identified actions based on your review of the report. Based on briefings on the diagnostic evaluation results, I recognize that actions to address some of these items have already been initiated by the staff.

In view of the importance of this subject, I intend to monitor the resolution of these items via WITS. Your offices should also closely monitor and track the status of each assigned action item until final resolution. Within 60 days, please provide a written summary of the schedule and status of each item within your responsibility, as identified in Enclosure 1, including those that you have additionally identified. Further, I request that you prepare a written status report on the disposition of your items (and anticipated actions for uncompleted items) within 6 months. Every effort should be made to resolve these items promptly.

The items in Enclosure 2 are areas for suggested follow-up that may be resolved through normal staff processes, and no written reply is requested. Routine

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inspection follow-up such as additional plant inspections or potential enforcement actions are expected to be defined and implemented in the normal manner in accordance with NRC regulations and procedures.

Victor Stello, Jr.
Executive Director for Operations

Enclosure:
1. McGuire Diagnostic Evaluation,
   Staff Actions Required
2. McGuire Diagnostic Evaluation,
   Areas for Suggested Follow-Up

MCGUIRE DIAGNOSTIC EVALUATION

STAFF ACTIONS REQUIRED

contents list

1. Item: The McGuire Inservice Testing (IST) program has not been approved by the NRC. The Diagnostic Evaluation performed at Dresden during August 1987 had an identical concern, and the staff was requested to resolve this concern. The McGuire (IST) program had numerous deficiencies (Sections 3.3.1.1, 3.3.3.1 and 3.3.3.4).

   Action:

   (a) Review and evaluate the McGuire IST program. Coordinate with Duke to address all deficiencies and approve the program. Responsible Office: NRR.

   (b) Inspect and evaluate licensee corrective actions to resolve IST program deficiencies. Responsible Office: Region II.

   (c) Review the approval status for IST programs of all operating nuclear power plants to determine which facilities have not had their IST programs approved. Expedite the review process for these facilities. Responsible Office: NRR.

2. Item: Reverse flow testing of ASME Section XI check valves at McGuire was limited to containment isolation and system/pressure boundary valves. The team found that several normally open safety-related check valves which must close during an accident were incorrectly omitted from the IST program or that inadequate reverse flow testing was performed to satisfy Section XI requirements. Furthermore, the failure of some of these valves had been previously experienced at both McGuire and Catawba. In response to the team's concerns regarding testing of check valves, an initial review by the licensee discovered additional valves for which testing was inadequate.

   Following the event at San Onofre Unit 1 on November 21, 1985, in which there were common-mode failures of several safety-related check valves, the NRC issued Information Notice 86-01, "Failure of Main Feedwater Check Valves Causes Loss of Feedwater System Integrity and Water Hammer Damage," dated January 6, 1986, INPO issued SOER 86-3, "Check Valves Failures or Degradation" dated October 15, 1986 in response to NRC and industry concerns on check valve failure. The team recognizes that the staff has several long-term reviews, described in SECY 88-74, "Evaluation of Licensee Programs for Testing and Inspecting Check Valves," to address the issue of check valve reliability and failure. However, more than two years following the San Onofre event and more than a year after INPO SOER 86-03 was issued, the above situation at McGuire was found to exist (Section 3.3.3.1).

Action:

Rossi

Evaluate the issue of check valve failures and industry's response and determine if additional generic communications are warranted to feed back the experience and lessons learned from McGuire and to ensure that appropriate short-term corrective actions (e.g., check valve testing) are implemented by licensees. Responsible Office: NRR.

3. Item: Inservice testing (IST) of safety-related relief valves, in accordance with Section XI of the ASME Code (1980 Edition), was interpreted at McGuire to require testing of only the main steam and pressurizer relief valves. The remainder of the safety-related relief valves were also not routinely tested through any other program at McGuire. The team concluded that additional relief valves should have been included in their IST program and that the other safety-related relief valves should receive periodic testing. A contributing cause to McGuire's incomplete testing program is that the NRC staff has not provided a clear position regarding required ASME Code relief valve testing for various applicable versions of the ASME Code. During the evaluation Duke committed to develop a testing program for McGuire's safety-related relief valves (Section 3.3.3.6).

Action:

P Tam

(a) Review and evaluate the licensee's proposed relief valve testing program and its implementation. Responsible Office: Region II.

(b) As part of the action required under Item 1 above, establish a uniform position regarding testing requirements for safety-related relief valves and review IST programs for conformance with the position. Responsible Office: NRR.

4. The team found that the MSRG had not been performing all of the functions which were identified as part of the licensing basis in accepting the MSRG as meeting staff guidelines of TMI Action Item I.B.1.2 and was, therefore, not meeting the full intent of the McGuire TS, i.e., the scope and focus of the MSRG activities have evolved to the point that the majority (85-90 percent) of their time is spent investigating plant events with little time spent on surveillance of plant operations and maintenance activities (TS 6.2.3.3) and essentially no time spent on making recommendations concerning revised plant procedures and equipment modification (TS 6.2.3.4).

Additionally, the team learned that Duke intends to submit a proposed TS change to the McGuire and Oconee TS that would delegate the NSRB review function for determining the adequacy of 10 CFR 50.59 evaluations to the MSRG. This change needs to be evaluated in conjunction with the team findings concerning the MSRG as previously described (Section 3.4.6.1).

Action:

(a) Evaluate and take prompt action to resolve the differences between the MSRG review functions, as described in the SER and TS, and as currently conducted under the Charter of the MSRG. Responsible Office: NRR.

(b) Evaluate the proposed TS change in conjunction with the staff action to address Item (a) above. Responsible Office: NRR

5. Item: Damaging vibration affecting all six McGuire auxiliary feedwater pumps was caused by insufficient pump minimum recirculation flow due to erroneous data provided by the pump vendor. A similar problem for residual heat removal pumps at certain nuclear plants was reported in NRC Information Notice 87-59, "Potential RHR Pump Loss" (Section 3.2.3.1).

Action:

Evaluate this McGuire problem to determine if a potential generic issue exists and determine if generic communications are warranted. Responsible Office: AEOD.

6. Item: The report transmittal letter requests a licensee response.

Action:

Review and evaluate the licensee's response. Prepare correspondence, for signature by the EDO, which replies to the licensee's response to the Diagnostic Evaluation Team report. Responsible Office: Region II with assistance as appropriate from NRR and AEOD.

MCGUIRE DIAGNOSTIC EVALUATION

AREAS OF SUGGESTED FOLLOW-UP

1. Item: Torque switch data for seven safety-related Limitorque MOVs were not available at the station. Design engineering personnel at the Duke General Office obtained these settings within several days. The data were retrieved from the original procurement records. Because of the uncertainty over the correctness of the torque switch settings for these MOVs, the licensee plans to physically inspect the valves when they become accessible to ensure that the torque switches are set to their prescribed values (Section 3.2.2.1).

   Action:

   As part of the routine inspection program, verify that the actual torque switch settings for these MOVs are in conformance with the design requirements. Responsible Office: Region II.

2. Item: Weaknesses regarding Duke 10 CFR 50.59 safety evaluations were identified. First, evaluations were apparently not checked at the completion of design, introducing the possibility that details might change or assumed analyses might not be completed, unknowingly negating the evaluations. Secondly, a number of problems involving a lack of attention to detail were evident; for example, the proposed changes in several cases affected the FSAR and technical specifications, but the safety evaluation indicated otherwise (Section 3.5.4.2).

   Action:

   As a part of normal staff actions (Project Manager reviews and routine inspections) involving review of 10 CFR 50.59 design changes, consider the findings identified by the team. Responsible Office: NRR/Region II.

3. Item: Design pressure of the auxiliary feedwater pump discharge piping was less than the pressure likely to be encountered in service. Duke intends to perform stress calculations to verify piping integrity. Similar oversights have been noted in other inspections, including the Callaway Integrated Design Inspection and the Rancho Seco Augmented Systems Review and Test Program Inspection (Section 3.5.3.5).

   Action:

   (a) As part of the routine inspection program, review and evaluate licensee corrective actions. Responsible Office: Region II.

   (b) As part of the routine events analysis program, evaluate this problem to determine if a potential generic issue exists and determine if generic communications are appropriate. Responsible Office: AEOD.

4. Item: Some technical issues that could have benefited from a Design Engineering Department evaluation did not receive it and were

insufficiently evaluated by the Nuclear Production Department (NPD). The team believed that Design Engineering's support should be enhanced by increasing its involvement in the front-end discussions with NPD on how to evaluate technical problems and programmatic issues which affect the plant. The team understands that Duke intends to assign a full time Design Engineering presence to the McGuire site to accomplish this (Section 3.5.7).

Action:

As part of the normal inspection process to follow-up the Region II previously identified design support issue, review and evaluate licensee corrective actions. Responsible Office: Region II.

NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

APR 8 1988

Mr. Hood: Transmittal ltr for McGuire (Final) + 2 copies of Rpt
Sue 4/20/88

Docket Nos. 50-369
50-370

Mr. Warren H. Owen, Executive Vice President
Engineering, Construction and
Production Group
Duke Power Company
Post Office Box 33189
Charlotte, North Carolina 28242

Dear Mr. Owen:

SUBJECT: DIAGNOSTIC EVALUATION TEAM REPORT FOR MCGUIRE NUCLEAR STATION

This letter forwards the Diagnostic Evaluation Team Report for the McGuire Nuclear Station. The evaluation was conducted by a team of NRC headquarters and regional evaluators with team leadership and support provided by the Office for Analysis and Evaluation of Operational Data over the period November 30 to December 11, 1987 and January 4-8, 1988. As you are aware, this is a new NRC assessment tool that is intended to provide an independent assessment of licensee performance, and as such, its principal focus is on safety performance and not compliance with regulatory requirements. Following the conclusion of the onsite evaluation, the findings were discussed at an exit meeting with you and other company executives and managers on January 22, 1988.

The NRC effort involved an assessment of overall plant operation and the Duke Power Company major programs for supporting safe plant operation at the McGuire Nuclear Station. Particular attention was directed in the areas of engineering support, operations, maintenance, testing, quality programs, management oversight and organization culture and climate.

The team concluded that the overall performance of McGuire was a solid SALP Category 2 with an improving trend. Although the team observed a number of strengths in Duke's organization and programs which contributed to the improving trend, the team also identified some organizational and programmatic weaknesses, which could slow down the improvement efforts. Section 2 of the enclosed report provides the team evaluation results which include: (1) major findings and conclusions, (2) specific findings and conclusions, and (3) root cause determinations. Section 3 of the report provides the detailed evaluation findings. Some of these items may be potential enforcement findings. Any enforcement actions will be identified by our Region II office.

This report is provided for your evaluation and use in formulating and implementing appropriate action in response to the team findings. I request that you evaluate the report and, that as soon as appropriate, provide my office a written response. Since I have directed the NRC staff to review and followup the more detailed findings of the evaluation, your response to the specific evaluation results delineated in Section 2 of the report, would greatly facilitate that effort.

In accordance with 10 CFR 2.790(a), a copy of this letter and the enclosure will be placed in the NRC Public Document Room.

Should you have any questions concerning this evaluation, we would be pleased to discuss them with you.

Sincerely,

Original signed by
Victor Stello

Victor Stello, Jr.
Executive Director for Operations

Enclosure: Diagnostic Evaluation
Team Report for McGuire Nuclear
Station

DIAGNOSTIC EVALUATION TEAM REPORT

FOR

MCGUIRE NUCLEAR STATION

U.S. Nuclear Regulatory Commission
Office for Analysis and Evaluation
of Operational Data
Division of Operational Assessment
Diagnostic Evaluation and Incident
Investigation Branch

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OFFICE FOR ANALYSIS AND EVALUATION OF OPERATIONAL DATA
DIVISION OF OPERATIONAL ASSESSMENT

DIAGNOSTIC EVALUATION REPORT NUMBER 2

Licensee: Duke Power Company

Facility: McGuire Nuclear Station

Docket No.: 50-369/370

Onsite Evaluation: November 30, 1987 through December 11, 1987

Corporate Evaluation: November 30, 1987 through December 11, 1987
January 4, 1988 through January 8, 1988

Exit Meeting: January 22, 1988

Team Manager: R. Lee Spessard, AEOD

Deputy Team Manager: Stuart D. Rubin, AEOD

Team Leaders: Dennis P. Allison, AEOD
Henry A. Bailey, AEOD

Team Members: Steven D. Butler, AEOD
Robert G. Freeman, AEOD
Michael Goodman, NRR
Arthur T. Howell, AEOD
Ronald L. Lloyd, AEOD
Robert L. Perch, AEOD
Robert L. Nelson, RIII
Perry J. Stewart, RIV
Kevin P. Wolley, AEOD
Robert Gura, NRC Contractor
George Morris, NRC Contractor
Donald Prevatte, NRC Contractor
Paul Thurmond, NRC Contractor

Submitted by: R. L. Spessard 3/8/88
R. Lee Spessard, Team Manager — Date

Approved by: E. L. Jordan 3/8/88
Edward L. Jordan, Director, AEOD — Date

EXECUTIVE SUMMARY

During the NRC senior management meeting in June 1987, NRC executives concluded that additional information was needed regarding the overall performance of the Duke Power Company (Duke) and its nuclear stations. This additional information was needed to better understand and supplement other findings and inputs from regular sources such as those associated with the Systematic Assessment of Licensee Performance (SALP) reports, performance indicator (PI) analysis, and the routine NRC inspection program. Although these sources showed that the Duke nuclear plants (McGuire, Catawba, and Oconee) were all average or above average performers, there were inconsistencies between the perceived strengths and capabilities of the Duke organization and actual plant performance which frequently involved significant and repetitive problems in operations, maintenance, and other areas important to safety. Additionally, the NRC senior managers believed that Duke was a strong utility from which the NRC could learn, thereby making the Diagnostic Evaluation Program more effective. The McGuire Nuclear Station was chosen as the basis for the diagnostic evaluation of the Duke nuclear program.

In order to fully evaluate the nature of licensee and plant performance, the Executive Director for Operations directed the Office for Analysis and Evaluation of Operational Data to conduct a diagnostic evaluation of McGuire with the guidance that, "The evaluation should be broadly structured to assess overall plant operation and the strength of Duke Power Company's major programs for supporting safe plant operation at McGuire."

The team confirmed the NRC senior managers' perceptions of Duke and concluded that McGuire's overall performance was a solid SALP Category 2 with an improving trend. As had been expected, the team observed a number of strengths in Duke's organization which contributed to the gains in performance. The team found overall corporate management leadership, direction, and support to be good. For example, clear direction was provided through corporate and department level goals and action plans; performance was tracked and reviewed monthly; and the corporate support staff and nuclear station staff worked together effectively to develop and apply new or improved technologies, management systems and programs. The overall climate, culture and attitude were also found to be positive with high morale, quality consciousness, good communications, and a strong loyalty to Duke found throughout the plant and corporate organization. The overall technical capabilities of the staff were good. The nuclear support staff was technically competent with significant operating plant experience while the Design Engineering Department was found to be a large and knowledgeable resource. Corporate staff involvement in nuclear industry committees and organizations also promoted awareness and understanding of industry operating problems and improvement programs applicable to McGuire.

Although it was determined that the performance at McGuire was improving, the team concluded that the improvement efforts could be slowed by several factors. Foremost among these was the limited utilization of Design Engineering in the evaluation of plant operating problems and programs. The team found that although Duke's Design Engineering Department was a large and capable resource, it was not being fully utilized in the day-to-day support of the operating plants due to attitudes within both the Design Engineering and the Nuclear

Production Departments which tended to limit Design Engineering involvement. Other factors of concern included the near-term limitations on the contributions of QA for enhancing plant safety performance and some instances of inadequate performance of Construction and Maintenance Department personnel working at McGuire due to inadequate training. The team was also concerned about the potential for reduced corporate oversight, direction, and leadership for the operating nuclear stations due to the competing demands with Duke's growing outside business interests.

The operations, maintenance, and testing functional areas were found to have a number of noteworthy programmatic strengths and some programs were judged to be above the industry average in overall quality. For example, a 12 hour operating shift contributed to good morale among the operators and good communication and cooperation between operations and support groups. Additionally, the preventive maintenance program was found to be comprehensive and the completion of surveillance tests was ensured by an integrated scheduling group at the station.

Notwithstanding the above strengths, a number of programmatic weaknesses, technical problems, and concerns were identified in each of the functional areas which were uncharacteristic of Duke's commitment to quality in all activities. In maintenance, for example, weak root cause determinations, combined with the lack of a formal integrated failure trending program resulted in recurring common-cause bearing damage for five of the six McGuire auxiliary feedwater pumps. Significant deficiencies were found in the Inservice Testing Program for safety-related check valves and some air-operated valves. The Inservice Testing Program deficiencies resulted in check valve failures in the auxiliary feedwater system and the steam supply system to the turbine-driven auxiliary feedwater pump not being detected in a timely manner. The team found that poor technical reviews, resulting from weak involvement by Design Engineering in the development of the initial Inservice Testing Program and, subsequently, in the development of a comprehensive action plan to address check valve failures and problems discussed in INPO SOER 86-3, were a significant underlying cause for the identified testing deficiencies. Lack of adequate management review and weaknesses in the technical capabilities of the QA surveillance group were also found to be important underlying causes for administrative limits regarding reactor coolant system and pressurizer cooldown rates being exceeded on a recurring basis.

Duke responded to the findings and issues raised by the team in a positive and constructive manner which was considered indicative of Duke's strong desire to improve the performance of the McGuire Nuclear Station.

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ACRONYMS

AC	Alternating Current
AE	Architect Engineer
AEOD	Office for Analysis and Evaluation of Operational Data
AFW	Auxiliary Feedwater (See also CA)
ASME	American Society of Mechanical Engineers
BOP	Balance of Plant
CA	Condensate, Auxiliary (Duke Nomenclature for AFW)
CFR	Code of Federal Regulations
CM	Corrective Maintenance
CMD	Construction and Maintenance Department
CR	Control Room
CVCS	Chemical and Volume Control System
DC	Direct Current
DCA	Design Change Authorization
DCN	Design Completion Notice
DCRDR	Detailed Control Room Design Review
DE	Design Engineering
DES	Duke Engineering Services Company
DET	Diagnostic Evaluation Team
ECP	Estimated Critical Position
EDG	Emergency Diesel Generator
EDO	Executive Director for Operations
EMO	Electric Motor-Operated
EOP	Emergency Operating Procedure
EPRI	Electric Power Research Institute
ESF	Engineered Safety Feature
ETQS	Employee Training and Qualification System
°F	Degrees Fahrenheit
FWST	Feedwater Storage Tank
FSAR	Final Safety Analysis Report
GO	General Office
gpm	Gallons Per Minute
hr	Hour
hp	Horsepower
HP	Health Physics
IAE	Instrument and Electrical
I&C	Instrumentation and Control
IE	Office of Inspection and Enforcement
IEEE	Institute of Electrical and Electronics Engineers
IIR	Incident Investigation Report
INPO	Institute of Nuclear Power Operations

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CVCS	Chemical and Volume Control System
DC	Direct Current
DCA	Design Change Authorization
DCN	Design Completion Notice
DCRDR	Detailed Control Room Design Review
DE	Design Engineering
DES	Duke Engineering Services Company
DET	Diagnostic Evaluation Team
ECP	Estimated Critical Position
EDG	Emergency Diesel Generator
EDO	Executive Director for Operations
EMO	Electric Motor-Operated
EOP	Emergency Operating Procedure
EPRI	Electric Power Research Institute
ESF	Engineered Safety Feature
ETQS	Employee Training and Qualification System
°F	Degrees Fahrenheit
FWST	Feedwater Storage Tank
FSAR	Final Safety Analysis Report
GO	General Office
gpm	Gallons Per Minute
hr	Hour
hp	Horsepower
HP	Health Physics
IAE	Instrument and Electrical
I&C	Instrumentation and Control
IE	Office of Inspection and Enforcement
IEEE	Institute of Electrical and Electronics Engineers
IIR	Incident Investigation Report
INPO	Institute of Nuclear Power Operations

IST	Inservice Testing
ITL	Initiation-to-Light
IWV	ASME Section XI Valves Subsection
IWP	ASME Section XI Pumps Subsection
KVA	Kilovolt-Amperes
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LPSW	Low Pressure Service Water
LTL	Light-to-Light
MCC	Motor Control Center
M&TE	Measurement and Test Equipment
MFW	Main Feedwater
MOV	Motor-Operated Valve
MSAR	McGuire Safety Analysis Report
MSRG	McGuire Safety Review Group
MWt	Megawatts thermal
MWe	Megawatts electric
NCI	Nonconforming Item
NEO	Nuclear Equipment Operator
NPD	Nuclear Production Department
NRC	Nuclear Regulatory Commission
NSM	Nuclear Station Modification
NSRB	Nuclear Safety Review Board
NTS	Nuclear Tracking System
OAC	Operator Aid Computer
OE	Operating Experience
OEMA	Operating Experience and Management Analysis
OSRG	Oconee Safety Review Group
pcm	Percent Milli-Rho
PI	Performance Indicator(s)
P&ID	Piping and Instrumentation Diagram
PIR	Problem Investigation Report
PORV	Power Operated Relief Valve
PSD	Production Support Department
psig	Pounds Per Square Inch Gauge
PWR	Pressurized Water Reactor
QA	Quality Assurance
QAPA	Quality Assurance Performance Assessment
QC	Quality Control
RCM	Reliability Centered Maintenance
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RIA	Required Instrument Accuracy
RO	Reactor Operator

SA	Main Steam Supply to Auxiliary Equipment
SALP	Systematic Assessment of Licensee Performance
SER	Safety Evaluation Report, Significant Event Report
SITA	Self-Initiated Technical Audit
SOER	Significant Operational Event Report
SPDS	Safety Parameter Display System
SPR	Station Problem Report
SRG	Safety Review Group
SRI	Senior Resident Inspector
SRO	Senior Reactor Operator
STA	Shift Technical Advisor
STE	Sensor Temperature Effect
TMI	Three Mile Island
TOPFORM	The Overall Plan for Organizational Review of Modifications
TS	Technical Specifications
UC	Unit Coordinator
VCT	Volume Control Tank
VN	Variation Notice
VST	Valve Stroke Time

1.0 INTRODUCTION

1.1 Background

During the NRC senior management meeting in June 1987, NRC executives concluded that additional information was needed regarding the overall performance of the Duke Power Company (Duke) and its nuclear stations. This additional information was needed to better understand and supplement other findings and inputs from regular sources such as those associated with the Systematic Assessment of Licensee Performance (SALP) reports, performance indicator (PI) analysis, and the routine NRC inspection program. Although these sources showed that the Duke nuclear plants (McGuire, Catawba, and Oconee) were all average or above average performers, there were inconsistencies between the perceived strengths and capabilities of the Duke organization and actual plant performance, which frequently involved significant and repetitive problems in operations, maintenance, and other areas important to safety. Additionally, the NRC senior managers believed that Duke was a strong utility from which the NRC could learn, thereby making the Diagnostic Evaluation Program more effective. The McGuire Nuclear Station (McGuire) was chosen for the diagnostic evaluation of Duke's nuclear program.

Areas where performance inconsistencies were perceived to exist at McGuire included:

- Duke corporate engineering and design capabilities were considered strong, yet an apparent lack of coordination, cooperation, and communication between the offsite engineering organization and the McGuire plant staff had either resulted in or had the potential for safety system modification design deficiencies, inadequate system operating procedure revisions, and inadequate operator training on modified systems.

- The apparent oversight and involvement intentions by Duke corporate and McGuire plant management had been significant, yet both corporate and plant Quality Assurance/Quality Control (QA/QC) inputs to management performance monitoring systems had been at times ineffective in identifying programmatic problems involving operations, surveillance, and engineering support areas.

- Duke corporate technical support capabilities in the areas of design analysis, operations, and surveillance testing were considered strong, yet the offsite technical assistance and support provided to McGuire in these areas had at times been slow or lacking.

- Duke management had stressed the importance of following plant operating and surveillance procedures and identifying deficiencies in these procedures, yet procedural noncompliances and operational deficiencies remained more numerous than expected.

In order to more fully evaluate the nature of corporate and McGuire performance and to determine the root causes of any identified problems, the Executive Director for Operations (EDO), in a memorandum dated October 9, 1987, directed the Office for Analysis and Evaluation of Operational Data (AEOD) to conduct a diagnostic evaluation of McGuire.

1.2 Scope and Objectives

The EDO directed the Diagnostic Evaluation Team (DET) to conduct a broadly structured evaluation to assess overall plant operation and the strength of Duke's major programs for supporting safe plant operation at McGuire.

To provide the assessment of overall plant operations and major support programs required by the EDO memorandum, the DET investigated several areas with the following specific goals:

- Functional area effectiveness: assess the effectiveness (including strengths, weaknesses, problems, and issues) of the operations, maintenance, testing, QA/QC and station engineering groups in ensuring safe plant operation; assess the adequacy of procedures, programs, and compliance by the licensee to codes, standards, commitments, and regulatory requirements.

- Technical support: assess the effectiveness (including strengths, weaknesses, problems, and issues) of the technical support provided to the station by the Duke Nuclear Production Department in the areas of operations, surveillance testing, maintenance, and operator training and quality verification.

- Engineering support: assess the quality and timeliness of engineering support provided by the Design Engineering Department including analysis, design modifications, equipment operability determinations, technical program development, and technical advice.

- Management controls: assess the effectiveness (including strengths, weaknesses, problems, and issues) of management leadership direction, oversight and involvement, and the organizational climate at McGuire.

The root cause(s) of performance deficiencies were to be determined to the degree possible.

1.3 Methodology

The diagnostic evaluation at McGuire combined several methods of assessment with special emphasis on the interfaces and relationships between operations and various corporate and plant support groups. In the course of the evaluation, the DET observed plant operations, reviewed pertinent documents, conducted interviews with plant and corporate personnel at all levels and assessed the functional areas of operations, maintenance, testing, plant and corporate engineering, quality programs, station and corporate management controls, and organizational climate. The team utilized contractors to assist in the evaluation of corporate engineering support, management controls, and organizational climate.

The diagnostic evaluation began with a visit by the Deputy Team Leader to the NRC Region II offices and to the McGuire site. These preparatory visits included a detailed review of McGuire SALP, regulatory and enforcement history, a meeting with the McGuire Station Manager and his staff, and examination of selected McGuire documents. Following these visits, there were several weeks of in-office document review and preparation which included team meetings and briefings by NRC regional and headquarters staff knowledgeable of Duke and McGuire. Briefings by Region II personnel provided the team particularly good insight into performance issues at McGuire. On November 30, 1987, the team began an initial two-week evaluation at the station and corporate offices, and departed on December 11, 1987. The Team Managers, Team Leaders, and selected team members returned to the Duke Corporate offices on January 4, 1988 for an additional week to complete the evaluation. The exit meeting with corporate officers and managers was held on January 22, 1988 at the Duke corporate offices in Charlotte, North Carolina (see Section 4.0 for details).

The team's evaluation methods in the specific areas were as follows:

- Operations activities were assessed by reviewing the adequacy and control of procedures, records and operating logs, temporary modifications, and system tagouts, and around-the-clock shift coverage of control room activities. Operator training was also evaluated.

- Maintenance was assessed by reviewing procedures, vendor manuals, work orders, work practices, the trending program and maintenance corrective actions, and by performing a physical walkdown to determine the material condition of the Auxiliary Feedwater (AFW) System. Maintenance of safety system motor-operated valves (MOVs) was specifically evaluated.

- Inservice testing (IST) was assessed by reviewing procedures, observing surveillance tests, and reviewing related IST documentation. The IST program for safety system MOVs and check valves was specifically addressed.

- Quality assurance activities were assessed by reviewing the QA program and organization for QA audit and surveillance efforts and QA improvement initiatives. Administrative controls affecting quality were assessed by examination of documents and by interviews with appropriate licensee personnel.

- Corporate technical support to the station was evaluated by a review of applicable programs, records, correspondence and procedures, and interviews and observations.

- Engineering support by station and corporate groups was evaluated by a review of the control, quality and completeness of design modifications, and by interviews with engineering staff.

- Management controls were evaluated by assessing corporate and management leadership, direction, oversight and involvement and also evaluating the organizational culture and climate. These evaluations were accomplished by the review of records, correspondence and procedures, and interviews and observations.

During the evaluation period Duke responded to issues raised by the team in letters to the Team Manager, R. Lee Spessard, dated December 15, 1987 and January 15, 1988

Throughout the initial two-week evaluation, the Team Manager or his deputy and other team members met daily with the Station Manager to discuss team activities, observations, and preliminary findings. The team also met at the end of each day to discuss observations and findings in each functional area. The McGuire Senior Resident Inspector (SRI) frequently attended these meetings and functioned as a technical advisor to the team during the onsite evaluation.

1.4 Plant Description

McGuire Units 1 and 2 are located in Mecklenburg County, North Carolina, 17 miles northwest of Charlotte. Construction of both units was authorized by the NRC by issuance of a construction permit on February 28, 1973. Units 1 and 2 were completed and went into commercial service in December 1981 and March 1984, respectively. Duke is the sole owner.

Units 1 and 2 are essentially identical. Each unit consists of a Westinghouse designed pressurized water reactor (PWR) with a four-loop reactor coolant system designed for operations up to a thermal output of 3411 MWt which corresponds to a net electrical output of 1180 MWe.

1.5 Organizational Structure

1.5.1 Corporate Organization

The Duke corporate organization is structured as shown in Figure 1.1. The station managers for each of the three Duke nuclear stations (i.e., McGuire, Catawba, and Oconee) report directly to the Vice President, Nuclear Production Department, who reports to the Executive Vice President of Engineering, Construction and Production. Also reporting to the Executive Vice President are the corporate QA and Project Control Managers and the Vice Presidents for Design Engineering, Fossil Production, Production Support, and Construction and Maintenance. The Executive Vice President of Engineering, Construction and Production, and the vice presidents of other nontechnical groups report directly to the President (and Chief Operating Officer) who reports to the Chairman of the Board (and Chief Executive Officer). In addition, a corporate (General Office) nuclear support staff, headed by a general manager, reports to the Vice President, Nuclear Production Department (NPD). The General Office (GO) nuclear support staff is organized into the functional areas of Operations, Maintenance, Technical Services, Reliability Assurance, Safety Assurance and Department Services. The role of the Duke GO nuclear support staff is to provide technical direction, guidance, assistance and oversight in ways which promote quality and consistency in each of the functional areas at the three nuclear stations, while the role of the station line organization is to manage station activities in a manner which ensures high work quality, safety, and reliable production.

The Operations, Maintenance, Technical Services and Department Services groups within the GO nuclear support staff are each headed by a manager and are internally divided into subordinate functional units headed by first-line supervisors. The functional units within these nuclear support staff groups closely parallel the work responsibilities of the line organizations (i.e., station superintendents and section heads) at the plant sites. The organizational parallelism between the NPD line and staff organizations has resulted in a "counterpart" relationship between the functional area managers and supervisors at McGuire and the Duke corporate office.

1.5.2 Station Organization

The organizational structure at McGuire is illustrated in Figure 1.2. The highest level manager is the Station Manager, who reports to the Vice President, NPD. The station staff, totalling approximately 700, is organized into five functional groups: (1) Operations, (2) Integrated Scheduling, (3) Maintenance, (4) Station Services, and (5) Technical Services. Each functional group is headed by a superintendent who reports to the Station Manager. Each of the five functional groups is organized into sections, as illustrated in Figure 1.2. Engineering capabilities at the station reside primarily in the Project Services, Instrumentation and Electrical Maintenance, and Mechanical Maintenance sections. Other corporate departments such as Quality Assurance, Construction and Maintenance, Production Support and General Station Services also have groups located at the site.

