DIAGNOSTIC EVALUATION TEAM REPORT

FOR THE

ARKANSAS NUCLEAR ONE UNITS 1 AND 2

DECEMBER 1989

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

Enclosure

Licensee: Arkansas Power & Light Company

Facility: Arkansas Nuclear One Units 1 and 2

Location: Pope County, Arkansas
About 6 Miles West-Northwest of Russellville, Arkansas

Docket Nos.: 50-313 and 50-368

Evaluation Period: August 21, 1989 through September 15, 1989

Team Manager:
Gary G. Zech

Deputy Team Manager:
Stuart D. Rubin

Team Members:
Henry Bailey
Morris Branch
Zelig Falevits
Robert Freeman
Paul Gage
Edward Girard
Steven Guthrie
Robert Perch
William Reckley
Dennis Sullivan
Jefferson Tedrow

Consultants:
Robert Burns
Robert Gura
Donald Prevatte
Paul Thurmond

Submitted By: Gary G. Zech 12/6/89
Gary G. Zech, Team Manager Date
Arkansas Nuclear One Diagnostic Evaluation Team, AEOD

Approved By: E L Jordan 12/6/89
Edward L. Jordan, Director Date
Office for Analysis and Evaluation
of Operational Data

EXECUTIVE SUMMARY

During the Nuclear Regulatory Commission (NRC) Senior management Meeting in May 1989, NRC senior managers recommended that a Diagnostic Evaluation (DE) be conducted at Arkansas Nuclear One (ANO). The recommendation was based upon an apparent decline in plant performance as reflected by recurring and significant maintenance, engineering and operational problems, and by relatively poor communications with the NRC. In addition, a number of organizational and management changes had recently occurred, the effects of which had not been evaluated and for which additional information was considered necessary to further assess ANO's performance.

Based on these issues and concerns, and the recommendations of the NRC senior managers, the Executive Director for Operations (EDO) directed the Office for Analysis and Evaluation of Operational Data (AEOD) to conduct a broad-based DE at ANO to provide additional information regarding the quality and trend of plant performance, the effectiveness of improvement programs and recent changes in licensee management, and the root causes of any confirmed performance problems at ANO.

A 17 member Diagnostic Evaluation Team (DET) spent a total of three weeks at the ANO site, and at the corporate and engineering offices in Little Rock, Arkansas, during August and September 1989, evaluating the functional areas of management and organization, operations and training, maintenance, surveillance and testing, and design and engineering support.

During the ANO Unit 1 refueling outage in late 1988, a number of equipment problems and personnel errors occurred including, the loss of shutdown cooling; a plant heatup with the steam driven emergency feedwater pump inoperative; and a Reactor Coolant System (RCS) leak, while critical. This last event was caused by a lack of tagout control, poor communications and incomplete maintenance work. In reviewing these events, corporate management recognized that there were serious material and management problems at ANO and took a number of actions to address them. Following an internal senior level review, and an independent external assessment in early 1989, the Vice President, Nuclear implemented a number of management changes and an organizational restructuring.

The team found that ANO had several substantial management, organizational and technical problems that were caused by a number of longstanding deficiencies, which over a period of time became more evident.

The team concluded that the root causes of ANO's performance problems were (1) weak corporate leadership, oversight and involvement coincident with a period of site management weaknesses, that had resulted in poor cooperation and teamwork among ANO organizations and a lack of accountability and ownership within the staff, (2) the lack of a clearly documented plant design basis which adversely impacted corrective action programs, (3) inadequate maintenance and engineering support to the plant that adversely impacted plant performance, and (4) a sense of complacency regarding plant performance and a willingness to live with material and equipment problems, both of which resulted from various cultural issues and influences, including (a) a lack of outside experience with high industry performance standards, (b) a compliance versus safety approach to problems, (c) weak self-assessment and performance monitoring efforts, and (d) previous assessments by outside organizations which had not been sufficiently critical.

At the time of the DE, AP&L and ANO were still in a period of transition. The team found that the structural changes were substantially complete, but that the new organization was still learning to work together as a team and to deal with the numerous issues confronting it.

The team found that corporate involvement in the oversight of plant activities had improved as indicated by the Nuclear Vice President's role and involvement in the management and organizational changes. The new site management team was more visible in the plants, was emphasizing personal accountability and was committed to improved teamwork and communications. However, the team found that some of these initiatives were not fully implemented and not all of the commitments had been effectively communicated to plant personnel. For example, clear guidance for entering Technical Specification Limiting Conditions for Operations for maintenance activities had not been provided to the plant operators and incorrect interpretations were identified .

The functional areas of maintenance, operations and engineering support continued to be adversely impacted by longstanding design basis and configuration control problems. Although significant progress had been made, weaknesses still existed in the engineering design and technical support area. For example, several design and operational problems were identified during the team's review of the service water system, several of which were similar to findings identified during ANO's 1989 self-assessment of the Unit 1 Decay Heat Removal System. Programs existed or had been identified to address these problems, but in many cases their implementation had met with delays due to resource and scheduling conflicts.

Corrective and preventive maintenance support was found to be weak, which, among other things, adversely impacted the plant material condition and operating performance. These maintenance weaknesses were caused by material control problems, including the lack of qualified spare parts; poor tracking and trending; poor communications and coordination with Engineering and Operations; weak root cause determinations; and inefficiencies in the planning and scheduling of maintenance work.

The team found that the new management team had taken steps to address the cultural issues and influences that had adversely affected plant performance in the past. For example, the new managers from outside the ANO organization were implementing policies and were establishing performance standards that were having a positive effect on the staff. The licensee had also made progress in its efforts to improve communications with the NRC, for example, by emphasizing safety over the regulatory aspects of its operability determinations.

Assessments by outside organizations had not been sufficiently critical of the performance of ANO. The licensee's weak self-assessment and root cause analysis efforts, combined with the results of these outside assessments contributed to a sense of complacency on the part of the licensee regarding its overall performance and the adequacy of any corrective actions. Although progress had been achieved, there was still evidence that plant staff and managers were willing to accept poor material conditions, marginally functional equipment and degraded system performance. Repair efforts seemed to focus on restoring equipment to service at the expense of aggressive and effective corrective actions.

Strengths were noted in the experience level and number of licensed operators as well as the management commitment that existed for a quality training program. In addition, the team concluded that, overall, the recent management changes and initiatives were having a positive effect, but that a number of areas needed increased management attention. These included (1) identification and resolution of equipment problems with the highest safety-significance and potential impact on plant operations and on operator performance, (2) resolution of the plant design-basis and as-built configuration problems, (3) establishment of resource commitments and priorities to more expeditiously resolve longstanding maintenance, engineering and materials control problems, (4) implementation of better performance monitoring, self-assessment and root cause analysis efforts, and (5) increased emphasis on teamwork, communications and accountability among ANO organizations.

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ACRONYMS

ac	Alternating Current
A/E	Architect Engineer
AIT	Augmented Inspection Team
ALARA	As-Low-As-Reasonable Achievable
ANO	Arkansas Nuclear One
ANSI	American National Standard Institute
AO	Auxiliary Operator
AOP	Abnormal Operating Procedure
AP&L	Arkansas Power & Light
ASME	American Society of Mechanical Engineers
BOP	Balance-of-Plant
BQR	Baseline Quality Requirement
B&W	Babcock & Wilcox
B&WOG	Babcock & Wilcox Owner's Group
CAP	Composite Action Plan
CCW	Component Cooling Water
CE	Combustion Engineering
CEO	Chief Executive Officer
CFR	Code of Federal Regulations
CR	Condition Report
CREVS	Control Room Emergency Ventilation System
CRS	Condition Reporting System
dc	Direct Current
DCD	Design Configuration Documentation
DCP	Design Change Package
DE	Diagnostic Evaluation
DED	Design Engineering Directive
DET	Diagnostic Evaluation Team
DHR	Decay Heat Removal
dp	Differential Pressure
EAR	Engineering Action Request
ECP	Emergency Cooling Pond
EDG	Emergency Diesel Generator
EDO	Executive Director for Operations
EFW	Emergency Feedwater
EIC	Electrical/Instrumentation and Control
EOI	Entergy Operations, Incorporated
EOP	Emergency Operating Procedure
EPRI	Electric Power Research Institute
EQ	Environmental Qualification
ESF	Engineered Safety Feature
FERC	Federal Energy Regulatory Commission
FSAR	Final Safety Analysis Report
GL	Generic Letter
GE	General Electric

HPI	High Pressure Injection
IA	Instrument Air
I&C	Instrument and Control
IN	Information Notice
INPO	Institute of Nuclear Power Operations
I/P	Current/Pressure Ratio
IST	Inservice Testing
IV	Independent Verification
JO	Job Order
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LOCA	Loss-of-Coolant Accident
LOOP	Loss-of-Offsite Power
LPSI	Low Pressure Safety Injection
LRGO	Little Rock General Office
MCC	Motor Control Center
MCS	Mechanical/Civil/Structural
MOV	Motor-Operated Valve
MOVATS	Motor-Operated Valve Analysis and Test System
MSSV	Main Steam Safety Valve
MWe	Megawatts (Electrical)
MWt	Megawatts (Thermal)
NDS	Nuclear Design Services
NOD	Nuclear Operations Directive
NON-Q	Nonsafety-Related
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
NSSS	Nuclear Steam Supply System
O&M	Operations & Maintenance
OP	Operations
PEAR	Plant Engineering Action Request
PI	Pressure Indicator
P&ID	Piping and Instrumentation Drawing
PIE	Plant Impact Evaluation
PM	Preventive Maintenance
PMEE	Preventive Maintenance Engineering Evaluation
PSC	Plant Safety Committee
PWR	Pressure Water Reactor
Q	Safety-Related Included in 10 CFR Appendix B Program
QA	Quality Assurance
QC	Quality Control
RB	Reactor Building
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RWT	Reactor Water Tank

SAL	Service Advisory Letter
SAR	Safety Analysis Report
SER	Safety Evaluation Report
SERI	System Energy Resources, Incorporated
SG	Steam Generator
SIT	Safety Injection Tank
SIAS	Safety Injection Actuation System
SOER	Significant Operating Experience Report
SPDS	Safety Parameter Display System
SRC	Safety Review Committee
SRO	Senior Reactor Operator
SS	Shift Supervisor
SSFI	Safety System Functional Inspection
STA	Shift Technical Advisor
STM	System Training Manual
SW	Service Water
SWIP	Service Water Integrity Program
TMI	Three Mile Island
TS	Technical Specification
UL	Underwriter Laboratories
WCC	Work Control Center
WCO	Waste Control Operator

1.0 INTRODUCTION

1.1 Background

For the systematic assessment of licensee performance (SALP) period ending June 30, 1988, the Arkansas Nuclear One (ANO), Units 1 and 2 performance involved three Category 1, eight Category 2, and no Category 3 ratings. Although the overall performance was considered to be improving, three of the Category 2 areas, Maintenance/Surveillance, Engineering/Technical Support, and Safety Assessment/Quality Verification were identified as having a common theme involving weaknesses in root cause evaluations, narrow corrective actions, and ineffective communications between maintenance and engineering. Program changes were implemented by the licensee in those areas and the effectiveness of those changes were to be monitored and assessed by the licensee during its subsequent SALP period (July 1, 1988-September 30, 1989).

In the first few months of that period, which included the Unit 1 1R8 refueling outage, several Unit 1 events occurred. These included a loss of shutdown cooling; plant heatup above 280°F with the steam-driven emergency feedwater pump inoperative (Tech Spec Violation); and, a 25 gpm reactor coolant system (RCS) leak that occurred while critical when a make-up line isolation valve packing blew out following leak testing for a seal weld repair. This final event resulted from a lack of tagout control, poor communications and incomplete maintenance activities. Other instances were found during Nuclear Regulatory Commission (NRC) inspections in which Arkansas Power & Light (AP&L) had failed to correct potential safety problems promptly once they had been identified, as well as instances in which adequate control of safety-related components had not been maintained. The NRC staff also found a number of associated weaknesses including failure to pay adequate attention to detail, communication weaknesses, performance of activities without proper authority, inadequate performance of system/component tagout, and failure to take prompt correction actions.

Following the Unit 1 1R8 outage, licensee management appeared to acknowledge the existence of problems and took various actions to address them. Foremost among these were management changes and an organizational restructuring that occurred in early 1989. These changes included separate plant managers and maintenance managers for each unit (Figure 1.1-1) and an infusion of new managers from outside the ANO organization.

In view of these recent management and organizational changes and because of continuing concerns regarding design issues and operating performance, a recommendation was made to the Executive Director of Operations (EDO) during the May 1989 NRC Senior Management Meeting that a diagnostic evaluation (DE) should be conducted at ANO Units 1 and 2.

1.2 Scope and Objectives

The EDO directed the Diagnostic Evaluation Team (DET) to conduct a broadly structured evaluation to assess the current status of ANO performance and to determine the root causes of any performance problems identified.

To provide the assessment of plant performance directed by the EDO, the DET evaluated several functional areas with the following specific goals:

- Functional Area Effectiveness: Assess the effectiveness (strengths and weaknesses) of the operations, maintenance, surveillance and testing, and engineering areas in ensuring safe plant operation; assess the adequacy of procedures, programs, and compliance to codes, standards, commitments, and regulatory requirements.

- Technical Support: Assess the effectiveness (strengths and weaknesses) of the technical support provided to the station in the areas of operations, surveillance and testing, maintenance, and operator training.

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

- Management and Organization: Assess the effectiveness (strengths and weaknesses) of management leadership, direction, oversight and involvement, and the organizational climate and culture at ANO.

1.3 Methodology

The DE at ANO combined several methods of assessment, with emphasis on the interfaces and relationships between operations and various corporate and plant support groups. In the course of the DET, the team observed plant operations, reviewed pertinent documents, conducted interviews with plant and corporate personnel at all levels, and assessed the functional areas of operations, surveillance and testing, maintenance, design and engineering support, and management and organization. The team used contractors to assist in the evaluation of engineering design and technical support, and management and organization.

Before arriving onsite, the team devoted several weeks to in-office document review and preparation that included team meetings and briefings by NRC regional and headquarters staff knowledgeable about AP&L and ANO. On August 21, 1989, the team began an initial 2-week evaluation at the station and corporate offices. The team returned on September 11, 1989, for an additional week to complete the evaluation. Throughout the evaluation, team representatives met periodically with plant management 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 ANO resident inspectors frequently attended these meetings and functioned as technical advisors to the team during the onsite evaluation. The exit meeting with corporate officials and managers was held on October 18, 1989 at the AP&L offices in Little Rock, Arkansas (see Section 4.0 for details).

1.4 Plant Description

The ANO site, located in Pope County, Arkansas, is about 6 miles West-Northwest of Russellville, Arkansas and contains ANO Units 1 and 2. ANO-1 is a B&W pressurized water reactor (PWR) and ANO-2 is a CE PWR. Both units have a reinforced concrete, dry, ambient pressure containment. The licensed thermal power for Unit 1 is 2568 MWt with an electric rating of 836 MWe, and 2815 MWt and 858 MWe for Unit 2.

Construction of both units was authorized by the Atomic Energy Commission/NRC by issuance of construction permits on December 6, 1968 and December 6, 1972 for Units 1 and 2, respectively. Full power operating licenses were issued to Unit 1 on May 21, 1974 and Unit 2 on July 18, 1978. Unit 1 began commercial operation on December 4, 1974, and Unit 2 on March 25, 1980.

1.5 Organization

AP&L, as well as Louisiana Power & Light (Waterford 3), and System Energy (Grand Gulf), are wholly owned subsidiaries of the Entergy Corporation (Entergy), formerly Middle South utilities. The Entergy organization is shown in Figure 1.5-1. AP&L along with the Grand Gulf and Waterford licensees, have applied to the NRC, the Securities and Exchange Commission, and the Public Service Commissions in each of their respective states for approval of a corporate restructuring that would result in those facilities being operated by a newly created company, Entergy Operations Incorporated (EOI). EOI would also be owned by Entergy (Figure 1.5-2).

The AP&L corporate officer who has primary responsibility for ANO is the Vice President, Nuclear, who at the time of the evaluation reported to the AP&L Chief Executive Officer. The licensee intends to permanently relocate to the site the ANO Vice President, Nuclear, his staff, as well as the General Manager, Engineering and the Nuclear Engineering design organization, all of which were located in the AP&L corporate offices in Little Rock.

When the corporate restructuring is approved, the ANO Vice President, Nuclear will report to the Executive Vice President and Chief Operating Office of EOI.

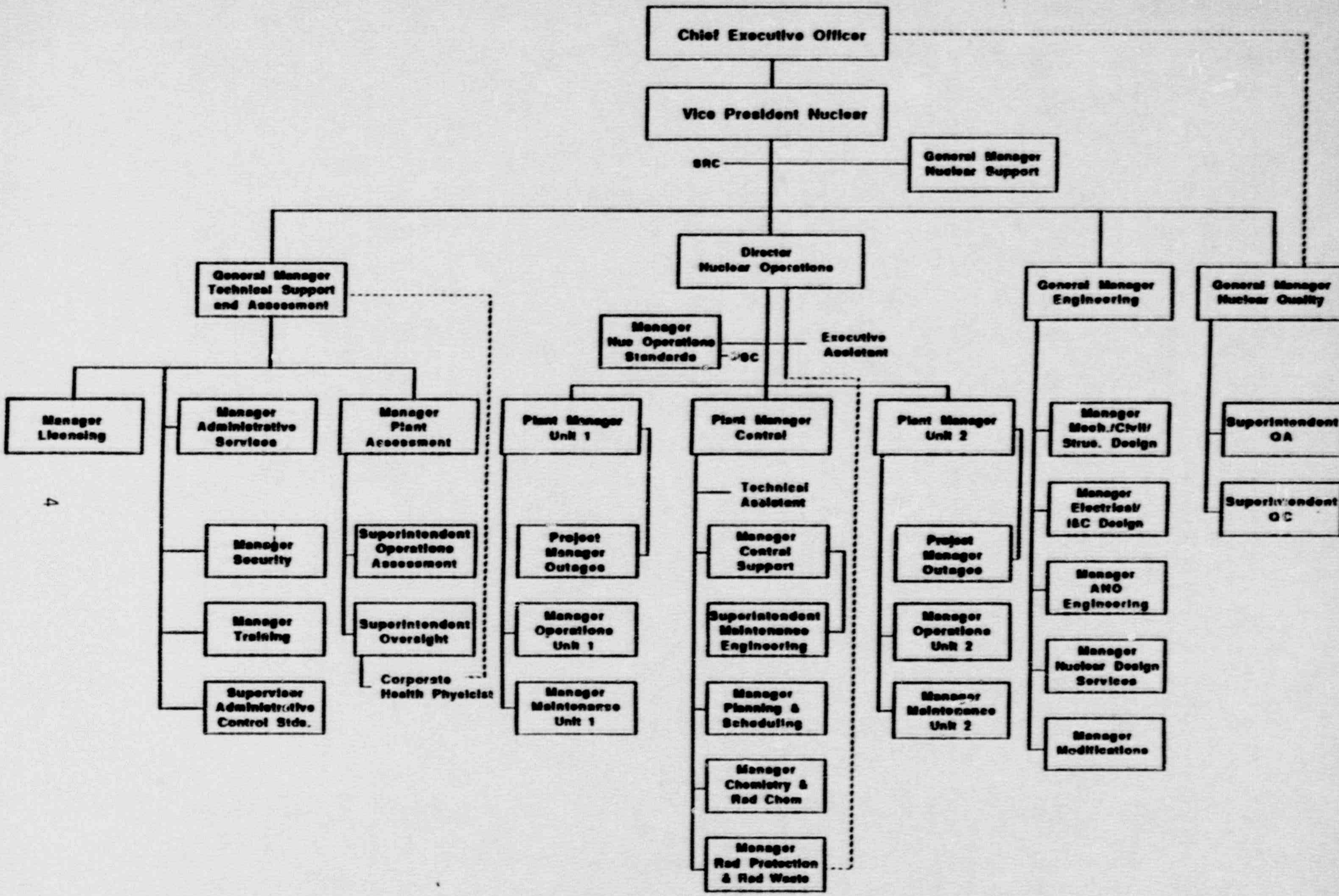

Figure 1.1-1 Arkansas Nuclear One Organization

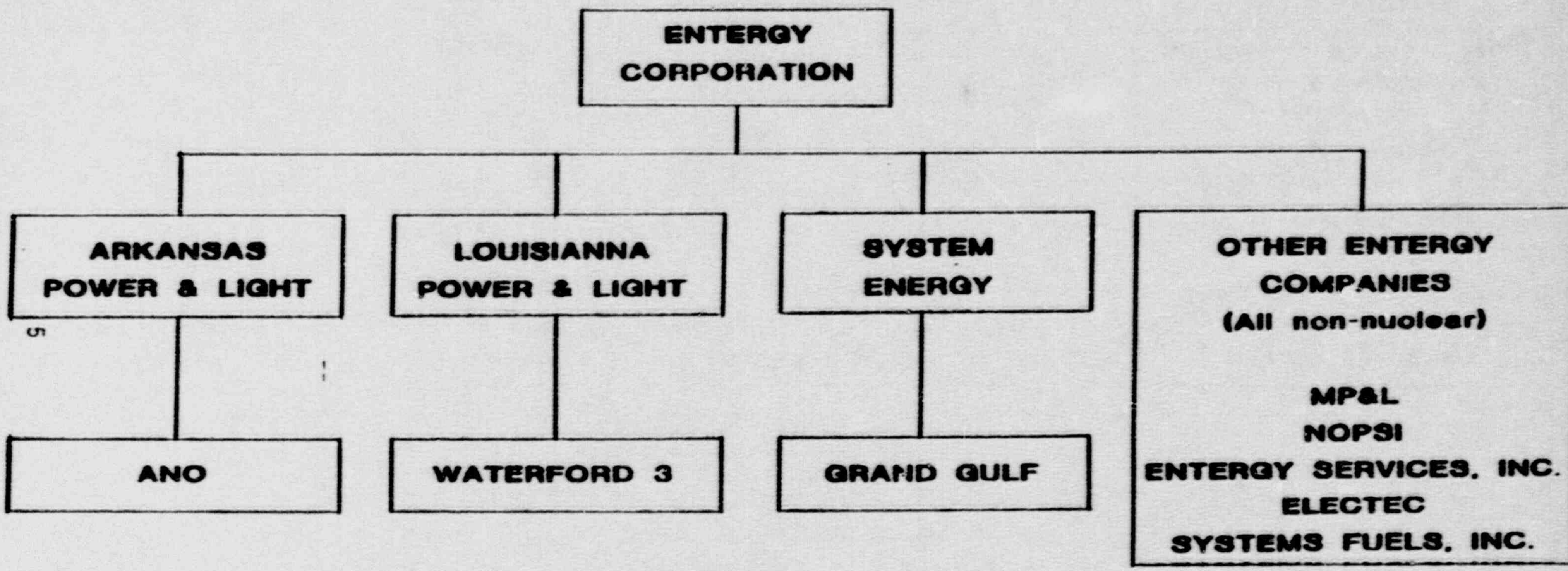

Figure 1.5-1 Entergy Corporation Organization (Present)