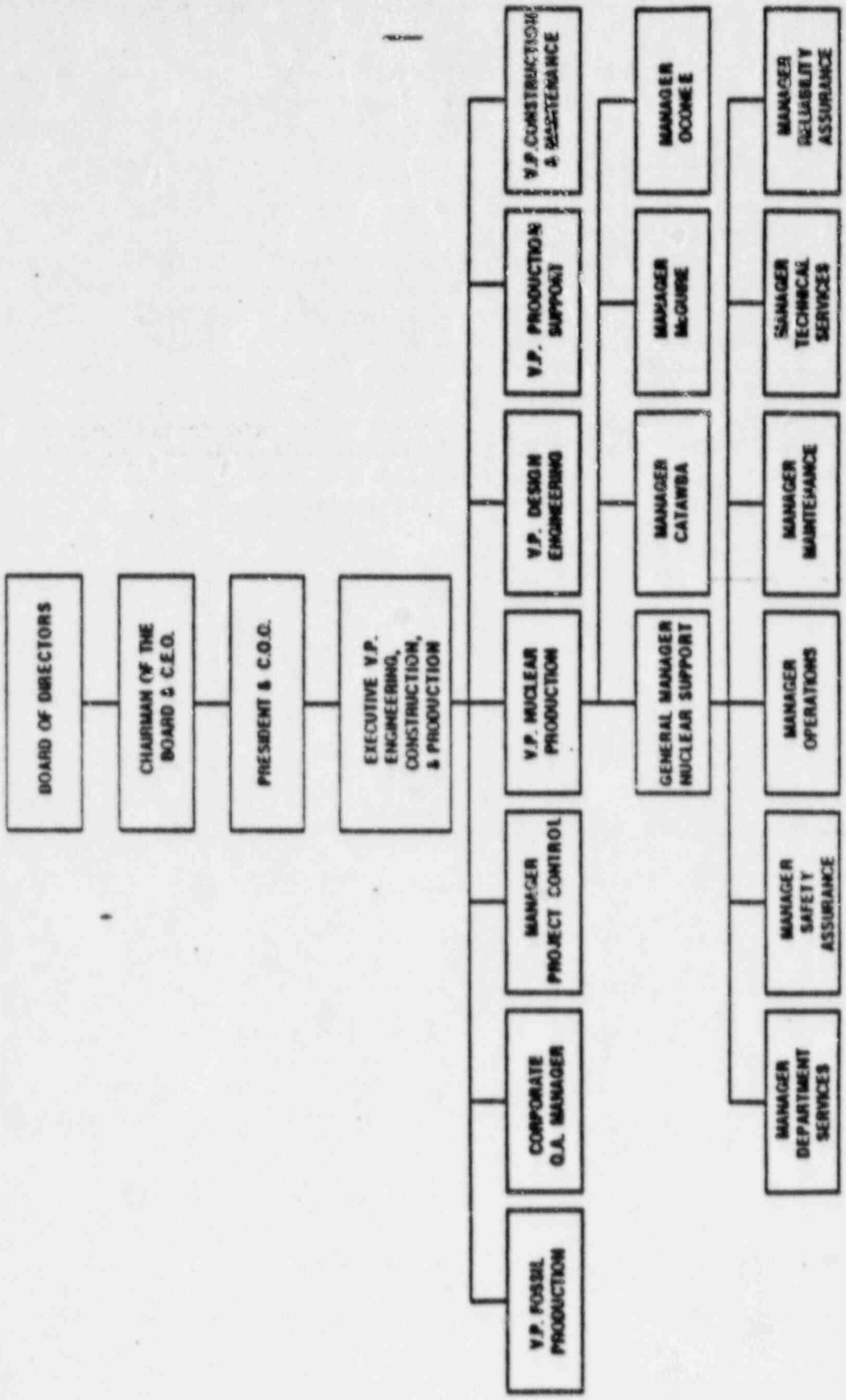

Figure 1.1. Duke Power Company Corporate Organization

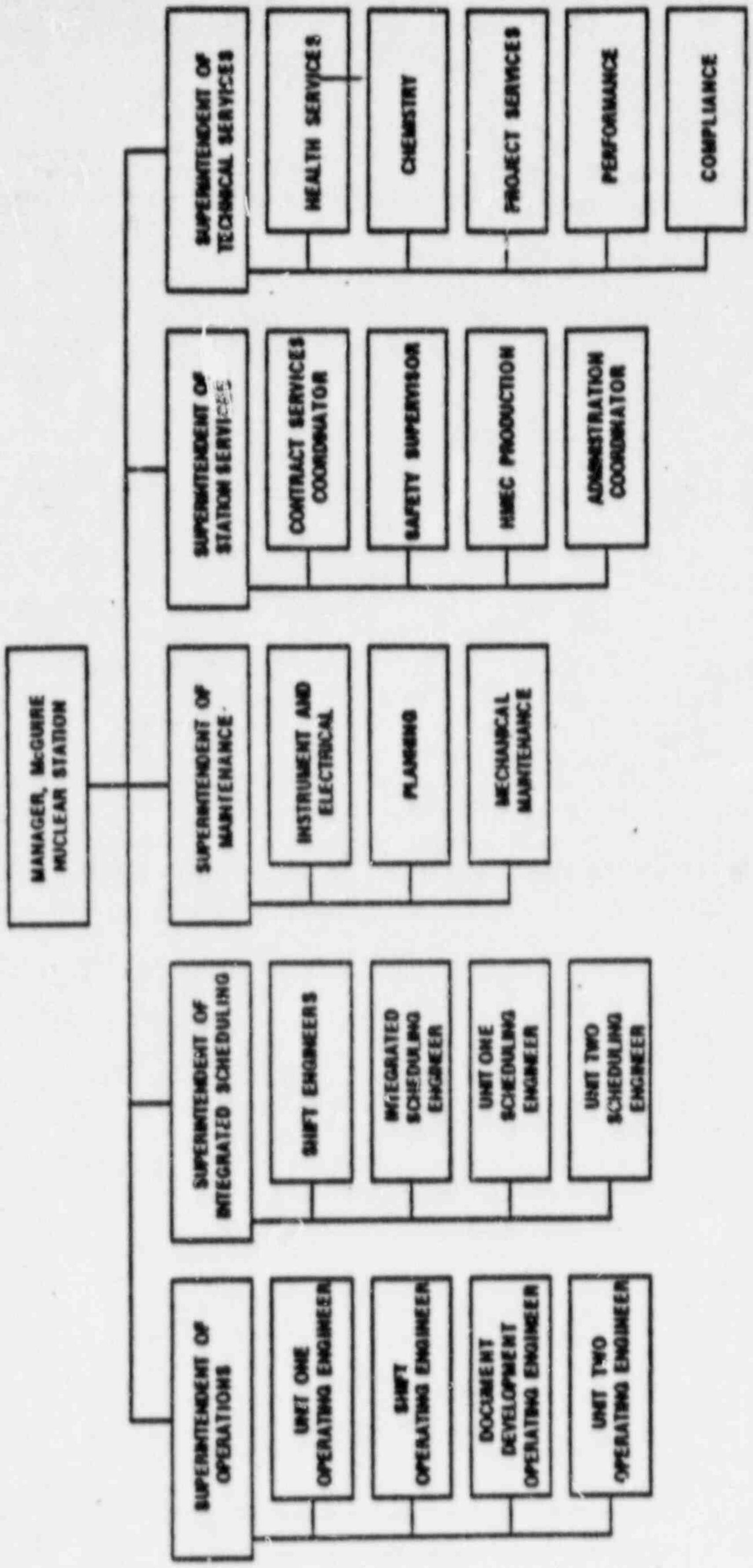

Figure 1.2. McGuire Station Organization (NPD Personnel)

2.0 EVALUATION RESULTS

2.1 Major Findings and Conclusions

The team concluded that McGuire's overall performance was a solid SALP Category 2, with an improving trend. The team believed that there had been improvements at McGuire as a result of a number of factors including: greater focus of corporate goals and resources on operational performance improvement; greater emphasis on quality in all activities; improved engineering support for nuclear station modifications and operability determinations; and increased efforts to ensure quality and consistency of NPD programs across all functional areas.

As had been expected, the team observed a number of strengths in the Duke organization which contributed to improved performance. The team found overall corporate management leadership, direction, and support to be good. For example, clear direction was provided through corporate and department-level goals and action plans; performance was tracked and reviewed monthly; and the corporate support staff and nuclear station staffs worked together effectively to develop and apply new or improved technologies, management systems and programs. The overall climate, culture, and attitude were also found to be positive with high morale, quality consciousness, good communications, and a strong loyalty to Duke throughout the plant and corporate organization. The overall technical capabilities of the plant operating staff were good. The corporate nuclear support staff was technically competent with significant operating plant experience while the Design Engineering Department was found to be a large and knowledgeable resource. Corporate staff involvement in nuclear industry committees and organizations also promoted awareness and understanding of industry operating problems and improvement programs applicable to McGuire.

Although it was determined that the performance at McGuire was improving, the team concluded that the improvement efforts could be slowed by several factors including: the limited utilization of Design Engineering (DE) in the evaluation of plant operating problems and programs; the near-term limitations on the contributions of QA for enhancing operating plant safety performance; and inadequate work performance of Construction and Maintenance Department (CMD) personnel at McGuire due to inadequate training. The team was also concerned about the potential for reduced corporate oversite, direction, and leadership for the operating nuclear stations due to the competing demands with Duke's growing outside business interests.

The operations, maintenance, and testing functional areas were found to have a number of noteworthy programmatic strengths and some programs were judged to be above the industry average in overall quality. For example, a 12-hour operating shift contributed to good morale among the operators, and good communication and cooperation between operations and support groups. Additionally, the preventive maintenance program was found to be comprehensive and the surveillance test program implementation was aided by the integrated scheduling group at the station.

Notwithstanding the above strengths, a number of programmatic weaknesses, technical problems, and concerns were identified in each of the functional areas which were uncharacteristic of Duke's commitment to quality in all activities. In maintenance, for example, weak root cause determinations, combined with the lack of a formal integrated failure trending program, resulted in recurring common-cause failures for each of the six McGuire AFW pumps. Significant deficiencies were found in the IST program for safety-related check valves and some air-operated valves. The IST deficiencies resulted in check valve failures in the AFW system and steam supply system to the turbine-driven AFW pump not being detected in a timely manner. The team found that poor reviews, resulting from weak involvement by DE, in the development of a comprehensive action plan to address check valve failures and problems discussed in INPO SOER 86-3, was a significant underlying cause for the identified deficiencies. Lack of adequate management review and weaknesses in the technical capabilities of the QA surveillance group were also important contributors to administrative limits for the reactor coolant system and pressurizer cooldown rates being exceeded on a recurring basis.

Duke responded to the findings and issues raised by the team in a positive and constructive manner which was considered indicative of Duke's strong desire to improve the performance of the McGuire Nuclear Station.

2.2 Specific Findings and Conclusions

In order to properly evaluate the performance of McGuire, particularly with regard to the degree of DE involvement, the degree of corporate and station management oversight and direction, and the effect of recent programmatic initiatives, a number of specific areas were evaluated in detail. The results of this evaluation provided the principal inputs into the major findings and conclusions discussed in Section 2.1 and the fundamental or root cause determinations discussed in Section 2.3 The specific areas evaluated were: operations and operator training, maintenance, testing, quality programs, engineering support, management overview, and organizational culture and climate. The findings and conclusions for each area are summarized below. Additional details involving each finding and conclusion can be found in the appropriate subsection for each area evaluated in Section 3.0.

2.2.1 Operations

1. The operating shift oversight, including the unit supervisors, shift supervisor, shift engineer, and the unit coordinator provided good supervision that enhanced the quality of plant operations. In addition, the McGuire operations shifts were staffed with significantly more personnel [i.e., reactor operators (ROs), senior reactor operators (SROs), and nuclear equipment operators (NEOs)] than required by Technical Specifications (TS) (Section 3.1.1.2).

2. The control room occasionally became noisy and crowded during the day shift which could increase the potential for personnel errors (Section 3.1.2).

3. Overall, the control room operating staff was generally proficient in the use of plant procedures. However, the considerable flexibility given the operators in implementing some procedures, as well as a lack of detailed guidance and technical information in certain procedures, contributed to

the procedural deficiencies and the personnel errors in following procedures which were observed or identified in records (Section 3.1.3).

4. The operating staff had repeatedly exceeded the administrative limits regarding reactor coolant system and pressurizer cooldown rates. Additionally, during a shutdown of Unit 2 on April 21, 1985, the TS heatup and cooldown rates for the pressurizer were exceeded and the associated TS action statements were not met (Section 3.1.4).

5. The combination of infrequent system alignment checks and a lack of "independent" verification of valving operations could make the plant more susceptible to undetected valving errors such as those identified by Duke internal audits (Section 3.1.5).

6. Instances in which plant equipment problems remained uncorrected for extended periods of time were identified [i.e., recurring problems with numerous control room chart recorders, a leaking AFW pump casing relief valve, and a leaking volume control tank (VCT) divert valve]. These problems appeared to be tolerated by plant management over an extended period of time without strong and lasting corrective action being taken (Sections 3.1.6 and 3.3.2.1).

7. The operator training program at McGuire was well-organized and comprehensive, and consisted of formal classroom training, simulator training, on-the-job training and a qualification program. Strong management commitment to high quality training was apparent at every level. However, some weaknesses were found concerning operator training facilities, the quality of training material, the number of hours of simulator requalification training and the operators' understanding of the requalification program (Section 3.1.8).

2.2.2 Maintenance

1. The Maintenance Department was well-staffed and well-managed and exhibited high morale. The Superintendent of Maintenance and the Instrument and Electrical (IAE), Planning, and Mechanical Maintenance Engineers all had several years of experience with Duke. A technical support staff of approximately 46 maintenance engineers significantly enhanced the capabilities of the Maintenance Department (Sections 3.2.1.1 and 3.2.1.4).

2. The scope of the McGuire preventive maintenance (PM) program was significantly greater than the industry average. For example, McGuire had extensive oil analysis and vibration analysis programs which encompassed numerous safety-related as well as balance-of-plant (BOP) system components (Section 3.2.1.2).

3. The McGuire Maintenance Department and the General Office Nuclear Maintenance Group were continuously seeking to improve the preventive maintenance program at the station. For example, Duke volunteered to participate in the Electric Power Research Institute (EPRI) sponsored reliability-centered maintenance (RCM) pilot program. Duke intended to expand the scope of the RCM program to several systems to further evaluate RCM applicability to the commercial nuclear industry (Section 3.2.1.3).

4. Despite the lessons learned from the 1986 Rotork MOV outage, numerous MOV torque switch setting control and document deficiencies were identified (e.g., settings were not specified in the design document that lists MOV torque and limit switch setpoints, and no data was available at the site for seven of these MOVs). Additionally, correct torque switch settings were not verified for Limitorque MOVs by technicians performing periodic preventive maintenance. As a result, torque switch settings for these MOVs may not be in conformance with the design requirements. Duke intended to verify proper torque switch settings for these MOVs.

   The Duke commitment to review and test MOVs greatly exceeds in scope the requirements of Inspection and Enforcement (IE) Bulletin 85-03, "Motor-Operated Valve Common-Mode Failures During Plant Transients Due to Improper Switch Settings." However, the program review and test for all McGuire safety-related MOVs will not be completed for another four refueling outages which is too long a period to completely implement one of the elements of the program, involving improved methods of controlling MOV torque switch settings. Interim steps needed to be taken to assure that the electric motor-operated (EMO) valve list accurately reflects actual safety-related MOV switch settings. Duke intended to correct the inconsistencies and data omissions of the EMO valve list as well as improve its utility (Section 3.2.2).

5. The determination of the root causes of equipment failures appeared to be weak. The team identified instances in which the symptoms of chronic equipment problems were addressed before the root causes were determined and corrected. Recurring equipment problems at both McGuire units that spanned several years included: excessive vibration and damage of five of the six AFW pumps; chemical and volume control system (CVCS) VCT divert valve leakage, and several Rotork MOV motor failures (Section 3.2.3).

6. The Maintenance Department had no integrated program in place to trend equipment problems or failures. At the time of the evaluation, the licensee had developed a draft procedure for the analysis of equipment failure trends from equipment work histories. The Maintenance Department was trending some, but not all, types of component failures (e.g., Rotork MOV corrective maintenance was trended annually, but corrective maintenance for Limitorque MOVs was not trended) (Section 3.2.4).

2.2.3 Testing

1. The IST program and its implementation were considered to be above the industry average in overall quality, however, significant programmatic and technical weaknesses with respect to completeness and depth were identified. Additionally, the program, originally submitted to the NRC for review and approval in 1980 for Unit 1 and 1981 for Unit 2, had not been approved by the NRC (Section 3.3).

2. The McGuire Integrated Scheduling Group, which coordinated operations and maintenance activities to schedule surveillance tests, functioned very well. Tests were scheduled with the least amount of impact on operations and with sufficient time allowance to minimize the probability of missing

a test. The number of missed surveillances during the last year was very low (Section 3.3.1.2).

3. A program for tracking and trending test results, as required by ASME Section XI, to ensure that proper corrective action was taken in the event of test failures did not exist. In some instances, engineering evaluations or corrective actions were not performed even though test results were found to be unacceptable (Section 3.3.1.2).

4. Test personnel were generally knowledgeable and followed test procedures properly. However, test technicians and engineers focused on step-by-step completion of procedures and showed little concern for potential problems that did not directly relate to test performance and acceptance (Section 3.3.2.1).

5. Reverse flow testing of ASME Section XI check valves was limited to containment isolation and pressure/system boundary valves, and thus, was inadequate to satisfy ASME Code requirements. Safety-related check valves in the AFW system and main steam supply to the turbine-driven AFW pump had been incorrectly omitted from the IST program, and there had been repeated failures of some of these valves in the 1984-1986 time frame which could have been identified sooner had reverse flow testing been conducted (Sections 3.3.3.1 and 3.3.5).

6. In response to the NRC's request that the industry develop and implement a comprehensive program to provide assurance that safety-related check valves would perform properly and reliably under all design conditions, INPO issued SOER 86-3 to provide guidance on the nature and scope of such a program. The resulting Duke design study on check valves for McGuire was inadequate, however, because: (1) it failed to include the safety-related check valves in the steam supply lines to the turbine-driven AFW pumps, even though these valves had a recent failure history at both McGuire and Catawba and were specifically included as examples in the SOER; and (2) it did not adequately address the need for reverse flow testing of check valves within its scope (Section 3.3.3.1).

7. With the exception of the main steam and pressurizer relief valves, the licensee did not routinely test any safety-related relief valves. This practice is not consistent with the ASME Code or Appendix B to 10 CFR 50 (Section 3.3.3.6).

8. Surveillance test procedures, which were recently revised to clarify test requirements and acceptance criteria, were thorough and presented in a standardized format to reduce the potential for personnel error (Section 3.3.4.1).

9. The valve stroke time trending requirements specified in ASME Section XI were not met for 11 safety-related air-operated valves in each unit. These valves, which were tested as part of the periodic engineered safety feature (ESF) actuation test, demonstrated erratic stroke times from test to test without corrective action being taken as required by Section XI. (Section 3.3.4.2).

2.2.4 Quality Programs

1. McGuire had a comprehensive quality verification program that emphasized achieving quality results in the line organization. However, the team found that the QA organization could not provide as strong a quality verification role as the line organization in verifying plant safety performance (Section 3.4.2).

2. The near-term technical capabilities of the QA Station Surveillance Group were considered weak in that it was staffed with personnel without indepth operating plant knowledge and experience. In addition, QA attempts to obtain operations personnel had been hampered by corporate policy which placed emphasis on maintaining technical resources within the line organization. A comprehensive QA training program had been developed and implemented, but was scheduled to take several years to complete (Section 3.4.2).

3. Although the near-term technical capabilities of the QA Audit Division staff were also considered weak, they were compensated for by the use of technical expertise from other line or staff organizations on QA audit teams. The use of technical expertise significantly strengthened QA audits. The staff resources which were available from Duke's large Design Engineering Department and other operating nuclear units at three sites retained the audit team independence from the audited organization (Section 3.4.2).

4. The technical contributions to plant safety performance of both the QA Station Surveillance Group and the QA Audit Division were limited. Although the audits and surveillances reviewed were generally comprehensive in the areas addressed, the findings were not generally technical in nature because the audit and surveillance program emphasis was programmatic rather than technical (Section 3.4.3).

5. The corrective actions associated with Audit and Surveillance staff findings were, in some cases, narrowly focused with minimal review and/or analysis of the findings for generic and long-term preventive actions. Accordingly, follow-up attention was at times ineffective or lacking for the identification and correction of potentially generic or chronic problems (Section 3.4.3.2).

6. Licensee initiatives such as the QA training program, Self-Initiated Technical Audits (SITAs), and QA Performance Assessment Program were considered strengths which should improve the technical capabilities of the QA organization (Section 3.4.4).

7. The Problem Investigation Report (PIR) program appeared to be well implemented at McGuire. The McGuire Compliance section, which had primary responsibility for the program, provided good oversight in the implementation and monitoring of the program (Section 3.4.5.1).

8. The corrective actions in the McGuire Station Incident Investigation Reports (IIRs) concentrated on correcting the specific physical or procedural deficiencies with minimal analysis for generic or station-wide

problems and preventive actions. Recurring events were frequently evaluated too narrowly (Section 3.4.5.3).

9. The McGuire Safety Review Group (MSRG) was not performing all of the functions identified as part of the McGuire licensing basis and, therefore, did not appear to meet the full intent of McGuire TS. The scope and focus of their activities had evolved such that the majority of their time was spent on investigation of plant events, with little or no time spent on surveillance of plant operations and maintenance activities. A proposal to increase their scope, as defined by the licensing basis by transferring responsibility for 10 CFR 50.59 reviews from the NSRB, may severely overload the capacity of the MSRG (Section 3.4.6.1).

2.2.5 Engineering Support

1. The Design Engineering Department was found to be a large and capable organization. Personnel were qualified and experienced. Management was involved in assuring timely and correct completion of assigned tasks. Resources applied to engineering support of McGuire were adequate to fulfill the DE role of providing support as tasked by the NPD (Section 3.5.1).

2. Several initiatives had recently been implemented to improve the engineering support for McGuire. The Overall Plan for Organization Review of Modifications (TOPFORM) contained 14 action plans to improve specific areas in the nuclear station modification program. Other initiatives such as semiannual feedback meetings between the station managers and engineering managers also promoted improvements to the modification process. These substantial efforts were directed at appropriate areas. It was too early to fully assess the effectiveness of these programs from completed work products (Section 3.5.2.2).

3. The AFW pump discharge piping design pressure was lower than the pressure that could be encountered in service. Duke agreed to perform analyses to verify that ASME Code allowances for operating conditions would be met (Section 3.5.3.5).

4. Safety evaluations of modifications performed in accordance with the requirements of 10 CFR 50.59 were not checked at the completion of design work. This introduced the possibility that details might change or assumed analyses might not get done as expected, negating the evaluations. Lack of attention to detail in several 50.59 reviews was also evident (Section 3.5.4.2).

5. Good support was being provided to the operators in their efforts to maintain the plant within the requirements of plant TS, including written equipment operability determination provided by DE (Section 3.5.6.1).

6. The Design Engineering Department was not being fully utilized in day-to-day support of the operating stations. Accordingly, some McGuire technical issues which were not evaluated adequately by NPD could have benefited from greater DE involvement. The role of DE was defined as providing support when specifically tasked by NPD. The NPD engineering

personnel normally evaluated and solved technical problems and developed technical programs themselves, which tended to limit requests for DE assistance (Section 3.5.7).

2.2.6 Management Overview

1. The technical capabilities of the Duke line and support staff were excellent throughout the organization. The GO Nuclear Support Staff was found to have considerable hands-on nuclear plant experience. The Design Engineering Department was knowledgeable of the plant design basis and experienced in the required analysis methods. The technical capabilities of station personnel directly involved in the operation and maintenance of the units were of a high level. The low turnover rate and the involvement in nuclear industry committees contributed to staff knowledge, skills, and capabilities required to continue quality improvements (Sections 3.5.1 3.6.1.1, and 3.6.2.3).

2. Adequate financial and human resources were being provided to implement the ongoing programs for the site and to maintain needed levels of technical, design engineering, and maintenance support. A large construction and maintenance work force was located at the station to assist in modifications and major maintenance tasks (Sections 3.5.1, 3.6.1, and 3.6.2.3).

3. The Duke corporate organization had established a comprehensive, consistent, and clear direction for the company through a broad range of corporate goals and objectives which were supported by department-level goals, strategies, and action plans. The NPD goals placed strong emphasis on year-to-year improvements in plant performance, and action items and plans were found to be diverse, relevant and comprehensive. The GO Nuclear Support staff also provided good technical leadership, direction and guidance for improved performance of the operating nuclear stations (Sections 3.6.1.1 and 3.6.2.1).

4. The NPD 1987 Master Work Plan did not include an explicit goal for public (nuclear plant) safety even though the corresponding plans for Design Engineering and Quality Assurance contained such goals. The absence of an explicit documented nuclear safety goal to compliment and balance the performance (production) improvement goals could have the potential unintended effect of diminishing the day-to-day nuclear safety consciousness and attitude at the working level (Section 3.6.1.1).

5. The team found that the corporate line organization oversight and involvement in the day-to-day activities and problems at McGuire had been temporarily weakened compared to the overall levels which had existed in the recent past. This was due to the NPD reorganization following the departure of the General Manager of Nuclear Stations and the Assistant to the Vice President, NPD (Section 3.6.1.2).

6. The communications between the NPD corporate organization and the McGuire Station and within the station were diverse and effective which kept the entire organization informed and motivated, however, differences in training and qualification requirements for CMD and NPD personnel resulted in some instances of inadequate performance by CMD personnel at McGuire (Sections 3.6.1.3, 3.6.2.4, 3.7.2.4, and 3.7.2.5).

7. Duke committed considerable resources to developing and upgrading the capabilities of management personnel at all levels. A formal process for management succession planning had also been implemented at Duke to ensure continued availability of qualified management personnel to fill vacancies when they arise (Section 3.6.1.5 and 3.7.2.3).

8. The team found that a number of GO departments, including Design Engineering, Quality Assurance, and Nuclear Production had committed technical resources and established activity level goals to support The Duke Engineering Service Company (DES). The team was concerned that with time, the needed technical resources could be diverted away from McGuire performance improvement efforts. The team was also concerned that the level of involvement by the DE Vice President and other higher level Duke corporate officers in ensuring the success and growth of DES could detract from the high level corporate oversight, involvement and leadership needed to ensure continued performance improvement at the three Duke nuclear stations (Section 3.6.1.6).

2.2.7 Organizational Culture and Climate

1. Most attributes of the culture and climate at the station and in Duke Power Company at large were quite positive. These included an excellent work ethic, loyalty to the organization, pride in working for Duke and in individual jobs, a low employee turnover rate, and a quality orientation. Other positive attibutes included high employee morale, commitment to goals attainment, excellent staff communication and emphasis on teamwork (Sections 3.7.1, 3.7.2.4, and 3.7.2.5).

2. The exempt employee appraisal system was viewed by most interviewees as unfair. This was reported to have a negative impact on morale, job satisfaction and individual job performance (Section 3.7.2.2).

3. Since completion of Catawba, career advancement opportunities within Duke had diminished. Management had taken actions to improve the situation including: (1) the elimination of quotas within some job progressions, (2) the establishment of a specialist position for NEOs, and (3) the use of human resource professionals to help restructure jobs and create job interest. Generally, interviewees believed that management could also improve the situation by: (1) offering some form of career counseling to help individuals better define career options, (2) posting job openings, and (3) providing feedback indicating that the current transfer request program was working (Section 3.7.2.2).

4. Most Duke employees seemed committed to anticipating and mitigating problems that might arise, as well as improving ongoing operations. Interviewees universally indicated no hesitation about identifying problems (Sections 3.7.2.4 and 3.7.2.5).

5. All interviewees agreed that management was stressing reactor safety to a greater degree than in the past. However, approximately one-fourth of the personnel interviewed still thought that management considered meeting

schedules and production were more important than safety, particularly during outages (Section 3.7.2.5).

6. A number of operators expressed anger and concern towards the NRC regarding the operator requalification program and a pilot examination that had at one time been tentatively scheduled at McGuire. The operator's concerns appeared to be based in part on poor communication between Duke Management and the operators involved (Section 3.7.2.5).

2.3 Fundamental or Root Cause(s) Determination

Based on the team assessment, the fundamental or root causes of McGuire's past performance and current performance were attributed to:

Past Performance

The McGuire Station, since startup, has been on a learning curve. The learning experience was made more challenging by design features (e.g., ice condenser containment and upper head injection) which proved to be an additional source of operational problems. In addition, a large number of plant modifications and programs were required during its startup and early years of operation such as the post-TMI requirements of NUREG-0737. These factors coincided with the construction, licensing, startup, and early operation of Catawba while Duke was acting as its own AE. This resulted in a number of indications that McGuire had not in the past received priority, indepth and focused corporate attention.

There were indications that past initiatives to improve performance were not fully developed and focused by senior management in terms of comprehensive and integrated goals and objectives and related action items and plans. Further, there were indications that competition among Duke's operating fossil and nuclear plant programs for available financial, human, and technical resources limited the scope and pace of past performance improvement initiatives at McGuire. Additionally, it appeared that the priority focus for the deployment of Design Engineering capabilities was for Duke plants in the design, construction, and startup phase. This significantly limited past Design Engineering involvement and assistance in improving the quality and scope of McGuire station support for design modifications, technical programs, and operational problem support. There were also indications that past work attitudes in the nuclear power program placed a higher priority on work schedules than on work quality and an emphasis on correcting immediate problems rather than seeking ways to become more proactive in preventing problems.

Current Performance

The anticipated competition from alternative commercial and residential energy companies in its service area has motivated Duke to improve efficiency and productivity in all areas, including gains through performance improvements of its operating nuclear plants. Additionally, with new plant construction licensing and startup for the most part behind them, Duke is better able to place a higher priority and focus on the performance of its operating nuclear plants, including McGuire. Furthermore, the Duke corporate culture is to not only provide leadership for the nuclear industry, but to seek out and learn from others in the nuclear utility community to improve its own nuclear program.

These factors have come together and resulted in Duke effectively focusing corporate goals, resources, and activities on performance improvements for its operating nuclear plants. These goals have been clearly communicated to the entire organization with well-defined, comprehensive, and fully integrated action plans for their attainment. In order to achieve long-term rather than immediate or short-term gains in performance, greater emphasis was being placed in all work activities on the quality of work as compared to meeting schedules. To enhance the quality completion of work performed by DE for the operating plants and to overcome its historical orientation toward new plant design and construction, changes to the communications and coordination processes between NPD and DE have been put in place. At the same time, the contributions of the Nuclear Support staff to McGuire performance were improved through active involvement in learning and applying the lessons from other industry groups and utilities and through its improved working relationship with the Duke operating nuclear station staffs. The overall capabilities of the McGuire staff in operations, maintenance and testing have increased at all levels with experience and training. Additionally, the staff climate and attitude at the station have become more quality conscious, motivated, team oriented, and committed to performance improvement. This was achieved through improved communications, increased staff responsibilities, employee development, changes in plant management, and improved corporate direction.

Notwithstanding the greater organizational focus, priority, and commitment to performance improvement, McGuire is still on a learning curve and the benefits of these improvement initiatives have not been fully realized. Accordingly, McGuire's current performance, although improving, is still lagging expected performance. Additionally, several root causes were identified for organizational and programmatic weaknesses which could significantly undermine performance improvement efforts at McGuire. It was found that DE, a large and capable engineering resource, was still not being fully utilized in the day-to-day support for operating plant problems and programs. As a result, some technical issues which could have benefitted from indepth DE attention did not receive it and were not evaluated well. For example, recurring plant equipment problems resulted from weak equipment problem/failure root cause determination due to a lack of proactive DE involvement. Furthermore, the inadequacies identified in the IST program (e.g., vital check valves in the AFW system and the steam supply system to the turbine-driven AFW pump not being tested for reverse flow, and lack of testing of safety-related ASME relief valves), were principally due to inadequate corporate oversight in the development of the IST program and DE taking a passive role in supporting the development and administration of the IST program. Additionally, the inadequate response by Duke DE to INPO SOER 86-3 contributed to these testing deficiencies not being detected sooner. The DE role was to support the station and its programs when specifically tasked by the NPD and the NPD attitude was to handle its own problems and issues so far as practical.

Additionally, inadequacies in the effectiveness of the quality programs were caused by weaknesses in both the QA verification function and the line organizations corrective actions. The QA organization contribution to plant safety performance was found to be limited by the lack of a strong operations background within the QA staff. The root cause for this situation was a corporate policy which placed priority for quality achievement and quality verification and, therefore the placement of technical resources, in the line organization. Furthermore, QA audit and surveillance program emphasis was placed on conducting programmatic rather than technical reviews. In addition, within the line organization, ineffective or lack of comprehensive corrective actions taken in response to identified problems in incident investigations, audits, and procedures were due to corrective actions being narrowly focused, with minimal review and/or analysis of the findings for generic and long-term preventive actions.