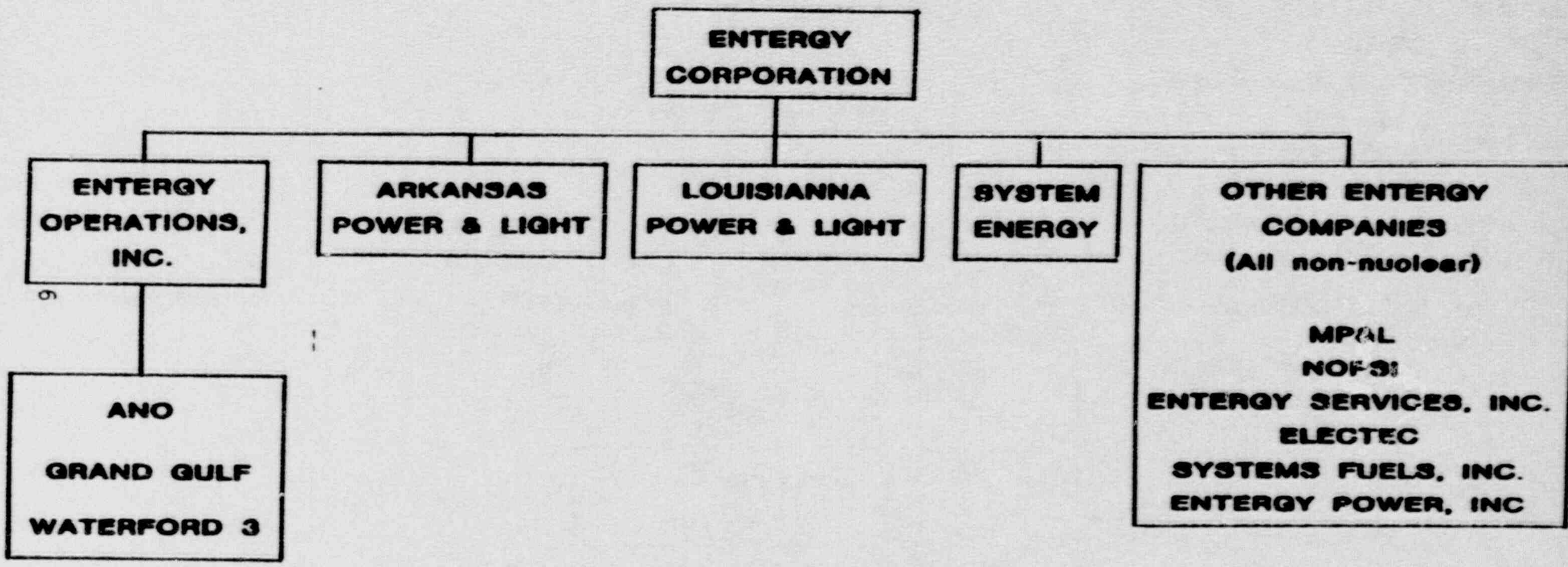

Figure 1.5-2 Entergy Corporation Organization (Future)

2.0 EVALUATION RESULTS

2.1 Findings and Conclusions

At the time of the DE, AP&L and ANO were in a period of transition that had resulted from a number of management changes and an organizational restructuring. The structural changes were substantially complete, even though the new organization was still learning to work together as a team and to deal with the numerous issues confronting it.

Corporate involvement in the oversight of plant activities had improved as indicated by the Nuclear Vice President's role and involvement in the management and organizational changes. The new site management team was more visible in the plants, was emphasizing personal accountability and was committed to improved teamwork and communications. However, some of these initiatives were not fully implemented and not all of the commitments had been effectively communicated to plant personnel. For example, clear guidance for entering Technical Specification Limiting Conditions for Operations for maintenance activities had not been provided to the plant operators.

The functional areas of maintenance, operations and engineering support continued to be adversely impacted by longstanding design basis and configuration documentation problems. Although significant progress had been made, weaknesses still existed in the design and engineering support areas. For example, several design and operational problems were identified during the team's review of the service water system, several of which were similar to those identified during ANO's 1989 self-assessment of the Unit 1 Decay Heat Removal System. Programs existed or had been identified to address these problems, but in many cases their implementation had met with delays due to resource and scheduling conflicts. Corrective and preventive maintenance support was found to be weak, which, among other things, adversely impacted the plant material condition and operating performance. These maintenance weaknesses were cause by material control problems, including the lack of qualified spare parts; poor tracking and trending; poor communications and coordination with Engineering and Operations; weak root cause determinations; and inefficiencies in the planning and scheduling of maintenance work.

The new management team had taken steps to address the cultural issues and influences that had adversely affected plant performance in the past. For example, the new managers from outside the ANO organization were implementing policies and establishing performance standards that were having a positive effect on the staff. The licensee had also made progress in its efforts to improve communications with the NRC, for example, by emphasizing safety over the regulatory aspects of equipment operability determinations.

Assessments by outside organizations had not been sufficiently critical of the performance of ANO. The licensee's weak self-assessment and root cause analysis efforts, combined with the results of these outside assessments, contributed to a sense of complacency on the part of the licensee regarding its overall performance and the adequacy of corrective actions. Although progress had been achieved, there was still evidence that plant staff and managers were willing to accept poor material conditions, marginally functional equipment and degraded system performance. Repair efforts seemed to focus on restoring equipment to service at the expense of effective long term corrective actions.

Strengths were noted in the experience level and number of licensed operators as well as the management commitment that existed for a quality training program. Overall, the recent management changes and initiatives were having a positive effect, but a number of areas needed increased management attention. These included (1) identification and resolution of equipment problems with the highest safety-significance and potential impact on plant operation and on operator performance, (2) resolution of the plant design-basis and as-built configuration problems, (3) establishment of resource commitments and priorities to more expeditiously resolve longstanding maintenance, engineering and materials control problems, (4) implementation of better performance monitoring, self-assessment and root cause analysis efforts, and (5) increased emphasis on teamwork, communications and accountability among ANO organizations.

The findings and conclusions for each evaluated area are summarized below. A reference is made to the appropriate report section for additional details.

2.1.1 Management and Organization

1. There had been weak corporate level leadership, oversight and involvement in site activities and in some cases corporate guidance and directives did not always reach the supervisory and working level staff members. These weaknesses coupled with the management style of senior site management contributed to plant performance problems. Following the reorganization, the Vice President, Nuclear had become more involved in the operation of ANO and the various improvement programs including the unitization of plant functions, the recruitment of new managers, the development of station goals and objectives and the development of the Composite Action Plan following the Unit 1 1R8 outage. (Section 3.1.3)

2. Top site management had placed a limited emphasis on high individual and organizational standards of performance. It had relied extensively on programs and administrative controls to accomplish its objectives and did not ensure the needed level of direct personnel communication required for success. In early 1989, following a number of management changes, there were improvements in the quality and extent of management leadership and direction. (Section 3.1.3)

3. The licensing organization had heavily influenced operational decisions which emphasized legalistic positions that supported uninterrupted plant operation and minimized the consideration of regulatory concerns. Management was making progress in improving communications and cooperation with the NRC, for example, as in their efforts to emphasize safety over the regulatory aspects of equipment operability determinations. (Section 3.1.4)

4. Organizational culture was in transition. Management had begun to grasp the nature and extent of the cultural issues and influences and had taken steps to address their adverse impact on performance. However, there was still evidence that plant staff and managers accepted deficient conditions, including equipment out-of-service, rather than pursuing aggressive and effective corrective actions.. (Section 3.1.1)

5. The restructured organization and management changes which consolidated engineering functions, unitized plant activities and hired/rotated middle

and upper managers were substantially complete and appeared responsive to past problems. However, staffing issues and continuing communication/coordination problems detracted from the effectiveness of the changes. In addition, plant-wide policies, guidance and expectations were still not well defined or controlled. (Sections 3.1.2 and 3.1.3)

6. While some segments of the staff remained skeptical that the involvement and responsiveness of the new management team would continue beyond the short term, many among the staff were optimistic and positive about the new leadership and generally supportive of their initiatives. (Section 3.1.3)

7. A comprehensive list had not been developed of those equipment problems with the highest safety-significance and potential impact on plant operation and on operator performance. Therefore, an action plan with established priorities and resource commitments to resolve those problems did not exist. This contributed to a reactive approach to problem solving which was further exacerbated by the large backlog of work, competing priorities of major improvement programs, and emergent equipment problems. Certain issues involving questions of equipment operability had not been recognized or adequately addressed. (Section 3.1.4)

8. The Work Control Center (WCC) had been a major obstacle to the effective prioritization and scheduling of inplant work. Competing priorities among operations, maintenance and the WCC management were not well managed. Since the reorganization, planning and scheduling were assigned to the manager having the responsibility for implementation of maintenance activities which resulted in improved communications and coordination of work priorities between operations, maintenance and the planning and scheduling groups. (Section 3.1.5)

9. Management initiatives and improvement programs existed to address most of the significant issues at ANO, but the successful implementation of the these programs often met with delays as a result of resource issues and/or a lack of management emphasis. (Section 3.1.6)

10. Assessments by outside organizations, had not been sufficiently critical of ANO's performance. The licensee's weak self-assessment and root cause analysis capabilities combined with these other assessments contributed to a sense of complacency on the part of the licensee regarding its overall performance including the adaquacy of corrective actions. (Section 3.1.4)

2.1.2 Operations and Training

1. The experience level and number of licensed staff for both units was considered a strength and consisted of six crews on an 8-hour shift rotation, which reduced operator overtime. The shift rotation allowed for one standby shift that was available most weekdays to assist in administrative and support functions. (Section 3.2.2)

2. Control room activities were conducted in a professional manner. Annunciator alarms were properly announced and acknowledged. Shift relief and turnover were performed in a thorough and discipline manner. "Red

zones" were established for critical control room areas and were effective in limiting personnel access and distractions to the control board operators. (Section 3.2.3)

3. Weaknesses in operability determinations were identified which were attributed to a general lack of knowledge by operations personnel and demonstrated a need for training in this area. In addition, administrative guidance provided by management to operators for making operability determinations was weak and in some cases appeared nonconservative. Licensing had maintained an informal handbook of previous determinations which was available for use, but these had not been reviewed or approved by engineering or station management. (Section 3.2.3)

4. The shift supervisors (SSs) demonstrated adequate leadership during control room and plant operations, shift turnover meetings, and during simulator exercises. However, during the day shift, the SS spent approximately 75 percent of his time processing job orders, which detracted from his primary responsibility to supervise and monitor plant operations. (Section 3.2.3)

5. There was no administrative procedural guidance for the use of station logs. For example, Limiting Conditions for Operation (LCO) log entries were not made for surveillance testing that removed equipment from service. This could result in multiple trains of safety-related equipment being simultaneously removed from service. In addition, the standards of observation and acceptance by the Unit 2 auxiliary and waste control operators during the performance of their rounds were not thorough and concentrated only on plant areas where log taking was required. (Section 3.2.3)

6. No management guidance existed for the use and control of the night orders which the Operations Managers used to convey information to the operating shifts. This resulted in informal communications (i.e., unsigned and undated statements) that had the potential to be misinterpreted by the operating crews and were known to have circumvented the standard operating procedures. (Section 3.2.3)

7. Numerous problems with plant equipment had existed for an extended period. Poor equipment reliability and availability placed an excessive burden on the operators, degraded safety margins and challenged safety equipment. A number of examples were identified where plant management appeared to live with equipment problems rather than pursue aggressive and effective corrective action. (Section 3.2.4)

8. Although housekeeping practices in visible and accessible areas of the plant were generally good, less traveled areas were found considerably more cluttered and less organized with consumables, debris, and unstowed and unsecured equipment very much in evidence. Many deficiency tags were observed identifying equipment which needed maintenance and other visible conditions which required repair. (Section 3.2.4)

9. Operator adherence to procedures appeared to be adequate, and adequate control existed to ensure that operations personnel were being provided

the correct documents for the conduct of day to day operations. However, several examples of procedural deficiencies were identified as needing correction and which were known by plant personnel to exist. The apparent lack of corrective actions for these known procedural deficiencies was considered to be an additional indication of a willingness by plant personnel to accept known problems. (Sections 3.2.5 and 3.2.6)

10. Independent verifications (IVs) were performed only for isolation valves in safety system major flowpaths. This did not include containment penetration vent and drain valves and did not appear to encompass the intent of NUREG-0737, Three Mile Island (TMI) Action Plan Requirements, Item I.C.6, regarding IV. In addition, existing IVs contained in plant procedures only addressed the specifics that were implemented in 1980 to satisfy TMI Action Plan Requirements. This would tend to negate the intent of NUREG-0737, Item I.C.6, in that systems added or modified after 1980 would not be covered by the IV process. (Section 3.2.6)

11. The procedure for controlling temporary modifications was not being effectively implemented. A majority of the temporary modifications were found to be in place for greater than 90 days and were not being periodically reviewed as required by procedure. (Section 3.2.6)

12. The integrity of valve lineups was negated because of the excessive use of exceptions. This raised the potential for incorrect system lineups that could impact plant and personnel safety. (Section 3.2.6)

13. The operator training program was well organized and comprehensive, and received strong management support. However, a concern was expressed by the instructors regarding strained resources which could impact the overall quality of the training program. The replacement and requalification training programs were effective in developing and maintaining knowledgeable, skilled, and competent operators. Simulator improvement programs were effective in maintaining a high degree of simulator fidelity with that of the control rooms of the respective units. (Section 3.2.7)

2.1.3 Maintenance

1. Although some staffing increases for mechanical and instrument and control (I&C) maintenance were approved in the 1990 budget, it was not clear that sufficient resources would be available to address deficiencies in the technical support area, reduction of the job order and modification backlog, implementation of the preventative maintenance (PM) program, and completion of the reorganization. (Section 3.3.1)

2. Morale within each maintenance group was good, and craft and technician personnel appeared to be competent and knowledgeable in performing their jobs. (Section 3.3.1)

3. Corrective maintenance was weak overall, and inadequate for much equipment, including some safety-related components. A number of areas were identified where longstanding repetitive problems existed, where corrective actions were apparently ineffective and where the licensee was unable to effect a permanent fix. In addition, there were a number of

related weaknesses involving lack of tracking and trending of equipment problems, poor root cause analysis, lack of timeliness of corrective actions, lack of effective plant engineering involvement, and poor quality and retrieval of maintenance history files which significantly impacted the effectiveness of maintenance activities. (Sections 3.3.2 and 3.3.11)

4 The unavailability of spare parts and spare parts control were predominant contributors to the existing maintenance problems. Other deficiencies identified in material management included inadequate control of shelf life for relays and improper dedication of commercial grade components. (Section 3.3.7)

5. The large number of maintenance job orders was excessive and had significantly increased within the last eight months. The lack of concerted action by management, unavailability of spare parts, and the lack of meaningful tracking mechanisms and clear goals for managing and reducing the backlog were significant contributors to the backlog problem. (Section 3.3.4)

6. Preventive maintenance was weak overall. A number of examples were found of inadequate PM procedures that involved the failure to use equipment history, the absence of PM on some safety-related equipment, nonconservative maintenance frequencies and poor management oversight and involvement. A new PM program was being developed; however, the schedule for implementation had been extended several times and completion was at least a year away. Predictive maintenance programs were in place for vibration and lubricant analysis; however thermography analysis was only in its formative stages. (Section 3.3.3)

7. Despite an extensive program for periodically inspecting and lubricating motor-operated valves (MOVs), the program for ensuring reliable MOV operation was weak due to poor root cause analysis, inadequate communication between maintenance and engineering, and poor evaluation and incorporation of industry operating experience. In one case, plant operations continued without an engineering analysis, inspection or testing for potentially defective melamine torque switches in MOV operators. (Section 3.3.2)

8. A number of weaknesses were found in the planning of maintenance and in the preparation of work packages. For example, work packages did not always contain or reference the appropriate drawings, and craft personnel did not always verify that the correct drawings had been provided in the work packages. Drawing verification problems had been previously documented in quality assurance (QA) audit reports. (Sections 3.3.5 and 3.3.8)

9. In general, maintenance procedures, with the exception of PM procedures, were found to be adequate, although no specific procedures or guidelines were established for generic, post-maintenance testing. (Section 3.3.6)

10. Quality Control (QC) involvement in corrective maintenance activities was weak. Because of minimum participation in job order preparation and poor

assessment methods for identification of equipment problems, the QC Department effectiveness in supporting maintenance was significantly limited. (Section 3.3.9)

2.1.4 Surveillance and Testing

1. Inservice Testing (IST) was adequate and, with the exception of a few weaknesses, was a technically sound and competently executed program. (Section 3.4.1)

2. Surveillance and testing program weaknesses included the omission of some required tests such as for the Unit 2 service water (SW) pumps, the lack of design minimum performance criteria for pumps, weak evaluation of trending data and insufficient engineering support. (Section 3.4.1)

3. Inservice testing (IST) procedural deficiencies included a failure to document the cause of adverse trends, a failure to coordinate the trending effort with operations, errors or omissions in referencing procedures for component tests, and the lack of criteria for determining the need for revised test reference values. (Section 3.4.2)

4. Several TS surveillance tests were not performed when required during 1988. A new tracking system had even placed in operation, but recently, tests were again missed indicating the need for continued management attention.

5. For both units, the ASME IST program specified maximum allowable stroke times for several valves that exceeded the normally expected stroke time and, therefore, served no purpose in identifying significant degradation or failure. (Section 3.4.2)

6. Test data evaluations were weak in some instances and included nonconservative, incompletely resolved and undocumented operability determinations. (Section 3.4.6)

7. Program improvements included the addition of new test instruments, the testing of check valves, completion of upgrading the Unit 1 ASME IST program and initiation of an upgraded review for the Unit 2 ASME program. (Section 3.4.2)

2.1.5 Design and Engineering Support

1. Organizational and management changes at AP&L beginning in late 1987 had initiated broad improvements in the previous poor design and engineering support to ANO. Initial improvements focused on teamwork and communication between Engineering and ANO Nuclear Operations. These changes had split nuclear and fossil/hydro design engineering, and nuclear design engineering management was changed to report to the nuclear vice president. Subsequent changes in early 1989 consolidated engineering at ANO (except for maintenance engineering) and nuclear design engineering at the Little Rock General Office (LRGO) under a single General Manager reporting to the nuclear vice president. (Section 3.5)

2. Engineering personnel were, for the most part, competent and conscientious with expertise in their discipline. There was, however, a lack of systems knowledge in the system engineer group and the LRGO. Engineering had recently shown the capacity to address complex technical problems in a timely and conservative manner once resources were assigned and focused, as evidenced by efforts related to the high pressure injection (HPI) backflow event in early 1989. This effort was made possible with strong contractor support. (Section 3.5.1)

3. There were a number of continuing weaknesses in design and engineering support. The overall trend, except for staffing in Design Engineering, was improving. Recruitment and retention of Design Engineering staff were considered by management to be significant problems and hindrances to the success of improvement programs. (Section 3.5)

4. Morale was low among many nonsupervisory personnel. The reasons for low morale at the LRGO included plans to move to the site, pay scales (fossil vs nuclear and contractors vs employees) and the large workload and backlog. The reasons at the plant were partially due to the large workload and backlog. (Section 3.5.1)

5. Communications between Engineering and other ANO organizations had improved as the result of programs such as the system engineer program, the 2-week schedule and the 18-month plan. Communications within Engineering and with other ANO Departments were still weak in some instances. (Section 3.5.2)

6. The CRS initiated in 1988 was a significant improvement in problem identification and tracking of engineering problems. Prior to that, several systems were used that resulted in different priorities and a lack of focus on significant safety issues. Due in part to these problems, many events and problems were significantly late (months to years) in being reported to the NRC, and some cases went unreported. (Section 3.5.2)

7. There was a large backlog of corrective action requests for Engineering. The engineering staff responses to condition reports assigned to them were usually adequate except for timeliness. However, if engineering was not assigned the lead for a CR involving engineering problems, their involvement in operability determinations, root cause analyses and final resolution was sometimes weak due to both programmatic restraints and a lack of teamwork. (Section 3.5.2)

8. Issues identified in NRC or industry correspondence were frequently not reviewed adequately or documented in a timely manner by the responsible review group. Engineering involvement in the evaluation process was weak due to programmatic weaknesses, staffing deficiencies and lack of teamwork. (Section 3.5.2)

9. The development of new and revised procedures for the coordination of LRGO and ANO activities and the creation of the Modifications Section had significantly improved the design change and modification processes. A notable feature of the process was a detailed critique of each completed DCP. (Section 3.5.3)

10. Engineering supervisors and managers failed to fully recognize the safety-significance of SW system waterhammer and SW pump snap ring problems or to take adequate and aggressive compensatory and/or corrective actions. (Section 3.5.4)

11. Many of the ongoing problems at ANO could be traced to the poor documentation and control of the design basis and associated design configurations. The deficiencies were compounded by the lack of documentation turnover from the A/E after construction and by poor documentation of modifications during the first several years of operations. A major design basis documentation upgrade program was recently initiated. (Section 3.5.6)

12. The SW systems at ANO had a long history of problems. The response to some of these problems had been extensive, but was usually reactive in nature. The team identified several current examples of design and/or construction deficiencies; lack of design basis documentation; lack of configuration control; failures to promptly evaluate industry feedback; procedural deficiencies; failures to perform root cause analyses; and a failure to fully recognize the significance of a safety-related issue and take prompt and aggressive corrective action. The Service Water Integrity Plan (SWIP) was a recent attempt by AP&L to address SW system problems in a coordinated, timely and proactive manner. (Section 3.5.4)

13. Weaknesses in the AP&L valve program that raised operability questions included: inadequate MOV design torque, deficient voltage calculations for direct current MOVs, recurring check valve failures, failure to perform engineering studies of check valve problems, and inadequate sizing of backup air supplies to air-operated valves. (Section 3.5.5)

14. Discrepancies existed between the circuits in a safety feature control panel and the design drawings. One discrepancy would have resulted in two SW pumps failing to restart following ESF actuation and a slow transfer from station power to offsite power. The cause of the miswiring appeared to be a failure to properly implement field modifications, lack of adequate QC during construction and subsequent circuit modifications, failure to correct known wiring deficiencies and an inadequate testing program to detect extraneous sneak circuits. No concerted effort existed at ANO to take effective and timely corrective actions to correct the as-built electrical deficiencies. (Section 3.5.5)

15. The Engineering Department had initiated numerous improvement programs. Some initiatives suffered from a protracted schedule and a lack of priority and management attention, such as the PM and lubrication programs. The scope of a problem continued to grow in some cases and this also contributed to delays in some programs, such as resolution of the original as-built drawing and calculational discrepancies for Class 1 piping and supports. Other initiatives reflected recent generic industry problems, such as the secondary pipe wall thinning program. Finally, some initiatives were proactive in nature such as the safety system functional inspections. The resources required to support improvement programs represented approximately 18 percent of the AP&L nuclear engineering staff and 50 percent of the large engineering contractor staff. (Section 3.5.6)

2.2 Root Cause Analysis

Based on the team's assessment of management effectiveness and ANO performance, the root causes of the licensee's performance problems were (1) weak corporate leadership, oversight and involvement coincident with a period of site management weaknessess, that had resulted in poor cooperation and teamwork among ANO organizations and a lack of accountability and ownership within the staff, (2) the lack of a clearly documented plant design basis which adversely impacted corrective action programs, (3) inadequate maintenance and engineering support to the plant that adversely impacted plant performance, and (4) a sense of complacency regarding plant performance and a willingness to live with material and equipment problems, both of which resulted from various cultural issues and influences, including (a) a lack of outside experience with high industry performance standards, (b) a compliance versus safety approach to problems, (c) weak self-assessment and performance monitoring efforts, and (d) previous assessments by outside organizations which had not been sufficiently critical.

The previously weak corporate level leadership, oversight and involvement in ANO site activities, coupled with the weaknesses of the site management, contributed to poor plant performance that became evident during the Unit 1 1R8 refueling outage in late 1988. Site management previously had placed little emphasis on individual high standards of performance and had not clearly defined or communicated safety goals, priorities or expectations to the staff. Conflicts between site organizations existed as highlighted by the Work Control Center's authority to control and prioritize plant maintenance and repair activities rather than the line organization. This further exacerbated the poor sense of ownership within the plant staff, and undermined the cooperation and teamwork between groups. Site management was viewed as unresponsive to problems and the plant material condition worsened as the number of unresolved equipment problems increased.

ANO Units 1 and 2 are relatively old plants having received their operating licenses in May 1974 and July 1978, respectively. Due to a number of reasons, there was a lack of documentation turnover from the Architect Engineer following the construction period. Many of the current problems, as well as those experienced through the years, could be traced to the poor documentation and control of the design bases and the associated design configurations. The as-built electrical deficiencies identified by the licensee in its field inspections of switchgear in early 1988 and by the DET in control room safety system design drawings, which had existed since 1974, are examples of those problems.

A major factor adversely affecting the engineering support to the plants was the fact that until late 1987, the Design Engineering section at the Little Rock General Office (LRGO) was combined with fossil and hydro engineering and reported to a vice president other than the nuclear vice president for ANO. Two Engineering Department reorganizations within 18 months prior to the DE split nuclear and fossil/hydro engineering and consolidated ANO Engineering, Modifications and Design Engineering under a single General Manager of Engineering reporting to the nuclear vice president. Prior to these changes, ANO Engineering and Maintenance groups competed with other non nuclear AP&L organizations for design engineering support and the quality and timeliness of that support were often poor. Therefore, when engineering and maintenance problems occurred, the plants were often forced to live with those problems or conduct repairs that did not correct the underlying causes.

The licensee's weak performance monitoring and self assessment capabilities could be attributed, in part, to the lack of experience with higher standards that existed elsewhere in the industry. In addition, a compliance versus safety approach to problems contributed to a climate that resulted in weak evaluations of plant equipment and system performance problems. Additionally, assessments by outside organizations had not been sufficiently critical of the performance of ANO. The overall results of these efforts, taken as a whole, contributed to a sense of complacency on the part of the licensee regarding its overall performance, its willingness to live with problems and the adequacy of any corrective actions.

Although positive indications of improvement were noted in increased ownership and accountability, and improved communications, the full impact and success of these changes will not be known for some time. The team found that some of these initiatives were not fully implemented and not all of the commitments had been effectively communicated to plant personnel. In addition, a critical review of existing material and equipment problems was needed to ensure that those with the highest safety-significance and potential impact on plant and operator performance are resolved on a high priority basis. Finally, increased efforts were needed to resolve the longstanding plant design-basis and as-built configuration problems which continued to adversely affect overall plant performance.

3.0 DETAILED EVALUATION RESULTS

3.1 Management and Organization

Arkansas Power & Light (AP&L) and Arkansas Nuclear One (ANO) had implemented a number of management, staffing and organizational changes, some preceding the unit 1R8 refueling outage in late 1988, and most others after that outage, continuing up to the diagnostic evaluation (DE). These changes had initiated broad improvements in management practices and organizational relationships that were still evolving at the time of the DE. Therefore, in most cases, this section usually differentiates between the past (before these changes) and the present (after the changes), up to and including the time of the DE.

The team's objective in evaluating management and organization was to identify the cultural, management and organizational factors that affected past performance, and to the extent possible, evaluate those organizational, cultural and personnel changes that had occurred.

The evaluation of management and organization was based on approximately 160 structured and unstructured interviews with licensee staff, managers and corporate officers; direct observation of management and staff activities; and extensive review of documents including reports, plans, policies, employee newsletters, memoranda, manuals and audit reports. Issues addressed were those that contributed to (strengths) or detracted from (weaknesses) plant safety performance and included the following: organization; culture and climate; leadership and direction; problem solving and decisionmaking; planning and scheduling; and human resource utilization.

3.1.1 Culture and Climate

Culture is a group or organizational phenomenon defined for the purpose of the ANO evaluation as the shared beliefs or values that lead to behavioral and performance norms and expectations of the members. Culture is typically influenced by the experience, training, and personalities of managers and staff; attitudes; values; and the group's perception of themselves as members of the plant community, the company at large, and the local community. The purpose of examining culture was to determine the impact of culture on the behavior and performance of ANO staff. The team relied heavily on interview results in its assessment.

The predominant cultural issues and influences which existed prior to and during the extended 1R8 outage included:

- A general perception among workers and lower level managers that upper management did not want to hear about problems, and would not be responsive to those problems which were brought to their attention. Resigned to the notion that plant problems would not be addressed, the staff developed a willingness to tolerate degraded equipment, inadequate administrative support and large work backlogs.

- A production emphasis that manifested itself in weak operability determinations and a reluctance to enter action statements. This emphasis was characterized by legalistic interpretations and inadequate consideration for regulatory requirements.

- A limited sense of ownership and accountability at all levels of the organization. Problem resolution was commonly considered to be someone else's job, to be the responsibility of some administrative program, or to require a special project staffed by contractors.

- Low morale throughout all departments and at all but the highest levels of management, particularly among members of the bargaining unit, following failure to reach a negotiated labor agreement.

- A lack of cooperation among departments. Teamwork in pursuit of a common goal was generally absent.

- Evidence of erosion of the work ethic and declining individual pride in job quality and plant performance and appearance.

The team found the organizational culture to be in transition. Management had begun to grasp the nature and extent of these cultural issues and influences and had taken steps (Section 3.1.3.1) to address them and their impact on plant performance. However, there was still evidence that plant staff and managers accepted deficient conditions, including equipment out of service, rather than pursuing aggressive and effective corrective actions. This was considered to be an issue requiring increased management awareness and attention.

In general, station morale appeared to be up from the lows indicated by a company-wide survey in early 1989. Bargaining unit morale was improved somewhat following favorable contract settlement and optimism existed that elimination of the Work Control Center (WWC) would reduce the administrative obstacles to getting work done. However, morale was found to still be low in some organizational units. Among design engineers, concern over the pending move to the site had severely affected morale and had increased turnover. In addition, the absence of a pay differential for nuclear work, considered by engineers to be more demanding than fossil work, also contributed to low morale among design engineers. Plant engineers were discouraged by the workload and by their inability to reduce backlogs because of staffing shortages. Unit 1 operators assessed their morale as improved from its low point during the 1R8 outage although somewhat lower than that of Unit 2; but they remained skeptical noting that most of the immediate management in their unit had not changed with the reorganization, and they were cautiously awaiting a demonstration of improved responsiveness. Senior Reactor Operators (SROs) were disappointed over the phase-out of the college degree program. The team determined that while most individuals felt ANO provided above average earnings for the geographic area and reasonable working conditions, there was no strong evidence of company loyalty or sense of common goals. Pride in craftsmanship, productivity, or plant appearance was not evident.

There was a mood of cautious optimism and a declining sense of skepticism in response to management's increased visibility, openness, and responsiveness. The staff appeared to be looking forward to determining whether management's actions would be consistent with their announced plans to improve managment practices and policies, and station performance. There was evidence of a general willingness to participate in and contribute to those efforts.

3.1.2 Organization

3.1.2.1 Site Organization Restructuring

Prior to the reorganization, management of both units had been combined under a single plant manager. In May 1989, the onsite organization was restructured in an effort to consolidate functions, improve distribution of resources, and increase managerial involvement and ownership.

Under this restructured organization, individual unit Plant Managers were responsible for operations, maintenance, and outages for their unit (see Figure 1.1-1). A Plant Manager, Central, oversaw planning and scheduling, mechanical, electrical, and instrument maintenance, maintenance engineering, chemistry, and radiation protection. The Maintenance Department, at the time of the evaluation, had not yet been fully unitized and most of the craft personnel reported to the Plant Manager, Central. Therefore, the interface between the three Plant Managers (Units 1 and 2 and Central) required sharing of craft resources, and the upcoming 2R7 refueling outage on Unit 2 was viewed by management as a challenging test of the new organization and the ability of the managers to share those resources.

All three Plant Managers reported to the Director, Nuclear Operations, who in turn reported to the Vice President, Nuclear. Also reporting to the Vice President Nuclear were General Managers of Nuclear Quality, Technical Support and Assessment, Nuclear Support, and Engineering. There was a general understanding among these groups (no written policy existed) that although all reported directly to the Vice President Nuclear, each group had as their primary responsibility the support of operations.

Under the restructured organization, all engineering functions with the exception of maintenance engineering were consolidated organizationally and scheduled for physical consolidation on site. This consolidated Engineering organization resulted in improved engineering support to the facility, as described in Section 3.5.1.3.

In addition to the restructuring of organizational relationships, the reorganization included an infusion of new managers at the middle and upper levels and reassignment of several others. At the time of the DE, 36 key positions had been filled by newly hired or reassigned managers, including Director, Nuclear Operations; Unit 2 Plant Manager; Plant Manager Central; Manager, Nuclear Operations Standards; Manager, Licensing; Unit 1 Project Manager, Outages; and Manager, Central Support, who controlled all maintenance personnel. These managers and their philosophies generally were being well received by the plant staff. These philosophies included increased personal and organizational accountability, ownership of problems, a cooperative and communicative relationship with regulators, procedural adherence, improved teamwork and communication between station management and staff, and increased personal productivity with emphasis on pride and craftsmanship. These initiatives were in their early stages of development and implementation and, therefore, only a preliminary assessment of their impact on organizational cultural and plant performance was possible.

A few key managers from the previous organization were reassigned to other management positions in the restructured organization. Examples included the

Unit 1 Plant Manager and the Unit 2 Project Manager, Outages. Including these experienced managers in the new structure had the positive effect of retaining valuable corporate memory and technical knowledge within the organization. The management philosophies of these managers were found to be consistent with the philosophies espoused by the newer managers. The planned transfer of the Vice President, Nuclear, from the LRGO to the site was expected to strengthen communication and coordination of priorities and activities.

The licensee acknowledged that the organizational structure was likely to undergo minor revisions in the near term. The team found the unitization of plant staff and the consolidation of engineering functions were well researched and developed through the use of task force analyses and expert consultants. However, for certain technical groups and functions important to plant improvement, the reporting relationships appeared to be evolving. Examples included system engineers, maintenance engineering, and unitized, rather than station-wide, plant assessment capability.

The team concluded that the restructured organization and management changes that consolidated engineering functions, unitized plant activities and hired/rotated several middle and upper managers espousing new philosophies were substantially complete and appeared responsive to past problems. However, staffing issues that included delays in filling key positions with qualified personnel and continuing communication and coordination problems between groups detracted from the effectiveness of the changes. For example, although the organizational structure placed significant responsibility on the system engineer concept to facilitate problem resolution and coordination between groups, and systems were assigned on paper, the dedicated system engineer group was, at the time of the evaluation, significantly understaffed and undertrained. The licensee referred to most of these engineers as "responsible" engineers pending their qualification on assigned systems. Staffing concerns are discussed in more detail in Section 3.1.7.

3.1.2.2 Corporate Restructuring

The team qualitatively evaluated the degree to which budget restraints at ANO might have adversely affected safety operations and plant performance. The team conducted interviews with plant and corporate line managers and staff members, and reviewed budget and cost documents.

Although no specific instances were identified in which corporate financial concerns resulted in safety significant work or programs being neglected, ANO was found to be under some financial constraints. For example, in an effort to control rates and attract industry to the service area, the operating and maintenance (O&M) budgets had been frozen at 1988 levels through 1990. The decision by the Federal Energy Regulatory Commission (FERC) to assign 36 percent of Grand Gulf's construction and operating costs to AP&L imposed additional financial pressure to minimize expenditures. The AP&L Board of Directors had been generally responsive to the Vice President's requests for funding of capital budgets and staffing increases and the team concluded that the corporate reorganization would not be expected to result in any decrease in the necessary financial resources available to ANO.

3.1.3 Leadership, Direction, and Control

The team concluded that in the few years preceding the Unit 1 1R8 outage, there had been weak corporate level leadership, oversight and involvement in site activities and that in some cases corporate guidance and directives did not always reach the plant supervisory and working level staff members. These weaknesses at the Vice President, Nuclear level coupled with the management style of the top site managers contributed to the performance problems of ANO. In the past, top site management had placed little emphasis on individual standards of performance. Programs and administrative controls were relied on extensively to accomplish objectives. This management style did not ensure the needed level of direct, personal communication of goals or the personal accountability and ownership required for success.

The plant staff described the previous environment as stifling to creativity, enthusiasm, and teamwork. Many decisions which could have been made at lower levels were made by top site management, including authority to enter contracts, procedure changes, and approval of all employment interviews, candidates and hiring decisions.

3.1.3.1 Leadership and Direction

Although the involvement and effectiveness of the Vice President, Nuclear had been lacking prior to the restructuring, and was not sufficient to compensate for the site management problems, the team concluded that he had become more involved in a leadership role in the operation of ANO and the various improvement programs. Following the 1R8 outage, he assigned a committee of five senior ANO managers to conduct an investigation of the environment which existed at ANO during 1R8, and to identify the root and contributory causes of the management, equipment and performance problems that occurred. Based in large part on the results of that investigation, the organizational and personnel changes described in Section 3.1.2 were made, and other initiatives were started including the unitization of the plants; the recruitment of new managers from outside AP&L; the development of station goals and objectives; the successful labor contract negotiations; and the development of the Composite Action Plan (CAP). The Vice President, Nuclear communicated effectively with managers through the chain of command, and was known to seek information directly from personnel throughout the plant. The team concluded that he was aware of the issues confronting the facility; had a good understanding of the strengths and weaknesses of individual staff members; and had a commitment to emphasizing personal accountability and to pushing decisions to the lowest appropriate level in the organization. However, the team found that some of the initiatives were not yet fully implemented and some commitments had not yet been effectively communicated to plant personnel, as discussed in the following sections.

Following the organization restructuring and management changes in early 1989, the team found that there were improvements in the quality and extent of management leadership and direction. Under the leadership of the new Director, Nuclear Operations, plant management was found to be more visible in the plants and more communicative. There was an increased emphasis on teamwork and communication. The plant staff described management as being more accessible, and the team identified several examples of plant staff communicating ideas and concerns directly to top site management. While some segments of the staff remained skeptical that the involvement and responsiveness would continue beyond the short-term, many were optimistic about the new leadership and generally supportive of their initiatives. Managers interfaced more directly with their staff both in the work space and in special sessions. Attempts were made to ease administrative burdens on first line maintenance supervisors to permit additional time in the plant supervising craft work. Office spaces for managers and supervisors were relocated to place groups and managers who had to work together and communicate effectively in physical proximity of each other. Daily morning planning meetings were established with structured seating arrangements designed to foster face to face interaction. Special programs, such as as-low-as-reasonable achievable (ALARA) Day and ALARA Month, with goals of reducing total station radiological exposure, were established to focus the plant's attention on a particular objective. Improved responsiveness to employee concerns was demonstrated by relocating the helicopter landing area to minimize disruption to employee parking areas and by altering security procedures to expedite employees' egress at the turnstiles at the close of the day.

3.1.3.2 Control

Although improvements were noted, at the time of the evaluation, site management had not yet conveyed clearly defined performance expectations for effective job performance to all the plant staff. However, Nuclear Operations had made limited progress in this area through publication of Nuclear Operations Directives (NODs). Ten NODs were issued between September 8 and 25, 1989, addressing many of the issues raised by the team during the evaluation. The NODs provided management's philosophy and guidance on activities such as Accountability, Conservatism in Operations, Procedure Compliance, Logs, Plant Tours, Valve Operations, Safety, Quality Performance, and Housekeeping. The team did not evaluate the initial impact or effectiveness of the NODs, but determined that their message was consistent with management's stated goals of enhancing accountability and improving the quality of operations, and that the guidance was appropriately clear and addressed known deficiencies in operating, maintenance, and outage practices.

Department General Managers had specific performance expectations related to ANO Business Plan goals, and, at the time of the evaluation, goals and objectives were in draft for managers one level below the General Manager in the Operations and Engineering Departments. Interviews with plant staff below that level indicated that while the new management philosophy was understood and accepted at the manager level, it had not been fully communicated or accepted below that level. It was generally not clear to the members of the plant staff what an individual needed to change or improve in their performance in order to support the new initiatives.

In addition, the team identified instances where management had not provided clear, unequivocable guidance for activities involving plant safety. These included guidance for entering Limiting Conditions for Operations (LCOs) for maintenance activities; adherence to operations and maintenance procedures; and control of night order entries (Section 3.2.3).

The team concluded that despite the encouraging initiatives promoted by site and corporate management, plant-wide policies, guidance and expectations were still not well defined or controlled.

3.1.4 Problem Solving and Decisionmaking

3.1.4.1 Problem Solving

As discussed in Section 3.2.4, the team found a number of material and equipment problems that had burdened the unit operators and which in some cases had led to challenges of safety systems. Management had not yet demonstrated, or fostered among the staff, an aggressive policy to identify and solve these problems. The team found that a comprehensive list of equipment problems had not been developed which management recognized as having the highest safety significance and potential impact on plant operation and on operator performance. Therefore, an action plan that established priorities and resource commitments to address those problems did not exist. For example, although operators had compiled a list of problems affecting the units, they generally had not been evaluated, prioritized or integrated with other lists such as outstanding temporary modifications, maintenance and engineering request backlogs, deficiency tag status, and regulatory commitments. Management was relying principally on the problems and priorities established by the Corporate Action Plant (CAP) and the Five Year Business Plan which did not provide the level of detail or controls considered necessary to effectively address the existing problems.