The Maintenance Department lack of an equipment problem/failure trending program and lack of a system expert program also contributed to the weaknesses in the determination of root causes of recurring equipment problems. The lack of progress in establishing a failure trending program was due to the Duke decision to set a higher priority on establishing a broad scope preventive maintenance program.

Interface problems between NPD and CMD were traced to deficiencies in the training and qualification of CMD personnel who were providing modification and maintenance support for the station. Deficiencies in the training provided to CMD personnel compared to NPD personnel resulted in CMD personnel having less knowledge of plant equipment and work control processes. Duke recognized these problems at McGuire (and the other Duke nuclear stations) and had begun to take steps to identify the personnel requiring additional training and their specific training requirements.

3.0 DETAILED EVALUATION RESULTS

3.1 Operations

The team evaluated the adequacy of operator shift manning and experience, control of ongoing activities, with an emphasis on procedural compliance and adequacy, and operator training. Operations activities were assessed by reviewing the control of procedures, records and operating logs, temporary modifications, and system tagouts, including extensive interviews of licensed and non-licensed operators and several days of around-the-clock observations of control room activities. In addition, the team reviewed operator initial and requalification training programs, training and simulator facilities, training staff qualfications, and management oversight and support for the operator training program.

As described in the following sections, the operating staff was generally proficient in the use of operating procedures. Shift turnover practices were efficient and performed properly, and the operator training program was comprehensive and well organized. However, the team also identified a number of specific weaknesses in the areas of procedural and technical specification compliance, independent verification of operating activities affecting plant systems, and simulator training.

3.1.1 Conduct of Operations

The team observed several aspects of station operations and made the following observations.

3.1.1.1 Operating Shifts

The operating shifts at McGuire were twelve hours in length. The operating staff indicated that twelve hour shifts contributed to better morale of the staff by giving them more days off and also reduced the amount of overtime. A small core group from each of the other station departments also rotated with the operating staff on twelve hour shifts. The operating staff indicated that the interface with the other departments had improved significantly. The team believed that the licensee's implementation of the twelve hour shifts had a positive effect on morale and improved the operations department interface with other station departments.

3.1.1.2 Shift Staffing and Supervision

The team observed that the operating shift oversight, including the unit supervisors [senior reactor operator (SRO), shift supervisor (SRO), shift engineer, and unit coordinator (UC)] provided good supervision that enhanced the quality of plant operations. In addition, the McGuire operations shifts were staffed with significantly more personnel than required by TS. Operations shift personnel were also well-qualified.

3.1.1.3 Control Room Shift Turnover

The team observed several individual shift turnovers. Turnovers were accomplished efficiently and in accordance with the shift turnover procedures. However, the shift turnover checklist and the briefings which the offgoing watchstander gave to their oncoming counterparts addressed only equipment problems and ongoing activities which pertained to an individual watchstation. There was no integrated shift briefing given by the offgoing shift supervisor to the entire oncoming shift as a group. Because of the large amount of shared plant equipment, frequent cross-connecting of systems between units and past problems at McGuire with common plant equipment and cross-connected systems, an integrated preshift briefing to all oncoming operators by the off-going shift supervisor could enhance the safe operation of the plant.

3.1.2 Control Room Noise Level and Access Control

1. The team observed control room operations during dayshift, backshift and on the weekend. During the dayshift, the common control room (CR) occasionally became crowded and noisy due to the large number of personnel. During routine work activities on dayshift about 12-16 people worked in the CR. This number included six to seven operators, four to five technicians performing surveillances, one or two trainees, and one or two engineers obtaining information. During dayshift operations, all worked in close proximity to one another, which caused an abnormally high background noise level for the CR. During certain periods of high work activity on dayshift, the number of personnel in the common CR would increase to as many as 25. These conditions resulted in a noisy and potentially stressful environment for the ROs and increased the potential for personnel errors.

2. The team observed a large number of telephone calls coming into the control room that were answered by the ROs. Many of these calls appeared to be unnecessary and distracted the ROs from their normal duties. Several ROs indicated that the distracting calls had been routine since the McGuire units started operation approximately five years earlier and that plant management had made attempts in the past to reduce the calls, but the efforts had only been partially successful.

3. The licensee's procedure for access control to the CR area appeared adequate. However, in practice it was hard to enforce because of the multiple personnel access points to the control room, and because the SRO responsible for controlling access was not always present near the access points. Several operators felt that the CR should be modified to reduce both noise levels and improve CR access. The station manager indicated that proposed CR modifications were not approved because of concerns regarding the potential for introducing wiring errors in the relocation of the reactor coolant pump control panels.

3.1.3 Procedural Adequacy and Procedural Compliance

Overall, the control room operating staff was generally proficient in the use of plant procedures. However, the considerable flexibility given the operators in implementing some procedures, as well as a lack of detailed guidance and technical information in certain procedures, contributed to the procedural deficiencies and the personnel errors in following procedures which were observed or identified in records.

3.1.3.1 Plant Startup Procedures

On December 1, 1987, the team observed a Unit 2 startup from Hot Standby including generator synchronization and power operations. The control room operators conducted the startup in accordance with the ten applicable procedures. The team found the following:

(1) Operating Procedure OP/0/A/6100/06, Change 28, "Reactivity Balance Calculation," provides, in part, a method for for determining the reactivity balance of the reactor core prior to commencing a reactor startup. The team found that the RO had made an error during the performance of the reactivity balance calculation. In step 10 of Enclosure 5.2 of the procedure, the RO is required to verify that the Estimated Critical Position (ECP), the ECP plus 1000 percent milli-rho (pcm), and the ECP minus 1000 pcm are such that all the control rods are above the Technical Specification control rod insertion limit. The ECP minus 1000 pcm rod position was listed as 27 steps withdrawn on Bank C. However, this was 20 steps below the insertion limit, which was 47 steps withdrawn on Bank C. In addition, the team determined that the ECP was in error by approximately 700 pcm.

The team reviewed the data from past reactor startups, and found that a similar error had existed in the determination of the ECP in the previous reactor startup. The team determined that the 700 pcm error appeared to be caused by rough approximations used in determining the reactivity worth of xenon in the core, when the reactor is brought critical 12 to 24 hours after a reactor trip. The DE staff subsequently determined that two of the rough approximations used in determining xenon worth resulted in an approximate error of 500 pcm. The licensee determined the global core xenon worth was correctly modeled but an error was introduced by the plant computer due to inadequate curve fitting by the computer software. Additionally, the licensee determined that the graphs provided to the RO in the procedure introduced another error due to the rough step function approximation used in determining the reactivity worth of xenon in the range of 3000 to 4200 pcm.

It was found that in Unit 2 Licensee Event Report (LER) 85-14, "Reactor Criticality with Control Rods Below Minimum Insertion Limits," that on May 17, 1985, a similar, but larger error in the xenon predict computer program resulted in having the reactor brought critical with the control rods below the minimum TS rod insertion limits. The team believed that because of the previous errors in 1985 in the xenon predict computer program, as well as the error identified during the startup prior to December 1, 1987, the DE Department should have identified the current deficiencies responsible for the 700 pcm error prior to the December 1, 1987 reactor startup. The team concluded that the lack of effective corrective actions by DE in determining the root cause of the previous error indicated a weakness in the licensee's engineering support function. This is further discussed in Sections 3.5.5 and 3.5.6.

The team also observed that operating procedure OP/0/A/6100/06 was actually controlled by the Technical Service Department. The Reactor Engineer, responsible for the procedure, used terminology in the procedure which was not commonly used by the operators. The shift supervisor, who was overseeing the reactor startup, indicated that the procedure was difficult to follow and may have contributed to the error made by the RO. The team also believed that inadequate training in TS requirements regarding shutdown margin may also have contributed to the operator error. The licensee was revising the procedure and planned to address the problem in the operator requalification training program. In addition, the licensee made changes to reduce the large errors used in the determination of xenon reactivity worth.

(2) Several plant startup procedures frequently referred to the electrical components by name only, without including the component number in the description. The team believed that the failure to include component numbers in identifying electrical breakers and components was a contributing factor in the July 28, 1987 event at McGuire, in which the DC control power breaker to an Emergency Diesel Generator was not returned to service because the wrong breaker was checked as being closed. This was an example where procedural requirements did not provide an adequate component description.

(3) The team found that some startup procedures were written such that the steps were not required to be performed in a sequential order. Therefore, it appeared that some procedures were being used as a checklist, giving the operators a great deal of flexibility in implementing the procedures. The practice of giving the operators greater flexibility in some procedures could carryover into the use of this practice in other procedures which require strict verbatim step-by-step compliance to assure the safe operation of the plant.

3.1.3.2 Plant Cooldown Procedure

During the evaluation, the team became aware of a chronic problem concerning station operators not adhering to procedural cooldown limits for the pressurizer and reactor coolant system (RCS). The team determined that the pressurizer and RCS administrative cooldown limits were violated on several occasions, including one case in which the pressurizer cooldown and heatup TS limits were exceeded (Section 3.1.4.1). The review of station procedure PT/1-2/A/4600/09, Change 0, "Surveillance Requirements for Unit Shutdown," indicated that the procedure did not direct the RO to routinely determine the actual cooldown rate. The procedure required the RO to record the RCS pressure and temperature and pressurizer temperature every 30 minutes. However, the procedure did clearly specify the allowable cooldown limits and directed the RO to verify that the acceptance criteria (i.e., cooldown limits) were met. The team believes that the lack of a procedural step or requirement to specifically direct the RO to periodically determine the cooldown rate was a contributing cause for the errors. The team informed licensee management of this procedural weakness. The licensee initiated corrective actions by changing the procedure and planned to reemphasize the importance of adhering to administrative limits in procedures.

3.1.3.3 Containment Air Release Procedure

The team observed an RO not fully complying with procedure OP/2/A/6450/17, Change No. 2, "Containment Air Release." The RO was observed using the high alarm setpoint to initiate operator actions in maintaining containment pressure in lieu of the band in the procedure, which was 0.117 psig to 0.180 psig. The operator explained that his performance was a standard practice as the containment high pressure alarm comes in at approximately 0.188 psig which still allows sufficient time to take action to prevent exceeding the TS limit of 0.300 psig.

3.1.4 Compliance with Technical Specifications

Team observations indicated that Design Engineering was providing good administrative support in operability determinations, and the CR operating staff appeared to have adequate knowledge of the TS. However, one weakness was found in TS compliance.

3.1.4.1 Exceeding Pressurizer Cooldown and Heatup Rates

The team identified instances in which the TS pressurizer cooldown and heatup rates were exceeded during Unit 2 shutdown on April 21, 1985. The team reviewed the data documented in station procedure PT/1-2/A/4600/09.

The team found that the pressurizer cooldown rates between 0930 hours and 1030 hours, and between 1100 hours and 1200 hours were 219°F/hr and 204°F/hr, respectively. These rates exceeded the TS limit of 200°F/hr for the pressurizer. In addition, because of the heatup which occurred between 1030 hours and 1100 hours, the TS limit of 100°F/hour for pressurizer heatup was also exceeded between 1000 hours and 1100 hours (i.e., 128°F/hr).

If the pressurizer temperature limits are in excess of the allowable limits, TS 3.4.9.1 requires: (1) restore the temperature to within the allowable limits within 30 minutes; (2) perform an engineering evaluation to determine the effects of the out-of-limit condition on the structural integrity of the pressurizer; and (3) determine that the pressurizer remains acceptable for continued operation or be in at least HOT STANDBY within the next six hours and reduce the pressurizer pressure to less than 500 psig within the following 30 hours. Neither TS action requirement 1 or 2 was taken by the licensee. The team brought this concern to the attention of station management, and the licensee agreed that the cooldown and heatup rates which occurred on April 21, 1985 appeared to be a violation of TS 3.4.9.1. A problem investigation report (PIR) was initiated by the licensee to address the team's concern and LER 87-20, "Unit 2 Reactor Coolant System and Units 1 and 2 Pressurizer Exceeded Heatup and Cooldown Rate Allowed by Technical Specifications," was submitted covering the apparent TS violation. The licensee also subsequently identified in LER 87-20 three additional violations of TS 3.4.9.1 which had occurred between April 27, 1981 and May 3, 1983.

The team attributed these recurring TS violations to personnel error and a lack of management attention. These causes were also identified by the licensee in the above LER. Additionally, as discussed in Section 3.4.3.2, an underlying cause was the weakness in technical capability of the QA surveillance group.

3.1.5 Independent Verification of Operating Activities Affecting Plant Systems

The team reviewed Operations Department practices involving valve alignments, removal and restoration of equipment from service, and the implementation of independent verification of operating activities affecting the safe operation of the plant. Two weaknesses are noted below.

3.1.5.1 Systems Valve Lineups

During the evaluation, the team found that QA Department Audit NP-87-19(MC), identified six McGuire valves that were out of alignment. On the basis of this audit finding, the team further examined the licensee's method for ensuring that system valve lineups are correct. The team reviewed the current system valve and equipment alignment status files for several station systems. The team found that many systems had not had a valve alignment verification performed in over two years. There was no procedural requirement to perform system alignments, and system alignments were only performed when required by the Operations Department Unit Coordinator (UC). The UC indicated that he would require an individual system alignment on a case-by-case basis, and it would depend upon the amount of maintenance which had occurred on the individual system during an outage. Normally the licensee would rely on their equipment tagout procedures to restore system alignment after maintenance was completed. The UC indicated that a complete system alignment would be warranted only after a major system maintenance or modification was performed. The team found that most of the system alignment verifications on Unit 2 were last performed in 1985. Most would not be done again until 1989, after the next refueling, and then only if required by the UC. The lack of specific written criteria to periodically verify proper system alignments was considered a weakness in the licensee program for implementing Item I.C.6, "Verifying Correct Performance of Operating Activities," of NUREG 0737, "Clarification of TMI Action Plan." In addition, by leaving system alignment checks up to the discretion of the UC rather than specifying appropriate requirements in procedures, the UC could become subject to pressures from the integrated scheduling group during a unit outage.

3.1.5.2 System Lineup Independent Verification

During a walkdown and review of a valve lineup checklist for the AFW system, the team observed that independent verification was not required for the vent or drain paths associated with the pumps, or pump discharge lines to the steam generators. The team also found that the vents and drains in other safety-related systems were not independently verified, except those associated with the reactor coolant system or containment isolation function portions of a system. In response to the team's question regarding the lack of independent verification, a unit supervisor stated that mispositioned valves would be readily identified and corrected through observation of water leakage, or changes in tank water levels. The team also noted that the AFW valve checklist only required that the local position of actuator operated throttle valves be checked "open". This was considered a weakness in the checklist. Good operating practices would require that the correct throttle position for throttle valves be verified either by flow checks or physical positioning.

3.1.6 Material Deficiencies

The team found instances in which plant equipment problems had been allowed to remain uncorrected for extended periods of time. Plant management was apparently not sensitive enough to the numerous problems that were accumulating, and that lack of proper identification and prioritization of equipment problems by the Operations Department prevented support organizations from performing timely repairs and thus contributed to the accumulation of deficiencies. Three examples are cited below.

1. At the beginning of the evaluation, the team observed that approximately 50 outstanding deficiencies concerning control room chart recorders had been identified by the control room operating staff. The ROs use the recorders frequently to monitor plant parameters and control plant operations. The team brought this concern to the attention of plant management and most of the deficiencies were subsequently corrected. The chart recorder problems had been recurring, apparently due to poor communications of priorities between the Operations Department and the Maintenance Department.

2. The team observed that the auto-divert valves for the chemical and volume control system (CVCS) volume control tank (VCT) were operated manually rather than automatically. The operators indicated that the valve had a long history of leaking by its seat while operated in the automatic mode (see Section 3.2.3.2 for further details).

3. During the surveillance test of Unit 2 AFW turbine-driven pump, the turbine casing relief valve lifted or leaked excessively and quickly raised the pump room temperature and humidity to high levels. The test technicians knew of this chronic problem, however, corrective action was not taken until equipment reliability concerns were raised by the team. A modification was subsequently performed to remove the relief valves from the pump casings (see Section 3.3.2.1 for further details).

3.1.7 Control of Nonsafety-Related Equipment and Systems

The team performed limited reviews of the licensee's procedures for controlling and verifying the quality of balance of plant (BOP) equipment. The purpose of this review was to identify how BOP systems were controlled compared to safety-related systems. McGuire station directives did not require independent verification on removal or restoration from service; post-maintenance testing on restoration following maintenance activities; or periodic surveillance testing of BOP equipment. It was also found that BOP instrument calibrations beyond the testing of the instrument (i.e., loop calibrations) were not normally done, even if the instrument could cause an equipment protection (and subsequent reactor) trip. Some post-maintenance testing was normally performed on BOP equipment, but apparently it was at the discretion of plant management.

An example of the weaknesses in BOP equipment quality verification was found as a result of the reactor trip on November 30, 1987. The reactor trip followed a turbine trip on a one-out-of-one low generator stator cooling water pressure signal. The output from the instrument was determined to have been wired incorrectly since initial installation during plant construction. A loop calibration could have detected the error that tripped the reactor when the turbine tripped automatically. However, the pressure signal never had a loop calibration performed. The team observed that the above practice on BOP equipment at McGuire was not uncommon in the nuclear industry.

3.1.8 Operator Training

The team determined that the operator training program at McGuire was well organized and comprehensive and consisted of formal classroom and simulator training, on-the-job training, and a qualification program. Strong management commitment to high quality training was apparent at every level. However, some weaknesses were found concerning operator training facilities, the quality of training material, and the number of hours of simulator requalification training.

3.1.8.1 Requalification Program for Licensed Operators

Duke management in both the NPD and the Production Support Department (PSD) expressed a firm commitment to high quality training. Duke's training program had been fully accredited by INPO and reviewed and approved by the NRC using NUREG-0800 and guidance contained in the March 20, 1985, Commission Policy Statement on Training and Qualification of Nuclear Power Plant Personnel (endorses the INPO managed Training Accreditation Program). A reaccreditation schedule was being arranged with INPO.

(1) The operator requalification program for McGuire was described in the NPD Employee Training and Qualification System (ETQS) Manual. The program was conducted on a biennial basis and included formal requalification lectures, simulator training, written examinations, and an annual operation examination. Proficiency lectures covered topics such as abnormal and emergency procedure review, critical safety functions monitoring, technical specifications, facility design and licensing changes, procedures changes and related nuclear industry and in-house operating experience. Operators were required to participate in simulator exercises which included control manipulations, infrequent operating conditions and response to malfunctions and abnormal conditions. An annual evaluation of operator performance was conducted on the basis of a simulator operational evaluation and a written accident assessment examination.

    The format and conduct of the licensee's simulator operational evaluation and written accident assessment examinations appeared to be similar to the new guidelines being established for NRC operator requalification examinations in SECY-87-262. However, the operators interviewed did not appear to be familiar with the changes taking place with the NRC's requalification examination process. Nonlicensed NEOs were required to participate in the formal requalification program. Their training consisted of formal lectures on fundamental and operational proficiency topics and skill training for selected low frequency tasks. The entire operating staff spends ten weeks each year in requalification training (i.e., 2 weeks during each 10-week shift cycle).

(2) The team found that the 1987 training schedule consisted of only 20 hours of simulator time during requalification training. This was significantly below the industry average. Training program management indicated they were aware of the problem, but could not support additional training because the simulator was being fully utilized with initial license and requalification training for both the McGuire and the Catawba operators. It was apparent that the situation would be remedied shortly because of the completion of a new training facility at the Catawba site including a new plant simulator. Without the added load of Catawba personnel, 40 to 50 hours of simulator training were being scheduled for McGuire licensed operators in 1988.

(3) Classrooms for requalification training were in temporary facilities which were separate from the Technical Training Center simulator facility. Because of the layout of the facility, and the distraction due to a telephone immediately outside the classrooms, the training environment was less than desirable.

(4) Visual aids used during lectures were of poor quality. Many of the visual aids had numerous handwritten additions and changes, and in some cases chalkboard sketches were used when viewgraphs or color slides of the plant equipment being discussed would have been much more effective.

3.1.8.2 Training Staff

The operator training staff for McGuire consisted of the Director, five simulator instructors and seven classroom instructors. With the exception of one instructor (who is only involved with nonlicensed operator training), all the instructors had received Senior Reactor Operator licenses from the NRC and were maintaining their Operator Instructor certification. The Director of the training staff was also licensed and served as a Shift Engineer (and STA) at McGuire for two years. Among the simulator staff, plant experience ranged from 2 to 12 years with an average experience level of 9 years. Within the classroom instructor staff, plant experience consisted of only two instructors with 5 years experience each. Related experience of the classroom instructors consisted of nuclear/non-nuclear experience in the military ranging from 4 to 24 years.

Interviews with selected licensed and nonlicensed operators revealed that the operating staff generally had a high regard for the initial and requalification training program and staff. However, some operators had the perception that there was a lack of operational experience among members of the training staff. This perceived lack of experience affected the credibility of the staff and the effectiveness of training.

To maintain their qualification status, the Training and Qualification Program required that instructors participate in the requalification program and spend at least eight hours each month at the plant reviewing licensed and nonlicensed operator activities, touring the auxiliary and turbine buildings, observing training, conducting oral audit exams, and updating training material. Although this in-plant time was certainly beneficial for the classroom training staff, it did not increase their actual hands-on operating experience at the station. The Training Director indicated that several new positions in the training staff had been budgeted to accommodate the temporary transfer of experienced licensed operators from the plant to the training staff. These operators, after receiving the necessary training, would serve as instructors for licensed operator training and would significantly increase the experience level of the staff.

3.1.8.3 Simulator Facility

Duke had a McGuire simulator at the Technical Training Center at McGuire. The simulator had been used until recently to train licensed operators for both the McGuire and Catawba stations. Because of the need for additional simulator training capability and for a site-specific simulator for Catawba, Duke procured a simulator which had been delivered to the Catawba training center and was expected to be operational in the near future. Duke also made the decision to replace the McGuire simulator with a new state-of-the-art machine rather than upgrade the existing simulator. The new McGuire simulator was scheduled to be delivered to the site in October 1988.

Discussions with the operations and training staff indicated that although the current simulator usually represented an accurate model of the plant in terms of transient response, there were some inadequacies. Modeling of the residual heat removal system, for example, was very limited, and, therefore, required significant additional instructor discussion on the expected response of the system.

The team found that there was a backlog of approximately 50 modifications on the McGuire simulator. Training on these modifications was done through the use of prototypes and operation of the control board of the shutdown unit. However, these modifications were not modeled during Emergency Operating Procedure (EOP) drills on the simulator. The installation of a new simulator with significantly upgraded modeling capability should correct these shortcomings.

3.2 Maintenance

The evaluation of the McGuire maintenance program included: a broad review of the overall preventive maintenance program, as well as a detailed review of the AFW system preventive maintenance (PM) and corrective maintenance (CM) activities; a review of maintenance and testing of safety-related motor-operated valves (MOVs); interviews with GO and station maintenance managers, staff engineers, and technicians; and a review of the Maintenance Department staff qualifications and organization. To a lesser degree the team evaluated the maintenance training program, the post-maintenance testing program, BOP maintenance and several other long-term PM program enhancements that were in various phases of evaluation or implementation by Duke. The team observed many overall strengths in the licensee's maintenance programs as well as several specific items of weakness.

3.2.1 Maintenance Program

3.2.1.1 Maintenance Department Staff

The Maintenance Department was well-staffed and well-managed. The Superintendent of Maintenance and the Maintenance Engineers for Instrument and Electrical (IAE), Planning, and Mechanical Maintenance all have several years of experience with Duke. There were approximately 340 Duke employees in the McGuire Maintenance Department, and personnel turnover was low. The ratio of foremen to technicians was approximately one foreman for every six technicians. There were 46 mechanical and IAE technical support engineers on the station staff who had cognizance over major system components. In addition to the station technical support staff, there were maintenance personnel dedicated to procedure writing, maintenance training, measurement and test equipment (M&TE) control, and administrative support. Twelve-hour maintenance shifts provided 24-hour-per-day coverage for preventive maintenance.

3.2.1.2 Preventive Maintenance

The team found the scope of the McGuire PM program to be significantly greater than the industry average. For example, McGuire had extensive lubrication oil analysis and vibration analysis programs which encompassed numerous safety-related as well as BOP system components. The corporate nuclear support staff and station together had developed an effective systematic methodology for adding and deleting system components to the PM program. Generally, plant maintenance procedures appeared technically adequate and comprehensive. Duke had also initiated a major program to improve plant maintenance procedures.

3.2.1.3 Preventive Maintenance Improvement Programs

The Maintenance Department worked closely with the GO Nuclear Maintenance Group to continuously explore and develop new initiatives to improve the PM program. For example, Duke was voluntarily participating in the Electric Power Research Institute (EPRI) sponsored reliability-centered maintenance (RCM) pilot program. A systematic and detailed evaluation of main feedwater (MFW) system preventive maintenance activities was performed by licensee and contractor personnel to determine whether an optimum balance had been established for maintenance activities for the MFW system. The RCM effort encompasses methodologies that were pioneered by the Department of the Navy and the commercial airline industry. On the basis of the potential benefits of the pilot program, Duke intended to expand the scope of the program to include several other systems to further evaluate the applicability of the RCM program to the commercial nuclear industry. Additionally, the Valve Reliability Improvement Program was an example of the Nuclear Maintenance Group's effort to comprehensively improve overall station valve reliability through maintenance training, maintenance practices, valve application improvements and/or replacements, product improvement testing, and valve preventive maintenance planning.

3.2.1.4 Maintenance Department Climate

Almost all Maintenance Department technicians exhibited high morale. All the technicians interviewed felt that the company had a high regard for plant and personnel safety. For the most part, these technicians felt: they were adequately trained to perform their assigned duties; the quality of maintenance training was good; and that maintenance foremen and Quality Control Inspectors assisted them in performing quality work by working closely with them and giving them useful feedback.

3.2.2 Motor-Operated Valve Maintenance Weaknesses

Despite the corrective actions resulting from the 1986 Rotork MOV outage, the team found several weaknesses in the control and documentation of MOV torque switch settings.

3.2.2.1 Limitorque MOV Torque Switch Setpoints

The Electric Motor-Operated Valve Torque/Limit Switch Setting List (EMO valve list), Revision 12 provided safety-related design information for Rotork and Limitorque MOV torque and limit switch settings. The EMO valve list was used by maintenance technicians as a reference document for MOV switch maintenance and testing. The EMO valve list was the only controlled design document that lists prescribed MOV torque switch settings. The team reviewed the EMO valve list and found that torque switch setting values were not documented in the EMO valve list for numerous safety-related Limitorque MOVs. Proper MOV torque switch settings are essential for reliable MOV operation. For the valves listed in the following table, the close torque switch is used to stop motor rotation upon the completion of valve travel in the closed direction. The limiting torque requirement is at the end of travel when the closure thrust requirements are the highest, the effect on flow control is most significant, and the switch is almost never bypassed. Thus, it is extremely important that the thrust of the torque switch trip equal the most limiting closure thrust requirement and that margin is available to allow for valve and operator degradation. For these reasons, it is essential that the torque switch settings be properly set and controlled. The following safety-related Limitorque MOVs did not have torque switch settings documented in the EMO valve list:

Valve Number	System
2VI362A	Instrument Air
1NI430	Safety Injection
1NI431	Safety Injection
2NI430A	Safety Injection
2NC53B	Reactor Coolant
2NC195B	Reactor Coolant
2NC196B	Reactor Coolant
2NI288A	Safety Injection
2NI358A	Safety Injection
1(2)CA38	Auxiliary Feedwater
1(2)CA50	Auxiliary Feedwater
1(2)CA54	Auxiliary Feedwater
1(2)CA66A	Auxiliary Feedwater

Discussions with McGuire maintenance personnel revealed that for the first seven MOVs listed in the table above, no torque switch data were available at the station. Additionally, correct torque switch settings were not verified for Limitorque MOVs by technicians performing periodic preventive maintenance (Section 3.2.2.2). For these reasons, the correct torque switch settings for the MOVs in the above table may have been inadvertently changed over the past several years. Following discussions with McGuire maintenance personnel, DE personnel at the GO obtained within several days the torque switch settings for these MOVs. These data were retrieved from the original procurement records. The team found, however, that the subject MOVs were originally purchased for Catawba, but subsequently were transferred for use at McGuire. The original torque switch settings that were provided by Limitorque for use at Catawba were apparently unchanged. Because of the uncertainty over the correctness of the torque switch settings of the subject Limitorque MOVs, the team understood that the licensee planned to verify that the actual torque switch settings for these MOVs were in conformance with the design requirements.

3.2.2.2 Limitorque MOV Preventive Maintenance Procedure

The team reviewed maintenance procedure IP/0/A/3066/02D, Change 2, "Rotork Actuator Preventive Maintenance," and IP/0/A/3190/10, Change 8, "Limitorque Operator Preventive Maintenance." The team found that the Rotork preventive maintenance procedure required the recording of the as-found torque switch settings, but the Limitorque preventive maintenance procedure did not. The periodic verification of MOV torque switch settings is important because it provides a regular method of assuring that the switches are correctly set. In view of the lack of documentation of the correct torque switch settings (as discussed in Section 3.2.2.1), the lack of periodic verification of Limitorque torque switch settings may, over a period of time, lead to an actual loss of control of the torque switch settings and could eventually result in improper MOV operation or failure.

3.2.2.3 Rotork MOV Torque Switch Setpoint Changes

(1) The team found that the EMO valve list provided guidance that permitted maintenance technicians, without consulting with DE, to increase torque switch settings of the Rotork MOVs up to 15 percent. Discussions with IAE technical support engineers revealed that this activity had since been prohibited. The team observed, however, that this guidance had not been removed from the controlled working copy of the EMO valve list that was used by maintenance technicians. Confusion over this conflicting guidance might result in the continuation of the prohibited practice, and could subsequently result in a loss of control of Rotork MOV switch settings thereby affecting MOV operability.

(2) The team performed an indepth review of the EMO valve list and found one instance in which the close torque switch setting recorded on the list for Rotork MOV 1FW49B, feedwater storage tank (FWST) to recirculation pump, was not the same as the actual close torque switch setting. For MOV 1FW49B the close torque switch setting had been increased from 4 to 5 in December 1986 as a result of the findings from the 1986 Rotork MOV outage. The team observed, however, that the EMO valve list for this MOV still indicated that the close torque switch setting was set at a value of 4.

3.2.2.4 Rotork MOV Design Torque Values and Setpoints

The team observed that for Rotork MOVs 1NM260B (steam generator blowdown sample 1B vent) and 1NI103A (A NI pump suction from FWST) the actual design torque values for the close direction were provided in the EMO valve list but the torque switch settings corresponding to these torque values were not. The failure to provide the torque switch setting values that correspond to the actual design torque values on the EMO valve list made it difficult for a maintenance technician to determine (using the EMO valve list), whether the as-found torque switch settings that were recorded during MOV preventive maintenance were correct.

The team recognizes that Duke had committed significant resources to develop and implement a program to ensure that switch settings on all safety-related MOVs were selected, set and correctly maintained to accommodate the maximum differential pressure expected on these MOVs during both normal and abnormal events within the design basis. This commitment greatly exceeds the requirements of Inspection and Enforcement (IE) Bulletin 85-03, "Motor-Operated Valve Common-Mode Failures During Plant Transients Due to Improper Switch Settings." Because of the broad scope of this commitment, the program will not be completed for all McGuire safety-related MOVs for another four refueling outages which is too long a period to wait to completely implement one of the elements of the program, involving improved methods of controlling MOV torque switch settings. Interim steps needed to be taken to assure that the EMO valve list accurately reflected actual safety-related MOV switch settings. Discussions with IAE technical support and DE personnel revealed that the licensee intended to correct in the near future the inconsistencies and data omissions of the EMO valve list and to improve its utility.

3.2.3 Corrective Actions

The team reviewed the licensee's methods for determining the root causes of equipment problems and failures, and the effectiveness in correcting such problems and failures. The following deficiencies are indicative of a weak equipment problem/failure corrective actions program.