Certain issues reviewed by the team including unreliable Target Rock solenoid valves, and undersized valve operators (Sections 3.2.4 and 3.3.2.3), and service water (SW) pump snap ring failures (Section 3.5.4.7) had a protracted failure history that involved questions of equipment operability that had not been recognized fully or adequately addressed.

The team concluded that the lack of comprehensive knowledge among managers concerning the most safety significant equipment problems also contributed to a reactive approach to problem solving. The large backlog of work, competing priorities of major improvement programs and emerging equipment problems further exacerbated the situation.

3.1.4.2 Root Cause Analysis

Problem solving was hampered by inadequate root cause analysis. The team concluded that while root cause evaluations assigned to and performed by Engineering were generally thorough, those conducted by Operations and Maintenance showed evidence of weak analytical skills and an inclination to seek a conclusion that would not interrupt plant operation. The licensee had conducted some root cause analysis training, and the team noted that the quality of root cause analysis seemed proportional to the amount of training received by the individuals involved. The licensee had identified a deficiency in the condition report (CR) system process in that corrective action, job orders (JOs) and work in the field were routinely prescribed and initiated before the identified deficiency was evaluated for proximate and root causes. At the time of the evaluation, the licensee was modifying the CR process to address this deficiency.

Although plant performance indicators were published and distributed, the collection, tracking, analysis, and visibility of meaningful data were lacking. The facility's weaknesses in self-assessment and root cause analysis was illustrated by the team findings from its review of maintenance activities.

For example, maintenance data tracking systems did not provide for quantification or characterization of the work , although operators interviewed described routine instances of components undergoing repair up to 7 or 8 times before management became aware of the repetitive failures and concentrated the engineering and maintenance resources required to fix the root cause of the deficiency (see Section 3.3). Because maintenance history was often deficient, it was not used routinely to minimize errors in the repair process. Component failure analysis was generally weak and found to suffer from limited engineering resources. Problems with caustic recirc pump 2P-110, were illustrative. According to operators, with ten years of intermittent service, the pump began tripping on overload following repairs. Evidently, the operators did not recognize the characteristic of centrifugal pumps which caused tripping when a pump runs out with too little discharge pressure, and repeatedly called maintenance crews to troubleshoot and fix the problem. Once operations consulted and coordinated with Engineering, the problem was diagnosed and three corrective action alternatives were identified.

Also, discrepancies with as-built plant wiring described in Section 3.5.5.5, indicated that followthrough on CR resolution was not always thorough. Once the system engineer and maintenance engineer groups are fully staffed and functioning as planned, the CR process should be more effective.

3.1.4.3 Decisionmaking

In general, before the reorganization, most decisions were made at the highest levels of site management with few delegated down into the organization. This, coupled with delays or failures by management to reach timely decisions or to communicate decisions back to the staff, contributed to reduced personal accountability at the middle and lower levels of the organization. The opportunity for input into the decisionmaking process was limited and there was a reluctance to identify problems requiring a management decision. In addition, this tendency of senior site management to be involved in the lesser significant decisions distracted them from leadership, direction and team building.

The team determined that ANO senior management was aware of the causes and effects of the weaknesses in decisionmaking that existed before the reorganization. Emphasis was placed on the stated goal of pushing decisionmaking authority down lower into the organization, including decisions on budgets and staff selection. The emphasis on personal accountability and ownership was evident in observed work activities. A willingness to make decisions was more evident among the new managers than among those who had developed and worked in the old organization. An example was the observed actions of managers when presented with concerns over the use of "cheaters" to operate valves, described in Section 3.2.4. The decisions required to address and correct that problem were made more decisively and at a lower level in that part of the organization largely staffed by new managers.

The team found that, in the past, the Licensing organization had heavily influenced operating and regulatory decisions. These decisions were found to emphasize legalistic positions that supported uninterrupted plant operation and minimized the consideration of regulatory concerns. Management was making progress in their stated goal of improving communications and cooperation with the NRC and in their efforts to emphasize safety over the regulatory aspects, as in their equipment operability determinations. However, the licensee's actions and correspondence to the NRC following the team's identification of a 1988 Part 21 report involving potentially deficient melamine torque switches in safety-related Limitorque valve operators, which had not received timely licensee evaluation, were indicative of lingering problems in this area (Section 3.3.2.3).

3.1.4.4 Assessments by Outside Organizations

In general, assessments by outside organizations had not been sufficiently critical of ANO. A contributing factor may have been the underreporting of events by the licensee (Section 3.5.2.2). The licensee's weak self-assessment and root cause analysis capabilities combined with the results of these assessments contributed to a sense of complacency on the part of ANO, regarding its overall performance and the adequacy of any corrective actions.

3.1.5 Planning and Scheduling

Before the reorganization, the Work Control Center (WCC) was identified by the licensee as a major obstacle to the effective prioritization, coordination and scheduling of work. Competing priorities among operations, maintenance, and WCC management were not well handled. Each group worked to its own sense of urgency creating organizational conflicts. Originally conceived without the input of site department managers, the WCC suffered from poor teamwork and communications with all departments. Prioritization of work was generally uncoordinated, with virtually all work classified at the same priority and with departments generally not willing to negotiate or reassign those priorities. The difficulties associated with the WCC were considered by the licensee to be a major contributor to the problems and delays experienced during the Unit 1 1R8 refueling outage in late 1988.

As part of the reorganization, planning and scheduling were assigned to the manager having responsibility for implementation of maintenance. The results were improved communications and coordination of work between operations, maintenance, and the planning and scheduling group. Qualified Shift Supervisors (SSs) detailed to act as coordinators between operations and planning and scheduling appeared effective in coordinating plant operations and required work activities. SSs informed the team that they were now able to assert more influence on the planning process when their operating judgement indicated high priority maintenance was required. They indicated that teamwork between the groups had improved substantially.

Planning, scheduling, and prioritization of plant activities, including outages, were found to have been enhanced through direct participation of responsible site organizations at daily planning meetings. A new position of Outage Manager was created to provide dedicated outage planning for each unit. Planning and scheduling activities associated with the Fall 1989 2R7 Unit 2 refueling outage were well underway and the team determined that the process represented a significant improvement over the preparations for the 1R8 Unit 1 refueling outage. Programs to identify and control emergent work to minimize its impact on the schedule were in place. Processes were also established to ensure operations involvement in the prioritization of emergent work, and supervisory relationships had been established to provide 24 hour management oversight and to minimize delays while awaiting decisions on emergent work or action on spare parts problems. Controls were in place to provide SRO supervision of fuel vendor technicians who would actually conduct refueling, and dedicated personnel were assigned with responsibility for containment cleanliness. Early availability of engineering packages for scheduled modifications was found to exist. Segregation and staging of parts and materials to support planned maintenance work were generally weak, and licensee concerns were expressed that parts availability could impact on the outage schedule (Section 3.3.6 and 3.3.8).

Notwithstanding the observed enhancements, the team identified weaknesses in contingency planning for forced outages. Work packages, including engineering support input, were not on the shelf and available for implementation should a forced outage present an opportunity to accomplish deferred work.

For more routine work, administrative weaknesses detracted from efficient work control. For example, ready-to-work job packages were retained in the planning and scheduling offices rather than in the shops where first line supervisors who encountered delays could easily identify alternative jobs. A multiple JO concept that generated unique work packages for each craft or support group required for a particular maintenance activity further complicated the process. Parts availability was not well coordinated with planned work, resulting in work commencing on components or systems when qualified parts were not actually in stock to complete the planned work. QC was not involved in a manner that would permit early identification of work to be observed, forcing that group to spend an excessive amount of their time trying to stay abreast of work scheduled and in progress (Section 3.3.10).

Several improved scheduling vehicles were in various stages of development by ANO departments. In addition to daily work planning meetings and the outage plan, Engineering used a 2-week look-ahead schedule, a 6-month schedule, and a comprehensive 18 month engineering plan in its first revision. Improved teamwork was evident by Engineering seeking operations and maintenance involvement in the determination of priorities for engineering projects and an emphasis on setting realistic dates for scheduled completion.

3.1.6 Management Initiatives and Improvement Programs

A number of initiatives and improvement programs existed which were in various stages of implementation. The team found that the successful implementation of these programs, especially in engineering, had often met with delays due to a lack of the management attention needed to prioritize the efforts according to their safety significance and to commit the resources necessary to avoid further delays. A list of the major programs is provided below and a description of a few of the major engineering efforts is contained in Section 3.5.6.

o Incorporate ALARA efforts into design activities

o Develop a comprehensive site lubrication program

o Develop a site master plan

o Upgrade control room annunciators

- Develop a configuration management system
- Improve design configuration documentation
- Develop guidelines for instrument uncertainty and setpoint analysis calculations and reconstitute basis for various setpoints
- Resolve as-built drawing and calculational discrepancies for Class 1 piping and supports
- Develop improved materials control and acquisition program
- Improve plant security perimeter intrusion system
- Develop and implement a PM program
- Develop site specific probabilistic risk assessments
- Improve safety analyses basis documentation
- Continue and refine secondary pipe wall thinning program
- Perform self-initiated SSFIs
- Continue and enhance steam generator integrity program
- Establish guidelines and basis for structural design practices
- Review and confirm technical manual information

3.1.7 Human Resource Utilization

The licensee had emphasized human resource utilization in the organization restructuring and staffing of ANO and appeared to have a clear concept of how the new organization would function to address past weaknesses.

Managers recently recruited from outside ANO appeared to have a broad base of industry experience, plant operating backgrounds, and successful records in previous assignments. Managers recently promoted from within ANO had been generally successful in earlier assignments. The team considered that the interaction of outside experience and philosophies of the newly recruited managers with the prior experience of operating and maintaining the facility of the managers promoted from within was indicative of effective human resource utilization.

The licensee relied heavily on contractor support personnel, including health physics technicians, material management personnel, planners and schedulers, and a contractor maintenance force of approximately 200 craftspersons. For example, a review of major engineering projects staffed primarily by contractors indicated expenditures for contract personnel exceeded salaries for plant personnel in many of the identified projects, and revealed that some of the contractors had been supporting the Engineering department for several years in the same position. Problems related with this heavy reliance on contractors were a loss of corporate memory when the contracts ended and a lack of ownership of problems since the contractors did not have a personal tie to the company. Also, the longstanding contracts involving the some individuals have had a negative impact on AP&L staff because of the salary issue identified above. The licensee identified the replacement of contractors with permanent employees as a possible method of reducing expenditures and controlling annual operations and maintenance (O&M) budgets. This would also be expected to reinforce personal accountability and productivity within the organization.

In the Operations Department, the experience and numbers of licensed staff for both units was considered a strength, but competing interests for experienced licensed operators had the potential to dilute this base. Diversions to other assignments included: SRO training; the college degree program, which removed operators from the control room for periods of six months; transfers to other permanent assignments; and transfers to support assignments, such as outage planning or maintenance coordinator. The dilution of experience appeared somewhat more pronounced in Unit 2. However, the team noted the benefit to the organization of reassignment of licensed operators to other groups outside Operations. For example, a SS recently detailed as maintenance coordinator was observed to have a significant positive effect on the conduct of maintenance in his unit.

Maintenance was found to have benefitted from a low turnover rate, a strong technical training program that included oral boards as part of the journeyman certification, and an infusion of new managers at the upper levels of the organization. The maintenance crafts were a major source of staff for the QC Department which was viewed as a positive influence on that program.

There were no apparent manpower shortages among maintenance crafts, in part because of the licensee's heavy reliance on a maintenance contractor to handle work beyond the capacity of the ANO staff. However, management expressed concerns regarding craft workmanship and productivity. For example, the two units operated with a substantial maintenance backlog which was growing, but the data information system was unable to characterize that backlog to permit review for safety significance. Likewise, the system did not provide for quantification or characterization of rework (which resulted in the lack of root cause analysis in cases of recurring failure), although the team found that rework and repeat maintenance were extensive. Several impediments to productivity were identified, including parts delays; inefficient coordination of support groups required to perform a maintenance task, such as arranging for tagging, scaffolding, or health physics coverage; administrative weaknesses in the control room; the inability to recognize and therefore reduce rework; and a process for JO control which issued multiple JOs, one to each involved shop for each item of maintenance.

Design Engineering appeared to be staffed by competent engineers facing broad design-basis deficiencies and a long list of significant design problems, many of which had existed since construction. Design engineering also suffered from high staff turnover, attributed to low morale and anxiety among engineers over the planned relocation of all engineering functions to the site. This loss of engineers had depleted the collective knowledge of the department because experienced engineers were replaced by others less knowledgeable of the facility. Although additional engineer positions were authorized and budgeted, and recruiting activities were underway, the licensee had not taken adequate steps to aggressively recruit and assign design engineers to address the large backlog of design issues.

The Plant Engineering section was similarly overloaded and understaffed to complete the work assigned, even with extensive contractor support. Overtime was routine among plant engineers, whose workload was difficult to manage effectively because of the highly reactive nature of the response to CRs. Like Design Engineering, Plant Engineering had added some staff, but had not taken adequate steps to attract and hire enough qualified engineers.

Within the Plant Engineering section, the system engineers were significantly understaffed for the role envisioned for them (Section 3.5.1). While the licensee acknowledged the need for a training and qualification program for system engineers, the program had not been clearly defined or developed.

A review of training records indicated that ANO managers and supervisors had not systematically participated in training and development programs involving leadership and managerial principles and skills as they progressed through the managerial ranks. The licensee had recently begun a program for professional development for all managers and supervisors, the effectiveness of which could not be assessed during the evaluation. Senior executives participating in a separate program were receiving supervisory training and developmental assignments under individually designed development plans.

3.2 Operations and Training

Both units were operating at power during the evaluation period and no scheduled or unscheduled transients occurred. Therefore, the evaluation of operations included observations of control room and plant activities of both licensed and nonlicensed operators, tours of all areas of the facility, examination of the interface between operations and other organizations, a review of managerial involvement and effectiveness, and reviews of logs and records. Interviews of both licensed and nonlicensed operators, as well as operations management personnel, were conducted. Finally, the team evaluated the effectiveness of the operator training program by interviewing training unit personnel, observing operator training classroom and simulator sessions, reviewing requalification training programs, training and simulator facilities, training staff qualification, and management oversight and support for the training program.

The team concluded that the experience level and number of licensed staff for both units was a strength and was attributed to the operator training program which was found to be well organized and comprehensive, and received strong management support. The team, however, found weaknesses in the administrative guidance provided by management regarding operability determinations, the use of station logs, and control of night orders. Weaknesses were also found in the control of temporary modifications and independent verification of operating procedures and system valve lineups. In addition, the material condition of the plant was determined to be poor with numerous equipment problems that had existed for an extended period. These problems had, in some cases, burdened the operators and contributed to operator errors, and had also led to challenges of safety systems. Details of the teams findings and conclusions are presented in the following sections.

3.2.1 Organization

Operations was divided into separate organizations for each unit. Each operating organization was headed by an Operations Manager who reported to the Plant Manager for that unit (Figure 1.1-1). The Operations Managers for Unit 1 and Unit 2 were both licensed SROs. The Operations Manager for Unit 1 had an engineering degree and had been the Unit 1 Operations Superintendent for about 2 years. The Operations Manager for Unit 2 had been the Unit 2 Operations Superintendent for about 5 years. Six shift crews and an Operations/Maintenance Coordinator reported to each Operations Manager.

The Training Department was headed by the Training Manager, who reported to the General Manager for Technical Support and Assessment. The Operations Training Department was headed by the Operations Training Superintendent who reported directly to the Training Manager. His staff consisted of 21 instructors, 5 simulator support personnel, and 4 supervisors.

3.2.2. Shift Staffing

The team concluded that the experience level and number of licensed staff for both units, which consisted of six crews on an 8-hour shift rotation, was a strength. Each shift crew consisted of a SS and a shift SRO, who were both licensed SROs, two control room operators (licensed reactor operators), two or three nonlicensed auxiliary operators (AOs), and, a nonlicensed shift administrative assistant. The 6-shift rotation reduced operator overtime and allowed for one standby shift that was available most weekdays to assist in administrative and support functions. The use of shift administrative assistants significantly reduced the administrative burden on the SSs. A shift technical advisor (STA) supplemented the operating crews on a 24-hour duty rotation. The STAs supported routine plant operations with operability and reportability determinations when needed. The STAs held engineering degrees and had attended SRO training. Approximately 5 of the 10 STAs were licensed SROs. Another positive staffing practice was to bring in new hires at the AO level and eventually advance them to the SRO/SS.

The morale of the operating staff had improved over the recent period and Unit 1 operators assessed their morale as improved from the low point noted during the 1R8 outage, but still somewhat lower than that for Unit 2. The reasons cited for lower morale were lack of support for operations by the other organizations, chronic equipment problems, lack of promotion potential, and low pay. The recent management reorganization was viewed favorably by plant operations personnel because of the new emphasis on operations support and the ability of operators to effect changes.

3.2.3 Conduct of Operations

The team found that control room activities were conducted in a professional manner. Annunciator alarms were properly announced and acknowledged. Uniforms and nametags clearly identified control room personnel. "Red zones" were established for critical control room areas and were effective in limiting personnel access and distractions to the control board operator. There were two distinct control rooms for the two units that were physically separated by a floor to ceiling wall with a translucent door. This wall provided effective separation of noise and other distractions from one control room to the other.

3.2.3.1 Operability Determinations

The team found that weaknesses in operability determinations existed, which were attributed to a general lack of knowledge by operations personnel and demonstrated a need for training in this area. In addition, it was found that the administrative guidance provided to operators for making operability determinations was weak and in some cases, appeared nonconservative.

For example, on August 7, 1989, ANO Unit 1 experienced problems with the discharge check valve for the P4C SW pump. The licensee issued CR 1-89-434 describing the event which discussed the failure of the check valve as well as seat leakage of the discharge isolation valve and reverse rotation of the P4C SW pump. During a walkdown of the SW system, the team observed concrete damage on the support pad for the P4C discharge strainer as well as the P4B SW pump discharge strainer; this damage was not identified by the AOs during their rounds. In addition, interviews with operators involved with the event indicated that the P4C pump was rotating backwards at a high rate of speed and that the pump motor was vibrating sufficiently to cause the air baffles to shake. Approximately one week after the event, the pump again experienced vibration problems. Until questioned by the team, the effects of the strainer foundation damage on system operability were not assessed nor was the possible damage to the pump as a result of the reverse rotation combined with excessive vibration evaluated by the licensee. The lack of a detailed operational event analysis during the processing of CR 1-89-434 resulted in the failure to identify and analyze all possible equipment damaged by the event.

Also during Unit 2 startup on July 2, 1989, the Channel 3 safety injection actuation system (SIAS) for the low refueling water tank (RWT) level/low pressurizer pressure bypass did not automatically clear at the required set point. Although a CR was written to investigate and correct the problem, no maintenance was performed and the channel was considered operable even though the incorrect set point had not been reset.

Although operators were generally aware of equipment availability and support systems needed to ensure operability of Technical Specification (TS) equipment, control room operators did not consider that shutting the SW supply valve to the emergency feedwater (EFW) pump would place the plant in a TS LCO, nor did the acting Operations Manager who had reviewed and approved the action. The Final Safety Analysis Report (FSAR) and TS Basis discuss the need for the SW supply to the EFW system since it is the only seismically qualified source of water for the EFW system. Additionally, the dedicated volume of water in the condensate storage tanks (the normal source) would not be sufficient for the EFW system to perform all of its intended functions.

The corrective actions, with regard to the probable root causes for the incorrect operability determination of the proposed isolation of SW supply to the EFW pump (which was subsequently documented in CR-2-89-351), did not adequately evaluate the possible contribution of procedural guidance to the poor operability determination made by the SS. The CR indicated that the nonconservative (TS only) approach to operability was the root cause of the problem and management did not evaluate previous guidance that had been provided to the operators. In addition, during the review of several engineering operability determinations for earlier identified CRs on the SW system, it was found that incomplete and sometimes erroneous information was used during the determination (Sections 3.4.2.4 and 3.5.2.2).

The team found that administrative procedures for operability determinations did not provide adequate guidance to operating personnel, thereby allowing a wide range of interpretation. The official station administrative guidance for operability determinations was provided in the operability determination procedure (OP-1000.116, Revision 1). This procedure contained station policy and provided instructions as well as an attachment that discussed operability policy for previously identified operability issues. The described policy, instructions, and previous examples, contained information that was nonconservative and sometimes appeared to deviate from previous and current NRC staff positions on the determination of operability. The following is a partial list of items that appeared nonconservative:

- o Entry into a TS action statement begins at the time the decision is reached on inoperability and shall not be retroactively imposed.

- o Routine surveillances that affect equipment operability status do not require entry into TS action statements and need not be logged.

- o If not addressed in the TS, a system, subsystem, train, component, or device that fails to meet the quantitative acceptance criteria of the License Basis Document is operable pending an engineering operability determination.

  Note: On the average this engineering operability determination takes approximately 1-week.

ANO licensing had maintained an informal handbook of previous determinations, which was available for use, but had not been reviewed or approved by engineering or station management.

3.2.3.2 Shift Leadership

The SSs were responsible for overall leadership, direction and oversight of the operating crews. The team found that they demonstrated adequate leadership during control room and plant operations, shift turnover meetings, and during simulator exercises. They utilized the shift SRO to monitor the activities in the control room and to act as a filter to handle relatively minor items so that they could devote more attention to major plant activities. However, during the day shift, the SS spent approximately 75 percent of his time processing JOs, which detracted from his primary responsibility to supervise and monitor plant operations.

3.2.3.3 Shift Relief and Turnover

The team found that shift relief and turnover were performed in a thorough and disciplined manner. The relief process included a briefing, joint log reviews, and a walkdown of the control panels. The SSs held crew briefings to discuss past and planned activities. During shift relief and briefings, the SSs limited the attendance to only necessary personnel although attendance at the shift briefings was limited partly because of lack of available space in the control room area. Attendees at crew briefings typically included the operating crew, the STA, and health physics and chemistry representatives. Operations management personnel frequently were observed at these meetings.

3.2.3.4 Station Logs and Shift Work Practices

The team found a weakness in the absence of formal guidance in the use of station logs in that no LCO log entries were made for surveillance testing that removed equipment from service. The procedure for "Conduct of Operations," which specifies the items to be logged in the station log, only contained general recommendations (i.e., should) for logging operator actions and occurrences. The failure to document LCO entries for surveillance testing could result in multiple trains of safety-related equipment being removed from service. In addition, since no guidance existed as to the rough logs, significant data could be discarded which could then hinder management's assessment of the conduct of plant operations or root cause analysis following events. This was evident during a Unit 1 transient that occurred on January 20, 1989. The team reviewed the station log for this event and noted that only two log entires had been made during the six hours before the trip, one of which was a shift turnover entry.

The team found that the standards of observation and acceptance by the auxiliary and waste control operators (WCOs) during the performance of their rounds was inconsistent. For example, some Unit 1 operators were observed checking rotating machinery for heat, vibration, and lubrication levels; scanning valves and piping for leaks; and checking indicating lights on alarm panels and switchgear. However, this was not the practice of Unit 2 operators who were observed to concentrate only on plant areas where log-taking was required. The practice of incomplete tours of assigned spaces could allow equipment degradation beyond that anticipated. In addition, although control room operators routinely informed each other of plant activities, it was observed that the WCO did not communicate routine local valve manipulations performed during the course of rounds to the control room operator. This practice could result in unknown valve configurations if the operators were distracted during valve manipulation.

The team found that no guidance existed for the use and control of night orders, which the Operations Managers used to convey information to the operating shifts. Entries were made by several different individuals ranging from the Operations Manager to the WCO. The use of night orders that were not controlled was known to have circumvented the approved standing order process. This resulted in informal communication (i.e., unsigned and undated statements) that had the potential to be misinterpreted by the operating crews. An example of this included an ALARA goal of not performing second-party checks on tags in high radiation areas.

3.2.3.5 Communications and Teamwork

The ability of the operations organization to communicate its concerns and priorities to maintenance and design engineering at ANO had been previously identified as a weakness by the licensee. Additionally, operators indicated that it had been useless to request any modifications since little or no action had been taken on past requests. Recent organization changes were focused on correcting their weaknesses by establishing a single operations/maintenance coordinator for each unit to work with maintenance to establish priorities and improve plant material conditions. Previously, each SS had that responsibility, which resulted in changing priorities and ultimately a breakdown in communications with the maintenance organization. A number of operations personnel indicated that this change was a move in the right direction. However, no guidance existed for the role, responsibility and authority for the operations/maintenance coordinators. These individuals were performing interface functions between the two organizations to establish maintenance priorities based on their own experience and knowledge with little formal guidance on management's expectations for these positions. Furthermore, not all operations staff members were familiar with the changes that had been made to improve communications with design engineering and generally were taking a wait-and-see attitude until the material condition of the plants improved.

The conduct of operations procedure (OP-1015.01) required that the SS obtain the Operations Manager's permission to enter a TS action statement for maintenance. Discussions with operations management and SSs indicated that management wanted to be aware of entries into an LCO so that better control of station activities would occur. However, it was found that approximately 20 percent of the time the Operations Manager (SRO licensed) would override an SS decision to enter a TS LCO for maintenance activities. This practice did not appear to provide the support and confidence to the SS regarding his responsibility for operation of the plant in accordance with TS. More effective "up-front" planning and scheduling of maintenance and surveillance activities would provide operations as well as station management the necessary controls over planned activities.

3.2.4 Material Condition of the Plant

The team found the material condition of the plant to be poor, with numerous equipment problems that had existed for an extended period of time. These problems were generally associated with balance-of-plant (BOP) and some safety-related components, and at times, had burdened the operators in their efforts to maintain the plant on line. In some cases, they had contributed to operator errors, degraded the safety margins, and led to challenges of safety systems. The Operations Manager for each unit had provided separate lists of plant equipment problems at the request of the Director of Nuclear Operations. These lists were intended to be used to establish priorities and plan work, however, it was not apparent that these problems were receiving adequate management attention to reduce the number of long-term problems or to improve plant operations. In addition, multiple equipment failures had occurred during recent operational events that had complicated the plant response and had burdened the operators.

3.2.4.1 Equipment and System Operability

The team found a number of examples where licensee management appeared to accept equipment problems rather than pursue aggressive and effective corrective actions. Examples of longstanding chronic equipment problems included the following:

o A large number of valve wrenches were needed to open or close many of the manual valves and some of the motor-operated valves (MOVs) in the plant.

The team observed that a valve wrench was attached to the handwheel of SW crossover MOV 2CV-1422-2, and that a job request existed to troubleshoot the valve because it would not stroke. The Unit 2 SW crossover valves had a history of failures due to broken gears, sheared pins, and various other problems which indicated that excessive force had been applied to the valve operators. Several valves were also noted to be physically damaged (i.e., handwheels broken, stems broken, recorded internal gear damage), and appeared to be the result of the use of valve wrenches and the application of excessive force. Condition reports 1-88-0384 and 1-88-0401 documented two instances where excessive force was used to manually operate MOVs resulting in overtorquing the valve and damaging the valve's operating mechanism. It was also noted that the licensee was having valve stem lubrication problems on MOVs which resulted in increased running loads during valve stroke. The practice of using valve wrenches instead of correcting the underlying causes for the high torque needed to open or close the valves was considered indicative of a willingness to accept equipment problems.

- The DHR cooler outlet valves in Unit 1 have been inoperable and administratively locked open since October 1988. The inoperability of these valves resulted in difficult DHR system operation by requiring the manipulation of the manual DHR cooler inlet valves and the throttling of flow by the use of motor-operated gate valves to initiate and maintain proper plant cooldown rates. This evolution resulted in the need for at least one extra WCO during plant cooldown to assist in system operations.

- Seal injection valve CV-1208, letdown orifice bypass valve CV-1223, and Reactor Coolant System (RCS) makeup control valve CV-1235 for Unit 1 would not control properly from the control room and were often required to be manually controlled by a WCO. During heatup and cooldown, this required an additional WCO and licensed operator to keep flow paths adjusted to avoid distracting the control board operator.

- The Unit 2 steam generator (SG) blowdown drag valves 2CV-1017 and 2CV-1067 used to control flow from the SGs to the SG blowdown tank could not be remotely controlled from the control room. These valves were highly unreliable and often required local control of manual valves by the WCO for any adjustments of SG blowdown flow.

- Recurring main feedwater control system problems on Unit 2 included erratic valve control and failure to satisfactorily operate in automatic as designed. Difficulties were experienced in automatically controlling SG levels at less than 50 percent power and caused an unnecessary burden on the operator and required constant operator attention at a time when many other tasks were being performed.

- Access to the Unit 1 EDG rooms required passage through a radiation area because of the close proximity of the makeup tank. This situation was highly unusual since most EDG rooms are not posted as radiation areas.

- The Unit 1 automatic screen wash for the SW system was not being used because of equipment design and other problems. Operators had to manually operate the screen wash system approximately once a day.

- The inverter rooms for Unit 1 had very poor lighting which had existed since initial construction. Because plant operators neither routinely carry flashlights nor have them readily stored in accessible plant areas, poor lighting could become an operational problem in an emergency.

In addition, many other weaknesses were identified in the reliability and availability of plant equipment. Examples included:

- The Unit 2 B emergency diesel generator (EDG) had experienced three exhaust fires within the last year during the performance of monthly surveillance tests due to the combustion of lube oil which had leaked out of the flanged connections on the EDG exhaust system. This was a recurring condition with events dating back as far as June 1981. In most cases, these events had gone unreported to the NRC.

- SW supplied room coolers for both Units 1 and 2 had been highly unreliable due to a long history of coil leaks caused by the corrosion of the cooper-nickel material used in the fabrication of the coils. The coil leaks had resulted in reduced or loss of room cooling capability and elevated temperatures in several safety-related equipment rooms.

- The Target Rock solenoid valves had been unreliable and had caused problems due to failure to seat or operate. For example, many solenoid valves on the Unit 2 safety injection tanks (SITs) were known to be leaking resulting in a loss of inventory during various plant evolutions. The nitrogen vent solenoid valves on the SITs leaked excessively requiring them to be capped during plant operation and which prevented the remote depressurization of the SITs. In addition, there had been a number of safety-related Target Rock solenoid valve failures due to cable overheating from high valve internal temperature for valves used in high process temperature applications.

- The atmospheric steam dump valves associated with Unit 2 failed to perform as designed, resulting in a remote manual mode of operation. This mode of operation removed approximately 46 percent of automatic steam rejection capacity. Although the plant was analyzed for turbine trip without steam dump, operation of this control equipment in the off position caused a higher challenge rate to the high-pressure reactor protection system because the Unit 2 design did not include an anticipatory reactor trip as a turbine trip.

- The waste gas systems for both units were not fully utilized because of frequent failures of check valves, air compressors, and system leaks. Because degassing was the major method of reducing hydrogen concentrations and gaseous activity in the RCS during plant shutdowns, omitting this process could result in personnel safety hazards when work is performed on the system.

Finally, other equipment problems which were noted as impacting plant operations included: repetitive Unit 1 instrument air (IA) compressors and air dryer failures which resulted in increased moisture and oil intrusion into the IA system and the use of breathing air as an alternate source of IA (Section 3.3.2.2); a diminished Unit 1 pressurizer heater capacity due to ground faults that resulted in at power entries to correct problems, slow transient response, and a potential challenge to requirements for the number of operable emergency powered heaters; frequent Unit 1 moisture separator, reheater separator, distiller, and belly drain level control valve failures that required manual operation by AOs during power maneuvering; highly unreliable Unit 2 charging pumps which have become gas bound a number of times and whose failures have frequently caused increased RCS leakage, site radiation exposure, and entries into action statements; and marginally-sized valve operators on Unit 1 high pressure injection (HPI) valves which resulted in operators having to trend the number of valve cycles because of valve cycle limitations, and maintenance having to lubricate the valve stems weekly to minimize friction forces (Section 3.3.2.3).

3.2.4.2 Housekeeping

The team assessed the cleanliness, neatness, stowage and the existence of visible material defects, fluid leaks, corrosion, or other deficiencies within the plant. Although visible and accessible areas of the plant were generally good, with clean, new paint and suitable tool and equipment stowage, remote and less traveled areas were found considerably more cluttered and less organized with consumables, debris and unstowed or unsecured equipment in evidence. Numerous tours of the plant were conducted to assess material conditions. Many deficiency tags were observed identifying equipment which needed maintenance or visible conditions which required repair. Approximately 2000 deficiency tags were estimated by the licensee to exist in both units; most of which resulted from a contractor effort during 1988 to identify minor visible deficiencies.

In addition, other visible deficiencies were identified which apparently had not been noted by the licensee. Examples were:

- Motor Control Center (MCC) 55 - compartments 5511, had missing indicating lights; compartments 5512, 5513, 5515 and 5516 had indicating lights which were off. No deficiency tag was hung.

- Boric Acid panel 2C-330 and Heat Trace panel C-470 had indicating light bulbs and lens caps missing. No deficiency tag was hung.

- Deficiency Tag #829606, dated June, 1989, at 480Vac switchgear breaker #523 stated "Breaker mechanism dirty," (Reactor building (RB) cooling fan). No corrective action had been taken.

- Three-conductor cable, size 2, above MCC B41 and two-conductor cable, size 10, at cable tray EC2-31 were observed to be cut. No deficiency tags were noted.

- Decay Heat Check Valve pressure verification cabinet C502 contained pressure indicators (PIs) 1008, 1009, 1400, and 1401. All four PIs had a scale from 0-100 PSI; however, paper stickers placed inside the PIs indicated that two should read 0-1000 PSI and two should read 0-2400 PSI. This condition had the potential to cause confusion among operators, especially since no instructions were provided.

o ESF Control room panel C-18 components contained an excessive amount of dust. Also, electrical cables were stacked up inside the panel on the floor, making it difficult to walk and work without stepping on and possibly damaging the cables.

Based on these observations, the team concluded that plant management was not requiring strict adherence to the provisions of ANO Administrative Procedure 1000.18, Revision 13, "Housekeeping" which set forth the requirements and assigned responsibilities for housekeeping.

3.2.5 Operating Procedures

The responsibility for writing and improving procedures associated with operations had been recently reassigned to the Nuclear Operations Standards section. The function and personnel had been previously assigned to each Operations Manager and the recent change should significantly reduce their administrative workload. Periodically assigning operations personnel to the standards group for procedure writing should result in continued operations influence over procedure quality.

3.2.5.1 Normal and Abnormal Operating Procedures

There was a lack of specific precautions within the individual operating and surveillance procedures which had been previously recognized by the licensee. One example was the Unit 1 plant startup procedure (OP-1102.02) which referenced the precautions and limitations procedure (OP-1101.01) which contained more than 100 general precautions on different systems. The licensee had a procedure rewrite program under way to correct this deficiency.

3.2.5.2 Emergency Operating Procedures

The team reviewed the format and implementation of the Emergency Operating Procedures (EOPs) and conducted interviews and simulator observations of operating personnel during EOP exercises. The EOPs were viewed as overly wordy and excessively cluttered with caution notes and information items, which tended to delay the operator from performing the more critical steps needed to ensure plant safety. This had been previously identified during an NRC EOP inspection on Unit 1 and was documented in Inspection Report 50-313/88-17. Although the licensee's format could potentially delay operator response and implementation of accident mitigation actions, licensee and NRC observations of simulator exercises indicated adequate utilization of selective EOPs by the operators. However, the licensee was revising the EOPs for both units and had committed to using the owners group guideline as part of the Unit 1 EOP review and revision process. This effort, when implemented by the licensee, should provide improved EOPs as well as a documented basis for any deviations from the owners group standards.

It was noted that the cooldown with natural circulation procedure (AOP 1203.13), only addressed cooldown with the reactor head vents open. A procedure addressing cooldown with the reactor head vents closed during natural circulation conditions did not exist. This item was originally identified during the EOP inspection for Unit 1 during June 1988. When questioned as to which procedure the operator would utilize if the head vent could not be opened for natural circulation cooldowns, the licensee indicated that management would be notified and a 10 CFR 50.54(x) determination would be made, if necessary. This approach, although acceptable, did not allow for a disciplined preplanned review of natural circulation plant cooldown with the head vents closed.

3.2.5.3 Procedural Adherence

Operator adherence to procedures appeared to be adequate. Since no plant transients occurred during this assessment period, observations of procedure usage for nonroutine events was limited. During the two abnormal alarms on the Unit 1 control board that were observed by the team, plant operators appropriately referred to applicable annunciator response and abnormal operating procedures. However, in some cases, plant operators felt that all that was necessary to deviate from plant procedures was to obtain SS permission. This was contrary to guidance contained in the procedure for conduct of operations (OP-1015.01) and in the procedure program requirements (OP-1000.004), which specify management's intention for strict adherence to procedures. These procedures would allow the SS to grant verbal deviation from approved procedures only when emergency conditions exist or the procedure cannot be performed safely. In addition, administrative controls over procedural compliance did not specify as to when sections of a procedure could be deviated from or marked "not applicable" during nonemergency situations.

There were several instances where operations personnel failed to follow administrative procedures. For example, review of the Unit 2 startup procedure (OP-2102.02) that was performed on July 3, 1989, showed that a feed regulating valve stroke test was signed off as satisfactory even though the test acceptance criteria had not been satisfied. Although this discrepancy did not affect valve operability and a job request was generated to repair the indication, signing the test as completed satisfactorily was not in adherence to the procedure.

Another example involved an SS who attempted to deviate from the temporary change procedure. Specifically, an approved temporary change, which contained an incorrect statement had been made to the Unit 1 Shift Turnover Checklist. When the SS was made aware of the incorrect statement he directed the reactor operator to make a line-out and initial it. The SS thought this action was permissible because the temporary change had not yet been sent to document control for distribution. When questioned whether this action circumvented the review and approval process of the Plant Safety Committee (PSC), the SS redirected the operator to process another temporary change in accordance with administrative procedures.

An example of not properly following applicable administrative procedures for correcting operating procedures involved the manual operation of the motor-operated disconnects for the Unit 1 SW pump B. When the team walked through the operation of this equipment with an SRO the procedure, which required turning off dc control power in Step 11.2, did not instruct the operator to turn it back on at the completion of the evolution. When questioned, the SRO indicated that the procedure was not wrong, but that it only needed some "enhancements." However, verbatim compliance with the procedure would have left the dc control power off thereby losing motor-operated disconnect status indication in the control room. Accordingly, the team considered that the addition of a step to restore dc control power was a needed correction and not an enhancement. Furthermore, station administrative procedures did not recognize this as a procedure enhancement. Additional examples of required procedure changes that were considered enhancements, included no reference to energize Class 1E supplied backup heaters and no contingency for tripping the reactor external to the control room in the alternate shutdown procedure OP 1203.02. The apparent lack of correcting known procedural deficiencies was considered by the team to be an additional indication of a willingness of plant personnel to accept known problems.

3.2.6 Configuration Control

3.2.6.1 Control of System Valve Lineups and Independent Verification

The team found that there was a lack of IV on system valve lineup sheets and a general lack of IV throughout the operating procedures. The licensee performed IVs only for "Category E" valves, which only included isolation valves in safety system major flowpaths. However, in the Safety Evaluation Report (SER) dated November 12, 1981, which pertained to this TMI action item, the NRC concurred with this position stipulating the definition of Category E valves to be all manually activated valves on safety-related systems. The licensee's list did not include containment penetration vent and drain valves, as well as other manual valves, and did not appear to encompass the intent of NUREG-0737, Three Mile Island (TMI) Action Plan Requirements, Item I.C.6.

A weakness was found in the administrative guidance provided for procedure writers and operators with regard to valve lineups. Specifically, the procedure writers considered that valve lineups established the initial valve position for an evolution, but the operations staff believed that valve lineups specified the end point (i.e., at power alignment). This resulted in many exceptions to the valve lineups and caused questions as to the actual intent of valve lineups being performed at ANO. In addition, the potential existed for incorrect system lineups that could impact plant and personnel safety.

For example, an exception would occur when a valve was found in an incorrect position during the performance of the valve lineup and the "incorrectly" positioned valve would then be listed on the exception list. For example, approximately 60 exceptions were noted on the makeup and purification system valve lineup. Also, a valve lineup on the post-accident sampling system showed several valves that were not verified to be aligned because shielding prevented valve lineup from being performed. The excessive use of exceptions was viewed as negating the integrity of the valve lineups. In addition, it was found that the lineup discrepancies were not corrected in a timely manner.

Administrative guidance for IV contained in Station Policy SP-Z, "Independent Verification Requirement Policy," was not adequately incorporated into the Operations Department administrative procedures. Existing IVs contained in plant procedures only addressed the specifics that were implemented in 1980 to satisfy NUREG 0737, Item 1.C.6. This would tend to negate the intent of NUREG 0737, Item 1.C.6, in that systems added or modified after 1980 would not be covered by the IV process.

Operating Procedure OP-1000.027 allowed the SS to waive the IV process on tagouts if performance would result in physical risks (such as undue radiation exposure in high-radiation areas or contaminated areas, inaccessible areas or risk of falling, excessive heat, toxic chemical exposure or electrical hazards). This waiver was not in agreement with American National Standard Institute (ANSI) N18.7, Administrative Control and Quality Assurance for the Operational Phase of Nuclear Power Plants, which required an IV to be performed except in cases of significant radiation exposure.

3.2.6.2 Control of Temporary Modifications

The team found that the procedure for controlling temporary modifications was not being effectively implemented. A majority of the temporary modifications were found to be in place for greater than 90 days. The intention was that these modifications be installed for no longer than 90 days. The following are examples of weaknesses found in the temporary modification review and implementation process:

- Unit 1 open Jumper and Lifted Lead Nos. 2897, 2732, 2731, 2316, 2313, and 3036; and Unit 2 open Lifted and Jumper Leads Nos. 2652, 2649, 2585, 1897, and 1898 dating back to 1982 were not incorporated into the periodic review and control process as required by procedure 1000.028, Revision 12, "Temporary Modification Control." As a result, the periodic reviews of installed temporary modifications to determine impact on operations and if these temporary alterations should become permanent or be removed were not performed. In addition, the required periodic due date extensions were not obtained as required by the procedure. These were safety and nonsafety-related temporary modifications.

- Temporary Modification 88-2-0029 was removed from the control room; however, the index indicated it was still open.

- Not all required extension letters could be found in the control room log. For example, the extension letter for Temporary Modification 89-2-0002 could not be located.