3.2.3.1 Auxiliary Feedwater Pump Excessive Vibration

The team found a long history of excessive vibration and damage for five of the six McGuire AFW pumps. Several years were required to resolve the vibration and damage problems because of an apparent lack of an adequate root cause determination. After almost five years, damaging vibration was found to have been caused by insufficient AFW pump minimum recirculation flow. The air-operated minimum flow recirculation valves (i.e., 1(2)CA27A for motor-driven AFW pumps 1A and 2A, 1(2)CA32B for motor-driven AFW pumps 1B and 2B, and 1(2)CA20AB for turbine-driven AFW pumps 1 and 2) were all incorrectly set to provide approximately 50 percent of the recommended minimum recirculation flow. The purpose of these valves is to provide AFW pump protection when the pumps are operating against their shut-off head, and to provide a flow path during periodic pump testing. Discussions by the team with DE personnel revealed that on the basis of erroneous data supplied by the vendor, the minimum flow values were improperly established during preoperational testing several years earlier.

Excessive AFW pump vibration and bearing damage had occurred as early as 1982 as documented in Maintenance Department work requests. The McGuire Maintenance Department, however, apparently did not attribute the excessive vibration to insufficient AFW pump minimum recirculation flow even though the pump technical manual notes that excessive pump vibration can be caused, in part, by operating the pump below rated capacity. A review of maintenance records and discussions with maintenance personnel revealed that Mechanical Maintenance, in 1986, considered other possible causes of excessive vibration and bearing damage such as bent or improperly sized pump shafts or lubrication problems.

The correct AFW pump minimum recirculation flow values were not set until June 1987. The incorrect flow values were apparently discovered by the accountable project engineer who was responding to station problem report (SPR) MGPR-0783 that had been written in May 1986 by a McGuire Maintenance Department IAE technical support engineer. This SPR was written in response to recurring minimum flow valve position indication problems. Apparently, the minimum flow valves would continue indicating shut after stroking open to the throttle position required to deliver AFW pump minimum recirculation flow. After having made several switch adjustments, spanning several months, it was determined that the limit switches were not designed to operate over the extremely short range (approximately 1/4") that these valves were required to stroke. As a result, SPR MGPR-0783 was written to determine if the flow recirculation valves were designed to be throttled to only approximately 1/4" open.

The team observed that DE was not involved in resolving the excessive vibration problem until the accountable engineer in the McGuire Projects section responded to SPR MGPR-0783. During the course of his investigation, the accountable engineer concluded that excessive vibration was caused by low AFW minimum recirculation flow. Design Engineering verified this conclusion by comparing the data subsequently provided by the pump vendor's local representative with the preoperational test data for the AFW pumps.

3.2.3.2 Volume Control Tank Divert Valve Leakage

The team found from a review of maintenance records and station staff interviews that the 3-way, air-operated VCT divert valve for each unit (1(2)NV137) had a long history of leaking by its seat because its disc would not fully seat. For valve 1NV137, the team found that the Operations Department had written several work requests over nearly a three year period from July 1983 to April 1986 to investigate and repair leakage problems. The team reviewed these work requests and found that no effective solution to the leakage problems had been identified during this period. In July 1986, an IAE technician, who was working on 1NV137 in response to work request 126951, discovered the bench set data for the valve actuator were incorrectly listed in the I&C list and on the instrument detail diagram. Apparently, the valve actuator bench set was being set to these incorrect values. Setting the actuator to the incorrect bench set values prevented the actuator from developing enough force to fully seat the valve under normal operating pressure and flow. The incorrect bench set data were corrected on the design documents by variation notice ME-VN-514. The change to 1NV137 was accomplished by work request 94200 in March 1987. The bench set values for 2NV137 were also incorrect, but the station staff had not, by the time of the evaluation, written a work request to change the bench set for 2NV137.

The licensee indicated that the leaking VCT divert valve problem was widely known at the McGuire Station, but the problem was not severe enough for more aggressive actions to be taken to fully resolve the problem. As a result, the station never requested DE support in solving the valve leakage problem. Although the evaluation team had no safety concerns regarding VCT divert valve operability, the root cause of the problem went unidentified for almost three years in spite of extensive troubleshooting. The team concluded that the failure to determine the root cause of the valve leakage for such a long period of time was attributable, in part, to both NPD's reluctance to request DE assistance, and the relatively limited involvement by the DE staff at the station for day-to-day evaluations of equipment problems. Other instances of failure to fully utilize design engineering resources are discussed in Sections 3.5.6 and 3.5.7.

3.2.3.3 Rotork MOV Motor Failures

Maintenance procedure PT/0B/4350/31, Change 0, "Yearly Rotork Maintenance Review," provided for the annual review of Rotork MOV corrective maintenance activities. Although the annual review of Rotork MOV maintenance appeared to be an effective means of trending Rotork MOV problems and failures, it did not appear to be a completely effective framework for identifying and correcting root causes of MOV problems and failures. For example, the most recent annual review, which was completed on May 4, 1987, documented seven MOV motor failures for the 12-month evaluation period. The IAE technical support engineer who performed the review noted that in many cases the root causes of motor failures were not determined during the repair activity. A review of the work requests for these MOV motor failures confirmed that the root causes were not determined and/or documented. Discussions with McGuire and GO Maintenance personnel and DE personnel revealed that no analysis of these MOV motor failures had been performed to determine the root cause(s) of failure. The team also found that PT/0B/4350/31 provided no mechanism for management review of the results of the annual review of Rotork corrective maintenance or any method of coordinated commitment tracking of planned corrective actions which follow from these reviews.

3.2.4 Equipment Failure Trending

The team found that the Maintenance Department was trending some specific types of equipment failures (e.g., Rotork MOVs), but there was no integrated program in place to trend all safety-related equipment failures. The team also observed other specific weaknesses related to the trending of failed equipment as discussed below.

3.2.4.1 Equipment Failure Trending Program

The licensee had no program in place to trend safety-related equipment problems or failures. At the time of the evaluation, the Maintenance Department had a draft procedure entitled, "Equipment Trending and Failure Analysis Program." This procedure would provide for a periodic analysis of equipment work history by Maintenance Department planning and technical support personnel in order to identify the causes of equipment problems and failures. The team could not assess the effectiveness of this proposed failure trending program, however, because it had not yet been implemented.

3.2.4.2 MOV Maintenance Annual Review

Notwithstanding the weaknesses noted in Section 3.2.3.3, the team considered maintenance procedure PT/0/B/4350/31, Change 0, "Yearly Rotork Maintenance Review," to be a good mechanism for identifying recurring Rotork MOV problems and failures. The licensee had not developed a similar procedure that would provide for the annual review of Limitorque MOV corrective maintenance activities.

3.2.4.3 Work Request Documentation

During the evaluation, the team reviewed numerous work requests. Generally, technicians sufficiently documented the steps taken to effect repair of equipment. However, the team found that the causes or possible causes of equipment failure, which are essential elements of failure trending, were poorly evaluated and/or poorly documented.

3.3 Testing

The team reviewed the licensee's testing programs, including implementation, with particular emphasis placed on testing required by Section XI of the ASME Code. Test procedures were reviewed for adequacy; completed tests were reviewed for completeness including any follow-up corrective action; and the team witnessed the conduct of several tests. Testing for safety-related and BOP systems were included in the evaluation with special emphasis placed on Section XI testing as it was applied by the licensee to the auxiliary feedwater system.

Within the testing area, the evaluation team observed a number of specific strengths and good practices. The extent and types of strengths found led the team to conclude that the testing program and its implementation was above the industry average. However, the team did identify several significant programmatic and technical weaknesses within the testing area.

3.3.1 ASME Section XI Testing

3.3.1.1 ASME Section XI Testing Commitments

McGuire is currently committed to perform inservice testing (IST) of ASME Code categories A, B, C, and D valves and ASME Code Class 1, 2, and 3 pumps as required by Section XI, subsections IWV and IWP, of the ASME Boiler and Pressure Vessel Code 1980 Edition, with exceptions to the Code granted by the NRC. McGuire's IST program which was submitted to the NRC for approval in 1980 and 1981 for Units 1 and 2, respectively, had not yet been reviewed and/or approved. McGuire's second 10-year IST program is due to be submitted to the NRC for approval within the next two years. Because of changes in the Code and testing philosophies, a significant increase in Code-related testing will be required at McGuire. The changes may also necessitate plant modifications to accommodate the additional testing.

3.3.1.2 Overall Control of Testing Requirements

In 1985, the Integrated Scheduling Group was formed at McGuire to coordinate various maintenance and testing work. To accomplish this task, the Integrated Scheduling Group reviewed existing operations and maintenance schedules and developed an Operating Schedule data base. From this data base, an Operating Schedule Report is issued each week which projects the station work plan for the next two weeks. The final work plan takes into consideration equipment availability, train separation of work, and coordination of multiple work efforts to minimize equipment downtime. The system has worked very well, resulting in only a few missed surveillances out of approximately 3500 that are scheduled each year. However, the team found some weaknesses regarding test performance, including data evaluation, trending, and corrective action.

Station Directive 3.2.1, Revision 18; "Identifying and Scheduling of Plant Surveillance Testing," outlined the basic requirements for test scheduling, operations interface, and test conduct. Under the heading "Conducting Surveillance Testing," paragraph b requires that the Shift Supervisor be notified of components failing to meet acceptance criteria and the actions required to correct the deficiency. Paragraph d also states that "the individual group/section discovering the deficiency shall insure action is initiated to correct the [deficiency]. To insure proper evaluation for reportability, the group/section discovering the discrepancy shall notify the Compliance Section as soon as possible." The evaluation team found that no procedures existed to ensure that the above aspects of the directive were implemented. In addition, procedures were not in place to assure that corrective action was accomplished as required by the directive and various IWV/IWP articles of Section XI of the ASME Code. Section XI requires that corrective action be taken in the event of a failure to satisfy test acceptance criteria, which may include increased testing frequency, repairs, and/or engineering evaluations prior to resuming the normal surveillance test schedule. Although no formal procedures were in place to govern the process, it appeared that when test failures occurred, corrective action was performed which included system/component retest and verification except for the valve timing testing deficiencies discussed later in Section 3.3.3.2. When testing frequency was increased, the data base for the computer program used to schedule and track surveillance testing was revised through an informal process to reflect the increased frequency for affected components. During the evaluation, the licensee indicated that procedures would be developed to track surveillance test failures to ensure compliance with Section XI requirements.

3.3.2 ASME Section XI Pump Testing

The evaluation team reviewed the most recent revision of the McGuire pump IST programs. Reviews included observations of motor-driven and turbine-driven auxiliary feedwater pump tests, in addition to an examination of completed pump tests. Weaknesses involving test conduct and documentation are discussed below.

3.3.2.1 Test Conduct

During the performance tests observed by the team, the technicians were generally knowledgeable and followed test procedures properly. There was good coordination between personnel in the control room and the technicians at the equipment location as the tests were carried out. The team observed, however, that the technicians focused very narrowly on accomplishing the steps in the test procedure, and did not raise questions about potential problems they observed in the plant if not directly related to meeting the test acceptance criteria. This appeared to be indicative of a lack of a broad understanding of the system functional requirements by the test technicians and engineers. Examples included the following:

(1) The evaluation team observed a surveillance test of the Unit 2 AFW turbine-driven pump. During the test, the turbine casing relief valve lifted or leaked excessively during pump operation and quickly raised the pump room temperature and humidity to very high levels. The heat and humidity levels were sufficiently high that the technicians could not remain in the room continuously. The leaking relief valve did not affect meeting the test acceptance criteria, and consequently was not reported. When the team informed plant management concerning the possible consequences of the heat and humidity on long term equipment reliability, McGuire removed the relief valves in accordance with established plant modification procedures. The licensee determined that the valves were not required for overpressure protection.

(2) During an observation of a surveillance test of motor-driven AFW pump 1A on December 7, 1987, the team noticed that the tubing support for the air lines to the pump 1A miniflow valve (1CA-27A) was disassembled and the

tubing was bent and scratched. Although the test was performed with isolation valves shut to prevent the feeding of steam generators with the AFW system, the team observed local instrumentation which indicated auxiliary feedwater leakage past the isolation valve to steam generator 1A of approximately 57 gpm. Neither of these material conditions were of concern to test personnel until questions were raised by the team.

(3) A normally locked cover for bypass control valve 1CASV-0320 was found unlocked on December 11, 1987 by the team. This valve had been operated on December 9, 1987 as part of a surveillance test on AFW pump 1B. Steps were provided in the procedure to unlock and relock the cover at appropriate times to permit repositioning the bypass control valve. Although a step in the procedure had been initialled and dated to indicate the cover had been relocked, this step was apparently not performed.

3.3.3 ASME Section XI Valve Testing

The most recent revisions of the McGuire valve IST programs were reviewed by the team, and resulted in the identification of several programmatic concerns. The majority of deficiencies found involved the auxiliary feedwater (CA) or main steam supply to auxiliary equipment (SA) systems since this was the area of emphasis for the diagnostic evaluation. Examples of these deficiencies are presented below.

3.3.3.1 Check Valve Testing

The McGuire IST program was not consistent with the IST program approved by the NRC for Catawba even though the plant designs are very similar. Check valves SA-5 and SA-6 which are located in the steam supply line to the turbine-driven AFW pump, were not included in the McGuire IST program. However, the equivalent check valves (SA-3 and SA-6) were included in the Catawba program. In addition, AFW system valves CA-1 through CA-6, which include both isolation and check valves and serve to isolate three sources of nonsafety-related water to the AFW system, were included in the Catawba Section XI program, but were not included in the McGuire program. The nonsafety-related water sources included the hot well, AFW condensate storage tank, and the upper surge tanks.

The team found that other than containment isolation valves and pressure/system boundary valves, no reverse flow operability tests were being performed on check valves. This is inconsistent with Section XI of the ASME Code which requires testing in the open or closed position (or both) as necessary to verify the valve's safety function. Consequently, undetected check valve failures could exist due to lack of testing.

Regarding the SA check valves in the steam supply lines, the FSAR Chapter 15 analyses consider as a worst case a secondary side break involving the failure of a main steam line or feedwater line. The analysis assumes an uncontrolled blowdown of only one steam generator. However, the failure of a check valve (open) in the supply line to the AFW turbine from the steam generator with the line break would also result in the uncontrolled blowdown of the connected unfaulted steam generator by backfeeding through the failed check valve. The potential for an undetected failure due to lack of testing or maintenance on

SA-5 and SA-6 was brought to the attention of senior plant management by the team. Because of the team's concern, McGuire entered a 6-hour LCO on December 9, 1987, to perform a stem movement operability test on SA-5 and SA-6 to verify that a disc was installed. For the longer term, the McGuire Station Manager indicated that the SA-5 and SA-6 check valves would be added to their IST program.

A brief review of Catawba work request 2923 (for valve 1SA-3) dated September 1986, and McGuire work request 122433 (for valve 2SA-6) dated May 1986, indicated that both valves had been inoperable for some period of time. The valve discs were sufficiently stuck (partially open) that extraordinary means had been used to remove the discs from the valves, which included the use of a hydraulic jack. Valve 2SA-6 (McGuire) was badly damaged as a result of the disc removal process, which necessitated installing a replacement valve. A modification was performed by the licensee to remove the existing Walworth valve and install a Pacific valve. Valve 1SA-3 (Catawba) was able to be repaired in place and was put back in service.

Following the multiple failures of safety-related check valves at San Onofre Unit 1 in November 1985, the NRC requested the industry to develop and implement a comprehensive program to provide assurance that safety-related check valves would function properly and reliably under all design conditions. As a result of this request, INPO provided guidance to each plant on the scope and content of such a program in SOER 86-3, "Check Valve Failures or Degradations," dated October 15, 1986. The INPO SOER referenced Section XI testing requirements and stated that: "the code requires that applicable valves be tested to verify that they will open or close to perform their safety function." INPO also stated that "valve reliability could be improved by expanding the scope of inservice testing programs beyond the minimums required by the Code. In particular, the reliability of some important check valves not now included in inservice testing programs could be improved by a combination of periodic testing and preventive maintenance activities. Tests should be designed to demonstrate that check valves will fully open and close under actual or simulated operational conditions." Specific examples of check valve failures at San Onofre, Shoreham, and Turkey Point were given which involved the main feedwater, main steam supply to turbine-driven auxiliary feedwater pumps, and high pressure coolant injection system check valves. The main steam supply stop check valves that failed at Turkey Point were functionally equivalent to the stop check valves at McGuire (SA-5 and SA-6).

Duke performed a design study of check valves for McGuire and Catawba in response to this SOER. However, this design study was inadequate because: (a) it failed to include the safety-related check valves in the SA system even though these valves had a recent failure history at both McGuire and Catawba and their functional application was specifically cited as examples in the SOER; and (b) it did not adequately address the need for back flow testing of check valves within its scope.

The team also found other instances involving Section XI check valves which failed because of inadequate design, maintenance, or testing and were eventually replaced (See Section 3.3.5). Further, the McGuire program was not consistent with the program at Catawba. The corporate performance group realized that the various IST programs at Duke were not consistent with each other in either scope or implementation and were considering the establishment of a new position entitled "IST Coordinator." This coordinator would attempt to standardize the approach to IST and to benefit more from "lessons learned."

3.3.3.2 Valve Stroke Timing

The team observed several weaknesses associated with valve stroke timing:

(1) The NRC Region II office notified Duke in August 1986 that the McGuire valve stroke timing procedures were not in accordance with Section XI requirements. Subsection IWV-3413 defines the valve stroke time (VST) interval to be that time from initiation of the actuating signal to the end of the actuating cycle. This stroke time is referred to as the "initiation-to-light" (ITL) interval. McGuire had been measuring stroke times using the "light-to-light" (LTL) method which fails to account for the time interval between "initiation" and the point at which the limit switch activates a light. The transition phase to convert from the LTL to ITL stroke timing technique took until December 1987 to complete and was not well executed. Many completed IST procedures (performed during the transition phase) reviewed by the team contained confusing footnotes and notes in the margin indicating more than one VST for individual valves. Sometimes the values were labeled LTL or ITL, and sometimes they were not. Often the previous VST recorded was not labeled as either LTL or ITL, raising questions as to the validity of VST change calculations which were used for determining the need for increased testing frequency or corrective action. Conversations with NRC Region II personnel indicated that similar concerns may also exist at Catawba and Oconee.

(2) Conflicts also existed between manual timing methods and the Operator Aid Computer (OAC) which was used extensively at McGuire to measure stroke times of Section XI valves. Due to differences in individual limit switches in either manufacturing or installation, variations were found in the data between the stroke times obtained using a stop watch and the times determined by the OAC. The difference in stroke times appeared to be on the order of seconds. Accurate stroke timing is required to ensure that design requirements are satisfied and that accurate data is recorded for trending. This concern is of particular interest for short stroke times since the NRC has granted relief from Section XI trending requirements for stroke times less than five seconds.

(3) Inconsistencies existed between valve stroke time requirements in the latest revision of the IST program, piping and instrumentation drawings (P&IDs), and surveillance test procedures. Examples are provided in Table 3.1.

Table 3.1

STROKE TIME REQUIREMENTS

VALVE NUMBER	VALVE SIZE (Inches)	P&ID	IST PROGRAM (Seconds)	TEST PROCEDURE (Seconds)
CA-50B	4	12 seconds	10	12
CA-38B	4	12 seconds	10	12
CA-66A	4	12 seconds	10	12
CA-54A	4	10 seconds	10	12
NV-1013C	2	12 inches/minute	30	30
NV-1012C	1	12 inches/minute	30	30
NV-842AC	3	12 inches/minute	15	15
NV-849AC	2	12 inches/minute	15	15

3.3.3.3 Miniflow Valves

Valves were removed from the IST program without proper reviews. The miniflow valves for the centrifugal charging pumps were thought to have been physically removed from the charging system in 1982 by the performance of a modification, and were subsequently taken out of the IST program. It was later discovered that the valves had not been removed and surveillance testing was resumed on October 5, 1987. It was apparent that poor communication and coordination existed between DE, Performance, and Maintenance which allowed these valves to be removed from the IST program. The miniflow valves have an important function of protecting the charging pump against deadheading in addition to providing a recirculation flowpath for surveillance testing. It was also apparent that licensee personnel associated with the modification, the presumed valve removals, and the action required to revise the IST program, did not question the engineering basis for the assumed removal of the miniflow valves.

3.3.3.4 Valve Test Frequencies

Testing frequencies required by Section XI of the ASME Code were changed without first requesting relief from the NRC as required by the TS. Valves ND-15 and ND-30 (B and A RHR heat exchanger outlet crossover block valves, respectively) were being tested during cold shutdown, while Section XI required the valves to be tested quarterly. The evaluation team was informed by the Performance Group at McGuire that relief requests would be submitted concurrent with the next planned revisions to their IST program for Units 1 and 2.

3.3.3.5 Valve Train Designators

The use of train designators with valve numbers was not consistently applied in surveillance procedures or the IST program. Numerous cases were found where the train designator was missing (e.g., valve CF-17AB was listed as CF-17 in the IST program, and valve CA-36AB was listed as CA-36 in the surveillance procedure). Similar errors occurred with relief requests that have been submitted to the NRC. Valve identification nomenclature used in various procedures and programs should be consistent with current P&IDs to eliminate confusion.

3.3.3.6 Relief Valve Testing

With the exception of the main steam and pressurizer relief valves (contained in their IST program), the licensee did not routinely test any safety-related ASME Code relief valves. In addition to Section XI testing requirements are the requirements of Appendix B to 10 CFR 50 regarding testing of safety-related components during the operational phase of nuclear plants. The licensee initially responded to this concern by stating that relief valve testing (set point check) was accomplished following any known valve actuation or malfunction. A limited review of maintenance work performed on relief valves failed to verify the licensee's statement. In response to this concern, the licensee stated that a testing program for safety-related relief valves would be developed to assure that testing would be accomplished and properly controlled.

3.3.4 Inservice Test Procedure Adequacy

3.3.4.1 Test Procedure Strengths

In general, test procedures reviewed by the team were well written and thorough. McGuire was in the process of revising surveillance test procedures to include various human factors considerations and to standarized the test format. Procedures followed a logical sequence for performance of tests and ensured that proper test conditions were established, controlled, and that equipment was restored to proper status after test completion. Test results were recorded on the procedure sheets and compared to acceptance criteria. The team found that work control processes, both formal and informal, were used effectively at McGuire. For example, whenever pump performance was in the alert range, or an excessive increase in valve stroke time was observed, action was taken to increase the testing frequency on the affected component as required by Section XI. Although the process used to increase testing frequency was not documented in a formal procedure, it was carried out effectively by responsible Performance Group personnel. A "Performance Special Valve Controlling Procedure" had been written and implemented to administratively control valves that could not be tested when required, but which could be disabled in their safety position until testing could be performed. The procedure also had provisions to ensure that such valves were placed back in the normal testing cycle once they were repaired or replaced.

3.3.4.2 Test Procedure Weaknesses

The engineered safety feature (ESF) actuation periodic test procedure included stroke time testing of certain air operated Section XI valves. The team found that this procedure failed to include stroke time trending and corrective action requirements. When this concern was raised with McGuire personnel, the licensee indicated that sufficient data (three or more points) have only recently become available to provide meaningful trend information. Test data provided to the team indicated that seven tests had been completed for Unit 1 and at least five tests for Unit 2. Table 3.2 contains a listing of all Unit 1 and Unit 2 testing performed for 11 AFW air-operated valves, with the exception of tests performed during the 1987 Unit 2 outage which were not available to the evaluation team for review. As shown in the table, the recorded valve stroke times for these tests were erratic from test to test and did not meet the repeatability requirements of Section XI. Comparisons between Unit 1 and Unit 2 valve stroke times (e.g., 1CA-32B vs. 2CA-32B) also resulted in large variations which had not been analyzed by the licensee. Section XI, subsection IWV-3417, requires the test frequency to be increased to once a month until corrective action has been taken if a valve's stroke time varies from the previous stroke time by 25 percent for full-stroke times greater than 10 seconds, or by 50 percent for full-stroke times less than or equal to 10 seconds. McGuire had been granted relief from Section XI requirements for stroke times less than five seconds. From the test data made available to the team, it appeared that this requirement of Section XI had not been satisfied and that corrective action had not been initiated when stroke times changed excessively.

Most IWV valve stroke time test procedures which were reviewed by the team included a provision to record the percent change in the VST from the previous VST. This permitted easy comparison of test results with the acceptance criterion. However, a few test procedures were identified, including one approved as recently as November 30, 1987, that still did not place test results and acceptance criteria side by side as required by current Duke policy.

Some test procedures reviewed by the team contained a requirement to record VSTs in the "valve timing records," while most did not. Data contained in the valve timing records were used to determine the percent change in VST between successive tests to satisfy Section XI repeatability requirements. Possibly as a consequence of this procedural inconsistency, three instances occurred in which an improper time for the previous VST was used to calculate the percent change in VST. Two of these instances were for the July 1, 1987 tests of valves 2CA-46B and 2CA-116B. The remaining one occurred in connection with the October 18, 1987 test of valve 1NV-7B. The most recent previous test on 1NV-7B was conducted 60 days earlier on August 19, yet the previous VST used for the October 18 test was taken from a test done prior to August 19, 1987.

Many IST procedures reviewed by the team had recently been revised to specify that valves be declared inoperable immediately in accordance with current licensee policy if their stroke time exceeded the maximum allowable time. Section XI requires only that such valves be declared inoperable if they cannot be repaired within 24 hours, consequently, the McGuire IWV program is more conservative than ASME Code requirements in this area. Two procedures were found, however, that still permit the 24 hour grace period. These were the quarterly AFW and quarterly steam generator PORV IST procedures. In addition, the revision of the IST procedure for SA-48 and SA-49 was not thorough, inasmuch as an unnecessary reference to the 24 hour grace period had been retained.

Table 3 2

Auxiliary Feedwater Air-Operated Valves
Valve Stroke Time (Seconds)
(Diesel Generator Power)

Valve Numbers	Test Year 1980	1982	1983	1984	1985	1986	1986	1987	1987
1 CA-20AB	*	11.2	NA	9.8	18.4	2.5	13.4	14.8	14.8
2 CA-20AB	NA	NA	41.4	NA	49.6	4.0	4.0	**	**
1 CA-27A	*	48.6	NA	2.6	4.8	4.3	4.3	4.2	4.2
2 CA-27A	NA	NA	4.14	NA	49.6	4.0	4.0	**	**
1 CA-32B	*	51.0	NA	25.6	27.0	2.7	2.7	30.8	30.8
2 CA-32B	NA	NA	4.14	NA	2.2	3.0	3.0	**	**
1 CA-36AB	*	10.1	NA	9.6	9.6	9.6	9.4	9.8	9.6
2 CA-36AB	NA	NA	1.6	NA	.8	10.2	9.4	**	**
1 CA-40B	*	46.6	NA	25.4	26.4	25.4	22.4	26.4	22.4
2 CA-40B	NA	NA	39.6	NA	2.0	26.0	21.0	**	**
1 CA-44B	*	46.6	NA	24.8	26.2	25.2	22.2	26.2	22.2
2 CA-44B	NA	NA	39.6	NA	1.8	26.0	21.0	**	**
1 CA-48AB	*	9.7	NA	10.2	10.4	10.6	10.4	9.6	9.4
2 CA-48AB	NA	NA	2.8	NA	1.4	11.2	1.8	**	**
1 CA-52AB	*	10.5	NA	9.8	9.8	10.2	10.0	10.2	10.0
2 CA-52AB	NA	NA	1.6	NA	.8	10.4	9.6	**	**
1 CA-56A	*	21.2	NA	25.6	21.4	21.4	21.4	26.0	21.6
2 CA-56A	NA	NA	41.0	NA	23.8	24.8	20.2	**	**
1 CA-60A	*	21.6	NA	26.0	22.0	22.0	22.0	26.6	10.8
2 CA-60A	NA	NA	4.10	NA	24.2	25.0	20.6	**	**
1 CA-64AB	*	9.7	NA	10.0	10.2	10.6	10.2	10.8	10.4
2 CA-64AB	NA	NA	2.0	NA	.4	10.2	9.4	**	**

*Preoperational tests did not include these valves.
**Team did not receive tests for review.

3.3.5 Corrective Actions

A review of nuclear station modification packages and licensee event reports revealed recurring failures of Section XI check valves in the AFW system. Incidents in which check valves stuck open to permit back flow from one or more steam generators to the turbine-driven AFW pump suction occurred in August 1984 on Unit 2, and in January 1985 on Unit 1. The pressure instrumentation on the suction side of the turbine-driven AFW pump was overranged and damaged in these incidents, and the potential existed for disabling the pump due to steam binding. The McGuire Section XI program required forward flow testing of these valves, but not back flow testing. Additionally, as discussed earlier in Section 3.3.3.1, the McGuire Section XI program did not require back flow testing of the check valves in the main steam supply line to the turbine-driven AFW pump, and one of these valves failed in May 1986. Check valve problems could have been discovered and addressed sooner with less operational consequences if periodic back flow tests had been performed on the valves.

The purpose of IWV testing, as described in ASME Section XI, Subsection IWV-1100, is to ensure the operational readiness of valves important to the safety of light water reactors. Subsection IWV-2300(e) defines operational readiness as "the capability of a valve to fulfill its function." Under Subsection IWV-3523, a check valve must be declared inoperable if it cannot fulfill its function and the condition cannot be corrected within 24 hours. It is further specified that acceptable performance of the valve must be demonstrated prior to returning the valve to service. These guidelines were not met with regard to the AFW system check valves that failed to seat.

In particular, stop check valves 1CA-22 and 2CA-22 (on the discharge of the turbine-driven AFW pump in each unit) were not installed with the stem oriented vertically upward. The valves therefore could not be depended upon to seat properly under back flow conditions, as illustrated by the above events.

In addition, after the January 1985 event on Unit 1, valve 1CA-49 (turbine-driven AFW pump to 1C steam generator check valve) was found to be experiencing repeated mechanical binding. McGuire Incident Investigation Report 1-85-06 acknowledged that the repair and testing performed on the valve did not provide assurance that the valve would function as intended.

Furthermore, McGuire Technical Specification 3.7.1.2 required all three trains of the AFW system to be operable in Modes 1, 2 and 3. This requirement cannot be met with inoperable valves in the turbine-driven AFW pump flow path.

Both the August 1984 event on Unit 2 and the January 1985 event on Unit 1 involved repeated failures of check valves to reseat. The long term corrective action of replacing and/or reorienting the affected valves was not completed until a year and a half later. Administrative controls were not put in place (i.e., none could be found during the evaluation) to alert the operators to the continuing nature of these problems or to establish guidelines for responding to their recurrence in the interim.

The above examples serve to illustrate the importance of the IST program in assuring the operability of safety-related equipment. The IST program must be carefully designed to ensure that all appropriate safety-related valves are included and that the testing specified for each valve does in fact verify the valve is capable of fulfilling all of its intended functions. The McGuire IST program was deficient in that many check valves for which there are valid safety reasons to verify both forward and reverse flow performance were not being tested in both directions. The lack of thoroughness in the Duke response to INPO SOER 86-3 permitted many of these testing deficiencies to remain undetected, as discussed earlier in Section 3.3.3.1.

3.4 Quality Programs

The team reviewed the implementation of the Quality Assurance (QA) program to evaluate its effectiveness with respect to specific activities associated with plant operations. The team conducted a review of the licensee's organization and program for QA auditing and surveillance activities. The team found that although the QA program was comprehensive and met regulatory requirements, corporate policy and personnel qualifications tended to limit the near term contributions of QA to enhancing plant safety performance. Licensee initiatives to increase the comprehensiveness and effectiveness of audits and surveillances were considered a strength by the team, and should improve the technical capabilities of the QA organization. The team also conducted a review of the licensee's administrative controls affecting quality. The team reviewed the Problem Investigation Report (PIR) process and the offsite and onsite safety review group activities. Overall, the team found the PIR process was well implemented and was effective in bringing significant problems to the attention of licensee management; however, the team did identify some weaknesses regarding the activities performed by the safety review groups.

3.4.1 Quality Assurance Functional Organization

The QA Department is directed by a corporate QA Manager who reports to the Executive Vice-President, Engineering, Construction, and Production Group. The Corporate QA Manager is responsible for assuring the development, management, and implementation of the Duke QA program. The organization of the QA Department is presented in Figure 3.1.

The NPD has direct line responsibility for all Duke nuclear station operations. The NPD is responsible for achieving quality results during preoperational testing, operation, and maintenance of the Duke nuclear stations and with complying with applicable codes, standards, and NRC regulations. Quality results were provided through the use of qualified reviewers who verify the accuracy of work completed. Qualified reviewers, designated by divisional managers, were staff personnel possessing the necessary level of education, training, and experience, and who had demonstrated to management their capability of providing high quality work.

3.4.2 QA Audit Division and Station Surveillance Group Staff

At the time of the evaluation, neither the QA Audit Division nor the QA Station Surveillance Group appeared to be staffed with personnel who possessed indepth operating plant knowledge and experience. The staffs of both groups had extensive QA/quality control (QC) work experience (an average of 8-1/2 years); however, over half of this experience was nonproduction (e.g., construction) experience. Moreover, neither QA group had operators previously licensed by the NRC on their staff.

The Audit Division appeared to be weaker than the Station Surveillance Group in terms of their level of technical expertise. On the average, the Audit Division staff had less then three years experience in QA activities associated with plant operations, with a majority of the staff's previous work experience concentrated in QC activities associated with new plant construction. In addition, most of the staff in the Audit Division had an educational background in nontechnical fields. To upgrade staff capabilities, a comprehensive QA training program, requiring several years to complete, had been implemented (see Section 3.4.4).

Discussions with licensee management revealed that the primary responsibility for achieving quality results in station operations rests within the line (NPD) organization. For this reason, as a matter of policy, the technical resources were also placed within those organizations. Interest had been expressed by some members of the operating staff in joining the QA Station Surveillance Group, however, this had been met with management resistance primarily due to standing Duke policy. Thus, the QA organization could not play as strong a role as the line organization in verifying plant safety performance. However, organizations which have a quality verification responsibility should have the necessary technical resources to effectively perform this function.

To improve the scope and content of audits, the QA Audit Division routinely augmented their audit teams with technical expertise from other line or staff organizations to improve the ability of the audit team to evaluate technical issues. Duke appeared better able than most utilities to do this and maintain independence from the audited organization, since Duke has a large DE Department and seven operating units at three different locations. Approximately 70 percent of the audits conducted included technical expertise to help identify deficiencies and to evaluate the deficiencies found by other team members on the audit. The team considered it a strength to include technical experts on audit teams and believed that it should be increased where possible to further improve audit scope, content, and quality. Augmenting the QA Station Surveillance Group with technical expertise through rotation or reassignment of operations staff would provide for the same benefits as the QA Audit Division.

3.4.3 QA Audit and Surveillance Program

Based on a review of planned and completed audit schedules for 1986-1987, good coordination appeared to exist between the Nuclear Safety Review Board (NSRB) and the QA Audit Division in the scheduling and completing requested audits conducted under the cognizance of the NSRB. Schedules were prepared annually to cover the requirements set forth in the McGuire TS. Audit plans were submitted by the QA Audit Division to the NSRB in advance of the scheduled audit for a review and determination by the NSRB that the particular plan would meet the applicable NSRB requirements in McGuire TS.

The QA Station Surveillance Group is responsible for the implementation of the surveillance program, which consisted of scheduled and unscheduled surveillances and tour surveillances of plant activities. A surveillance was primarily a mini-audit which consisted of checking documents and records, and sometimes involved observations or reviews of work in progress. Tour surveillances emphasized reviews or observations of work in progress. About 65 surveillances and 7 tour surveillances were completed during 1987. The team reviewed selected checklists and reports of audits and surveillances for operations, maintenance, and testing activities. The team found the reports to be generally comprehensive in the areas addressed; however, the team found that emphasis was placed on conducting programmatic reviews (i.e., compliance with procedures and correctness of documentation) rather than technical reviews. In addition, the team found considerable overlap in the areas reviewed by the audit and surveillance programs even though there appeared to be good coordination between these groups. A more balanced and complete QA program could be achieved by eliminating unnecessary overlap and placing more emphasis on technical reviews rather than programmatic reviews within the surveillance program.

3.4.3.1 Tour Surveillances

The team observed a tour surveillance related to ongoing plant activities concerning the Emergency Diesel Generators (EDGs). The tour included a walkdown of the EDG room equipment, and witnessing a surveillance test conducted on the Unit 2, B EDG. Although the tour tended to be programmatic in nature (i.e., procedural compliance) and no significant findings/deficiencies were found, the team did find the tour to be comprehensive and thorough in the areas covered. Based on the team's observations and a review of tour surveillances conducted for 1986-87, the team determined that the tour surveillance program had the potential to enhance QA effectiveness in the identification of technical and operational issues. Increased efforts to conduct tour surveillances could further improve QA involvement in the oversight of day-to-day station operations.

3.4.3.2 Audit and Surveillance Findings

The team reviewed selected QA findings and corresponding corrective actions for the period of January 1, 1986 to December 9, 1987. The team found that although most of the findings were programmatic in nature, the program was identifying potentially significant indicators and precursors of technical problems. However, in some cases, the findings were not given sufficient follow-up attention for the identification and correction of potentially generic or chronic problems.

(1) Reactor Coolant System Pressurizer Heatup and Cooldown Limits

Surveillance Report No. MC-86-15 documents an observation made by the QA Station Surveillance Group where the pressurizer cooldown rate on March 16, 1987 was 149.3°F/hour during a shutdown of Unit 2. Operating procedure OP/2/A/6100/02, Change No. 32 stated in the limits and precautions section, and in a caution statement in Enclosure 4.2 of the procedure that the pressurizer cooldown rate should not exceed 100°F/hour. Although the shift operating engineer was informed of this observation, the surveillance report did not identify this observation as an apparent failure to follow procedures, nor why the finding was classified as an "observation" rather than a "Corrective Action Request." The latter classification required a departmental response to the QA Station Surveillance Group on actions to be taken to prevent recurrence.

Station procedure PT/1-2/A/4600/09 Change No. 0 entitled, "Surveillance Requirements for Unit Shutdown," requires the control room operator to record in Enclosure 13.1, the reactor coolant system (RCS) pressure and temperature and pressurizer temperature every thirty minutes and verify that the acceptance criteria are satisfied. The cooldown rates stated in the enclosure were 100°F/hour TS limit, 50°F/hour administrative limit for the RCS, and 200°F/hour TS limit, 100°F/hour administrative limit for the pressurizer. Although the March 16, 1986 pressurizer cooldown rate of 149°F/hr did not exceed TS limits, it was in excess of procedural administrative limits. The team also found that Audit Report No. NP-86-31(MC) reviewed a number of surveillance reports, including Surveillance Report No. MC-86-15, and did not identify any deficiencies.

The team determined that a programmatic weakness existed concerning the maintaining of temperature cooldown and heatup rates within allowable limits for the pressurizer and RCS, which was not identified by the QA Station Surveillance Group. Surveillance Report No. MC-87-51 documented another instance where the administrative cooldown limits for the pressurizer were exceeded. However, this instance was not identified in the surveillance report because the auditor failed to properly review the data taken during unit cooldown. A records review of station procedure PT/1-2/A/4600/09 conducted by the team identified numerous other instances where the administrative limits were exceeded for both the RCS and pressurizer, including three instances where the TS limits were apparently violated (see Section 3.1.4.1). Because QA failed to properly identify a condition which was contrary to station operating procedures, corrective actions had either not been initiated, or were ineffective to prevent recurrence following the March 16, 1986 occurrence. The following table is a listing of cases identified by the team where the administrative limits were exceeded by the licensee.

Temperature/Pressure (°F/psig)

	Date	Time	Beginning	Ending	ΔT(°F)	Unit
Pressurizer	5/3/83	1630-1730	610/1816	494/638	116	2
	1/9/84	0230-0330	310/4	203/67	116	2
	3/16/86	0130-0230	413/253	263.7/21	149.3	2
	9/3/86	1900-2000	395/170	260/26	135	1
	9/6/87	1300-1400	435/331	317/65	118	1
		1400-1500	317/65	212/3	105	1
RCS	5/3/83	1630-1730	497/1816	402/638	95	2
		1730-1830	402/638	334/556	68	2
	1/26/85	0300-0400	550/1798	493/1705	57	2
	5/2/87	1030-1130	284/326	216/328	68	2
		1100-1200	263/328	187/321	76	2

In addition, the team determined that the line organization quality verification procedural review regarding pressure/temperature surveillance requirements for unit shutdown was ineffective given the following observations:

1. The allowable cooldown rates for the RCS and pressurizer were clearly stated in the plant TS, and were also stated in the acceptance criteria, and in caution statements in station procedures OP/1-2/A/6100/02 and PT/1-2/A/4600/09;

2. Unit cooldown data reviews performed by control room operators, in accordance with PT/1-2/A/4600/09, did not identify any instance where the pressure/temperature limits exceeded the acceptance criteria;

3. Independent reviews conducted by operations personnel, in accordance with procedure completion verification requirements for PT/1-2/A/4600/09, also failed to identify any instance where the pressure/temperature limits exceeded the acceptance criteria; and

4. Final review by operations supervisory personnel for PT/1-2/A/4600/09 procedure completion verification also failed to identify any out-of-limit condition which was contrary to the acceptance criteria.

The team concluded that a breakdown in the quality verification review process occurred regarding RCS heatup and cooldown caused by an apparent lack of attention to detail by operations personnel in not thoroughly reviewing the procedures. In addition, the subject surveillances conducted by the QA Station Surveillance Group were ineffective because they failed to: (1) identify a recurring condition which violated station operating procedures; and (2) classify the condition as a deficiency requiring station management attention and corrective action. The QA Station Surveillance Group staff's weak operating plant knowledge and experience regarding unit shutdown requirements and associated operating procedures were considered to be the underlying cause for not effectively performing the subject surveillances.

(2) Measuring and Test Equipment

Audit Report No. NP-87-09(MC) documented an observation made by the QA Audit Division where an instrument, under the control of the McGuire Performance Section in the Technical Services Group, was found available for use with an expired calibration date. In addition, the instrument was subsequently found to have been issued for use after its calibration date had expired; however, the audit report stated that this was an acceptable practice according to station directives. The QA audit report did not identify the specific out-of-calibration instrument, the conditions under which it had been used after its expiration date, or why the situation was acceptable under the applicable station directives.

The team reviewed Station Directive 2.3.0, Revision 1, entitled "Control of Measuring and Test Equipment," and found that orange "Cal Past Due" stickers shall be affixed to devices not calibrated within the established interval. This sticker may be used in lieu of a "Rejected" sticker for devices to be used for troubleshooting only. Approval by the M&TE supervisor/engineer may allow use of the device after the due date of calibration if documented with the work request or procedure, but not beyond one-fourth of the calibration period. However, the instrument discussed above was apparently not removed from service after its calibration due date, was not affixed with an orange "Cal Past Due" sticker, and was subsequently issued for use on June 16, 1987, under Work Request No. 070584 to calibrate Rosemount Transmitter 2MHFPT5010 using Procedure PT/0/A/4700/18. This work request was not for the purpose of troubleshooting. There also was no documentation with the work request indicating approval by the M&TE supervisor/engineer to allow use of the instrument after the due date of calibration. The out of calibration device was subsequently identified as a Heise gauge Model No. 710A, Serial No. MCPRF24203, and was found to be within its calibration tolerances on September 18, 1987. Additionally, the Rosemount transmitter discussed above was not associated with safety-related equipment.

The team determined that QA Audit NP-87-09(MC) of the Performance Group M&TE was not effective because it found a practice acceptable which clearly violated the applicable station directives. Additionally, a programmatic weakness concerning segregation of non-conforming items existed which was not pursued by either the QA Audit Division or the QA Station Surveillance Group. Surveillance Report Nos. MC-86-13 and MC-86-33, and Audit Report No. NP-87-02(MC) document other instances where segregation of non-conforming items were found to be stored with available-for-use items, and were not in accordance with Criterion XV, 10 CFR 50, Appendix B. The team found that the corrective actions documented in the above QA reports concentrated on correcting the specific physical and/or immediate deficiencies with minimal review or analysis of the findings for generic and long-term preventive action.

The team also considered the practice of using out of calibration equipment for troubleshooting to be imprudent. It added additional administrative burdens on the M&TE program that could be avoided by promptly performing calibrations on M&TE equipment when required. Additionally, based on discussions with station management, there was confusion as to exactly what activities were allowed under current station directives with out of calibration equipment. Supervisory personnel within the corporate QA organization, for example, interpreted the station directives to allow use of out of calibration equipment for purposes other than troubleshooting, such as calibration of other equipment.

3 4.3.3 Trending of QA Findings

The team found that the licensee did not have an integrated trending program for deficiencies identified by the audit and surveillance programs. A review of QA procedure QA-150, Revision 7, entitled, "Trend Analysis/Documentation of Discrepancies Discovered by QA," revealed that trending of deficiencies, conducted by the corporate QA Technical Services Division, analyzes findings identified in Problem Investigation Reports, and General Office Noncompliances and Design Nonconformances. Contrary to the title of QA-150, these are documented discrepancies identified primarily outside of QA. Informal trending of audit and surveillance findings is conducted by the QA Audit Division and Station Surveillance Group for the purpose of identifying problem areas which should be covered in connection with scheduled audits or surveillances. However, generic analysis of all audit and surveillance findings for potential trends is not formally performed. Because the audit and surveillance programs were identifying potentially significant repetitive findings and because the discovery of discrepancies by QA having technical significance are expected to improve due to licensee improvement initiatives, implementation of an integrated trending program could improve QA effectiveness for the enhancement of operating plant safety performance.

3.4.4 QA Improvement Initiatives

In order to increase QA technical contributions and overall effectiveness, the licensee had several ongoing initiatives to improve the technical capabilities and focus of the QA Audit Division and Station Surveillance Group activities.

1. In addition to the new Quality Control training facility at McGuire, training programs had been established by the licensee to enhance the quality of audits and surveillances by providing technical training to QA Audit Division and Station Surveillance Group personnel. The Audit Division training program consists of 41 weeks of classroom instruction and 30 weeks of on-the-job training, for a total of 71 weeks of training. The program curriculum provides training in the areas of health physics, chemistry, basic thermodynamics and nuclear physics, systems, and concluded with 46 weeks of basic nuclear operator training. The Station Surveillance Group training program, which was developed and implemented before the audit training program, differed in that basic nuclear operator training is conducted first. Additional training is then provided to QA Station Surveillance Group personnel in their areas of specialization. Overall, the team found the training program to be generally comprehensive in the topics covered.

   A review of training records for the QA Audit Division indicated that except for basic operator training, a majority of the staff had completed most of the classroom instruction phase and approximately 30 percent of the on-the-job training phase of the program. At the time of the evaluation, only one individual was enrolled in basic operator training. For the QA Station Surveillance Group, approximately half the staff had completed basic operator training and the other half was either enrolled or scheduled to attend in mid-1988.

2. As part of the TOPFORM initiatives discussed later in Section 3.5.2.2, the QA organization had recently implemented a new program entitled, "Self-Initiated Technical Audits (SITAs)", described in QA Procedure QA-240, Revision 0. SITAs are "vertical slice" audits of selected systems performed by a team of technical experts led by a QA lead auditor. The SITA program was similar in approach and thoroughness to the Safety System Functional Inspections performed by NRC inspection teams. By the time of the evaluation the QA Audit Division had completed one SITA which was conducted on July 13, 1987 through August 19, 1987 for the Low Pressure Service Water System (LPSW) at Oconee. Review of the report indicated that the Oconee SITA team conducted an indepth, critical inspection of the LPSW system, and had identified a number of potential safety concerns. DE responses to the SITA team findings had been received and were in the process of being reviewed at the time of the diagnostic evaluation. This was an effective initiative, and if extended to other safety systems, could help provide assurance of the functional capabilities of other safety-related systems.

3. The QA organization had also recently implemented a new program entitled, "Quality Assurance Performance Assessments (QAPAs)", described in QA Procedure QA-151, Revision 1. The QA procedure required a periodic assessment of each department in the Duke organization by location and functional area that was similar in approach to the Systematic Assessment of Licensee Performance (SALP) assessments performed by the NRC. These assessments reviewed the findings produced by the audit and surveillance programs, Nonconforming Item Reports, Problem Investigation Reports, and Incident Investigation Reports. A rating was assigned to each functional area which was then used to help focus QA Audit Division and Station Surveillance Group activities. Assessments had been completed for the NPD and CMD activities at Catawba and McGuire.

   Review of the 1987 McGuire QAPA report indicated that the ratings assigned to each functional area appeared to be based on an analysis of the data for just the significant findings rather than a statistical analysis of all findings. The QA Station Surveillance Group supervisor who participated in the assessment indicated that the program was an effective method for providing management with an assessment of QA program performance and for adjusting audit and surveillance activities. Increased attention of surveillance activities in the area of EDG operation and testing was cited as an example resulting from the McGuire QAPA report. This program had the potential to improve the overall effectiveness of the audit and surveillance program, however, the success of the program was highly dependent upon the types of reviews conducted and resources of the QA organization. Thus, the team believed that unless the emphasis of the audit and surveillance programs was changed to conduct detailed technical evaluations, and the technical capabilities of the QA Station Surveillance Group were increased to adequately perform such reviews, the near-term effectiveness of this program would be limited.

3.4.5 Administrative Controls Affecting Quality

3.4.5.1 Problem Investigation Reports

The team conducted a review of the Problem Investigation Report (PIR) process. The PIRs are intended to provide initial written identification of any situation or occurrence wherein defective material, defective or malfunctioning equipment, personnel error, administrative or procedural deficiency, or other cause resulting in other than expected equipment performance, personnel action, or failure to operate within established limits. Any individual in the Duke organization was obligated to verbally report a condition in their area of responsibility for initiating a PIR for internal investigation and appropriate deposition. The PIR program was a relatively new program (implemented at McGuire in December 1986) which superseded the QA Nonconforming Item Report (NCI) process. The team reviewed approximately 100 PIRs from 1986 to 1987, and conducted interviews with various corporate and site personnel associated with review and disposition of PIRs. Overall, the team determined that the PIR process appeared to be well implemented at McGuire and was effective in identifying and bringing significant problems to the attention of licensee management for disposition.

3.4.5.2 Problem Investigation Report Trending

One of the responsibilities given to the onsite MSRG is to conduct and document incident investigations for those problems identified in PIRs which are reportable to the NRC (Section 3.4.6). For events described in PIRs which contained an Incident Investigation Report (IIR), the team found that the cause codes assigned in the IIRs were broad LER categories. These categories were not broken down far enough to identify the root causes of events. As part of Duke's operating experience (OE) program, a formal trending process for IIRs for identifying root causes and other performance and trending information has been developed and implemented. While the team was aware that the statistical count data for various categories was reviewed by the NSRB Director, the team did not assess the effectiveness of this trending process.

The Quality Assurance Manager, Technical Services Division was responsible for placing trend codes on PIRs, performing trend analysis, developing reports of analysis, and distributing the reports to appropriate line management. The classification codes contained in QA procedure QA-150, Revision 7, for the purposes of trending were not completely consistent with the trend codes used in the OE program. Since the IIRs are a subset of the reports covered under the PIR program, development of a single set of trending codes for both programs appeared appropriate and should result in better information transfer between the two programs as well as provide for consistent sets of data for analyzing trends.

By the time of the evaluation, the QA Technical Services Division had completed one PIR trend analysis report for the McGuire, Oconee, and Catawba stations which was issued on October 20, 1987. The report documented no adverse trends. However, because this was the first PIR trend analysis conducted representing the initial implementation of the PIR process, detecting adverse trends would prove difficult since no previous PIR trend data was available for comparison. Thus, the team could not make an assessment as to its overall effectiveness.

3.4.5.3 Incident Investigation Reports

The team found that the corrective actions documented in the McGuire IIRs concentrated on correcting the specific physical or procedural deficiencies, with minimal review or analysis on the investigation findings for implementation of generic or station-wide preventive actions. Recurring events appeared to be viewed too narrowly thereby eliminating the opportunity to make generic corrective actions across more than one group. An example of such a recurring event was breached fire barriers. Review of past McGuire IIRs indicated that IIRs M87-16-2, M87-021-2, M87-024-2, M87-045-2, M87-065-2, M87-077-1, and M87-083-1 all involved breached fire barriers. The corrective actions for most of these incidents generally only included repairing the breached fire barrier, and the few other corrective actions taken did not prevent these types of incidents from recurring. The more recent IIRs included additional training and increased awareness as corrective actions. These previous corrective actions were implemented, however, in increments that did not prevent these events from recurring. This category of incident was considered to be recurring with a high frequency at McGuire by the team and licensee.

3.4.6 McGuire Safety Review Group

The MSRG, as specified in McGuire TS, shall function to examine plant operating characteristics, NRC issuances, industry advisories, LERs, and other sources which many indicate areas for improving plant safety (TS 6.2.3.1). The MSRG is responsible for maintaining surveillance of plant activities, to provide independent verification that these activities are performed correctly, and that human errors are reduced as much as practical (TS 6.2.3.3). In addition, the MSRG has the authority to make detailed recommendations for revised procedures, equipment modifications, or other means of improving plant safety to the Director, NSRB (TS 6.2.3.4).

3.4.6.1 McGuire Safety Review Group Activities

During the evaluation, the team found that: (1) the MSRG had not been performing all functions which were identified as part of the McGuire licensing basis in accepting the MSRG as meeting staff guidelines of TMI Action Item I.B.1.2., and, therefore, did not appear to meet the full intent of McGuire TS 6.2.3.3 and 6.2.3.4, (2) the scope and focus of current MSRG activities had evolved to the point that the majority of their time was spent on investigation of plant events, with little or no time spent on surveillance of plant operations and maintenance activities, and (3) a proposed TS change concerning responsibility for review of written safety evaluations could adversely effect the MSRG review functions (assuming no change in their functions as defined by the licensing basis).

(1) The team found that not all of the functions described in the Safety Evaluation Report (SER) for McGuire were being performed by the MSRG. Specifically, the MSRG was not reviewing: (1) all design changes involving structures, systems, or components, and (2) all station procedures and changes to procedures. Discussions with the NSRB Director confirmed the team's observation that these two functions were not being conducted by the MSRG and, therefore, did not appear to meet the full intent of McGuire TS 6.2.3.4.

Supplement No. 4 to the SER for McGuire contained the NRC staff review of the MSRG. The staff review discusses the acceptability of the MSRG as proposed by Duke in the October 29, 1980 draft revision of McGuire Station Directive 3.1.32, "Station Safety Engineering Group." In addition to the functions and responsibilities stated in McGuire TS (see Section 3.4.6), the SER stated that the MSRG will function as an independent technical review group in the following areas:

a. Review of LERs for applicability to McGuire.

b. Review and evaluate the effectiveness of plant programs.

c. Review of all design changes involving structures, systems, or components with quality assurance conditions to insure all safety concerns are properly addressed.

d. Review all station procedures and changes to procedures to determine their adequacy.

e. Investigate all incident reports involving reportable items and conduct other investigations as deemed appropriate by the MSRG Chairman.

A review of the draft Station Directive 3.1.32, as revised by the letter dated October 19, 1980, was conducted and the team concluded that the functions as stated in the SER were essentially the same as contained in the revised draft Station Directive 3.1.32. The SER also assumed that the draft Station Directive 3.1.32 would be approved and implemented prior to fuel load of McGuire Unit 1. However, Station Directive 3.1.32 apparently was never formally approved or implemented by the licensee.

On January 6, 1981, the licensee provided a response to TMI Action Items I.B.1.2 and I.C.5. As part of this response, the licensee provided, as an appendix, the Charter of the MSRG. This Charter, dated January 21, 1981, is significantly different from the draft Station Directive 3.1.32; specifically, neither function c nor d described above was contained in the Charter. Based on discussions with cognizant NRC staff, this Charter and its subsequent revisions have not been formally reviewed or accepted by the staff. The current revision of the MSRG Charter is dated January 20, 1986.

(2) The MSRG Chairman indicated that recent activities of the review group resulted in 85-90 percent of their time being devoted to incident investigations. Safety Review Group (SRG) Procedure 3, Change 3, covers the monitoring of routine station activities and requires that work conducted under this procedure be entered in the SRG Work Assignment Log. A review of the SRG Work Assignment Log covering the year 1987 indicated that no routine station activity areas had been assigned to any MSRG member during 1987 and, therefore, did not appear to meet the full intent of McGuire TS 6.2.3.3.

(3) The team became aware of a proposed change to the McGuire and Oconee Technical Specifications which would delegate to the MSRG and Oconee Safety Review Group (OSRG) the responsibility for conducting independent reviews of safety evaluations performed under the provisions of 10 CFR 50.59. Under the proposed change, the independent reviews would be conducted under the cognizance of the NSRB rather than performed directly by the NSRB. In addition, the proposed change would make the McGuire and Oconee TS wording consistent with that of Catawba. This proposed change was unanimously approved by the NSRB at the full Board meeting on November 18, 1987, and submitted to the Duke General Office Licensing Section.

Assuming no changes in MSRG activities as discussed in (1) and (2) above, the proposed change could futher detract the MSRG from performing their principal review functions. In addition, the team observed that the number of members, technical disciplines, experience and competence required of the NSRB is more extensive and covers more disciplines than that required of the MSRG. The proposed TS change would shift reviews currently performed by the NSRB to a smaller, less experienced group covering fewer technical disciplines, although the team recognized that MSRG members function in their job on a full-time basis, whereas NSRB members function on a part-time basis, meeting usually semiannually.

3.4.7 Nuclear Safety Review Board

The team reviewed the activities of the offsite Nuclear Safety Review Board (NSRB) as related to McGuire. This review included document reviews of audits performed under the cognizance of the NSRB during 1987, NSRB Full Board Meeting Minutes for meetings conducted during 1986 and 1987, and discussions with the NSRB Director and members of the NSRB staff.

3.4.7.1 NSRB Full Board Meetings

The minutes of the 1986 and 1987 NSRB Full Board Meetings were reviewed by the team. In general, the items reviewed by the NSRB covered a broad spectrum of design and operational issues applicable to McGuire. In the meeting minutes, the items reviewed by the NSRB were listed as line items by subject title. This was followed by short summaries of selected items which were reviewed. These summaries, in general, provided little meaningful information as to the items reviewed. Many summaries contained statements such as "a presentation was made," "[an item] was discussed," and "the Board was satisfied with actions taken and planned." Without documentation in the minutes of the specific presentations made, details of items discussed or specific actions taken and planned, the NSRB meeting minutes provided minimal information to reconstruct any significant discussions on decisions made during these meetings.

Section 4.3.3.1 of American National Standard N18.7-1976/ANS-3.2 specifies that for organizational units functioning as independent review bodies, all documentary material reviewed should be identified. For the two-year period reviewed, it was not evident to the team that any formal documentation in the NSRB meeting minutes existed to demonstrate that the NSRB was conducting its reviews of written safety evaluations of changes in the facility as described in the McGuire Safety Analysis Report (MSAR), changes in procedures as described in the MSAR, and tests or experiments not described in the MSAR which were completed without prior NRC approval under the provisions of 10 CFR 50.59(a)(1). Subsequent discussions with the NSRB Director revealed that the review of written safety evaluations is covered under the line item "Response to Documentation of Review." None of the meeting minutes identified the written safety evaluations reviewed; only one identified any transmittals under which written safety evaluations were reviewed, which made the ability to trace and audit records difficult.

3.4.7.2 NSRB Safety Evaluations

In discussions with the team, the NSRB Director stated that the written safety evaluations were generally of poor quality. However, there was no indication through the NSRB meeting minutes of the past two years that the NSRB formally attempted to impact or correct this shortcoming even though it clearly fell within their review responsibility.

The process for independent review of the safety evaluations for approved station procedures, changes to procedures, and completed Nuclear Station Modifications is described in Duke Procedure NSRB/7, Change 2. Operating Experience Management and Analysis (OEMA) personnel within the Nuclear Safety Assurance Group perform a general review to verify the Nuclear Safety Evaluation 10 CFR 50.59 checklist has been completed and administratively screened those documents to be forwarded to the NSRB for their review. Any document with a checklist marked "yes" in any areas is indicative of a change or deviation to that described in the FSAR or TS. These documents are reviewed by the NSRB. Documents with a checklist marked "no" in all areas are not reviewed by the NSRB, but are forwarded to a master file.

Procedure NSRB/7 also states that on a selected basis, subsequent to the general review, OEMA personnel will perform an independent safety verification to confirm the accuracy and adequacy of the initial safety evaluation. However, discussions with OEMA personnel indicated that these detailed reviews were not being conducted. In addition, the team found that 10 CFR 50.59 evaluations which are not forwarded to NSRB because the change did not involve McGuire FSAR or TS, did not receive independent review and were not subject to QA audits. Review of both types of completed 10 CFR 50.59 evaluations by the team identified several instances where lack of attention to detail resulted in inadequate 10 CFR 50.59 reviews (see Section 3.5.4.2). In view of the generally poor quality of the written safety evaluations, a detailed review by OEMA personnel and audits by QA could be effectively used to improve the overall quality of 10 CFR 50.59 evaluations.

3.5 Engineering Support

The team conducted an evaluation of the off-site engineering support for McGuire including: the design and control of plant modifications; the resolution of technical issues, such as evaluating equipment operability and the causes of equipment malfunctions and; defining programs to respond to generic technical problems. The purpose was to assess the general adequacy of engineering support and the effectiveness of recent improvements undertaken by the licensee.

The team reviewed the licensee's staffing, procedures, and programs and interviewed personnel at the McGuire site and the Duke GO to determine the responsibilities of and the relationships among the groups involved. The general levels of resources provided and personnel qualifications were also evaluated. Primary emphasis was placed upon reviewing the adequacy of detailed work products such as calculations, safety evaluations, problem reports, and modification packages. The results of the team's evaluation in these areas is presented in the following sections.

3.5.1 Staffing, Resources and Organization

The DE staff was found to be well qualified, with the average experience level being greater than ten years. All of the engineers had at least a four year science degree, many had advanced degrees, and many of the design engineers and all of the supervising engineers had professional registration. Many of the engineers had design experience on more than one Duke plant.

All of the personnel interviewed had a dedicated attitude towards Duke. Almost all had started working with Duke upon graduation from college and therefore had little non-Duke experience. It appeared that Duke's involvement in a variety of industry organizations helped to expand this otherwise narrow experience base.

Another positive facet in the DE support for McGuire was the historical continuity. Unlike most plants, where the original design was performed by an outside architect/engineer, many of the people who designed McGuire were still with the company. Whenever questions arose concerning the design basis, the original designer usually could be consulted. The original designer might not have been assigned to the project, but was probably still in the company and accessible. One factor allowing Duke to retain this historical perspective was the institution of a wholly owned subsidiary, Duke Engineering Services, Inc., which was chartered to provide commercial engineering services to clients outside Duke. This provided the mechanism to retain original engineering staff even at the end of a major construction phase. It also provided another mechanism for the staff to maintain its proficiency by interaction with other industry organizations. (The team's concern about potential future effects of outside business interests are discussed in Section 3.6.1.6.)

As was generally true in the company, DE management was proactive and involved. The team reviewed numerous tracking systems and techniques used to assure that the department's work was being completed in a timely and competent manner. The managers appeared to be continually evaluating the department's way of doing business and looking for ways to improve it.

About 260 people in the DE Department were assigned to support McGuire. This number appeared consistent with other plants. Several company tracking systems indicated that DE was able to complete its assigned work in a sufficiently timely manner. Over the preceeding year, the number of outstanding McGuire modifications had decreased from 471 to 360 - somewhat more than a 3-year backlog, which was reasonable. The list of modifications cancelled or postponed due to budget considerations did not appear to indicate any cause for concern. Interviewees uniformly indicated that other work, such as selling design and engineering services to outside companies, was only considered after making sure that the nuclear stations would received sufficient support. Thus, the resources devoted to support McGuire appeared to be adequate for the DE identified role - to provide support as tasked by NPD. (The team's opinion that this role should be expanded is discussed in Section 3.5.6.)

At the time of the evaluation, DE was designing nearly all plant modifications and performing design studies when needed. At the same time, NPD engineering personnel at the station were coordinating requests for and implementation of plant modifications and resolving technical problems, such as determining the causes of equipment failures, so far as practical. The NPD personnel in the GO sometimes assisted station personnel in addressing technical issues such as battery maintenance and valve reliability.

3.5.2 Nuclear Station Modifications

Several years prior to the evaluation, the nuclear station modification program had been upgraded and standardized with implementation of the nuclear station modification manual. More recently, in 1986, several further enhancements were initiated as discussed in Section 3.5.2.2.

3.5.2.1 Design Change Process and Procedures

The process for modifications was normally initiated by an SPR which was sent to the Project Services Group at the station. An accountable engineer in this group was the focal point for dispositioning all reports applying to his or her specific systems. If a modification was required, the accountable engineer initiated a Nuclear Station Modification (NSM) Request and the Project Services Group determined whether the modification design would be done by station engineering personnel or DE personnel.