- The reasons cited for extensions to temporary modifications often did not appear to justify the delay being encountered. For example, temporary modification 88-1-032 had a non-Q breaker installed for the safety-related Y-11 inverter. The new "Q" breaker had been received, but the licensee did not install the new safety-related breaker until November 1989, during the next outage. The reason given for the extension of the temporary modification was to reduce shock hazards to personnel and to reduce hazards should a wrench or bolt be dropped into an energized inverter.

3.2.6.3 Control of Documents and Drawings

Adequate controls existed to ensure that the operations personnel were being provided the correct documents for the conduct of day-to-day operations. A monthly audit of controlled procedures and a quarterly audit of plant drawings were performed by the shift operations assistants and appeared to be effective. All control room procedures and drawings that the team checked were of the correct revision. Of approximately 10 procedures and 30 drawings checked in other plant operating areas, the team found one procedure and two drawings with incorrect revisions. These appeared to be isolated cases.

3.2.7 Operator Training

The team found that the operator training program at ANO was well organized and comprehensive. A strong management commitment to high quality training was apparent at every level. However, a concern was expressed by the instructors regarding strained resources which could impact the overall quality of the training program, as well as correcting some minor deficiencies that had been identified in the quality of training materials. Also, weaknesses were noted in training provided to the operators regarding operability determination and the basis for entering LCOs for maintenance activities.

3.2.7.1 Training Staff

All instructors were qualified through the SRO level and were permanently assigned to the training staff. Most of these instructors were reassigned from plant operations to the training staff and appeared to take pride in doing a good job. 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.

The operator license training instructors' work load was extremely high, which caused a reduction in the preparation time for lectures because instructors were allowed only minimal overtime to prepare for lectures. Each instructor was responsible for updating certain lesson plans and training materials that the instructor then used to teach the material to support nonlicense, initial license, requalification, and system engineer training. Instructors were used for outage support on shift and for development of the new requalification examination bank.

For the Unit 2 outage scheduled in September 1989, the Unit 2 trainers will activate their licenses as necessary to support the operation crews, while requalification training is delayed. This would allow the simulator support group time to implement the modifications and updates for the Unit 2 simulator. Upon outage completion, operations will support training in assisting development of the new requalification exam bank. The initial staffing availability met the training demands. However, a potential concern was expressed that the quality of training may suffer if work load demands continued to increase with no additional resources.

3.2.7.2 License Operator Training

The team found the replacement and requalification training programs were effective in developing and maintaining knowledgeable, skilled, and competent operators, as noted by the high passing rate on NRC examinations. Training of the operators was observed in both classroom and simulator conditions. The presentations contained a good mixture of lecture, questions, and positive individual feedback for correct as well as incorrect answers. The simulator presentations re-enforced the information presented in the classroom.

ANO's operator training program was fully accredited by the Institute of Nuclear Power Operations (INPO) in January 1984. Operations training was re-accredited on August 24, 1988, with the next accreditation visit to commence on or about January 1, 1992.

During the training week, the SS and training section instructors provided direct input to the crew members on how to improve their performance, both individually and as a team. The team observed a simulator requalification session for Unit 1. The objectives were stated in advance and reviewed after the scenario was completed. The Operations Manager for Unit 2 was directly involved (once per week) in supplying policy guidance and expectations for the associated crew members for both normal and emergency plant operations. All simulator sessions were followed by a critique session that was led by the SS. It was facilitated by the training section instructors.

3.2.7.3 Training Material and Facilities

Both simulators were operational and used for training. Certification of the Unit 2 simulator was completed. The Unit 1 simulator was scheduled for certification during February 1990. Simulator improvement programs were utilized to maintain the hardware and software capabilities to reflect the response as seen under actual plant conditions. These programs were effective in maintaining a high degree of simulator fidelity with that of the control rooms of the respective units.

The team observed simulator performance of the alternate shutdown procedure as part of the requalification training cycle. Simulator modeling appeared to be consistent with the plant expectations for natural circulation and subsequent cooldown of the plant.

Discussions with the operations and training staff indicated that the simulator usually represented an accurate model of the plant in terms of transient response. However, at the time of the evaluation, a backlog of approximately 50 discrepancy reports on the Unit 2 simulator existed although approximately one-third of these were ready to be cleared during the outage scheduled for September 1989.

The licensee had a comprehensive program to maintain simulator fidelity as near to actual plant conditions as possible. Highlights of this program included a comparison of operational data for all plant transients with the characteristics the simulator displays for the same malfunction. In addition, current control room status was duplicated as to equipment availability and operational status.

One minor deficiency was identified by the team in that there were delays in updates of the system training manuals (STMs) as well as some procedures and lesson plans. System training manuals were used to conduct initial and requalification training for the plant operators and should reflect the actual conditions in the plant. It was found that the SW system STM described radiation monitors that would, upon reaching setpoint, isolate the SW cooler discharge valves. This feature, however, had been removed from the plant but was still discussed in the STM. In addition, a description difference exists between the Safety Analysis Report (SAR) and the STM regarding the pressurizer heater arrangement.

3.2.7.4 Training/Operations Interface

The licensee had a good feedback program in place for updating the simulator with data on plant occurrences. There was a method by which the operators, on an individual basis, could provide the training staff with feedback on system/component modeling. The operations manager viewed this training as "his opportunity" to ensure that the operating crews were abreast of current operations management philosophy. The operations manager also observed and evaluated the weekly simulator exercise for each crew. The exercise critique provided the operations manager an opportunity to comment on how he would expect the crews to respond to particular facets of the event (e.g., when to enter the site emergency plan).

As noted in Section 3.2.3.1, weaknesses were identified in operability determinations made by the unit operator and in their knowledge of the bases for entering TS LCOs for maintenance. Additional training was considered necessary in these areas.

3.3 Maintenance

The evaluation of maintenance activities consisted of document reviews, personnel interviews, observation of work in progress, review of pertinent past practices and events, and an examination of factors affecting maintenance efficiency and effectiveness. The SW and IA systems and components were selected for evaluation to determine whether corrective maintenance activities were accomplished in an effective and efficient manner, and whether problems were addressed adequately by the licensee. In addition, licensee efforts to resolve longstanding material deficiencies were reviewed as a means of assessing the overall effectiveness of corrective maintenance.

The major factors affecting ANO maintenance activities were the lack of an engineering design basis and configuration documentation, and the overall poor material condition of the plant as evidenced by the recurring equipment problems. This latter factor was itself attributable in large part to a maintenance program characterized by weaknesses in corrective maintenance and preventive maintenance; poor communications with engineering and operations; materials control problems; a lack of effective QC involvement; and an absence of management oversight and involvement. Recent organizational changes had occurred to address some of the problems, however the team concluded that significant, increased management attention to maintenance activities was necessary to enhance overall plant performance.

3.3.1 Maintenance Organization and Staff

At the time of the evaluation, the Maintenance Department was being reorganized in a manner intended to ultimately provide dedicated maintenance groups for Unit 1 and Unit 2. The reorganization had mainly affected management and support groups; the mechanical, electrical and instrument and control (I&C) maintenance groups were not yet organized into plant-specific departments.

The team concluded that the reorganization was too recent to allow a complete evaluation of its effect on maintenance activities. However, it was possible to make the following observations:

o The new maintenance and outage managers had a sense of ownership and accountability for the maintenance effort at their units. However, some apprehension existed because they did not control the maintenance resources and there was also some uncertainty regarding the resolution of potential conflicts in maintenance priorities between units.

- o The new organization affected only management and support groups. Division of crafts by units would probably be delayed at least until completion of the Unit 1 mid cycle outage and, therefore, it was not possible to evaluate the effect of the reorganization on craft efficiency and effectiveness or on maintenance activities overall.

- o The crafts and technicians were apprehensive about the timing of the proposed split and its effect upon overtime, work priorities and established routine. Management was actively involved in discussions with the union and with the crafts on these issues during the evaluation.

- o The newly established maintenance engineering group should be able to provide some of the technical and analysis support that had been lacking.

The turnover rate among mechanical and electrical crafts and I&C technicians was low and this contributed to a relatively stable and experienced maintenance staff. Workers who did exit the craft work force usually did so for other career opportunities in QC, Planning and Scheduling or other plant support groups. Although maintenance staffing appeared adequate at the time of the evaluation, and some increases were approved in the 1990 budget for the mechanical and I&C areas, it was not clear that sufficient resources would be available to address (1) weaknesses in the technical support areas requiring more engineering technical expertise, (2) management and reduction of the job order and modification backlog, (3) implementation of the PM program, and (4) completion of the planned split of crafts between Units 1 and 2 as part of the reorganization.

Morale within each maintenance group was good and craft and technician personnel appeared to be competent and knowledgeable in performing their jobs. On-the-job training given to electrical maintenance crafts on electrical drawings and procedures and on the performance of PM on 4.16kV circuit breakers was an example of good training involvement on the part of supervisors.

3.3.2 Corrective Maintenance

The team found corrective maintenance to be weak overall. A number of areas were identified where longstanding repetitive problems existed, where corrective actions were apparently ineffective and where the licensee was unable to effect a permanent fix. In addition, there were a number of related weaknesses involving lack of tracking and trending of equipment problems, poor root cause analysis, lack of timeliness of corrective actions, lack of effective plant engineering involvement, and poor quality and retrieval of maintenance history files which significantly impacted the effectiveness of maintenance activities. As an example, recurring wiring problems and loose electrical terminations were identified for which root cause analysis and corrective actions were not performed. Other examples of longstanding, well known, uncorrected problems were the 480Vac breaker failures, the control room emergency ventilation problems, the DHR cooler outlet valve failures, the RB cooler outlet valve failures and the 125V DC ground deficiencies. The team concluded that increased management and engineering attention was needed to significantly improve these areas.

3.3.2.1 Electrical Maintenance

A number of examples of inadequate corrective maintenance of electrical components were identified that involved as-built wiring discrepancies, poor root-cause determination, a lack of prompt corrective action and poor management oversight or involvement.

Wiring Discrepancies: During field inspections, numerous examples of wiring discrepancies were identified between actual installations and design drawings. These discrepancies made maintenance activities, modifications, testing and troubleshooting difficult and potentially unsafe, possibly leading to personnel errors and challenges to safety systems. Discussions with licensee personnel revealed that electricians had on numerous occasions used the latest revision of engineering prints and found wires not connected as shown. In addition, the team found that wiring discrepancies had also been identified by the licensee in 1988, but had not been incorporated into the controlled drawings to inform users of known deficiencies (see Section 3.5.5.5).

480Vac K-Line Breakers: The team identified numerous instances of failure of 480Vac K-Line breakers to close or trip. On March 2, 1989, safety-related breaker B-614 failed to close during post maintenance testing when a closing signal was applied. This was the second safety-related breaker to fail in 1989 in an identical fashion (CR-1-89-0137). Failure of these breakers to close during plant operation would result in a loss of one train of ESF equipment fed from the MCC. The cause of both failures was mechanical binding due to contamination and drying of the lubricant. The contamination consisted of dirt and dust accumulation in the mechanism. It was noted that prior to this failure, the last PM performed on the breakers was in 1982. Further document review indicated that at least 42 safety and nonsafety-related 480Vac K-Line breakers failed to close, trip or operate properly during the last three years, mainly due to excessive buildup of dirt and dust within the breaker, insufficient lubrication, and lubrication with unqualified lubricants that resulted in mechanical binding of the operating mechanism. The causes of failures appeared to be lack of proper PM and testing and use of WD-40 to lubricate the breaker components resulting in hardening of grease in the breaker operating mechanism.

In connection with the review of corrective maintenance actions on K-Line breakers, the team also reviewed Preventive Maintenance Engineering Evaluation (PMEE) Procedure No. 064, "Low Voltage Circuit Breakers", Revision 4, dated March 22, 1989. It was found that the specified interval for maintenance on the 480Vac K-Line breakers had been increased from 4 years (in the old PM program), to 6 years (in the new PM program). Based on the failure rate of these breakers, it appeared that the maintenance interval should have been reduced rather than increased and that the licensee failed to recognize breaker failure as a recurring problem and to give it the attention necessary for resolution.

Control Room Emergency Ventilation System: A review of CRs indicated that between February and September 1989, the control room emergency ventilation system (CREVS) had automatically started 35 times as a result of invalid initiation signals from radiation monitors or chlorine concentration detectors (Licensee Event Reports (LERs)-89-009 and -011). During the review and evaluation of the licensee's root cause determination, corrective action, and maintenance actions to address this issue, it was determined that a CR had been written for each of the CREVS starts and that root cause analysis and corrective action determination was assigned to at least six different individuals. The interface and coordination of activities among the assigned individuals was weak and undefined. Although several different corrective actions had been taken these actions had not been effective in preventing recurrence of the problem. Temporary Modification 89-2-002 had been installed in April 1989 in an attempt to resolve the problem, but it was not effective. Plant Engineering Action Request (PEAR) 89-0560 and Engineering Action Request (EAR) 89-152 were issued in April 1989; however, this engineering effort had not identified the cause or developed a fix. The problem had existed prior to February 1989, but was not reported through the LER system due to incorrect licensee interpretation of 10 CFR 50.73(a)(2). This was an example of a non-aggressive approach to root-cause determination and a failure to take prompt corrective action.

125V DC Grounds: During field walkdowns, the team observed that a DC ground fault existed in the reactor coolant pump (RCP) emergency oil lift pump circuitry (JO 777046, dated January 27, 1989). Further evaluation revealed that at least 12 JOs had been issued since 1985 to troubleshoot and identify the root-cause and location of this DC ground. The licensee had recently determined that the ground existed at the P80A connector, but maintenance had been deferred because a spare connector was not available. A review of the licensee's response to NRC Information Notice (IN) No. 88-86, "Operating with Multiple Grounds in Direct Current Distribution Systems," issued on October 21, 1988 indicated that the licensee had developed a draft procedure to detect and isolate DC grounds; however, the procedure had not been issued. The fact that a known ground had existed in the DC systems for a considerable period without adequate corrective action was another example of a non-agressive root cause determination and lack of prompt corrective action.

Cracked Weld in SW Pump Breaker: General Electric (GE) Service Advice Letter (SAL) 325.1, dated March 3, 1978, described a situation at Wolf Creek Generating Station where failed tack welds on the striker plates within 4.16KV breakers could "preclude breaker reclosure" as the breakers cycled open and then shut in sequence to fulfill their safety function. ANO initiated CR-C-89-002 to address this issue. The licensee contacted GE and was informed that the condition did not constitute a defect, as defined in 10 CFR Part 21. In December 1988, the licensee performed a limited visual inspection of several Unit 2 4.16kV breakers and identified that SW pump P4B, breaker 2A303, had a crack in the tack weld similar to that described in the GE SAL. The licensee elected to continue operating with the crack unrepaired and decided to inspect the remaining Unit 1 and 2 breakers during the upcoming outage in late 1989 (a year later). The decision to continue operating with a known crack in the breaker striker plate tack weld and not to inspect the remaining breakers promptly for potential cracks was an example of a nonagressive and nonconservative approach to correcting known equipment deficiencies.

Pressurizer Pressure Instrument: CR-2-89-286, CR-2-89-296 and CR-2-89-353 documented a repeat problem with the low pressurizer pressure/low RWT level instrument. On July 2, 1989, after the "C" channel pressurizer pressure instrument had automatically come out of bypass at 570 psia instead of 500 psia, corrective maintenance was not performed to identify and correct the problem prior to continuing heatup and power operations. Subsequently, on August 31, 1989, the licensee determined that the channel should have been placed in the trip condition and/or repaired. This event resulted in a violation of the TS and was another example of weak root cause determination and inadequate corrective action.

Loose Electrical Connections: Many LERs, CRs and JOs had been issued to identify equipment problems that resulted from loose electrical connections in I&C and electrical components. The following were some examples:

- o JO 769974 - erratic output indications on the neutron flux monitors occurred on channel "D" for logarithmic power and rate due to loose electrical connections.

- o On October 7, 1987, while at power, a control rod drive mechanism cooling water pump motor was energized, but the pump did not turn. A loose connection on a motor contact caused the contact to chatter, resulting in a failure of the pump to operate.

- o CR-2-89-0140 - while at power, the variable setpoint for the channel "D" pressurizer pressure instrument the plant protection system was at very low level and periodically spiking. The failure occurred as a result of poor electrical connections in the instrument.

In addition, a computerized list of electrical and I&C failure data was reviewed and the review indicated that a definite failure trend due to loose connections existed in electrical and I&C components. The licensee had not performed an analysis to assess this trend and to address the possible root causes such as plant aging, inadequate maintenance or improper original installation, nor had management determined the corrective actions needed to correct the problem such as thermography or physical verification of tight connections during PMs.

Fuse Control: In October 1988, the DHR system was out of service for twenty minutes after the wrong fuses were pulled (LER 313/88-014). In addition, several CRs over a long period identified problems with fuses and the control of fuses. For example, CR-1-88-0434 reported a temporary loss of offsite power when the A211 breaker (which was supplying all plant loads) tripped due to a transformer fuse drawer on the breaker being pulled during corrective maintenance and as a result, the DG did not tie in. A dedicated program and procedure to control activities related to fuses, such as positive identification, and orderly removal and replacement, did not exist at ANO, and the team concluded that there was need for additional management attention in this area.

Tuf-Loc Bearings in 4.16 KV Breakers: IN 84-29 and GE Engineering SAL dated April 17, 1979, identified a potential generic problem with Tuf-Loc sleeve bearings that were wearing excessively and resulted in the failure of GE 4.16 kV Magna Blast circuit breakers. The licensee was unable to provide data for all portions of the inspections for this defect that had been performed because of problems with retrieving maintenance history data prior to 1985, which was not kept on the computer system in a readily accessible manner.

3.3.2.2 Mechanical Maintenance

Review of LERs, CRs and JOs for mechanical components identified several examples of inadequate maintenance and followup. A common element was a lack of management and supervisor persistence in identifying root cause and pursuing corrective action.

MSSV Failure to Reseat: On May 1, 1989, ANO Unit 1 experienced a main turbine trip from 50 percent full-power. The post-trip transient was complicated by two equipment failures, one of which was a failure of main steam safety valve (MSSV) PSV-2688 to reseat. The cause of PSV-2688 remaining open after lifting was that the cotter pin that held the release nut on the valve stem was not reinstalled following previous testing, allowing the release nut to move down the stem and against the manual lifting mechanism holding the valve stem up so that it could not return to its normal position. An analysis of the licensee's actions in response to this event as documented in CR-1-89-287 revealed the following:

- Procedure 1306.017, Revision 6, "Unit 1 Main Steam Code Relief Valve Test", contained a step instructing the reinstallation of the cotter pin, however, the step did not contain an individual step signoff. While this procedural deficiency was identified in a CR, early revisions of procedure 1306.017 did contain a step-by-step signoff. In addition, the QC holdpoint contained in procedure 1306.017, Revision 6, was inadequate in that installation of the cotter pin was not identified as a critical step following MSSV testing and, therefore, no QC verification was provided.

- Licensee actions in response to IN 84-33, "Main Steam Safety Valve Failures Caused by Failed Cotter Pins," was inadequate in that (1) verification of proper installation of the release nut cotter pin was not adequately addressed in Procedure 1306.017 by step signoffs, independent verification, QC holdpoint, or procedural caution statements, and (2) Procedure 1306.017, Revision 6, and previous revisions did not specifically require the installation of new release nut cotter pins following testing nor was a new cotter pin specified in Procedure 1306.017, Section 5.0, "Test Equipment, Special Tools, Supplies" as being needed as a prerequisite to perform the procedure. The B&W Owners' Group (B&WOG) guidelines for MSSV assembly/reassembly specifically stated that a new stainless steel cotter pin should be installed every time a MSSV was disassembled, and that the proper installation of the cotter pin should be documented. The licensee's evaluation of the B&WOG guidelines was also considered to be inadequate.

- JO 784744 which documented the troubleshooting of the failure of PSV-2688 to reseat, indicated that a non-Q cotter pin was installed in the valve without adequate justification. The cotter pin was issued as non-Q on material ticket CS-9610 based on a conversation memorandum between plant engineering and a maintenance planner. No engineering dedication was conducted to justify the basis for this engineering decision. In addition, non-Q parts which were being requested for use in Q or F category components were evaluated and authorized for use by the end use authorization process. However, in this case, the end use authorization process was bypassed and the cotter pin was issued without end use authorization based on an existing baseline quality requirements (BQR) authorization. Procedure 1032.006, Revision 13, "Procurement Technical Assistance," allowed the use of an existing BQR authorization for another component provided the component meets the same criteria (e.g., identical manufacturer, model number, QA category and environmental qualification (EQ) classification) as the component for which the existing BQR was authorized for use; however Unit 1 and Unit 2 MSSVs had different valve manufacturers (Crosby and Dresser), the existing BQR authorization was not applicable for use for PSV-2688, and, therefore, end use authorization should have been obtained. In addition, no engineering dedication had ever been conducted to justify engineering analysis for PEAR 85-0348 which allowed the use of non-Q cotter pins in Unit 2 MSSVs nor had a BQR authorization ever been prepared. It was also noted that no QC involvement occurred for JO 784744 except for the JO package closeout review.

The team concluded that inadequate management and supervisory attention had been given to the failure of PSV-2688.