Most modifications were designed by DE, in which case the NSM would be processed through the Project Management Division of DE. A project engineer from the Project Management Division monitored schedule and status. A lead engineer was assigned from one of the other departments, such as Electrical Engineering, to coordinate design activities associated with the NSM. This included major activities such as: a scope meeting if required, design analyses and calculations, issuance of limited edition drawings detailing the changes, integrated design reviews and a 10 CFR 50.59 review. The completed package, along with a design completion notice (DCN) was returned to the Accountable Engineer at the site for review and to coordinate implementation. Any discrepancies found during implementation were resolved through the responsible design organization using a variation notice (VN).

One alternative processing method was called an "Urgent Modification," which allowed for the use of red-lined drawings instead of limited edition drawings to expedite the process, when (1) a unit shutdown was likely, (2) a unit outage might be extended or (3) the unit would be in violation of a regulatory or licensing requirement. For special circumstances, an "Exempt" change could be issued by the station which required less approvals, review and documentation. Exempt changes were minor changes which received verbal concurrence from DE. The modification design was completed by the station. Although the modification might be installed, the system or equipment could not be returned to service until written concurrence was given by DE.

3.5.2.2 Improvements in the Modification Process

Prior to the evaluation the licensee and NRC Region II personnel had noted some problems in the engineering support provided to the operating Duke plants in the area of modifications. By the time of the evaluation the licensee had already begun making improvements.

A number of these improvements were identified by interdepartmental working groups and issued in a DE Department document entitled "The Overall Plan for Organizational Review of Modifications" (TOPFORM), October 1986. TOPFORM contained fourteen action plans. Some of the actions were aimed at improving interface communications among departments by the use of specific steps such as scope review meetings, pre-design surveys and design review meetings. Other actions were aimed at producing more complete and understandable modification packages through specific steps such as final scope documents that described and summarized important information. These were transmitted together with design completion notices and relevant safety evaluations. Items such as systematic provision of post-acceptance test criteria, additional safety reviews for non-urgent modifications and improved documentation of design inputs were intended to improve certain areas. A program of self initiated technical audits, discussed further in Section 3.4.4, was intended to review the operational readiness of existing systems. Two of the action plans were aimed at improving the safety evaluations performed to comply with the requirements of 10 CFR 50.59. TOPFORM generally applied to design modifications initiated after March 1987. Since the time from initiating a modification until it is installed runs from many months to a few years, few modifications had been completely processed and installed under the new programs at the time of this evaluation.

In addition to TOPFORM, Duke had initiated several other actions to effect improvements, including: (1) semiannual meetings between the plant staff and DE management to provide feedback on engineering support; (2) increased staffing levels of accountable engineers on the station staff who coordinate modification work; and (3) a policy of conducting and documenting post-modification testing for every modification.

During the evaluation the licensee had just begun implementation of a program of system experts for important systems at the station. Although this was not specifically a design initiative, the availability of experts who could be fully aware of important system status regarding maintenance, testing, modifications, and the design basis was expected to provide a positive contribution to the modification process.

Based on a programmatic review, the initiatives described above appeared to be substantial and directed to appropriate areas to improve the modification process. The team believed the initiatives should be effective when fully implemented. In many cases, however, it was too early to judge results from the work products and completed modifications. In the area of safety evaluations, performed in accordance with 10 CFR 50.59, the team did develop a concern which is discussed in Section 3.5.4.2.

3.5.3 Engineering Design Control

3.5.3.1 Original Mechanical Analyses

For the small sample reviewed, the quality of the original mechanical design analyses appeared to be very good. An example was the flow calculation for the auxiliary feedwater system. The calculations were compiled in a document which contained approximately 350 pages of analyses of the various flow conditions for the system. It addressed all of the limiting considerations such as flow to the steam generators at the rated conditions, net positive suction head, and suction pressure to prevent air entrainment. This document was very thorough in its consideration of what appeared to be every credible scenario that might be encountered by the system, as well as several scenarios outside the design bases which were done as sensitivity studies.

3.5.3.2 Instrument Loop Accuracy Calculations

The team reviewed three instrument loop accuracy calculations and found some errors in each. The DE Department Supplementary Procedure MDIC-PR-2

"Safety-Related Instrumentation Qualification Review and Documentation Procedure," Revision 0, detailed the steps necessary to calculate instrument loop accuracies. This procedure also specified which instrument loops required accuracy calculations.

Calculation MCC-1210.04-00-0012, "Auxiliary Feedwater Flow Indication," dated March 28, 1985, was reviewed and found to be in error. In section 4F, the Sensor Temperature Effect (STE) was calculated incorrectly due to an error in interpolating data between the lower range limit and the upper range limit. When the calculation was redone using the correct STE factor, there was sufficient margin between the Total Loop Accuracy and the Required Loop Accuracy such that the error did not change the conclusion.

Calculation MCC-1210.04-00-0013, "Main Steam Pressure Instrumentation Loop," dated April 23, 1985, was reviewed and found to be in error. In section 4F, the Sensor Temperature Effect (STE) was calculated incorrectly because of an error in interpolating data. An incorrect required loop accuracy (11 percent instead of 10 percent) was taken from the instrumentation functional requirements specification sheet. Also, the accuracy of the instrument power supply was not accounted for in the calculation. The calculation was redone and no concern was developed because of the calculated accuracies.

Calculation MCC-1210.04-00-0014, "Containment Pressure Instrumentation Loop," dated April 1, 1985, was reviewed and an error was found. The required instrument accuracy (RIA) was calculated incorrectly. When the calculation was redone, no concern was developed because there was sufficient margin between the determined instrument accuracy and the recalculated RIA.

One cause for these calculation errors appeared to be that the original calculations were done by personnel from the mechanical piping analysis group, who were unfamiliar with instrumentation, using a procedure developed by the Mechanical Instrumentation Group. Apparently, the resources were available within this group at the time the calculations needed to be done. Licensee personnel had made previous plans to review all the instrument loop accuracy calculations by March 1, 1988, using a revised procedure. In response to the team's request the licensee provided an accelerated schedule based on priority (margin available and safety function) which would have all calculations redone by January 22, 1988. This would allow for quick resolution of any safety issues. Verification and final approval would then be completed by March 1, 1988. In addition, the three calculations that were reviewed and found in error were done by the same individual. The licensee agreed to review other work done by this individual in the piping analysis area for possible inaccuracies.

Regulatory Guide 1.105, "Instrument Setpoints," described a method for ensuring that all instrument setpoints in systems important to safety remain within the specified limits. Part of this methodology was the calculation of the actual and required accuracies for all instruments. Although the licensee had not committed to Regulatory Guide 1.105, procedure MDIC PR-2 was issued which listed those instruments for which instrument accuracy calculations were required. It was not clear to the team as to the basis for the list and what methods would be used to maintain it. Licensee personnel indicated that they were addressing this concern by reviewing their overall program for establishing and maintaining instrument setpoints.

3.5.3.3 Instrument Setpoint Calculations

The team reviewed two instrument setpoint calculations and found an inconsistency between one of the calculations and the FSAR. Calculation MCC-1223.31-00-0003, "Verification of Groundwater Drainage Sump Level Switch Setpoints," determined the sump water level at which the pumps shut off. The FSAR specified levels which were incorrect in that they were too low. Licensee personnel indicated that the actual setpoints used in service were those developed in the calculation and that the FSAR would be revised accordingly.

3.5.3.4 Vital Instrument and Control Power System Battery Sizing

The team reviewed the sizing of the vital instrument and control (I&C) power system batteries and found the sizing adequate. However, there was a deficiency in the handling of test discharge results in that no account was being taken of the temperatures at which test discharges were performed. Both of these subjects are described in further detail below.

TOPFORM action item V.A concerned the periodic review of cumulative changes to analog models. One calculation, which described the sizing of the equipment associated with the 120 volt Vital Instrument and Control Power System, MCC-1381.05-00-0162, was scheduled for review before May 1989. Part of this calculation described the sizing of the vital 125 volt I&C batteries. Licensee personnel had recently reviewed the loading on these batteries as calculation MCC-1381-05-00-0174, dated September 1, 1987. This calculation utilized the database of the Low Voltage Load Data List to establish the one minute, one hour and three hour loads on the associated DE and inverter fed AC power panels. These loads formed the load profile which was input into the Duke computerized battery sizing calculation.

The team noticed that the battery sizing calculation input list did not contain an input for minimum battery temperature. In fact, the McGuire FSAR (Section 8.3.2.1.4.2) stated that the battery room minimum design ambient was 77°F and the battery was sized on the basis of its capacity at 77°F. The McGuire TS (4.8.2.1.2.b.3) and the battery weekly surveillance procedure (PT/0/A/4350/28A) both permitted a minimum battery electrolyte temperature of 60°F. The battery would lose approximately 11 percent capacity at this temperature compared to its rated temperature of 77°F. The team observed a battery electrolyte temperature of 70°F during the evaluation.

Each of the McGuire I&C batteries was sized to carry both the continuous emergency load of its own vital buses and the loads of another battery from the other unit in a "backup" capacity. The FSAR (Section 8.3.2.1.4.2) committed to a one hour discharge period. The computer program was set up to size the battery based upon a two hour profile. In response to the team's concern for the battery's capacity below 77°F, the licensee personnel reran the program with the load profile inflated by 11 percent to account for the loss in capacity at 60°F. The results showed that the McGuire batteries could not meet a two hour profile but would still have adequate voltage at the end of one hour which met the commitment.

Since the Catawba plant had the same size batteries and was committed to a two hour profile, the team requested that the licensee evaluate the the adequacy of the Catawba batteries. Unlike the McGuire batteries, the Catawba batteries were not specified to assume the loads of the other unit's batteries in a backup mode. Thus, they also were adequate.

The team also reviewed the verification of the Duke computer program for battery sizing (BATT2HR). The Duke program utilized an interactive computational method to establish battery load current as a function of battery discharge voltage. This approach presented a more realistic picture than the IEEE Recommended Practice for Sizing Large Lead Acid Batteries (IEEE 485) which considered resistive loads at their normal dc rated voltages and constant KVA loads (such as the inverters) at minimum DC voltages. In addition to reviewing BATT2HR, the team used the latest load profile and calculated the required size of the vital I&C battery using the more conservative method from IEEE 485, including correction factors for a minimum temperature of 60°F. This confirmed the adequacy of the size of the I&C batteries at McGuire for the FSAR committed one hour profile.

Because of the concerns raised by the team with regard to the inconsistencies in battery minimum temperature, McGuire Station personnel issued a PIR (PIR 0-M87-0302) requesting DE assistance in evaluating the effect of the minimum acceptable temperature on battery capacity and the effect on the performance of the battery service test. Up to that time no attempt had been made by McGuire personnel to correlate the results of the battery service test with the acceptable minimum battery temperature. The team considered this a deficient practice because battery capacity depends significantly on battery temperature. Battery capacity was rated by the manufacturer at 77°F. More capacity is available at higher temperature (about 106 percent at 90°F) and less capacity is available at lower temperature (about 90 percent at 60°F). Therefore, unless the battery service test results are referenced to the lower permitted (or actual service) temperature, the service test may overstate the battery capacity available.

Battery temperature considerations were poorly handled from the standpoint of their effects on service discharge performance tests, as well as maintaining specified capability conditions as discussed earlier. Thus, this appeared to be an area where the station could have benefitted from additional technical support.

3.5.3.5 Design Input and Output Control

The design pressure rating for the AFW pump discharge piping was denoted on drawing MC-1592-1.1 (design output). The basis for this design pressure should account for the design output pressures of the pumps (design input). The specified design pressures for this piping were found to be significantly less than that which could be encountered in service. The design pressure rating for the turbine-driven pump discharge piping was 1730 psig at 160°F. From the pump curve, the discharge pressure at rated speed (3600 rpm) could be as high as approximately 1855 psig, which exceeded the design pressure. This pressure was generated at flow rates that were well within the operating range that was likely to be experienced for an accident condition (e.g., when throttling flow using the discharge valves to the steam generators).

A similar situation existed for the motor-driven pumps. Their discharge piping was rated at 1665 psig at 160°F. The pump curves for the lower end of their operating range showed discharge pressures of approximately 1710 psig for one pump and 1740 psig for the other pump, again exceeding the design pressure.

A higher pressure would be generated by the turbine-driven pump for its overspeed condition. The nominal overspeed trip point for the turbine was 125 percent of rated speed, or 4500 rpm; with tolerance it might be higher. For worst case (low flow) conditions the discharge pressure at the nominal overspeed condition could be as high as approximately 2900 psig (approximately 67 percent over the design pressure). Regarding the pump overspeed case, licensee personnel stated that the design was within the requirements of the ASME Code, Section III, 1971, to which McGuire was committed. That version of the code required, in general terms, designing for the most severe condition of coincident pressure, temperature and loading. Subsequent versions were revised to explicitly specify consideration of overpressure transients.

Licensee personnel stated that analyses would be performed to check stresses in the piping against allowables with pressures that envelope the operating conditions for the piping. In the case of the overspeed condition for the turbine-driven pump, licensee personnel expected that the Code allowances for overpressure for the "upset" condition would be met.

3.5.4 Evaluation of Specific Modifications

3.5.4.1 Motor Operated Valves

Modification number MG-22042, Revision 0, Unit 2 was performed as an "urgent modification" to replace the failed sixteen horsepower motor operator for safety-related valve 2NI83B with a ten horsepower operator. However, key parts of the modification package such as the modification summary and the elementary diagram indicated that the new actuator would be twelve horsepower rather than the ten horsepower unit actually installed. In addition, the electrical overload relay heater was sized for a twelve horsepower motor rather than a ten horsepower motor. Licensee personnel indicated that either a ten or twelve horsepower motor would be adequate for the application and stated that the inconsistencies in the modification package would be corrected.

Regarding the overload heaters, the team observed that McGuire was not committed to Regulatory Guide 1.106, Revision 1, March 1977, "Thermal Overload Protection for Electric Motors on Motor Operated Valves." The regulatory guide would generally specify that, for safety-related motor-operated valves, the electrical overload protection be set high or else bypassed under accident conditions to enhance the assurance of operation when needed. Instead, as documented in the FSAR, McGuire did not employ overload protection for its safety-related motor-operated valves. Overload heaters were used to provide alarms in the control room. This scheme was acceptable.

The team determined that overload heaters 2 to 6 sizes smaller than those installed would provide an earlier indication of potential motor damage without causing nuisance alarms. However, the alarms were not expected to protect the motors they served, i.e., the operator would not deenergize the motor within seconds of receiving the alarm as an overload protection device would do. Instead, the alarms were expected to simply alert the operator that something might be wrong with an actuator. In this context, the licensee's sizing was acceptable.

3.5.4.2 Safety Evaluations

The team reviewed a number of safety evaluations performed in accordance with 10 CFR 50.59 and developed two concerns. First, the lack of checking safety evaluations at the completion of design when appropriate details were available for review could cause problems. If assumed details should change or assumed analyses were not completed, the evaluation could be unknowingly negated. Second, the number of problems found appeared to indicate a lack of attention to detail in completing the required evaluations. It might have been too early to judge the full effect of TOPFORM improvements, but two of the evaluations reviewed were completed after the implementation of TOPFORM and exhibited the same types of problems as earlier evaluations. Further details are provided below.

The safety evaluation process required by 10 CFR 50.59 was addressed by DE procedure MNSA-101 and the NMS Manual, Appendix E, which was applicable to all departments. Both procedures, prepared since the implementation of TOPFORM, required that written safety evaluations be performed for all changes in the plant and that records be maintained of these evaluations. Specific problems noted were as follows:

1. Urgent Modification Number MG-22042, Revision 0, Unit 2 described above in Section 3.5.4.1 was performed to replace the motor operator for a safety-related valve with a smaller motor. Since it was an urgent modification, the safety evaluation was done in parallel with the design work. In reviewing the documentation of the safety evaluation the team discovered that it did not describe the reviews that had actually been performed, but rather it described in the future tense the reviews that were planned. Although the planned reviews seemed to address the proper areas to be considered, there was no written evidence provided that the reviews had actually been performed at the completion of the design, nor any documentation of the findings of the reviews. Licensee personnel subsequently assured the team that the reviews outlined in this specific safety evaluation had, in fact, been performed and the results had all been satisfactory. This resolved the teams concerns about this particular evaluation.

   For safety evaluations to be effective on a generic basis they must be checked after the design is complete - when all of the pertinent details are available for evaluation. Writing a safety evaluation, as in the above case, with all of the reviews to be performed in the future, produces documentation that may imply by its existence and being signed off that the analysis is complete and the modification is ready for implementation when, in fact, an evaluation may not have been performed and the package may not be ready for execution.

2. NSM MG 20616 "Refeed Power to Control Centers 2EMXB1, 2EMXB2 and 2EMXB3" was another example of where the 50.59 evaluation described reviews that were to be performed (e.g., cable routing will be evaluated per Appendix R criteria) at a future date. This was particularly confusing since a single 50.59 evaluation was used for two similar NSMs which were to be completed at different times for Unit 1 and Unit 2. In addition, the list of calculations indicated that no calculations were affected whereas Breaker Coordination Calculation MCC 1381.05-00-0094 had been revised. This calculation was the basis for some of the major conclusions reached in the 50.59 evaluation.

3. Two examples were found where the 50.59 evaluation recently performed on changes to the battery surveillance procedures failed to recognize that the change would affect the FSAR or the TS.

   (1) The vital I&C Battery Service Test Procedure, PT/0/A/4350/08A, Change 7, was issued 9/23/87 to incorporate a revised load profile. The profile was changed from a constant current 445 Ampere/60 minute profile to a profile enveloping that obtained from the latest battery loading calculation, MCC-1381.05-00-0174, 9/1/87. The battery duty cycle was described in both the FSAR (section 8.3.2.1.4.2, Figure 8.3-6 and Table 8.3.2-5) as well as TS 4.8.2.1.2.d.

   (2) The vital I&C Battery Performance Test Procedure PT/0/A/4350/08B, Change 11, was issued 10/8/87 to change test conditions and to meet IEEE 450-1980 requirements. The battery performance test criteria were described in TS 4.8.2.1.2.e and f.

   In both instances the changes cited would result in a change to either the FSAR, TS, or both. However, the modification package indicated that neither document would be changed as a result of these procedure changes.

4. The licensee's procedures described a screening process to which all changes were to be subjected to determine if they required the full safety evaluation process. The team reviewed these procedures and noted two instances where the wording could be misleading. Licensee personnel agreed to clarify the language in those cases. In other respects, the procedures appeared to be sound.

3.5.4.3 Design Change Authorizations

The team performed a brief evaluation of Design Change Authorizations (DCAs) at McGuire because implementation of a DCA at Catawba had led to a significant event in 1986. No discrepancies were found.

The DCAs were modifications installed during the construction phase of a Duke plant. Because they were intended for the construction phase, DCAs were not covered by NSM (operational phase) procedures and DCAs were not reviewed to determine whether operator training or procedure changes needed to be considered. At Catawba, a DCA which was written to modify the remote shutdown panel without these considerations was partially implemented after operation began.

Because of this implementation a significant event occurred where the operators were not able to control the plant from the remote shutdown panel. The event at Catawba occurred during post-modification testing so that the operators were able to regain control of the plant by shifting control back to the control room. The licensee reviewed all DCAs implemented since system turnover at Catawba and found two additional DCAs that required further follow up, i.e., procedure changes and training.

This item concerning the review of DCAs was used by NPD GO personnel to initiate a review of a similar DCA done at McGuire to modify the remote shutdown panel and its effect on station procedures and training. A review of DCAs implemented at McGuire after system turnover was not done. However, licensee personnel indicated that at McGuire, after system turnover, DCAs had been reviewed for procedure revision and training considerations at the time they were implemented. Thus, the licensee had concluded that it was not necessary to review them again.

3.5.5 Human Factors Initiatives

One additional aspect of the diagnostic was an assessment of personnel attitudes and perspectives regarding the impact of human factors initiatives at McGuire. Of particular interest was the degree of general awareness of these initiatives and their perceived impact on plant safety.

The McGuire human factors efforts were directed at upgrading emergency operating procedures, control room and training improvements, and implementing the Safety Parameter Display System (SPDS). The McGuire procedures upgrade efforts were extended to all operating and maintenance procedures, with distinct groups within the Maintenance and Operations organizations responsible for upgrading procedures. The other human factors activities appear to be directed solely at meeting regulatory requirements. A design engineer is specifically designated to support human factors at McGuire, however, his expertise in human factors was minimal, and the scope of his responsibilities were limited to the control room, the auxiliary shutdown panel, and auxiliary feedwater panel.

Almost all personnel interviewed were aware of the human factors efforts at McGuire. However, there was little agreement as to their importance and impact on plant safety. In particular, higher level operations personnel did not believe human upgrades had a significant impact on plant safety. This perception may have been due in part to the fact that many of these changes required relearning of established operations, locations, nomenclature, etc. Lower level operations personnel generally believed the impact to be more significant. For example, the NEOs pointed out that the plant was compactly designed and they were routinely required to perform climbing, bending or difficult physical movements to enable them to operate valves and other equipment. Because of human factors problems associated with these task, NEOs have suffered minor steam burns and occassionally back strains. The NEOs also noted that heavy lifting was occassionally required and was difficult at times, particularly when working on the turbine lube oil purification system.

Outside of operations, there appeared to be much more respect for, and interest in, human factors issues. This was particularly true with maintenance personnel who felt that there was not enough attention to human factors problems associated with their job; they believed there were number of aspects of their job that could be enhanced or made safer. There was also a belief that human factors should be involved in the review process for all modifications, not only those specifically designated as human factors modifications. One reason given was that maintenance is often made more difficult by systems modifications.

It was pointed out earlier that DE supports human factors initiatives in the control room. Originally, during the detailed control room design review (DCRDR) activity, regular and frequent liaison was established between DE and Operations; Operations had assigned a designated contact point. With completion of the DCRDR, this contact point was lost and the frequency of the interactions was greatly reduced. This situation appears to have diminished the credibility of human factors issues within Operations and made implementation of human factors related modifications more difficult to achieve by placing the human factors staff in a more adversarial role.

One additional aspect of the human factors program involved the SPDS. At McGuire there appeared to be a general feeling that it did not contribute very much to plant safety. One specific problem with the system was that the computer points feeding the displays were not clearly defined on the display. Without such definitions, the operators were wary of the information they received. For example, the information could be coming from an instrument that might be in error. This tended to reduce confidence in, and reliance on, the information provided by the displays. Prior to the diagnostic evaluation, this issue had been identified and pursued by Duke as well as the NRC's Office of Nuclear Reactor Regulation. After the evaluation, in February 1988, Duke committed to address the problem.

3.5.6 Station Equipment Problems and Programs

3.5.6.1 Equipment Operability Determination Support

NRC Region II personnel had previously raised concerns about determining equipment operability. The licensee had initiated improvements in this area, including a new procedure for requesting written operability determinations from DE. The team reviewed several documents including the Interpretation Section of McGuire TS, Station Directive 2.8.2, "Operability Determination," and the TS Reference Manual - a guide used by operators to determine equipment operability and evaluate TS compliance. The team also reviewed examples of written equipment operability determinations provided by DE in response to requests from McGuire. It appeared that good support was being provided to the operators in their efforts to maintain plant operations within the confines of plant TS.

3.5.6.2 Circuit Breaker Coordination

The team requested responsible DE personnel to provide information on a circuit breaker coordination question that had been raised in connection with a trip of Unit 2 on September 6, 1987. The responsible personnel were unaware of any concern at McGuire, which led the team to examine the event as an example of a communications problem.

Prior to the trip, an instrument power inverter had been bypassed for maintenance and the alternate supply for the instrument power panel was being fed from motor control center SMXT. When the A instrument air compressor, which was also out of service for maintenance, was started for post-maintenance testing, its motor faulted to ground. The overcurrent tripped both the compressor supply breaker and the motor control center's (MCC) incoming breaker. Normally, circuit breaker protection levels are coordinated so that one would expect the breaker supplying the motor to trip but not the incoming breaker supplying the entire MCC.

There are two circuit breakers in series in the power supply to the MCC. The one closest to the MCC (called the MCC incoming breaker above) is the one that tripped. The event was discussed between a DE liaison engineer assigned to McGuire and his supervisor in Design Engineering on the day the trip occurred. The term "feeder breaker" which was used in the discussion meant, in the supervisor's mind, the other circuit breaker farther from the MCC (the load center breaker). This breaker had a ground fault protection feature whereas the MCC incoming breaker, which is the one that tripped, did not. The supervisor assumed that the ground fault protection had caused the feeder breaker to trip. This had been a problem at Catawba and this type problem was scheduled to be reviewed at McGuire as part of the TOPFORM analog model reviews. Because of this apparent misunderstanding, no further action was assigned to DE on the PIR for this event, the matter was dropped, and the PIR was not forwarded to DE.

The team reviewed the events as described in the PIR and the applicable calculation (MCC 1381.06-00-0026, Rev. 10, 10/9/87) describing the coordination between the load center breaker and the MCC breakers. The team concluded that lack of breaker coordination was the probable cause. When comparing the circuit breaker time-current characteristic curves presented in the calculation, it was found that there was only a 200 ampere margin between the maximum trip point current for the instrument air compressor circuit breaker (400 amperes for a 225 ampere trip unit), and the minimum trip point current for the load center breaker (600 amperes). In addition, there was only a 300 ampere margin to the minimum trip point of the 700 ampere MCC incoming breaker. The team estimated from the MCC one line diagram that the total load on MCC SMXT could be as high as 600 amperes. The DE personnel confirmed this estimate.

The DE personnel have determined that no changes are needed at this time for MCC SMXT. The team did not disagree with this conclusion because circuit breaker coordination is insufficient for this MCC primarily in the maintenance configuration, where inverter loads are being fed from the MCC and the MCC is thus heavily loaded, in combination with running the instrument air compressor which is a relatively large load for the MCC. Circuit breaker coordination is better when the MCC is operating in its normal configuration.

Regarding communications, the LER to the NRC and the Company's internal incident investigation report did not indicate any misunderstanding of the event by NPD personnel. However, it would have been better if the responsible DE personnel had also understood the event correctly so that they could have looked into some of the follow-up areas discussed below. Ironically, achieving such understanding is one of the reasons the liaison engineer was onsite and called his supervisor about the event. In this case the liaison engineer system did not fully achieve the desired result.

The team reviewed the instrument air compressor motor data in an attempt to determine why the instrument air compressor breaker rating was selected so high (both the 225 ampere and especially the 400 ampere trip setting appeared too high). The team found that the full motor current was only 134.8 amperes. The acceleration curves indicated that the load should reach full speed in 2 seconds or less. A review of the motor thermal capacity curve and the motor's locked rotor withstand time indicated that inadequate motor protection was provided by the motor starter's thermal overload relay. (The motor starter provided the primary protection because its thermal overload relay was set lower than the circuit breaker's thermal overload protection.) Based on thermal capacity data from the motor manufacturer, thermal overload heaters two sizes smaller would provide better protection but still provide adequate margin for motor operation. This matter was referred to the licensee personnel for resolution; however, no regulatory guidelines were involved and no NRC followup was considered necessary.

MCC SMXT is a nonvital motor control center. The team asked if a similar situation could exist on safety-related motor control centers. In response DE personnel reviewed the safety-related MCC for other potential problems with large loads fed from MCC's. One potential MCC was identified. MCC IE MXG compartment 2D feeds the 75 hp safety-related control room air handling unit fan motor. From the data that were available during the evaluation, it appeared that this motor, with a 70.4 ampere full load current, would be marginally protected for motor overloads with the identified H90 overload relay heater. However, a smaller (H85) heater is used to actuate an alarm on smaller overloads.

Motor fault protection was provided by a 150 ampere circuit breaker. However, the incoming breaker at the MCC was only a 250 ampere breaker. Also, the load center breaker feeding the MCC was set at 275 amperes. This 600 ampere rated MCC was lightly loaded at the time of the evaluation and the feeder cable was sized accordingly, which accounted for the low setting on the incoming MCC feeder breakers. If the connected load were permitted to grow approximately 55 percent of the rating of the incoming breaker, coordination with the 150 ampere breaker might not exist. However, breaker coordination was not considered a problem at the time of the evaluation because of the then currently existing light load.

3.5.6.3 Auxiliary Feedwater Pump Vibration

For almost 5 years the auxiliary feedwater pumps experienced excessive vibration accompanied by recurrent bearing damage. The root cause, as eventually determined by station personnel, was inadequate pump recirculation flow. Recirculation flow had been improperly established during preoperational testing. The team observed that DE was not involved in resolving the vibration problems until after station personnel had correctly diagnosed the cause at which time DE verified the conclusion. This was an important problem and station personnel should have resolved the problem or requested assistance earlier (see Section 3.2.3.1).

3.5.6.4 Volume Control Tank Divert Valve Leakage

For almost 3 years the volume control tank divert valves had a history of leaking by their seats. The cause, as eventually determined by station personnel, was incorrect bench set information for the valve actuator on the I&C list and the instrument detail diagram (engineering errors). The relatively low importance of this issue probably explained why station personnel did not request assistance or solve the problem earlier. However, allowing problems to continue for a long time establishes a poor precedent (see Section 3.2.3.2).

3.5.6.5 Check Valve Testing and Reliability

The check valve portion of McGuire's ASME Section XI inservice testing program was found to have serious deficiencies. The McGuire program was not consistent with the program at Catawba. Moreover, the Duke response to check valve reliability issues, as exemplified by INPO SOER 86-3, was poor because it did not include several safety-related check valves, some of which had recently experienced major failures, and it did not address the need for back flow testing of check valves (see Section 3.3.3.1).

It was noted that DE was only peripherally involved in the IST and Duke's response to SOER 86-3. DE could have provided the technical direction to achieve a good program if given such a charter.

3.5.6.6 Xenon Reactivity Determination

Errors were introduced into the operators calculations of estimated critical position because of rough approximations used to determine Xenon reactivity worth and rod worth curves. Previous errors in estimated critical positions should have led to correcting the problem (see Section 3.1.3.1).

3.5.7 Design Engineering Involvement and Communications

As discussed previously, the team found DE to be a large, capable organization with adequate resources to fulfill its defined role of providing engineering support as specifically tasked by NPD. However, the team concluded that the role DE played did not appear to fully utilize its technical capabilities in day-to-day support of the operating plant.

Most of the day-to-day technical issues at McGuire, other than designing modifications, were handled by onsite NPD technical personnel who reported to the McGuire Station Manager. The full capabilities of DE were not usually applied to day-to-day problems unless the scope or complexity, as determined for the most part by NPD personnel onsite, was outside the station staff capabilities. Because of the strong work ethic, can-do attitude and sense of personal responsibility that was observed at the plant, there appeared to be a tendency not to call for assistance from DE. In addition, the team detected some sense of separation between DE and the site personnel. The willingness to call DE for informal assistance or discussion appeared to vary from individual to individual, depending on personal contacts rather than being a routine practice. As a result, some technical areas that should have been addressed by DE were not.

Examples of technical issues that could have benefited from more DE involvement or better communications between departments were discussed earlier in Section 3.5.6 and are listed as follows.

(1) Excessive AFW pump vibration (Section 3.2.3.1).
(2) Check valve testing and reliability (Section 3.3.3.1).
(3) VCT divert valve leakage (Section 3.2.3.2).
(4) Battery temperatures (Section 3.5.3.4).
(5) Circuit breaker coordination (Section 3.5.6.2).
(6) Xenon reactivity determination (Section 3.1.3.1).

Interviews with management personnel also indicated that there were other instances which the team had not identified.

The team recognized that there were many positive aspects to DE involvement. For example, the Electrical Engineering Division employed two Liaison Engineers spending half of their time at McGuire and half of their time at the GO to improve communications and interfacing. The DE managers generally encouraged their engineers to spend time at the site and followed up to see that they did. Interviewees at the site and in DE readily provided general examples of improvements that have been made in engineering support and specific examples of good interactions between DE and site personnel.

Still, the DE defined role was to provide support as tasked by NPD. Its management practices and tracking systems were focused on assuring that assigned and scheduled work was completed in a timely and proper manner - not more broadly at finding areas and issues that needed work. As in some of the examples cited, if an issue was not assigned, it might not get DE's attention. Thus, the team concluded that corporate engineering support could be improved by increasing the DE involvement in front-end discussions on how to handle technical problems or programmatic issues affecting the plant.

3.6 Management Overview

An important aspect of the McGuire diagnostic evaluation was an assessment of management and leadership factors at Duke which impacted the day-to-day operation and performance of McGuire. The purpose of this assessment was to identify the contributions of these factors to licensee performance.

Although corporate and middle management are presented separately in this report, they clearly are related. The dependence of middle management on senior management for leadership, guidance, support, and resources was recognized, as well as senior management's dependence on middle management to implement the corporate directives and to operate efficiently and safely within the philosophical and policy boundaries established at the corporate level. In fact, a critical dimension of this evaluation was to not only assess performance at the two defined management levels, but to determine if top corporate policy guidance and direction was consistently followed at all management levels and whether that philosophy, and management practices, maintained the proper emphasis on the safe operation of the nuclear reactors.

In order to assess the capabilities of Duke senior management, the team: (1) interviewed management and nonmanagement personnel; (2) reviewed corporate, department, and station policies, procedures, plans, and other documentation; and (3) observed operating practices.

3.6.1 Corporate Management

3.6.1.1 Leadership and Direction

The team evaluated the methods and the extent to which the corporate organization, including the corporate line executives and GO Nuclear Support Staff (described in Section 1.5.1) provide effective leadership and direction to the McGuire Station. Based on the team's review, overall corporate leadership and direction was found to be a Duke strength.

(1) Line Management Direction

To provide overall consistent direction, Duke had developed a broad range of corporate goals and objectives for the company. These corporate goals had, in turn, been translated into and supported by department level goals, strategies and action plans. The goals for NPD were further broken down into specific goals for each nuclear station. These NPD goals, action items, and action plans (which supported goal attainment), were developed and/or updated each year for each plant with the input and assistance of the corporate nuclear support staff and plant managers. The NPD goals were found to be quantitative and challenging, and placed strong emphasis on year-to-year improvement in plant performance. The corporate and NPD goals, and action plans, which were formally documented in the "NPD Master Work Plan," closely followed the industry (INPO) good practices for management objectives programs. The broader corporate goals and NPD goals had been made relevant and appropriate to each corporate support staff unit and plant line organizational unit through specific action items. These items provided the programs and tasks which must be completed by organizational units to improve plant production, safety, and reliability. The team found that the 1987 NPD goals placed emphasis and focus on improved plant performance (e.g., increased plant availability, decreased reactor trips). The team noted that DE and QA had similar work plans.

The 1987 NPD Master Work Plan did not include a goal for public (i.e., nuclear plant) safety. Although a number of the 1987 NPD performance-based goals would have an implicit effect on improving plant safety, the team believed that the absence of an explicit and specific nuclear safety goal was a weakness of the 1987 Plan. The team was concerned that the absence of an explicit, documented nuclear safety goal, to compliment and balance the performance (production) improvement goals, could have the unintended effect of diminishing the day-to-day nuclear safety consciousness and attitude at the working level. The team noted that the 1987 work plans for DE and QA had a nuclear safety goal (based on violations of NRC requirements) and that McGuire had established a similar goal in their 1987 station-level goals program. Following discussions with the plant and corporate management on these observations, the team was informed that the draft 1988 NPD Master Work Plan contained an explicit nuclear safety goal which would be measured in terms of a regulatory compliance index. Further discussion of organizational climate characteristics related to this concern are provided in Section 3.7.2.5.

(2) Nuclear Support Staff Leadership and Direction

As described earlier in Section 1.5.1, a primary role of the GO Nuclear Support staff is to provide leadership, technical direction and guidance to NPD (i.e., the operating nuclear stations) and to promote consistency in the policies, programs, practices, and personnel knowledge and skills utilized at the plants. To provide this leadership and direction, the corporate Nuclear Support staff had been organized into functional areas which closely paralleled the functional areas set up for the line organizations at each plant. In this way various functional areas, involving line/staff counterparts among the three plants and the GO support organization had been established. Specific functional areas such as Mechanical Maintenance, Performance Evaluation, Health Physics and Chemistry, therefore, had been established to promote good working relationships between the plant and corporate office. An important forum for the Nuclear Support staff's direction and leadership was the periodic functional area meetings among the corporate and plant supervisors who represented each functional area. With this counterpart arrangement, the GO and nuclear plant functional area representatives were high enough in the organization for significant technical matters to be decided, but low enough for the decisions to be specific and practical.

The team found, based on both discussions with corporate and plant management, and a review of functional area meeting correspondence, that the corporate support staff had provided leadership and direction to a broad range of activities. These included developing and applying new technologies and management systems for station use, developing new programs, procedures, guides and directives for station use, establishing goals and maintaining staff focus and resources on performance improvement action plans. For example, the Technical Services Group has developed and monitors advanced techniques for determining heat exchanger performance and for handling radiological waste. It also appeared to the team, based on interviews and observations, that the Nuclear Support Staff was effective in providing leadership and direction for the resolution of unexpected technical (e.g., equipment) problems which periodically arose at the plant sites. The team also believed that the leadership and direction exhibited by the GO staff was enhanced by the credibility, respect, and capability which came from the considerable hands-on nuclear plant operating experience which resided within the GO staff.

3.6.1.2 Line Management Oversight and Involvement

The team evaluated the quality and the extent of corporate line management oversight and involvement in the day-to-day activities and problems at McGuire. From its review, the team believed that the oversight and involvement of the corporate line organization had become weaker compared to the overall levels which had existed in the recent past. The team found that the previous NPD organization included: a General Manager of Nuclear Stations, who directly supervised the managers of Duke's three nuclear stations; and an Assistant to the Vice President, NPD, who reported to the Vice President. At the time of the evaluation, the employees in both positions had left the company and the positions had been abolished. In the previous organization, the Assistant to the Vice President handled a number of the industry liaison and representational responsibilities assigned to the NPD Vice President. The departure of both individuals left the NPD Vice President as the sole provider of direct line management oversight and involvement for the stations with the additional burden of personally handling many of the outside liaison activities.

A review of records showing corporate line management visits to McGuire for the one and one-half year period prior to the team's evaluation confirmed that total corporate visits to the site had fallen off since the Assistant to the Vice President and the General Manager of Nuclear Stations departed. The McGuire Station Manager also indicated that his immediate corporate supervisor was more difficult to access for day-to-day problem discussions than had been the case in the previous organization, but that when necessary he could be reached. To partially compensate for the decrease in the frequency of face-to-face contact between corporate and station management, additional responsibilities and decisionmaking authority were given to the plant managers and a weekly teleconference call between the station managers and the NPD Vice President was initiated.

The team expressed its concerns on the overall apparent decrease in corporate management involvement and oversight for the three Duke stations. The team was informed that plans were being made to reestablish and fill the Assistant to the Vice President position. It was anticipated that the employee in this position would handle all of the outside representational responsibilities as well as other duties. The team concluded that this action, when implemented, would increase the time available for corporate line management oversight and involvement in the day-to-day activities and problems at McGuire and the other Duke nuclear stations.

3.6.1.3 Communications and Information Systems

The team evaluated the effectiveness of communications between the corporate organization and the Duke nuclear stations. The team found that the communications within NPD was an area of strength. However, the interface between NPD and other departments involved areas of weakness.

Communication of the Master Work Plan goals and actions down to the working level was considered excellent. Senior corporate officers, including the NPD Vice President, presented and discussed the station goals for the new year and station performance against the previous year's goals with the staffs at each of the stations as part of comprehensive beginning of the year site visits. Plant performance against each goal was updated monthly on placards and charts, which were extensively displayed throughout plant work areas. Further, at the station, goal achievement status was reported daily via the station television system. The tracking of actual performance for each plant site against the goals was formally compiled and documented each month for senior corporate management review. This was followed at the beginning of each year with an annual review of the past year's performance. Based on these communications and information systems, and employee interviews (see Section 3.7.2), the team concluded that the corporate organization had succeeded in instilling a strong commitment within the NPD organization for goals attainment.

The team found the task action plan documentation and action plan status monitoring and tracking systems to be extensive and detailed. Communications of ongoing task activities involving both the corporate support staff and the plant staff were facilitated by the functional area meetings. The major reliability improvement program items identified for each station were clearly communicated within the organization. Additionally, progress toward completing the necessary development and implementation steps were communicated and coordinated through frequent Reliability Management Committee meetings among cognizant and responsible management within the NPD.

Duke had also taken steps to improve the coordination and communication among the various departments which had a permanent support group at the site (e.g., CMD, PSD, QA) by establishing a "Site Coordination Council" for McGuire (and similar councils for the other stations). The senior manager or management representative for each department represented at the site served as members, and the station manager served as chairman. The council was set up to meet periodically to discuss approaches for resolving site-specific issues involving the support groups and facilitate cooperation in the pursuit of operational improvement.

Notwithstanding the above, interface problems between CMD and NPD were recognized by the NSRB and became a significant discussion item at the NSRB meeting held November 18-19, 1987. This resulted in inadequate work performance of CMD personnel at McGuire. Differences in training and qualification requirements for CMD personnel involved in plant maintenance activities versus modification activities were identified, and action items were generated by the NSRB to address and resolve the training issues.

As discussed in Sections 3.3.3 and 3.6.1.4, the support provided by DE to NPD for the development of programs affecting McGuire were found to be inappropriately limited at times due to weak communications between the Nuclear Support staff and DE. Additionally, as discussed in Sections 3.2.3 and 3.5.7, DE involvement in the support of the stations for the resolution of day-to-day operating problems was on occasion limited by inadequate communications between the plant operating staff and the corporate DE staff. For both situations the team concluded that DE involvement was limited by the NPD "solve our own problems," and the DE "support the plant when tasked" attitudes, which resulted from their organization charters.

3.6.1.4 Awareness of Industry Problems and Improvement Programs

The team performed a limited evaluation of the extent and the means by which the Duke corporate organization stays current on industry operating problems and improvement programs and the effectiveness of these processes. The team found that Duke placed a high priority, and expended considerable resources, on maintaining a high degree of awareness and understanding of industry problems and improvement programs. However, as discussed below, this understanding was not always translated into effective corrective actions for generic industry problems which were applicable to McGuire.

(1) Participation In Industry Groups

Most Duke corporate managers and officers were expected to participate in one or more industry-related committees, organizations, task forces, professional societies, or codes and standards groups. Within the nuclear power area alone, the team found Duke corporate managers were well-represented in numerous industry organizations including the Babcock and Wilcox and Westinghouse Owner's Group, and the Nuclear Utility Management and Resources Committee.

Duke also was a strong supporter of INPO, having provided considerable staff resources and leadership in support of INPO programs and initiatives. Duke also participated in INPO-sponsored nuclear utility plant site and corporate evaluations. In this way Duke provided an opportunity for its senior corporate and plant managers to not only learn from the experiences of other facilities, but to share with other utilities the programs and experiences of the Duke nuclear stations. The team found the OE staff to be extensively represented on a broad range of professional society codes and standards committees. Participation in industry groups was driven in large part by Duke's strong desire to seek out and identify causes of nuclear unit unavailability and improve nuclear unit reliability through the experiences of other utilities and industry groups. Overall, the Duke corporate organization effectively maintained a high level awareness of industry problems and improvement initiatives through its active participation in industry organizations.

(2) Operating Experience Program

At the time of the evaluation, industry operating experience was received, screened, distributed and evaluated in accordance with NPD Directive 4.8.1, "Operating Experience Program Description." Under this directive, NRC correspondence requiring a formal response (e.g., NRC Bulletins, Generic Letters) was received and processed by the GO Licensing section while NRC and industry correspondence not requiring a written response (e.g., NRC Information Notices, INPO SERs, Vendor Information Letters) was processed by the GO Operating Experience Management and Analysis (OEMA) section. Documents handled by the OEMA section were screened and distributed to: (1) the Production Training Services organization or the Nuclear Support/Engineering Support groups for "problem awareness" (i.e., incorporation into training programs or review by technical groups for information) if they were considered not to be an immediate concern for plant safety, or (2) the appropriate Nuclear Support/Engineering Support groups for "problem avoidance" (i.e., for evaluation and appropriate corrective actions) if they involved operating experience issues which were considered significant with respect to nuclear safety and reliability. Similarly, the GO Licensing section evaluated and responded to problem avoidance documents with the assistance and input provided by the GO Nuclear Support/Engineering Support groups and the Station Compliance section.

The team found the Duke program and process for operating experience receipt, screening, and review to be systematic, comprehensive and generally effective. The procedures which implemented the program provided effective safeguards to ensure that operating experience documents which were either routed to the wrong technical groups for evaluation or inappropriately designated for "problem awareness" were caught and rerouted to the appropriate technical groups for the required evaluation.

It appeared to the team that the OE program worked effectively for those problems and issues which involved technical complexity and technologies which were within the scope and depth of the technical knowledge and experience levels of the applied engineering resources found in the Nuclear Support staff. However, the team observed that when DE support was needed to fully evaluate the operating experience document corrective actions, DE involvement could be inappropriately limited by the NPD Nuclear Support staff member having lead responsiblity for the evaluation. An example, which the team reviewed, was Duke's evaluation and the corrective actions taken with respect to INPO SOER 86-3 "Check Valve Failures and Degradation." The team found Duke's review and the resulting corrective actions to be significantly less than adequate. For example, the team found that Duke had not added the AFW turbine steam supply stop check valves to those being tested for reverse flow in the McGuire check valve test program. The valves had not been included even though they were functionally identical to valves cited in the INPO SOER and these check valves had failed at both McGuire and Catawba. The team found that an underlying cause for this situation was that the DE staff was not fully involved in front-end decisionmaking of the needed scope and content of Duke's evaluation of the SOER. The team discussed its concerns with the licensee on the adequacy of the McGuire check valve testing program. Following these discussions, Duke agreed to have DE perform a reevaluation of the need for additional check valve testing in connection with the operating experience and guidance provided in the SOER. Further detailed discussions of the McGuire IST Program are presented in Section 3.3.3.1.

3.6.1.5 Management Attitude and Development

The team found the quality and the level of knowledge and experience of the Duke corporate officers and senior managers to be high. Considerable power plant design, construction, and operating experience was evident throughout the corporate management ranks. Although the prior nuclear plant operating experience among the senior corporate officers involved in the line management and support of the operating plants was not extensive, the team found a clear appreciation and commitment by the corporate officers and managers to support the operating and maintenance needs of the three Duke nuclear stations. Appreciation and commitment were evident in the strong financial support given to upgrade programs, facilities, equipment, and staff at the nuclear stations.

Duke commits considerable resources to developing and upgrading the capabilities of management personnel at all levels. In-house management, administration, and supervisory skills training was provided through the Lake Hickory training facility. Outside consultants were brought in to provide specialized management training. Senior managers were provided opportunities for advanced management training through Harvard University and University of Michigan management schools. Individuals were rotated through various line and staff management positions in order to expand their experience and capabilities.

For its senior and middle corporate and station managers, Duke had expanded its management development process into a formal leadership development and management succession planning program. Specific knowledge, skill, and experience levels had been identified for a range of executive and management positions within the Duke organization. Management development through direct training and rotational assignments ensured that a number of Duke employees are available and qualified through broad experience and training to fill vacancies which may arise within the organization. The team found the formal process for succession planning to be forward looking and a strength of the company.

3.6.1.6 Outside Business Interests

Duke anticipated that increased competition from alternative commercial and residential energy companies in its service area would increase pressure on Duke to hold down rates. Duke perceived that the increasingly competitive business environment would threaten Duke's future sources of income, earnings, and return on investment for its shareholders. To offset and respond to these pressures, Duke was seeking ways to enhance earnings through nonregulated business ventures. One of these ventures was the Duke Engineering Services Company (DES), headed by the Duke Vice President of DE.

The team found that a number of Duke departments including DE, QA, and NPD had committed resources and established activity levels goals in support of DES. The team reviewed the current level of actual GO manpower involved with DES support and found it to be relatively small, with DE having the largest commitment. Although the human resources which were involved in DES support were limited, and the benefits to DE morale and the maintenance of a large diverse engineering staff were obvious, the team was concerned that with time, as the support to DES increased, needed technical and engineering support could be diverted away from McGuire performance improvement efforts. The team was also concerned that the present level of involvement by the DE Vice President and higher level Duke executives and corporate officers in ensuring the success and growth of DES could detract from the high level oversight, involvement, and leadership needed to ensure continuing performance improvement at the three Duke stations.

3.6.2 Middle Management

The middle management evaluation focused on management practices, organizational functions, and personnel capabilities associated with the exempt positions from superintendents down through first line supervisors in NPD at the station and equivalent levels in other departments. The evaluation was designed to answer key questions in the areas of: (1) goal development and implementation; (2) management oversight and involvement; (3) work organization and implementation; (4) organizational interfaces; (5) decisionmaking practices; and (6) problem solving.

It should be noted that the major areas of evaluation are not mutually exclusive, so there was, by necessity, some overlap and repetition. It also was impossible to totally separate the discussion of management and leadership from the results of the organization culture and climate review, which is addressed in Section 3.7.

3.6.2.1 Goal Development and Implementation

As discussed in Section 3.6.1.1, Duke Power had an extensive goals program. The program had several exceptional qualities which impact middle management.

- The broader corporate goals were well integrated at each organizational level. Corporate goals were translated into specific action items or improvement programs that were relevant and appropriate to each organizational unit. The action items addressed specific tasks and levels of performance to improve electric production, safety and equipment reliability. Therefore, Duke did not have a separate effort to establish "improvement programs" per se. The company continually pursued improved performance through the goals program and the establishment of action items designed to enhance safety, reliability, and performance.

- An effort was made to ensure that all personnel understood the relationship between goals and individual task assignments. Clear accountability for achievement of specific milestones for each task was provided. Goals were well publicized.

- Feedback on the status of goal achievement was extensive. Placed throughout the station and DE offices were charts indicating goal status. Further, at the station, goal achievement was reported daily via the station television system. Numerous tracking systems kept managers informed monthly on the status of quantitative performance measures.

3.6.2.2 Management Oversight and Involvement

Station management oversight and involvement at McGuire was extensive. This was particularly evident at the station manager and superintendent levels. Personnel in these positions spent considerable time in the plant and extensively interacted with subordinate staff at all levels. Management involvement was further enhanced by open door policies from first line supervisors to the station manager. It appeared, from the interviews, that station management had always been technically strong, and that the changes that were made in station management personnel over the last few years had contributed to further improvements in the morale, safety consciousness, and quality orientation of station personnel. These station management changes had included a new station manager and new superintendents for all technical groups with the exception of maintenance.

An important aspect of management oversight and involvement was demonstrated in the large number of "programs" underway at McGuire. Improvement actions as part of the goals program were discussed earlier. It should also be noted that Duke had implemented an extensive number of programs, such as communications studies, that focused on organizational and individual development. These programs were effective in improving morale and providing for personal needs.

3.6.2.3 Work Organization and Implementation

Work organization and implementation were reviewed with respect to functions directly related to plant operations and maintenance, and technical support functions (e.g., design modifications, post-modification testing, and other problem solving activities).

Plant operations and maintenance functions were conducted largely by shift personnel. McGuire shifts were 12 hours long and implemented in a manner that minimized adverse effects on the ability of station personnel to perform their functions. Additionally, approximately two years earlier, shift manning was expanded from only operations personnel to include maintenance, health physics, chemistry and performance personnel. The interviewees' attitudes toward the 12 hour shift and toward the inclusion of personnel from maintenance, health physics, chemistry, and performance were universally favorable. Individuals from each group on shift reported that cooperation and communications had greatly improved.

There had been few problems related to personnel having difficulties adjusting to shift work. In cases where individuals did fail to adjust adequately, management demonstrated considerable flexibility by providing counseling services or by accommodating these people in other jobs if necessary. However, several interviewees stated that employees were reluctant to seek counseling services, because it was noted on the employee's permanent record.

Another important feature of shift staffing was that, in addition to maintenance personnel from NPD, maintenance personnel from CMD worked on shift. Duke recognized that this could cause a problem, as discussed in Section 3.4.5.2, because CMD maintenance personnel were not as familiar with plant equipment and processes as station personnel. Accordingly, CMD maintenance personnel were being provided extensive training and were not allowed to work on safety-related equipment until they had demonstrated competence through the employee training and qualification system (ETQS).

Another positive aspect of the shift organization is that the McGuire operations shifts are staffed with more personnel (SROs, ROs, and NEOs) than required by TS. McGuire utilized the additional personnel to implement operator training and the operations group ETQS, to support procedures development and revision efforts, and for testing. In some cases, personnel who support these activities were taken off shift and placed on regular day work. In addition, all shift personnel rotated through training every fifth week. The diversity in shift jobs and the rotation through off-shift assignments helped to break up shift monotony and contribute to improved morale.

Generally, technical qualifications and capabilities of Operations personnel were found to be high. In addition, as discussed in Sections 3.2 and 3.3, the organization and implementation of testing and maintenance functions at McGuire were generally good. Key positive characteristics included: (1) effective shift organization, (2) technically qualified personnel, (3) effective on-the-job training, and (4) adequate manpower and material resources.

The organization and implementation of technical support functions was not as effective in the areas of design and installation of plant modifications and technical problem solving (see Section 3.5.7). The team's principal observations on this subject are discussed below.

The engineering support capability that resides at the station is a part of the station manager's line organization rather than the DE. Site engineering primarily resides within: (1) The Projects section (which is part of site Technical Services), and (2) the IAE and Mechanical Maintenance sections (which are part of Maintenance).

The Projects section was primarily responsible for planning and coordinating plant modifications. This group provided the major interface between DE and the station and was a major interface between CMD and the station (CMD also interfaced directly with Maintenance in support of shift corrective and preventive maintenance functions). The Projects section's major responsibilities included: preparing NSMs based on SPRs; providing coordination between DE and the station during NSM design; providing review and approval of NSMs; providing coordination between CMD and the station for modification installation; reviewing and approving installation procedures; and post-modification testing.

Technical problem solving resides primarily within the technical support units for the IAE and Mechanical Maintenance sections. The primary responsibilities of the technical support units were to: implement improvement programs (i.e., action items tied to the goals program); review and analyze operational/maintenance problems and determine the root causes; and define corrective actions and initiate SPRs.

A significant amount of the technical support work required coordination between and among DE, Projects, Maintenance technical functions, CMD, and in some cases, GO. It was reported by personnel at the site as well as the GO that communications and coordination had been steadily improving among these groups.

A number of examples of good interactions were readily provided. However, it was also reported that some problems remain. The observations below provide examples:

- The traditional roles and independence of DE and site engineering personnel inhibit coordination activities between DE and the station. The DE was clearly making a transition from a construction orientation to providing support to an operating plant where there is a significant increase in the need for interactions with plant personnel. On the other hand, the station was changing from a post-startup orientation towards establishing consistency in production and safety to an orientation which emphasizes optimizing these performance factors. This orientation was reflected in the increasingly challenging performance goals, extensive improvement action items, and the emphasis on quality operations.

- A significant amount of the coordination, implementation, and technical review of NSM design, installation, and post-modification testing was the responsibility of the McGuire Projects section. This section had expanded considerably over the past three years. However, the qualifications and experience levels of some Projects section personnel were still found to be limited. These personnel were also specialized by system/equipment categories or mechanical functions, thus further reducing the availability of technical expertise.

- The qualifications and experience profiles of the engineering staff in maintenance technical support were similar to those of the Projects section staff, i.e., some were limited. Technical support also was organized by system equipment types or mechanical functions further limiting the expertise and experience available. Problem solving and corrective action determination were constrained by the qualifications and experience of the technical functions staff. In some functional and system/equipment areas there appeared to be no support problem because the personnel routinely relied on assistance and advice from DE or the GO Nuclear Support staff. However, the degree of interaction between technical functions and DE or GO was uneven and was generally based on relationships among individuals instead of standard practices.

- Design, installation, and post-modification testing of NSMs was conducted on a matrix basis with different tasks and responsibilities assigned to different organizational units. However, there appeared to be a lack of matrix management procedures and controls and a general lack of familiarity with matrix management processes by the implementers.

- Station engineering personnel received supervisory skills training when they became exempt employees. The training was oriented toward the job requirements of line supervisors, including subjects such as alcohol and drug abuse, communications skills, counseling, and team building. Several level 1 supervisors in DE and station technical support areas expressed a need for more training in subjects such as matrix management; project scheduling, management, and controls; and time management.

3.6.2.4 Organizational Interfaces

The focus of this area of evaluation was how well various components of the organization interacted and how management facilitated communications and other forms of interaction.

Based on the interviews, it appeared that with some exceptions, communications among organizational units were good. The primary reasons for this included the following:

- Establishment of the 12 hour shift including station Operations, Maintenance, Health Physics, Chemistry and Performance groups had greatly increased cooperation among the groups.

- Management had established extensive methods for the dissemination of information and encouraged, as well as practiced, the sharing of information.

- The goals program promoted unity of purpose and tended to break down walls between groups at the stations. It was more difficult for station personnel to identify with the goals of DE or GO personnel.

- Duke's policy of entry level local hiring had largely resulted in a closely knit, homegrown culture at the station. This had contributed positively to openness in communications at the station.

3.6.2.5 Decisionmaking Practices

The team concluded that decisionmaking at the middle management level was carried out in an effective and efficient manner. There were three primary reasons why the decisionmaking process functioned well.

- The personnel who were given middle management and supervisory responsibilities also had delegated to them the authority to make decisions. Higher management had provided the operational guidelines via the goals program and policy, and interviewees believed that they were expected to make the day-to-day decisions necessary to accomplish their assigned tasks.

- Almost all interviewees indicated that they considered input from subordinates when making a decision and they frequently were asked to provide opinions or inputs to their superiors in making decisions. Participation in decisionmaking had led to a greater feeling of involvement in station operations at all levels.

- Several interviewees indicated that Duke management had made a conscious effort to push decisionmaking down to the lower echelons of middle management in order to make individual jobs more challenging and to increase operational efficiency.

A potential weakness in the decisionmaking process was that in some areas (e.g., the Projects sections and the Technical Support units within IAE and Mechanical Maintenance sections), the background knowledge and experience of some personnel responsible for modification and problem solving activities were not strong. Although these lower level managers and supervisors were responsible for these activities and made important decisions impacting budgets, manpower resources, schedules, and technical issues, they did not receive management training until they were promoted to the next level of management.

3.6.2.6 Problem Solving Process

The problem solving process at the station was assessed to determine if: (1) it was conducive to identifying problems, determining root causes, and developing and implementing corrective actions; and (2) adequate manpower and financial resources had been committed to effectively implement the problem solving activities. The results of the assessment were mixed. Positive aspects of station problem solving included the following:

- The formal PIR process was helpful, as discussed in Section 3.4.5.1.

- Teamwork was emphasized in problem solving. The McGuire staff conducted several different types of meetings that were designated to identify, characterize, and solve problems. Examples of scheduled meetings included functional area meetings, eight o'clock station staff meetings, post-trip review meetings, abnormal plant event meetings, and ad hoc committee meetings (such as the station communications committee meeting which was observed by team members).

- Duke had assigned to the technical support engineers in the IAE and Mechanical Maintenance sections a primary responsibility to review problems, develop PIRs, and define related corrective actions, as well as implement equipment monitoring and reliability improvement programs.

- Station management was extensively involved in problem identification and resolution. Station superintendents met biweekly to review APRs, including the proposed resolutions to the identified problems. At this meeting, the superintendents determined if the proposed resolution was adequate and assigned a priority to a problem prior to a modification being prepared.

There were two negative observations made by the team with regard to station problem solving:

- As discussed in Section 3.6.2.3, some of the technical support personnel responsible for problem solving did not have broad experience and could have benefitted from training in project management, matrix management, and time management.

- DE was not fully involved in station problem solving. This appeared to be due to the traditional operating roles of the station personnel and the infrequency with which station personnel request DE support. DE could effectively fill the gaps in experience, expertise, and manpower that existed within station engineering capabilities.

3.7 Organizational Culture and Climate

An evaluation of organizational culture and climate was made to examine unique blends of beliefs, attitudes, practices, and history that shaped the way business was conducted at Duke as well as key sociological factors affecting personnel behavior and job performance.

The method of evaluation was similar to that for evaluating middle management (Section 3.6.2). It included the following activities:

- Administration of 46 detailed interviews with middle management and non-exempt personnel.

- Administration of an additional 22 core interviews of limited scope that were designed to collect supplemental information about the impact of certain management policies and practices as well as specific McGuire organizational features.

- Review of documentation regarding organizational structure, programs, policies, and procedures.

- Evaluation of the observations of the management and organization review team members.

- Observations and judgment by other team members regarding the impact of management practices on specific technical functions.

3.7.1 General Cultural Characteristics

Duke had long been an industrial leader at the national level and a community leader in the Charlotte area. The corporate goals reflected the company commitment to maintain this important external leadership position as well as to efficiently and safely generate electricity at its nuclear units. At both the corporate and station levels, there was pride in the Duke accomplishments in nuclear power and a feeling of obligation to share the Duke experience and learn from others in the nuclear industry via participation in industry organizations.

The sense of pride and the striving for excellence were characteristics that are found throughout the company. To a large degree this was due to a personnel policy to hire at entry levels and make a strong commitment to personnel development and employment security. There had also been an emphasis on local hiring, particularly at the station, where the work force may be characterized as almost completely homegrown. Within DE, there was a greater diversity in background, but the majority of engineers were still with their first company, and the colleges of the Carolinas were by far the most represented by the Duke engineering staff.

First line supervisors on shift and personnel in other supervisory positions were initially hired at the entry level: they had come up through the ranks and had clearly demonstrated technical competence. Supervisory skills training (generally focused on personnel management) was provided to each individual upon promotion to a supervisory position.

Duke management had demonstrated technical competence and leadership as well as establishing people oriented programs. Duke management was quite sensitive to the well-being and morale of employees and their families, as well as to their technical and managerial competence.

There were also some historical patterns of operations that characterized both McGuire and DE. The work force at McGuire took pride in and was confident about its self-sufficiency. Historically, the units, after completion, had performed much of their own engineering and other technical support work. This way of doing business was fostered by the commitment of DE and other technical support groups to new plant construction. DE had traditionally had a construction orientation and operated much like a construction project architect-engineer.

Those factors had become partially obsolete by the time of the evaluation. The new role of DE was to support operating units. To successfully fulfill this role, designers had to be sensitive to the fact that modification design is driven and constrained by the existing plant configuration and operating parameters. On the other hand, the goal at McGuire was to optimize reliability, production, and safety through improved problem identification, problem solving, and corrective action programs. Achievement of this goal depended, in part, on getting the extensive expertise of DE involved in plant activities.

Duke management was addressing the need for changes and both DE and station cultures were in transition. The actions that were being implemented to bring about an orderly change and their consequences, are addressed in other sections of this management and organization overview.

Appreciation of the culture, at both corporate and station levels, facilitates understanding of current management policies and practices. The following key organizational and personnel attributes were products of the Duke culture.

- High commitment to goals attainment
- Excellent staff communications
- Quality orientation
- Strong loyalty
- High morale and strong work ethic
- Pride in Duke and individual jobs
- Very low employee turnover
- Exceptional mutual respect among the organizational units under station management
- Strong "can do" attitude and belief in individual abilities at the station

3.7.2 Organizational Climate

The results of the review of organizational climate are organized by the major areas of evaluation, which included: (1) human resources emphasis, (2) selection, qualification, and promotion, (3) training, (4) attitude and morale, and (5) organizational communications. Within each area, positive and negative observations are made.

3.7.2.1 Human Resources Emphasis

Positive Observations

- At McGuire, management placed a significant emphasis on personal health and safety. This had been incorporated as an integral part of the corporate goals. Implementation of the health and safety policies was comprehensive and included awareness programs, training, and frequent emphasis at regular staff meetings. All personnel interviewed expressed a strong commitment to both personal and nuclear safety.

- As stated earlier, a key cultural characteristic of the Duke organization was a commitment to the well-being and morale of employees. This characteristic was manifested in a comprehensive personnel policy that had generated a wide spectrum of employee support programs and practices. Included were counseling services, preventive health programs, educational assistance programs, sponsorship of programs such as weight watchers and alcohol/drug rehabilitation, and most importantly, an active training and awareness program designed to increase sensitivity to employee needs throughout the organization.

Negative Observations

- There were many circumstances in the plant, particularly in the auxiliary building and containment where the environment is hazardous (e.g., obstructions, excessive noise, poor lighting). Working under these adverse conditions can be very taxing on plant personnel. More could be done to provide a better work environment (minor modifications, e.g., lighting, communications, fewer obstructions), and better equipment to enhance safety, efficiency and the quality of the work performed.