Repetitive RB Cooler Valve Failures: On August 11, 1988, SW valve CV-3814 failed to open during performance of surveillance test OP1104.32, Supplement 3. Valve CV-3814 was an air-operated outlet valve for train A RB coolers VCC-2A and VCC-2B, which was normally closed and automatically opened on an ESF signal or on a loss of IA. Valve CV-3814 subsequently failed to open during surveillance testing on January 18, 1989 and again on May 28, 1989. A review of the license's root cause analysis and maintenance followup revealed the following:

- o The licensee's root cause analysis and timeliness of corrective actions were found to be inadequate. The cause for the initial valve failure was attributed to pressure binding between the motor-operated inlet SW supply valve CV-3812 and air-operated SW outlet valve CV-3814 which prevented CV-3814 from opening. The licensee determined that this was a acceptable condition and system operability was not affected since both valves received an open signal on an ESF actuation and any pressure buildup between the valves would be relieved by the opening of inlet valve CV-3812. Design engineering involvement regarding the pressure binding between CV-3812 and CV-3814 did not occur until after the third valve failure, approximately one year after the first valve failure occurred. In addition, the licensee's design basis documentation for the proper sizing of air-operated valves was found to be weak (Section 3.6.5.4.4).
- o JO 770936, which documented the troubleshooting of the second valve failure, did not adequately describe in the work performed section, the as-found and as-left valve conditions, the expected cause of valve failure, the specific post-maintenance testing performed and the results of such tests. In addition, the job was delayed due to poor planning in that the material tickets issued specified the wrong parts. JO 787573, which documented the troubleshooting of the third valve failure, also did not adequately document the as-found conditions in that the JO did not identify that the valve operator was leaking past the stem and needed to be rebuilt. Lack of adequate documentation of maintenance activities in

completed JO had been previously identified by the NRC as a weakness and this condition significantly contributed to the poor quality of the licensee's maintenance history files.

- Post maintenance testing for JO 770936 was not adequate in that within less than three months, the newly installed valve operator required rebuilding due to the valve operator again leaking past the stem. It was concluded that either the new valve operator was improperly installed or was defective, and because of a lack of adequate post maintenance testing, rework of the valve was required. In addition, it was noted that QC involvement regarding the repetitive failures of CV-3814 was limited to JO package closeout reviews and, therefore, independent assessment of maintenance activities for potential contributions repetitive valve failures were not accomplished.

The team concluded that additional management attention was required to ensure proper operation and maintenance of RB cooling valves.

Shutdown Cooling Flow Bypass Valve: There were numerous instances of failures of the valve 2SI-5091-3 gearbox. Valve 2SI-5091-3 was the Unit 2 shutdown cooling full flow control butterfly bypass valve around shutdown cooling flow control valve 2CV-5091. Valve 2SI-5091-3 ensured continuity of low pressure safety injection (LPSI) flow in the event of an inadvertent closure of 2CV-5091 during injection which would interrupt the flow from the LPSI pumps. On June 27, 1989, it was discovered during maintenance that at both ends of valve travel, the 90 degree gear teeth were sheared off. Review of CR-2-89-291 indicated that the gear had been replaced at least five times and that the condition had existed for approximately ten years. The cause of the valve failures was inadequate design in that the operator was undersized for this application and could not provide the required torque. Based on the number of valve failures and the long standing nature of the problem, the team concluded that corrective actions had been inadequate to prevent recurrence because of a lack of effective engineering involvement, poor equipment failure trending, and a willingness to live with known equipment problems.

DHR Cooler Outlet Valves: As previously mentioned in Section 3.2.4.2, DHR cooler outlet valves CV-1428 and CV-1429 had been administratively locked open since October 1988 as a result of two loss of DHR cooling events. A review of the maintenance history of the valves indicated that valve problems had existed for several years. In addition, the results of the licensee's in-house Safety System Functional Inspection (SSFI) of the DHR system stated that past maintenance performed on these valves occurred without third party (QC) verification and without documenting as-found and as-left conditions. The SSFI team had concluded that maintenance corrective actions to return CV-1428 and CV-1429 to an operable condition have been inadequate due to poor root cause analysis and a lack of effective engineering involvement to resolve the problem.

IA Systems: The IA system provided an example where weak corrective action and inadequate maintenance and engineering followup contributed to system unreliability and operator difficulties. A review of LERs, CRs, and JOs indicated that the licensee had recurring problems with moisture and dessicant in the IA system and that these contaminants had caused repeated problems with instruments and regulators. For example, on two separate occasions, dessicant carryover into the IA system had caused the current to pressure (I/P) converters in the Unit 2 main feedwater regulating system to malfunction, causing a high SG level and a reactor trip. As part of the analysis of the problems with desicant carryover that occurred on October 20, 1988 with the Unit 1 IA system, the licensee discovered several maintenance weaknesses:

- o The IA system filters F8A and F8B for the M1 dryer had not been changed for several years.

- o During this period the filters were clogged and essentially not functional.

- o The IA filter differential pressure switches, whose function it was to indicate clogged or faulty filters, were not functioning properly. The switches had not been recalibrated since installation in 1984 and were not part of the PM program. At the time of the evaluation, the pressure switches were still not recalibrated.

Document review and interviews by the team revealed that during most of 1988, the licensee had indications of excessive moisture and dessicant in the IA system and had issued a number of CRs and JOs to find and correct the problems. However, these actions were not effective. The team also found that the associated local differential pressure instruments across the air filters, which were read and logged twice a shift by operations personnel, had never been recalibrated and did not appear on IA system engineering drawings.

In addition, the team reviewed the maintenance history for the IA system air compressors and found that the compressors had been rebuilt and overhauled frequently. Operations personnel also commented on the unreliability of the Unit 1 IA compressors, which were frequently unavailable due to various problems resulting in the use of breathing air as a source of IA. The C2A and C2B compressors each had been rebuilt four times and C2C compressor once within the last 14 months. The team learned that the compressors were operating under the maximum load specified by the vendor, causing excessive component wear. It was also noted that the high pressure gasket on the Unit 2 IA compressor 2C-27A had repeatedly failed causing air to enter the component cooling water (CCW) system and air-binding the CCW pumps. Although the CCW system was nonsafety-related, it did supply cooling water to the RCP's seals, lube oil, and motor coolers. At the time of the evaluation, the M1 air dryer was not operating properly and parts were on order to repair it; the M57A air dryer although operable, was not functioning as designed. Work on the M57A air dryer could not be performed until the M1 air dryer was repaired. At the time of the evaluation, no system engineer was assigned to the IA system.

3.3.2.3 Motor Operated Valve Program

Despite an extensive program for periodically inspecting and lubricating MOVs, the licensee's overall program for ensuring reliable MOV operation was found to be weak. Although many MOV deficiencies were known by licensee personnel, as evidenced by CRs, NRC inspection reports, and SSFI findings, the licensee had not always taken sufficient and timely action to resolve them. The team reviewed LERs JOs, CRs, procedures, and responses to generic communications and had the following observations:

Unit 1 HPI Valves: On April 5, 1989, Unit 1 RCS HPI valve CV-1227 failed to open during surveillance testing. Valve failure was attributed to lack of adequate stem lubrication. Maintenance requested engineering to approve a new stem lubricant which had better lubrication properties and to place more priority on the installation of design change packages (DCPs) for all 100 cycle valves. During the review and evaluation of the licensee's root cause analysis and corrective actions the team learned that the sizing of motor-operators for Unit 1 HPI valves CV-1219, CV-1220, CV-1227, CV-1228, and Unit 2 valve 2CV-0789-1 were marginal in providing the required thrust range for proper valve operation (Section 3.5.5.4.1). While design engineering was preparing the DCPs for valve modification, valve thrust ratings were allowed to be increased to approximately 110 percent of rated design, however, the useful life of the valves would be limited to 100 cycles. Although several interim corrective actions had been taken, these actions had not always been effectively implemented due to poor coordination between various licensee organizations.

As a result of valve CV-1227 failing to open, maintenance recommended an increase in the frequency of stem lubrication for all 100 cycle valves from a 90-day interval to weekly. Due to the 100 cycle limitation, maximum allowable handwheel torque value limits were established and documented in a memorandum by design engineering such that the valve strokes during maintenance would not count as a cycle. Implementation of these actions, however, was less than adequate and resulted in the HPI injection valves being manually torqued with an instrument which could not be calibrated (CR-1-89-297). The CR also stated that no procedure or work plan was developed or provided to implement the actions specified in the memorandum. Region IV previously requested that manual handwheel torquing of the valves be stopped due to concerns that the valves would not open electrically due to the potential for excessively torquing the valves manually shut. In addition, an in-house SSFI noted that valves which were on the 100 cycle valve list were not identified on the Unit 1 control panels, and unit operators were unsure of the definition of a valve cycle. These two conditions could result in incorrect valve cycle data and result in some valve operators going beyond the 100 cycle limit for valve replacement.

At the time of the evaluation, the licensee was still manually torquing 100 cycle valves during stem lubrication, and was lubricating 100 cycle valve stems weekly to ensure proper operation. Due to the generic applicability and safety significance of the HPI valves, and the duration of the condition, the team concluded that the licensee had not taken timely correction actions and that this resulted in maintenance having to take compensatory actions to minimize the friction forces of the HPI valves to ensure proper valve operation.

MOV Pinion Gear Failure: The team determined that on at least one occasion MOV failure occurred because the MOV pinion gear setscrew vibrated loose. The April 27, 1988 containment isolation valve for the LPSI system to the "C" RCP failure occurred because there was no lockwire installed to secure the set screws in place. The team found that none of the current licensee procedures had been revised to ensure that the lockwire was installed following maintenance. In addition, Significant Event Report 9-88 described events which involved loose shaft keys on MOVs becoming disengaged due to setscrews loosening. The licensee's plant impact evaluation (PIE) 88-0132-B, dated December 6, 1988 which evaluated the significant event report stated that lockwires were considered optional as a means of securing shaft keys. No further action was deemed necessary despite the fact that a previous MOV failure had occurred due to the loosening of a setscrew because the lockwire was not reinstalled.

DC Powered MOVs: The team found that the design engineering support of dc powered MOVs was deficient. As an example, electrical calculations associated with the dc MOVs failed to account for certain design criteria which could have affected the results of the calculations in a nonconservative manner. Also several calculations were not available. The team concluded that the nonconservative approach and the lack calculations resulted in designs which did not provide high confidence in the performance of dc MOVs under design basis conditions (Section 3.5.5.4.2). In addition, the team found the licensee's evaluation of IN 88-072 "Inadequacies in the Design of dc MOVs," and IN 89-11 "Failure of dc MOVs to Fully Develop Rated Torque Because of Improper Cable Sizing" was inadequate (Section 3.5 2.4).

Independent Assessment Results: The licensee's March 1989 SSFI of the Unit 1 DHR system found a number of MOV-related problems which supported the teams' finding of weaknesses in the MOV program. Some examples included thermal overload settings not in compliance with NRC Bulletin 85-03 (Section 3.5.2.1), and MOV torque switch settings for the borated water storage tank outlet valves CV-1407 and CV-1408 and DHR injection line valves CV-1000 and CV-1401 having torque switch setpoints above the calculated maximum allowable thrust ratings. In addition, the SSFI team found inconsistencies in the JO work description for MOVATS testing for criteria such as before and after test requirements, and found poor implementation of the trending program for the 100 cycle valves previously discussed.

Melamine Torque Switches: In November 1988, the Limitorque Corporation (Limitorque) issued a 10 CFR 21 (Part 21) report regarding two known failures of MOVs because of cracking and distortion of torque switches fabricated from melamine. Limitorque recommended that melamine torque switches be replaced as soon as possible. For valve operators that were inaccessible, Limitorque recommended remote testing for binding. The licensee identified 43 safety-related MOVs in Unit 1, and 42 in Unit 2 which were possibly a subject of the Part 21 report and, in early 1989, issued CRs to make a PIE and to identify the corrective actions required. In addition, a total of 36 out of the 85 safety-related MOVs were known to have melamine torque switches. However, at the time of the DE, the licensee had not performed any of the specific testing or inspection recommended by Limitorque and had deferred completion of action until the 1990 refueling outages for both plants. ANO did not consider completion of inspection and testing to be a heatup or operating constraint. The team concluded that the licensee failed to take timely corrective actions in the review and evaluation of the Part 21 report and did not adequately evaluate and justify continued plant operation with a significant number of safety-related MOVs subject to a Part 21 report. The team referred the followup and resolution of this issue to Region IV.

3.3.3 Preventive Maintenance

The team found that PM was weak overall and inadequate for much equipment, including some safety-related components. A new PM program was being developed by ANO Engineering which, when fully implemented, would provide approximately

850 maintenance and surveillance procedures for safety-related and other important plant equipment. However, the schedule for implementation of this program had been extended several times and completion was at least a year away. (Section 3.3.3.1) The licensee had predictive maintenance programs in place for vibration analysis and lubricant analysis, but was only beginning a thermography survey effort. There were a number of examples of inadequate PM procedures that involved the failure to use equipment history, the absence of maintenance on some safety-related equipments, nonconservative maintenance frequencies and poor management oversight or involvement.

3.3.3.1 Preventive Maintenance Program

Formulation of a new PM program was initiated in October 1985 as a contractor effort. In January 1989, the program was turned over to ANO Engineering for completion. At the time of the evaluation, 20 percent of the new PM procedures were implemented and in use by mechanical, electrical crafts and I&C technicians; the remainder were under preparation or in some phase of the review cycle. The licensee was committed to full PM program implementation by October 1990.

The following problems with PM program formulation and implementation were identified:

- Plant personnel initially viewed the PM procedure preparation process as a contractor effort and participation by crafts and plant engineers was minimal. Interviews revealed that technical review by both groups was cursory.
- After ANO Engineering assumed the procedure preparation task in January 1989, there continued to be limited involvement on the part of craft personnel. The crafts considered that their knowledge and experience in performing PMs over the years was being ignored and that their recommendations were not being incorporated. As a result, there was little craft ownership of a completed PM procedure.
- Plant management did not provide for craft involvement in the PM procedure preparation process. Consequently, there was an absence of craft acceptance of the procedures and in many cases an inadequate review.
- Although the new PM procedures text appeared to be detailed, they often did not consider human factors and lacked detailed component figures which are very helpful in the conduct of maintenance activities. These figures were included in the old procedures that were superseded when the new Preventive Maintenance Engineering Evaluations (PMEEs) were issued.

Plant management had recently taken positive steps to improve timely review and involvement by the crafts. These steps included reducing the length of the procedure review cycle and establishing scheduled discussion periods among the crafts charged with accomplishing the PM and the engineer responsible for preparation. A positive aspect associated with program preparation was the status of vendor manuals and the PMEE. As a starting point for the PM program, vendor manuals for safety-related and other important plant equipments were organized, updated and reviewed for mandatory and recommended maintenance. From the manuals and other inputs including regulatory commitments, engineering standards, and maintenance history, the PMEE were written to provide the basis for equipment maintenance and the justification for deviations from procedure for each equipment. Both the PMEE and vendor manuals were controlled documents, subject to continuing review and update; together they provided a technical baseline for the PM effort.

3.3.3.2 Preventive Maintenance Performance

The following are examples of deficient PM and inadequate PM procedures which involved the failure to use maintenance history or a lack of conservative maintenance frequencies.

<u>480V K-Line Breakers</u>: PM activities such as cleaning, lubricating and adjusting requirements for the closing and tripping mechanism of 480Vac K-Line circuit breakers were not specified in the new electrical PM Procedure No. 1412.043, Revision 2, "480Vac K-Line Circuit Breakers with Overcurrent Trip Device OD-4", dated May 5, 1989 (this omission could have been a contributing factor in the large number of failures of K-Line breakers to trip and close noted in 3.3.2.1 above.) In addition, many PM requirements such as checking contact pressure, contact gap, and operations checks in connected positions were not included in the new procedure. This same procedure also specified 6 year PM intervals on K-Line breakers (the old procedure specified 4 years) even though many breakers had failed to trip or close in the last several years.

<u>Molded Case Breakers</u>: Except for safety-related containment penetration overcurrent protection molded case breakers, the licensee did not perform maintenance on identical safety-related and BOP molded case breakers. PM had been performed only on the breakers specified in TS.

<u>Protective Relay Testing</u>: Evaluation of the specified PM activity intervals for protective relays in PMEE Procedure No. 070, "Protective Relays," Revision 5, indicated that GE recommended various test and calibration performance intervals on different protective relays. The intervals varied from three months for synchronizing relay, type GES21A, to two years for time overcurrent relays, type IAC77A. The intervals were normally set by the vendor depending on the relative importance of the relay in the protective scheme and degree of exposure to unfavorable conditions. The licensee established a two year periodicity for all protective relays except for those associated with components that could not be placed out of service during plant operations. For these relays, a periodicity of 18 months was established. The licensee established periodicity of two years appeared to be nonconservative in some cases. For example, the GE recommended test and calibration interval of the GES21 relay was increased from 3 months to 2 years, but no basis for the increase was given in the procedure. Another example of nonconservative maintenance frequencies were the 150/150 overcurrent protective relays. At least four JOs had been issued since 1988 to address problems with type 12IAC66K19A relays which were used in safety-related 4.16kV pump circuits. These problems included setpoint drift, shorting of terminals to ground, circuit defects and chattering during pickup. The vendor recommended that calibration be performed on the relays every year; however, PMEE Procedure No. 070 specified two year intervals. The licensee had not considered reducing the test and calibration intervals based on equipment failure history. This also applied to various other protective relays in PMEE Procedure No. 070 for which no justification existed for a non-conservative test interval.

Safety-Related Breakers: Maintenance procedures did not exist for all required PM activities on electrical components. For example, PM procedures for bus tie breakers 2Y1 and 2Y2 were nonexistant. In addition, DG 1 soak back pump breaker D1128, DGE 2 field flashing breaker D2116A and the SW manual bus disconnects were not included in the PM program. The team could not establish whether preventive maintenance had been performed on these equipments.

Safety-Related Air-Operated Valves: The team determined that PM had not been performed on RB cooler outlet valves CV-3814 and CV-3815. Discussions with maintenance personnel revealed that maintenance procedures for safety-related air-operated valves did not exist and that any PM performed on air-operated valves would have been conducted under the corrective maintenance program in response to an identified valve problem. At the time of the evaluation, a PMEE procedure existed for air-operated valves and PM procedures were being developed. The lack of PM on air-operated valves may have contributed to the failures of these valves as described in Section 3.3.2.2.

3.3.4 Maintenance Backlog

The team attempted to evaluate the maintenance JO backlog which the licensee initially estimated to be approximately 5000 items for both units. However, data furnished by the licensee was inconsistent. For example, after the DE, the licensee performed an extensive review of the JO data base, and as of October 2, 1989, the nonoutage corrective maintenance backlog had been redefined at 1308 JOs for Unit 1 and 1472 JOs for Unit 2.

The team noted the following regarding the maintenance backlog:

o The backlog had increased by about 32 percent since January 1989.

o Work delays were caused mainly by parts unavailability and slow engineering support and involvement.

o Rework items were not tracked separately to provide an indicator of improper work or inadequate testing. The licensee did not have a standard definition of rework.

o The backlog contained many minor, visible deficiencies identified by a contractor effort during late 1988.

The large number of backlog items appeared to be excessive, and the lack of concerted action, meaningful tracking mechanisms and clear goals for managing and reducing the backlog were significant.

3.3.5 Maintenance Planning and Scheduling

The Maintenance Planning and Scheduling group had formerly been part of the WCC. During the recent reorganization the group was placed in a more subordinate position under Plant Manager Central where its basic functions were the same as in the WCC. These functions included preparation of JOs, planning of corrective maintenance and scheduling of corrective and PM.

3.3.5.1 Maintenance Planning

The team found the following weaknesses in the planning of maintenance and in the preparation of work packages:

- o Rework of jobs was not tracked or defined. A worker or planner could not identify repetitive tasks as being part of an open JO or one that had been recently closed.
- o Required spare parts were not adequately staged.
- o Tracking and controlling of JOs while in the review process were weak.
- o Drawing and procedure revisions were not always identified as part of the work package.
- o Post-maintenance review of JOs was not always conducted.
- o Multiple JOs were issued for the same activity, contributing to the maintenance backlog when work was delayed. These weaknesses had been previously identified in other inspections and assessments.

3.3.5.2 Maintenance Scheduling

The team found that the presently established system for scheduling and controlling maintenance in the field was adequate. Work was scheduled on 1-day, 5-day and 30-day rolling schedules which were distributed daily in the late afternoon and which identified tasks to be accomplished during the specified time period. Operations Department coordinators who were licensed SROs were actively involved in scheduling to determine priorities and the impact of scheduled maintenance on operations. This was considered to be a positive aspect of the scheduling process.

3.3.6 Maintenance Documentation and Procedures

In general, the maintenance documentation and procedures were found to be adequate. However, there were no specific procedures or guidelines for general post-maintenance testing in that post testing requirements were written into established maintenance procedures. Therefore, in cases where a one-time procedure was prepared to meet a specific maintenance or trouble shooting requirement, there was no guidance to provide the level or depth of testing, criteria for acceptance or rejection, or general test requirements. These test parameters were left to the judgement of the planner which was considered to be a weakness.

The team reviewed the administration, upkeep and control of vendor manuals and documents and found that these activities made a positive contribution to the maintenance effort. Controlled vendor manual sets were maintained in the site technical library, in the maintenance shops and in the ANO engineering offices. Manuals were indexed, catalogued, organized and readily available to all. This vendor manual upgrade had been the starting point for the PM Improvement Program as noted in Section 3.3.3.2.