3.7.2.2 Selection, Qualification and Promotion

In general, personnel who were interviewed stated that selection and promotion standards and practices were fairly administered and were based on seniority and performance. The primary complaint was that advancement opportunities would be limited unless Duke began to expand. Interviewees pointed out several positive actions taken by management to improve this situation including (1) the establishing of a commercial engineering services company, (2) the elimination of quotas within some job progressions (maintenance specialist progression), and (3) human resources support to help DE restructure some jobs to make them more challenging and interesting.

There were some groups for which no career development path was evident. A number of individuals did not believe there was anywhere to go in their jobs and felt that there was no opportunity at the site or GO to obtain career counseling. Generally, "topping out" resulted from what was perceived as corporate policy (e.g., requiring a degree, not being able to transfer out of a particular group, and not publishing a list of available jobs). In some instances this "dead ending" was related to organizational structure; for example, IAE specialists felt there was no way to get out of the maintenance area. Across the board, there was a noticeable desire to advance in the organization with a realization that there was little opportunity. Many interviewees believed that some form of formal career counseling would help them define their career options.

One vehicle for pursuing opportunities at Duke was to request a transfer through a formalized process which included submitting a transfer request. When jobs became available, the qualifications of personnel who had submitted transfer requests would be automatically reviewed. Personnel perceived the process to be ineffective. For example, some interviewees indicated that they had requests for transfers in for an extended period without receiving any feedback. The general feeling was that supervisors did not use the system to find applicants and that requesting a transfer was pointless.

No issue consistently dominated the interviews more than that of the exempt employee performance appraisal system, either from the perspective of being evaluated or from the perspective of performing evaluations. Most interviewees believed that the collective performance ratings given to individuals within any one organizational unit had to comply with quotas, or at least predetermined guidelines defining an expected distribution. In essence, they believed that low ratings were being given to people who did not deserve them.

Some of the reasons given for the unfairness of the appraisal system and its negative impact were as follows: (1) complying with guidelines eliminated objectivity of the supervisor, (2) the system forced comparisons of all individuals in a working group even though individuals in the group may be performing entirely different jobs, (3) where differences in the employees' level of performance were not well established, supervisors were forced to "rotate" employees through the low categories of performance, (4) individuals were being paired in a lower category of performance where one individual's performance was far better than another's, (5) implementation of the appraisal system had a negative impact on morale, job satisfaction and individual performance. One supervisor reported that, because of these perceptions, people who actually deserved the lower ratings did not seem to believe it when told they needed to improve. It was also stated that management did not appreciate the full extent of the negative impact of the appraisal process because appraisals were conducted for each individual annually based on their hire-in date. If appraisals were conducted for all personnel at the same time, the problems with the approach would likely be more apparent.

Aside from questions about uniform and proper implementation, the appraisal system suffered from some fundamental technical flaws. Even if a normal distribution were appropriate for the overall population, the variations within subgroups of the population might be far from normally distributed. This is particularly true with very small groups. The performance evaluation implied that personnel were rated on the basis of meeting their goals as specified on the form. However, if personnel were actually rated on the basis of quotas, the meaningfulness of fulfilling the goals could be lost. Interviewee comments were consistent with academic studies that indicated this form of appraisal system did have a detrimental impact on employee morale and motivation. Since the team's information was based on interviews, it might not accurately reflect the true appraisal system. However, to the extent that there is a discrepancy, it would appear that there was a communications problem.

3.7.2.3 Training

The observations presented in this section address training issues within the context of organizational climate. The technical evaluation of operator training is contained in Section 3.1.8. In general, the nature and number of comments were consistent with a good training program.

Positive Observations

- Duke's commitment to technical and non-technical (supervisory and management) training was exemplary. The most obvious manifestations of this commitment were the new technical training facility, procurement of a new McGuire simulator, the Lake Hickory management training programs, use of external training sources for senior management, and staffing support of the ETQS. Each of these examples represented a significant commitment of people and dollars.

- There were few complaints about training being cancelled or missed due to other commitments. Duke followed up on its resource commitments with a practice of making sure that scheduled training was conducted.

- A significant effort was made to train station support staff, GO personnel, and DE personnel in unit systems/equipment operations. This included eight weeks of systems training for new engineering personnel and the expanding practice of getting nonoperating personnel SRO certified.

Negative Observations

- Several interviewees indicated a need for more training. Operations personnel stated that there was insufficient simulator training time for the RO/SRO programs. In addition, NEOs indicated that they needed simulator training in order to better understand how the units operate and to better perform their jobs (as discussed in Section 3.1.8.3, a new simulator was being procured which should alleviate the problem). Station and non-station engineering personnel indicated that the initial systems training was invaluable in helping them understand and perform their jobs; however, they needed refresher training on systems to increase their plant knowledge and to stay abreast of NSMs and operating practices. The IAE personnel stated that the classroom training was good, but they need more in-plant training on specific equipment. Full implementation of ETQS should resolve this need.

- Interviewees made several negative comments regarding the relevance of some of the training and the qualifications of some instructors. The largest number of criticisms were leveled at the operator requalification training program (see Section 3.7.2.5). The ETQS training was criticized only in so far as some ETQS elements were being met via classroom training. NEOs stated that the inplant ETQS was superior. Maintenance personnel felt that some of the maintenance instructors did not have sufficient plant experience and that the lack of detailed plant knowledge was reflected in some of the training. The interviewees felt that the inexperienced instructors should rotate through maintenance shifts. Operations personnel, to a lesser degree, stated that classroom training instructors needed more plant expertise.

3.7.2.4 Attitude and Morale

Positive Observations

- Morale was generally high across most organizational groups when units were on-line.

- All personnel interviewed communicated a great sense of pride in working for Duke and in doing their job.

- Personnel had a well defined sense of their capabilities and were confident in carrying out their job.

- Teamwork was frequently emphasized.

- Loyalty to Duke was frequently expressed.

- Personnel frequently indicated the importance of both nuclear safety and personal safety in their jobs.

- All personnel expressed a strong desire for self improvement, either through training or advancement.

- Professionalism was frequently expressed as a characteristic of the Duke work force.

- The emphasis on goals at all levels motivated personnel and provided a sense of accomplishment.

- Personnel indicated that there were frequent and open interchanges at meetings and great willingness to discuss any subject with supervisors.

- Personnel frequently indicated a high level of self motivation.

- Personnel were not willing to take action on the basis of incomplete or questionable information.

- Personnel generally did what they were told, but felt free to question a decision or action they believed to be incorrect.

- Personnel were capable and willing to work independently when necessary.

- Quality of work was emphasized at all levels.

Negative Observations

- As would be expected, many interviewees indicated that morale was lower during outages. This lowering of morale was typically a consequence of the workload, schedule, and overtime pressures. In addition, it was sometimes attributed to difficulties in interfacing with individuals where there wasn't already a working relationship or where it was necessary to work on unfamiliar equipment.

- There was a reluctance expressed by some site personnel to use the expertise and experience of DE and GO staff. From the standpoint of the people at the site, DE and the GO staff did not know the plant (or operations) well enough to help. The DE perspective was that they were not getting out to the sites enough and would welcome the opportunity for more interaction. Where there was little direct interface, there was little credibility.

3.7.2.5 Organizational Communications

In general, communications were excellent throughout the organization. These communications could be broken down into general information dissemination, formal communications, and informal communications. The general dissemination of information was characterized by an extensive distribution system that included newsletters, TVs, bulletin boards, and mailings. Formal communications included technical and policy information. Informal communications included verbal interchanges and notes. Interviewees recognized the importance of these communications and had a particular willingness to discuss problems and issues with coworkers and supervisors. In addition, Duke took the initiative to carry out a survey to measure communications effectiveness and to identify better ways to disseminate specific categories of information.

The McGuire operating philosophy and climate encouraged the open reporting and discussion of problems. Duke managers and personnel at all levels committed significant time and resources to anticipating and mitigating problems that might arise as well as improving ongoing operations. There was little reluctance to point out problems even when it involved admitting that errors had been committed. Two interviewees admitted that they had committed serious errors, and that while they had received disciplinary actions, they were given the opportunity to participate in identifying corrective actions that would prevent recurrence of the error.

Communications among station organizations were exceptional. This was due in part to the station culture, but more to existing practices such as the shift structure and the commonality of goals. Almost every interviewee from the station stated that since management implemented the 12-hour shift rotation, where the same personnel from Operations, Maintenance, Chemistry, Performance, and Health Physics were always together on a shift, station communications improved a great deal.

A number of individuals who were interviewed in the Operations group expressed considerable concern and anger towards the NRC concerning the requalification program and the intent of the NRC to give requalification exams just prior to the diagnostic team visit. Comments about the program were generally directed at the impact the issue had on morale, since the program was clearly seen as a threat to their jobs. Specific comments concerned the exam timing, format and relevance, and the implications of the exam results for the Operations personnel.

Problems with the requalification program were well known. Surprisingly, the operators were not aware of improvements that had been made. The entire requalification program had been redesigned, at the request of the industry, some time prior to the scheduled exam, and all of the issues identified in the interviews had been addressed to the industry's satisfaction, e.g., by industry review to assure relevant exam questions. The tentatively scheduled exam was, in fact, a pilot to test the new program. It had been rescheduled for another plant because of the timing of this diagnostic evaluation.

The relevant information had been made available to Duke management, but it had not been properly communicated to Operations personnel. When the team briefed management personnel on this subject, they indicated that the apparent misunderstandings would be corrected promptly. Regarding other plants, the NRC's Office of Nuclear Reactor Regulation was preparing a generic letter to all licensed operators to inform them of the program status.

It was not apparent that the goals program had fully resolved the inherent conflict between safety goals on the one hand and power generation and operating schedule goals on the other. All interviewees agreed that management stressed reactor safety to a greater degree than in the past. Communicating this point was one of the station manager's priorities. In addition, priorities could change during outages and some aspects of plant activities were not as significant to safety during outages as they were during operation. However, approximately one-fourth of the people interviewed still thought that management considered meeting schedules and generating electricity to be more important than safety goals, particularly during outages.

An example of the conflict between schedule and safety goals and management's response to this issue apparently occurred on November 7, 1987, shortly before the diagnostic evaluation. Unit 2 was shut down at the time, preparing to start up. A surveillance test on a component cooling water heat exchanger was coming due. Unit 2 was started up and the test was delayed into the grace period. Then with Unit 2 operating, the test was performed. The heat exchanger failed the test and was cleaned during plant operation.

NRC Region II personnel followed up on the event and issued an inspection report on the subject. A notice of violation was issued for an improper test schedule, i.e., tests were scheduled so infrequently that the heat exchangers usually failed. In addition, station management considered the implications and took action to reinforce it basic message on the priority of safety. On December 3, 1987, the Superintendent of Technical Services issued instructions to Performance personnel clearly stating that tests should not be delayed due to a fear that the component or system might fail. He also clearly articulated the philosophy that a safe plant should be ready to demonstrate, at any time, the operability of required equipment.

The QA/QC programs were not well appreciated by plant operations. Many technical personnel interviewed perceived that QA/QC personnel were not qualified to perform technical reviews of work and served only to "chase paper." Technically they were not considered credible nor accepted as an integral member of the team. The technical capabilities of QA/QC were being upgraded by management through training and personnel selection.

The relationships of operations and maintenance to health physics has improved since HP personnel went on shift, however, there were still perceived problems related to: (1) HP responsiveness to scheduling needs, and (2) dealing with the temporary (contract) HP personnel during outages. In both cases, a part of the problem appeared to be in the attitudes and practices of the HP section. On the other hand, operations and maintenance personnel did not seem to appreciate the important function that HP played in protecting personnel health and safety.

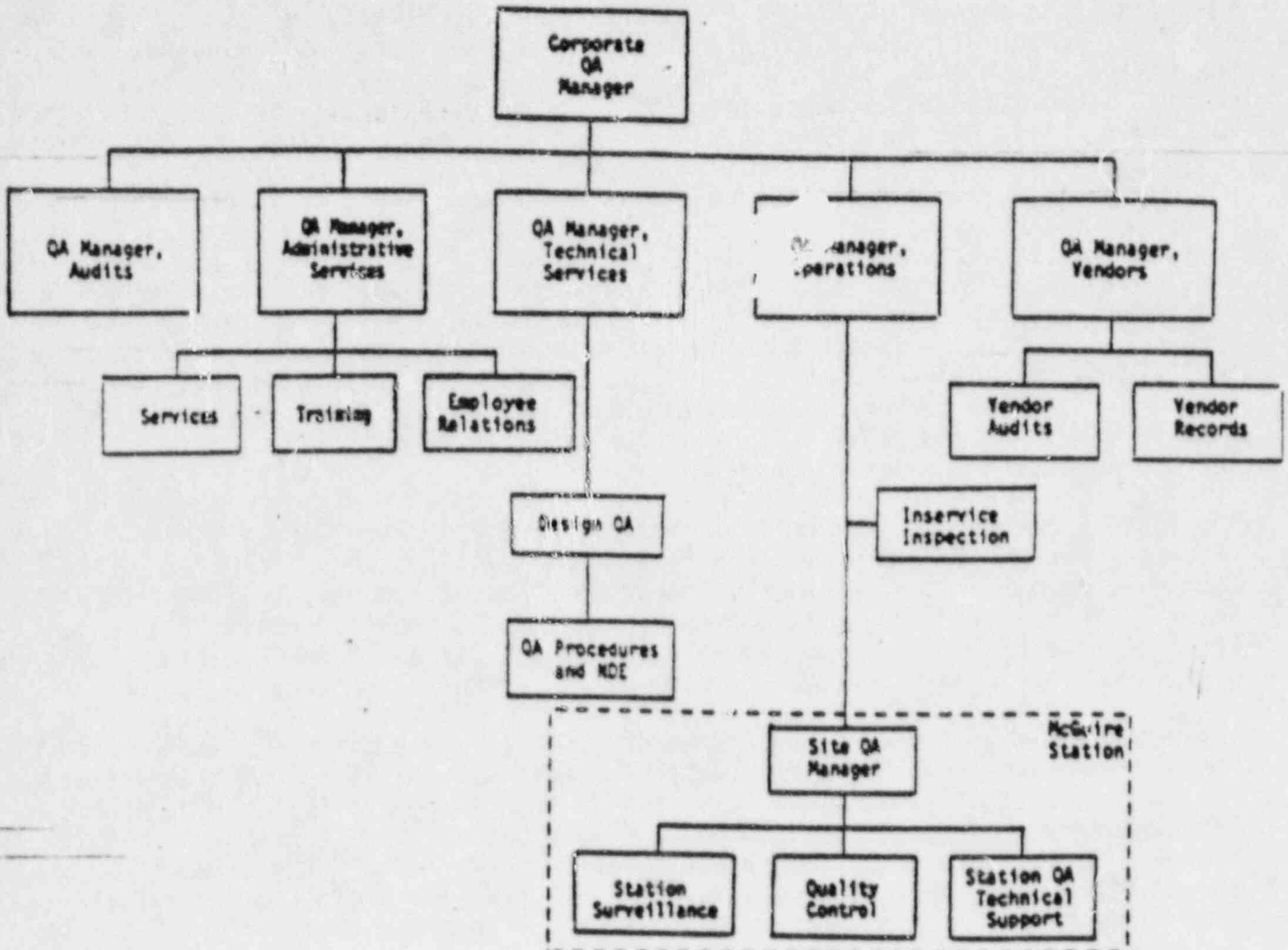

Figure 3-1. Quality Assurance Department Organization Chart

4.0 EXIT MEETING

The Director, AEOD, the Region II Administrator, the Team Manager and Deputy Team Manager and other NRC personnel met with Duke Power Company and McGuire management officials at the Duke corporate offices on January 22, 1988 to provide a briefing on the results of the McGuire diagnostic evaluation. The list of attendees is given at the end of this section. The briefing notes, which provided the team's preliminary findings and conclusions, are attached as Appendix A.

E. Jordan, Director, AEOD began the meeting by providing introductory remarks on the NRC Diagnostic Evaluation Program and the basis for the NRC's decision to conduct diagnostic evaluation of Duke and the McGuire Plant.

R. L. Spessard presented the preliminary results of the team's evaluation. Duke's response at the exit meeting was very receptive, reinforcing the team's preliminary findings and conclusions regarding Duke's positive attitude and commitment to improving McGuire plant performance.

R. Priory, Vice President, DE, agreed with the team's conclusions that DE could be more involved in support of the day-to-day problems of the operating plants. He indicated that Duke was developing a plan to have a DE office at each site, staffed by senior engineers, available to work on technical problems on a broad basis 40 hours a week. Their goal was to ensure that solutions to technical problems did not get missed.

W. Owen, Executive Vice President, Engineering, Construction, and Production, indicated that the DE office would make it easier for the plant managers to request support and to allow engineering to get involved earlier.

G. Grier, Corporate QA Manager stated that the team had gotten a clear picture of Duke's QA Program and he agreed that the QA Operations Surveillance Group could be made more capable with more operational experience. He indicated that Duke was working toward rotating NPD Operations staff into the QA surveillance areas and was confident that this could be achieved in the near future.

Hal Tucker, Vice President, NPD, indicated that borrowing from NPD was something the QA Operations Surveillance Group could do more of without detracting from line capability.

T. McConnell, McGuire Station Manager, stated that SROs were already being rotated into other areas such as Training, Integrated Scheduling, DE, and INPO assignments, but he agreed that QA had not had a priority for these resources and that the pressurizer cooldown limit violation could have been identified sooner with improved operations expertise in QA.

T. McConnell questioned the team's findings that no independent verification or post-maintenance testing was performed for nonsafety equipment. He indicated that quality verification/testing was performed on BOP systems and components and he urged the team to reevaluate its findings. [Pursuant to these comments, the team further evaluated the quality verification/testing performed at McGuire on BOP systems (see Section 3.1.7)].

T. McConnell agreed that performance test personnel tend to focus on the specific test acceptance criteria and steps and were not sensitive to observable equipment conditions which could adversely effect operability but were outside the scope of the test. He felt that the new System Expert Program that was being implemented at McGuire would correct this deficiency.

E. Jordan stated that the lack of an approved IST program at McGuire would be viewed as an NRC follow-up action and that the team would contact appropriate NRC staff to ensure timely review of the Duke IST submittals.

H. Tucker questioned the team's observation that the time he had available for oversight and direction had been temporarily reduced since the NPD organizational and staffing changes. He indicated he was spending more, rather than less, time involved with the plants since the reorganization.

W. Owen agreed, however, overall, the Vice President NPD was less accessible than the previous General Manager for Nuclear Stations had been, but that plans were in place to reestablish and fill an Assistant to the Vice President NPD position which would increase the time Mr. Tucker would have to be involved in oversight and direction of the operating units.

Mr. Owen indicated a concern with the team's finding that performance problems had been caused by the use of "excess" personnel in work assignments for which they were not qualified. He stated that there were no excess personnel working within Duke. He agreed, however, that construction personnel in CMD had not received adequate training, which was the cause of CMD personnel errors at the McGuire site.

Mr. Spessard agreed with this clarification and it was agreed that the term "excess" was an inappropriate characterization.

Mr. Jordan summarized the team's root cause analysis for the past and present performance trends at McGuire. He indicated that the NRC was especially concerned, however, about the potential negative impact of Duke's growing outside business interests.

Mr. W. Owen stated that Duke's priority was its operating nuclear plants. He indicated that he intended to brief W. Lee, Chief Executive Officer and Chairman of the Board and D. Booth, Chief Operating Office and President, following the meeting, of the team's findings and the NRC's concern in this area. He indicated that both Mr. Booth and Mr. Lee would have preferred to be in attendance for the briefing, but were not available.

Mr. Owen concluded by stating that although the team's evaluation efforts had significantly impacted Duke's organizational activities, the depth and quality of the team's evaluation made it very worthwhile.

ATTENDEES

McGuire Diagnostic Evaluation Meeting - January 22, 1988

Name	Organization
NRC	
V. L. Brownlee	Region II, Projects Branch 3, Chief
J. N. Grace	Region II, Regional Administrator
D. S. Hood	Office of Nuclear Reactor Regulation, Project Manager (McGuire)
E. L. Jordan	Office for Analysis and Evaluation of Operational Data (AEOD), Director
W. T. Orders	Region II, Senior Resident Inspector (McGuire)
T. Peebles	Region II, DRP, McGuire Section Chief
S. D. Rubin	AEOD, Diagnostic Evaluation and Incident Investigation Branch, Chief
R. L. Spessard	AEOD, Division of Operational Assessment, Director
W. M. Troskoski	Office of the Deputy Director for Regional Operations
Duke	
R. L. Dick	Vice President--Construction and Maintenance
G. D. Gilbert	Nuclear Production Department, Operating Engineer
G. W. Grier	Corporate QA Manager
S. B. Hager	Design Engineering, Civil/Environmental Chief Engineer
W. A. Haller	Corporate Technical Services Manager
J. M. Hart	Design Engineering, Project Management Manager
T. L. McConnell	McGuire Station Manager
M. D. McIntosh	Nuclear Production Department, Nuclear Support General Manager
T. C. McMeekin	Design Engineering, Electrical Chief Engineer
W. H. Owen	Executive Vice President--Engineering, Construction and Production
R. B. Priory	Vice President--Design Engineering
N. A. Rutherford	Nuclear Production Department, Licensing
H. B. Tucker	Vice President--Nuclear Production Department
T. F. Wyke	Design Engineering, Mechanical Chief Engineer

DUKE/NRC MEETING

ON THE RESULTS OF THE

MCGUIRE DIAGNOSTIC EVALUATION

JANUARY 22, 1988

Appendix A

Summary

Team Confirmed NRC Management's Perception of the Duke Power Company

- Numerous Strengths Observed (Solid SALP Category 2 with Improving Trend).

- Team Identified Some Weaknesses in the McGuire Programs.

5

McGuire Diagnostic Findings

- McGuire Program Strengths Observed by the Team
  - Overall Corporate Leadership/Oversight/Involvement
  - Staff Technical Capabilities
  - Functional Area Technical Programs
  - Programs for Improved Engineering Support
  - Organizational Climate/Culture/Attitude
- McGuire Weaknesses Identified by the Team
  - Design Engineering Involvement
  - QA Contributions To Enhancing Plant Safety Performance
  - Specific Operations, Maintenance, and Testing Issues
  - Specific Management and Organizational Issues

Overall Corporate Management, Leadership, Oversight and Involvement Good

- Clear direction through work plan goals and actions.
- Monthly tracking and annual review of performance.
- Adequate human and financial resources.
- Functional area interfaces promote quality improvement and consistency.
- New plant manager has positively affected plant safety performance.
- Commitment to goals instilled in staff.
- Management development and succession planning programs in place.

Staff Technical Capabilities Good

- Large, knowledgeable and experienced design engineering staff.
- Technically Competent Nuclear Support Staff with Significant Operating Plant Experience.
- Low turnover rate.
- Involvement in nuclear industry committees.
- Acts as own AE.

Functional Area Technical Programs Strengths

Operations

- First Line Management Involved In Start Ups and Evolutions
- 12 Hour Shift Contributes to High Morale
- Good Communications at Shift Turnover Meetings
- SRO at Control Board Panel for Each Unit

Maintenance

- Strong Staff and Organization
- Comprehensive PM Program
- New Preventive Maintenance Program Initiatives
  - Valve Reliability Improvement Program
  - Reliability Centered Maintenance (RCM) Pilot Program

Testing

- Integrated Scheduling Group Ensures Few Missed Surveillances
- Thorough Procedures Ensure Completeness of Testing and Documentation of Results

Functional Area Technical Programs Strengths (Continued)

Quality Assurance

- Use of Technical Expertise on QA Audit Teams
- Quality Assurance Performance Assessments
- Self Initiated Technical Audit Program
- QA Training Program
- New QC Training Facility

PROGRAMS FOR IMPROVED DESIGN ENGINEERING SUPPORT IN PLACE

- ENHANCEMENTS IMPLEMENTED TO ADDRESS IDENTIFIED STATION MODIFICATION PROGRAM WEAKNESSES.
- NEW PROBLEM INVESTIGATION REPORT PROCESS PROVIDES FOR GREATER DESIGN ENGINEERING INVOLVEMENT IN EQUIPMENT PROBLEMS.
- NEW STATION OPERABILITY DIRECTIVE PROVIDES FOR GREATER ENGINEERING SUPPORT IN OPERABILITY DECISIONS.
- DESIGN QUALITY FEEDBACK MEETINGS WITH EACH STATION SEMIANNUALLY.
- NEW STATION DIRECTIVE FOR SYSTEM EXPERT IMPLEMENTED.

Overall Organizational Climate/Culture/Attitude Positive

- High Commitment to Goals Attainment
- Excellent Staff Communications
- Quality Orientation for All Activities and Levels
- Effective and Open Communication to Identify Problems
- Team Work Emphasized in Problem Solving
- Strong Loyalty to Duke and Plant Manager
- High Morale and Excellent Work Ethic

DE, A Large and Capable Engineering Resource, Is Not Being Fully Utilized In The Day-To-Day Support of the Operating Plants.

- DE Charter Requires Engineering Support Be Provided When Tasked By NPD.
- DE Attitude of "Support the Plants When Tasked" Tends to Limit DE Initiative and Involvement.
- DE Not Organized to Provide Strong Representation at the Plant, e.g., Only Two DE Liaisons at Site Part-Time.
- NPD Charter Requires Safe Operation and Maintenance of Operating Plants.
- NPD Attitude of "Solve Our Own Problems" Tends to Limit Requests for DE Support.
- Process Implemented for DE Support Does Not Involve DE Participation with NPD in the Front End Decisionmaking on the Need for and Scope of DE Support and Has Resulted in Some Technical Problems and Programs Being Inadequately Evaluated, e.g.:
  - Breaker Coordination Problem of September 6, 1987.
  - Auxiliary Feedwater Pump Vibration and Damage.
  - IST Program For Check Valve Testing.
  - INPO SOER 86-3

DE, A Large and Capable Engineering Resource, Is Not Being Fully Utilized In The Day-To-Day Support of the Operating Plants (Continued).

Probable Root Cause: The NPD "Solve Our Own Problems," and the DE "Support the Plant When Tasked," Attitudes, Which Result From Their Organizational Charters. Have Tended to Limit Design Engineering Support of the Operating Plants in Areas Warranting Use of Their Expertise.

Recommendation: Enhance Design Engineering Support by Strengthening Their Involvement in the Front-End Decisionmaking on How To Handle Technical Problems and Programmatic Issues Affecting the Plant.

QA Contributions To Enhancing Operating Plant Safety Performance Is Currently Limited

- Near-Term Technical Capability of QA Operations Surveillance Group Is Weak.
  - Policy Emphasizes Quality Verification in the Line Organization.
    - Technical Resources Placed In Line Organization.
  - Surveillances Emphasize Programmatic Rather Than Technical Reviews.
  - Surveillance Group Staff Currently Lacks Strong Operations Background.
    - 4 Years Average Operating Plant Experience.
    - No Licensed Operators on QA Staff.
    - Operations Staff Transfers To QA Have Not Been Permitted.
  - Completion of QA Training Program Scheduled to Take Several Years.
- Technical Contributions To Plant Safety Performance Have Been Limited.
  - Surveillance Findings Generally Programmatic Rather Than Technical.
  - Some Repetitive Events Have Not Been Recognized and/or Pursued By QA.
    - M&TE Segregation of Nonconforming Tools.
    - Reactor Pressurizer Cooldown Administrative Limits.

QA Contributions To Enhancing Operating Plant Safety Performance Is Currently Limited (Continued)

<u>Probable Root Cause</u>: Corporate Policy and Personnel Qualifications Tend to Limit in the near term the Contributions of the QA Operations Surveillance Group in Enhancing Operating Plant Safety Performance.

<u>Recommendation</u>: Enhance The Near-Term Effectiveness of The QA Operations Surveillance Group Through Transfers or Rotational Assignments of Operations Staff Into The Surveillance Group.

SPECIFIC OPERATIONS, MAINTENANCE, AND TESTING ISSUES

OPERATIONS

- REPETITIVE REACTOR PRESSURIZER COOLDOWN RATE VIOLATIONS
- CONTROL ROOM ENVIRONMENT NOISY AND CROWDED AT TIMES
- NO INDEPENDENT VERIFICATION AND POST-MAINTENANCE TESTING FOR NON-SAFETY EQUIPMENT
- SIMULATOR FIDELITY REDUCED BY MODIFICATION BACKLOG
- SIMULATOR TIME FOR OPERATOR TRAINING LIMITED BY CATAWBA TRAINING NEEDS

MAINTENANCE

- NO FORMAL INTEGRATED FAILURE TRENDING PROGRAM FOR SAFETY-RELATED EQUIPMENT
- LACK OF TORQUE SWITCH SETTING CONTROL AND DOCUMENTATION FOR SEVERAL LIMITORQUE MOVS
- INADEQUATE ROOT CAUSE DETERMINATIONS
  - EXCESSIVE VIBRATION AND DAMAGE TO AFW PUMPS
  - MULTIPLE ROTORK MOV MOTOR FAILURES
  - VOLUME CONTROL TANK DIVERT VALVE LEAKAGE

Specific Operations, Maintenance, and Testing Issues (Continued)

Testing

- IST Program Not Approved by NRC
- Most Check Valves Are Not Tested for Reverse Flow
- The Only ASME Code Relief Valves Tested are the Main Steam and Pressurizer Relief Valves
- Some Section XI Air-Operated Valves are Not Trended for Stroke Time
- Performance Test Personnel Usually Focus on Surveillance Procedure Step Acceptance and Not on Integrated Test Acceptance
- McGuire's IST Program not Consistent with Catawba's

SPECIFIC MANAGEMENT AND ORGANIZATIONAL ISSUES

- RECENT NPD CORPORATE ORGANIZATION AND STAFFING CHANGES HAVE TEMPORARILY REDUCED THE TIME AVAILABLE FOR THE NPD VICE PRESIDENT TO PROVIDE OVERSIGHT AND DIRECTION FOR THE OPERATING PLANTS
- LIMITED CAREER ADVANCEMENT OPPORTUNITIES DUE TO SHARPLY REDUCED DUKE GROWTH HAS CONCERNED SOME DUKE EMPLOYEES
- A PERCEPTION BY EXEMPT EMPLOYEES CONCERNING THE EMPLOYEE APPRAISAL SYSTEM HAS NEGATIVELY IMPACTED MORALE
- THE USE OF ~~EXCESS~~* PERSONNEL IN WORK ASSIGNMENTS FOR WHICH THEY ARE NOT FULLY QUALIFIED HAS LED TO PERFORMANCE PROBLEMS
- QUALITY ASSURANCE IS NOT HIGHLY REGARDED BY LINE ORGANIZATION IN TERMS OF THEIR CONTRIBUTIONS TO OPERATIONS PERFORMANCE IMPROVEMENTS
- THE EMPHASIS AND DAILY FOCUS ON NPD PERFORMANCE GOALS MAY AT TIMES DIMINISH THE SAFETY CONSCIOUSNESS AT THE WORKING LEVEL

* Based on discussions at the exit briefing, the NRC agreed that the word "Excess" was not an appropriate characterization of the situation and agreed to delete it.

Root Cause of Past and Current McGuire Performance Trends

- McGuire Performance Improvement Was Hampered by Other Priorities:
  - Post-TMI Action Item Implementation
  - Catawba Construction, Licensing, and Start- Up

- McGuire Performance Now Starting to Improve as a Result Of:
  - Nuclear Production Goals and Resources Being Focused on Operational Performance Improvements
  - Greater Emphasis on Quality in All Activities
  - Engineering Support for Operating Plants Improved
  - Nuclear Support Staff Aligned to Ensure Greater Consistency and Quality Among Plants in all Functional Areas

ROOT CAUSE OF PAPT AND CURRENT MCGUIRE PERFORMANCE TRENDS (CONTINUED)

- - MCGUIRE STAFF EXPERIENCE AND KNOWLEDGE LEVEL INCREASING AT ALL LEVELS
- - STATION-TO-STATION STAFF COMMUNICATIONS PROCESS IMPROVED
- - IMPROVED ORGANIZATIONAL CLIMATE

- MCGUIRE PERFORMANCE IMPROVEMENT MAY BE SLOWED BY:
  - - LIMITATIONS ON ENGINEERING INVOLVEMENT IN PLANT PROBLEM REVIEWS AND EVALUATIONS
  - - LIMITATIONS ON QA CONTRIBUTIONS TO QUALITY OF OPERATIONS
  - - LESS THAN OPTIMIMUM NPD/CMD INTERFACE
  - - OUTSIDE BUSINESS INTERESTS