3.3.7 Materials and Material Management

The team performed a limited review of issues related to materials and material management and found several weaknesses which severely affected maintenance. Craftsmen, technicians and supervisors interviewed were unanimous in identifying the unavailability of spare parts and spare parts control as predominant contributors to the existing problems in performing preventive and corrective maintenance. Other inspections and evaluations had likewise identified deficiencies in the materials area, and the licensee had been aware of these shortcomings for some time. An ANO document entitled "Project Plan for Materials Controls Project" summarized many known materials problems, presented solutions, and outlined the plans and schedules for resolution with final completion in 1992. The team considered completion of this project to be a vital element in upgrading the entire ANO maintenance effort.

Some examples of materials and materials control problems identified by the team included:

Shelf Life Control: The team reviewed licensee's program to control the shelf life of safety-related components located in the site storeroom. The following concerns were identified:

- o Agastat commercial grade 7000 series relays, stock codes AR585-200, AR585-221 and AR585-354 were still located on "Q" stores shelves, even though the vendor informed ANO that these relays were not recommended for use in Class 1E applications.

- o A number of safety-related Agastat type E7000 series relays had exceeded their 10-year qualified life, but were not removed from the shelf in "Q" stores to prevent their being issued for Class 1E applications.

- o Dow Corning 55M O-Ring lubricant, stock code AR506-7410, was procured under BQR-88-0405 which did not require a shelf life limit. The vendor recommended a shelf life of 18 months. The team observed the item in stores with no shelf life assigned. In addition, stock codes AR505-5517 and 5520 required a 5-year shelf life, but this requirement was not applied to the existing stock.

The licensee had included review of all existing "Q" stock for shelf life deficiencies as one of the elements of the materials control improvement program.

Control of Tools: The control of tools in Hot Tool Room No. 122, located inside the controlled area, was found to be disorganized and inappropriate for contaminated equipment. The system for issue and return of tools was not computerized. Many tools were not returned and could not be accounted for due to poor documentation. Tool numbers and names of craft personnel obtaining tools were not always recorded. Contaminated tools returned were often dropped outside the decontamination room without physical or inventory control. Following decontamination, the tools were placed on a cart located outside the tool room without proper controls. The team concluded that greater management involvement was required to upgrade hot tool storage and handling to satisfy the control requirements.

Dedication of Commercial Grade Components: The dedication process, engineering evaluation and documentation appeared to be weak for commercial grade items in safety-related applications. As an example, during the evaluation, the licensee determined that commercial grade fuses that were not Underwriter Laboratories (UL) approved had been used in safety-related circuits at ANO without certification or dedication (CR-C-89-085). In addition, AMP splices (CR-C-89-087), overcurrent relays (CR-C-89-085) and nonqualified rotary relays (CR-C-89-344) were procured commercial grade without the required Q certification for safety-related applications and were used in some safety-related applications without dedication. Further review indicated that Temporary Modification 88-1-032, dated December 20, 1988, installed a non-Q DC input breaker for the safety-related Y-11 inverter after the safety-related breaker failed. Although the licensee determined that the non-Q breaker was of the same form, fit and function as the old breaker, the non-Q breaker had not been certified to meet seismic and quality requirements. These examples indicated that, even though the licensee had identified materials deficiencies, appropriate controls were not being exercised in the control of spares.

3.3.8 Drawings and Drawing Control

The team found that work packages did not always contain or reference the appropriate drawings to perform the required activity and it was left to the craftsmen to determine which drawings were needed and which revision should be used. However, maintenance craft personnel did not always verify that the latest drawings had been provided in the work package, and when they did, they frequently used the maintenance shop aperture card file which was not a controlled file. For example, the team found that the shop file contained both a superseded aperture card of piping and instrumentation drawing (P&ID) drawing M-221 (Revision 30) and the latest card which contained both Revisions 31 and 32 on the same card. In another example, schematic diagram E-226, Sheet 1, Revision 0, (a safety-related drawing) which was included in the work package for JO 792033 showed no evidence by initialing and dating of having been verified as the latest revision. Further, the team found crafts in the field using the incorrect revisions of drawings. The use of superseded drawings could result in as-built deficiencies and possible challenges to safety systems if, for example, the wrong leads were lifted during troubleshooting activities.

It was also noted that since 1988, the licensee's Quality Assurance (QA) Department had identified similar drawing verification problems as documented in at least seven audits and surveillances. In addition, the latest QA deficiency trend report, dated August 21, 1989, stated that the problems of maintenance personnel failing to verify that the latest drawing revision was being used appeared to have been resolved since there were no QA/QC deficiencies issued during the last quarter. That conclusion appeared to be premature based on the team's findings. The team concluded that management had not taken sufficient corrective actions to resolve this longstanding problem.

3.3.9 Quality Control Department Involvement

The team evaluated the activities of the Quality Control (QC) Department in support of the maintenance effort and found that QC involvement was weak, especially in the troubleshooting and maintenance of equipment requiring repetitive repairs. Examples previously discussed were the RB cooler valve failures (Section 3.3.2.2) and repair of the DHR cooler valves (Section 3.3.2.2). The team found the following additional examples of maintenance activities where QC involvement and verification were not apparent:

- The QC holdpoint contained in Procedure 1306.017 did not identify installation of the MSSV cotter pin as a critical step following testing (Section 3.3.2.2).

- CR-1-89-338 documented that a wire was terminated improperly on the motor-operator for RB purge valve CV-7404 resulting in the open limit switch being bypassed and allowing the valve to backseat and torque out. The licensee determined that the electricians who performed the MOVATS testing documented in (JO 758089) failed to terminate the wires correctly after the test. The team determined that Procedure 1403.166, Revision 1, "Testing of Motor-Operated Butterfly Valves using the MOVATS 2100 (as-left)," which provided written instructions and documentation requirements for setting limit switches on these valves, contained no QC holdpoints.

- CR-1-89-045 documented that an incorrect model solenoid valve was installed in SV-6203 which closed RB chilled water outlet valve CV-6203 on receipt of a RB isolation signal. JO 770165 which installed the wrong valve was not provided to QC for review prior to issue for work and there was no QC verification in the field during or after installation.

- CR-2-89-239 documented that the wrong make and model relief valve was installed in 2PSV-2988, which is the Unit 2, EDG #2 fuel oil pump relief valve. JO 707885, which installed the wrong valve as well as JO 00714893 which set the valve setpoint, were incorrectly identified as nonsafety-related and no QC verification was provided. The team noted that this condition was discovered on May 16, 1989, but had existed since June 30, 1986, and had not been corrected at the time of the evaluation.

- CR-2-89-329 documented the failure of EFW valve 2CV-0711-2 to close from the control room. Valve 2CV-0711-2 was in the SW supply to EFW pump 2P7A. On February 25, 1989, approximately three months later, the valve had an identical failure documented in CR-2-89-082. The team determined by interview that no QC involvement was provided during troubleshooting for these valve failures.

- CR-2-89-218 documented that the wrong type of studs and nuts were issued for use for the Unit 2 pressurizer safety relief valve 2PSV-4634 under JO 775611. A scope addition was made to the JO to replace the incorrect studs and nuts with the correct ones; however, the procedural QC holdpoint for torque verification was not included in the scope addition and the scope addition was not provided to QC for review prior to implementation. Therefore, the proper torquing of the replacement studs was not verified by QC.

- On three seperate occasions, IA compressors had to be reworked as a result of component installation errors which occurred when the compressors were rebuilt. In all the cases, no QC involvement was provided during the rebuilding process.

Based on discussions with QC and planning and scheduling personnel and the review of numerous JOs and applicable procedures, the team found that with the exception of JOs involving implementation of DCPs, QC did not regularly review all safety-related or BOP JOs prior to field implementation, nor did the WCC desk guide provide any guidance to the planner as to the type of JOs that would be appropriate for QC review prior to issuance to the crafts. For maintenance activities not covered by procedural holdpoints, QC was primarily determined on a daily basis by review of the master work schedule and component maintenance history reports, by information obtained from the daily status meetings, and by interface with maintenance personnel. This did not always permit sufficient time for the effective evaluation of JOs and the identification of work requiring QC verification and did not provide opportunity for the scheduling of necessary QC resources. In addition, the component maintenance history reports provided to QC did not provide sufficient information to be an effective tool for the identification of recurring equipment repairs requiring QC involvement. The team considered that the document and program deficiencies described above were major factors contributing to the weak QC involvement in maintenance.

Interviews with QC personnel identified further concerns about QC support to maintenance:

- o Memoranda of conversations were routinely used in JO planning and revision which tended to circumvent station administrative procedures in a number of cases; JOs containing these memoranda were not always forwarded to QC for review.

- o Extensive changes in the work scope of JOs were frequently made without informing the QC Department.

- o QC personnel did not routinely receive copies of closed-out CRs for independent review to identify potential areas for improvement such as additional hold points or increased surveillance.

- o "Skill of the craft" was used excessively in maintenance procedures and JOs, particularly in the I&C area.

The team concluded that a lack of QC involvement in the JO planning process and poor assessment tools for identification and evaluation of equipment problems significantly limited QC's effectiveness and its contribution to improved maintenance performance.

3.3.10 Problem Trending, Root Cause Analysis, and Corrective Actions

The team identified a number of apparently related deficiencies in licensee analysis of maintenance activities that contributed to the overall weak maintenance effort. There was a failure to identify, define, and trend repetitive equipment problems to determine effective corrective or preventive actions. In addition, the team found that neither NPRDS data or other failure history was used to evaluate the cause of component failure or to guide maintenance actions. Systems and components were repaired and put into service to keep the plant operating, but there was a lack of meaningful analysis that hindered long-term effective corrective action.

Several contributing factors were identified in the licensee's inability to identify, trend and correct persistent maintenance problems, including:

- Lack of a maintenance engineering function in the Central Support (maintenance) organization (a maintenance engineering group was established as part of the new organization).
- Absence of system engineers with technical cognizance over important systems and components.
- Lack of timely and effective involvement in maintenance problems by ANO Engineering and Design Engineering.
- Failure to utilize industry experience including NPRDS data from ANO and similar plants.
- Poor documentation and feedback to maintenance history of work accomplished during maintenance.
- Poor utilization of and difficulty in retrieving available maintenance history.
- Management inattention to the problem of the maintenance backlog and rework.
- Difficulty in retrieving information from maintenance histories.

3.4 Surveillance and Testing

3.4.1 Introduction

The evaluation of Surveillance and Testing placed emphasis on ASME Section XI inservice testing (IST) and on each unit's SW system components. Surveillance and testing to other requirements and of components from other systems were also evaluated to ensure comprehensive assessment. Evaluation of the licensee's actions to address generic check valve concerns, such as those described in Significant Operating Event Report (SOER) 86-03 was included as a closely related topic. The team's evaluation included a review of related documentation American Society of Mechanical Engineers (ASME) program, program correspondence, procedures and records), interviews with involved personnel, and observations of equipment conditions and test performance.

The team found that generic check valve concerns, such as those described in SOER 86-03, "Check Valve Failures or Degradation," were not fully addressed by the licensee. For example, a recommended design evaluation had not been performed by the licensee although it had been recommended more than 18 months previously.

The team concluded that surveillance and testing were adequate and were properly accomplished, although it identified weaknesses in some aspects and in related operational, maintenance and engineering work. These weaknesses detracted from what would otherwise have been a technically sound and competently executed program. Examples of these weaknesses included: omission of required tests, including the Unit 2 SW pumps; the lack of design minimum performance criteria for pumps; incomplete documentation and weak evaluation of trending data; insufficient engineering personnel for the ASME test program; weak evaluation of test data; and a history of missed TS surveillances.

3.4.2 Surveillance and Testing Program

The team selected a sample of about 50 components (25 from each unit) which, based on apparent function, should require ASME Section XI IST. Two of the 50 were found not to be specified for proper ASME Section XI testing by the licensee's program. These were the flow testing of a Unit 2 SW pump and the stroke timing of a Unit 2 valve in the the SW line for the EDGs. Further review determined that neither the three Unit 2 SW pumps nor the EDG auxiliaries for either unit was being inservice tested in accordance with ASME Section XI.

3.4.2.1 Section XI Inservice Testing

The licensee had requested relief from flow testing the Unit 2 SW pumps in accordance with Section XI of the ASME code in a program submittal to the NRC in 1978. The basis given for requesting relief was that necessary instrumentation had not been included in the original design and that installation was now impractical. The NRC granted the relief in a June 20, 1985 Safety Evaluation Report (SER) covering a review of the licensee's Unit 2 ASME Section XI IST program. The relief was granted based on acceptance of the licensee's contention that installing flow instrumentation was impractical and on the basis of an understanding that the licensee would perform a zero flow (shutoff head) test in place of the required flow testing. In a September 30, 1985 response to the SER, the licensee indicated they did not propose zero flow tests for the pumps. The NRC has not yet responded to the September 30, 1985 licensee letter and the licensee has continued as if the relief had been properly granted. The licensee initiated a Design Change Proposal in 1985 to install the necessary instrumentation for flow testing and it was installed for two of the three pumps during the last refueling outage. The licensee did not establish reference values or acceptance limits for the pumps and did not initiate ASME flow acceptance testing on any of the pumps since relief from the testing was considered to apply until 1990. In response to the team's concerns regarding this testing the licensee compared recent pump flow values obtained using the new instrumentation with the manufacturer's pump curves. Neither of the two pumps appeared to show significant flow degradation.

The omission of testing the EDG auxiliaries (e.g., fuel oil transfer pumps and cooling water valves) was also noted in the Unit 2 1985 NRC SER. The SER stated that this equipment should be tested. In their September 30, 1985 response to the SER the licensee disputed the SER on the basis that only ASME Class 1, 2 or 3 components were required to be in the program and the EDG auxiliaries did not fall into one of these ASME classes.

The Unit 2 proposed IST program also contained several other deficiencies. These included omission of proper leak testing of pressure isolation valves such as 2CV-5084 and 5086. In addition, the Unit 1 ASME Section XI IST program and its associated relief requests had not been evaluated by the NRC.

The team reviewed the draft of a supplemental NRC SER and found that it appeared to adequately address the unresolved issues remaining from the past SER. It did not, however, clarify the need for inclusion of EDG auxiliaries in the ASME testing program. This clarification should be provided.

Licensee personnel stated they were aware that the Unit 2 program contained possible deficiencies and that a contract was being let to correct the program and relief requests in time for required 10-year update due in 1990.

3.4.2.2 Procedure Deficiencies

ANO Engineering Services Procedures 1092.032 and .033, which defined the respective Unit 1 and 2 ASME Section XI IST programs, appeared deficient in several areas:

- o Some references to test procedures for component tests were incorrect or omitted even though the testing was performed (e.g., HPI check valve MU-66B had not been included in procedures, but was being tested).

- o No criteria were given for determining the need for revised reference values or setting acceptance limits, even when these limits differed from ASME Section XI requirements, as in the case of upper limits used for Unit 1 SW pumps. AP&L used upper acceptance and operability limits of 1.07 and 1.10 times reference values, whereas ASME specifies 1.02 and 1.03 times reference values for these limits.

- o The procedures required a report identifying significant trends to be issued quarterly, but there was no requirement that the cause of the trends be identified formally to aid in understanding the significance of the trends.

- o There was no provision for coordinating trending with Operations personnel who perform trending of the same test parameters in accordance with Procedure 1015.06.

Until recently, the licensee only had one individual assigned engineering responsibility for maintaining the ASME inservice testing program and evaluating test results, and that individual also often had other duties. Another individual had recently been assigned part-time responsibility. The team considered that inadequate staffing had been at least partly responsible for the weaknesses identified.

3.4.2.3 Pump Vibration Testing

The ANO program used obsolete, though ASME acceptable, methods for routine periodic vibration testing of pumps. In the team's experience the industry has rapidly moved to routine use of more sophisticated testing techniques. The licensee did use such improved techniques for troubleshooting and pump overhauls and the DET encouraged its wider application for routine testing.

3.4.2.4 Valve Stroke Testing

For both units, the ANO ASME IST program specified maximum allowable stroke time limits for valves that greatly exceeded the normally expected stroke times. This served no purpose in identifying significant degradation or failure of many valves, since actual valve failure would have occurred long before those values were achieved. This was a common program deficiency at many plants and was noted in GL 89-04. ASME Section XI did not provide criteria for setting maximum stroke times and, although licensees have had to contend with this lack of guidance since a requirement for maximum stroke times was included in Section XI over 15 years ago, the industry has made no apparent effort to provide adequately based criteria for setting maximum stroke times.

3.4.2.5 Trending of Test Data

Operations Department Procedure 1015.06 included requirements for entering and trending test data, such as that from ASME XI IST, in control room logs. This facilitated the recognition of significant changes in component performance and of testing deficiencies. This is not a common industry practice and the team considered it a strength. However, the procedure also appeared to contain several apparent deficiencies:

o It did not require that equipment maintenance or modifications be noted in the log to facilitate recognition of the cause of trend changes.

o Important procedure requirements were frequently prefaced by "should" indicating deviation from the requirements was acceptable. For example, it stated that acceptance limits "should" be placed on trend plots. The team noted instances where limits had not been included on plots in the control room logs (e.g., no limits on pumps 2P7A and B).

o It did not appear to have been kept up-to-date, as it failed to specify trending of stroke times for some ASME tested valves (e.g., 2 CV-2400, 2 CV-5282, and 2 CV-1016).

o It specified that appropriate corrective actions were to be taken based on reviews of trends and that these actions might include revisions of normal and limiting (acceptance) ranges. It failed, however, to provide criteria for altering these ranges.

o It required a quarterly review of trend data but failed to provide for coordination of the review (or its results) with the similar review performed by Engineering in accordance with Procedures 1092.032 and .033.

o It failed to provide for any written assessment or documentation of the cause of adverse trends to aid in assessing equipment degradation and determining the effectiveness of both the testing program and of maintenance.

3.4.2.6 Program Improvements

The team observed a number of improvements the licensee had instituted in the surveillance/testing program. These included:

o Improvements to instrumentation (such as addition of Unit 2 SW flow instruments, new discharge pressure instrumentation for HPI pumps).

o A contract was being let for revision of the Unit 2 ASME IST program.

- A number of test improvements had been added to the ASME IST program within the past year (e.g., full flow testing of HPI check valves MU-9A, B and C).

- The Unit 1 ASME Section XI program had been revised and upgraded.

Engineering personnel responsible for the ASME Section XI program and Operations personnel responsible for performing the ASME IST proved open and knowledgeable in questioning by the NRC team.

3.4.2.7 Technical Specification Surveillance

In a review of procedures for ten non-ASME TS surveillance/testing requirements and an examination of a master surveillance list, the licensee's surveillance program appeared to appropriately contain the TS required surveillance tests.

However, the licensee had discovered that seven TS surveillance tests had not been performed when required during 1988. The individual who had been responsible for manually scheduling the surveillances had retired and the missed surveillances were attributed to difficulties individuals experienced in use of the manual scheduling system. A computer scheduling system was placed in operation in March 1989 and the team's review of scheduling by this system, which also included a manual verification, found it satisfactory. However, the team was informed of two recent instances of tests not being performed on schedule that were unrelated to the scheduling method or each other. This indicated that continued management attention was necessary.

3.4.3 Surveillance and Testing Procedures

Except for the deficiencies noted below, the team found the surveillance and testing procedures to have good technical and human factor content. This was based on the team's review of about 10 procedures, including four reviewed in the course of test performance.

Although the Unit 2 ASME Section XI program (Procedure 1092.033) required quarterly testing for valves CV-1470 through 75 and 1480, the team found that these valves were only being tested at cold shutdown. This cold shutdown testing frequency was in accordance with requirements in Service Water Auxiliary Cooling Water & Cooling Tower Makeup Procedure 2104.29. It appeared to the team that these valves could have been tested quarterly. Licensee engineering personnel agreed and stated that corrective action would be initiated.

The team questioned ANO engineering personnel as to whether ASME XI pump test procedure flow and differential pressure limits took into consideration the flow and differential pressures needed to assure that system design requirements were met. The team was informed that the design limits were unknown and had not been considered in setting test procedure acceptance limits. The engineering personnel stated that this deficiency had recently been recognized and that corrective action was underway. The team verified that an EAR 89-057, dated February 22, 1989 had been issued to request minimum acceptable performance criteria for pumps.

The team found two weaknesses associated with the biweekly surveillance testing procedures for the containment coolers. First, the TS operability test requirements (T.S. 4.5.2.1.2 for Unit 1 and 4.6.2.3 for Unit 2) specified that operability of the coolers be demonstrated by verifying that the required SW flow to each group of cooling units could be achieved. However, there were no limitations on the differential pressure that could be used to obtain this flow. Therefore, these requirements did not actually demonstrate that the coolers could pass the required flow at the differential pressure conditions which might exist during an accident. The actual surveillance test (1104.33 and 2104.33 respectively), however, did consider differential pressure as part of the acceptance criteria. The second deficiency was that the acceptance criteria curves in the surveillance test procedures were nonconservative in that they did not account for the reduction in available differential pressure that occurred due to normal degradation of the SW pumps and the system piping downstream of the coolers.

The licensee was asked to assess the current status of the operability of the containment coolers in view of this deficiency. The response was that at the time the acceptance criteria curve data was taken in 1988, the Unit 1 pumps were in the alert range, so the pump degradation factor was inadvertently included in the data. However, since the common return line had just been cleaned and recoated, and was in good condition, its resistance was very low, and the pipe degradation factor was not included. Since the time of the baseline test, the Unit 1 pumps had been overhauled, and the condition of the common return line should not have changed significantly since it was coated. Therefore, at the time of the evaluation, the available differential pressure would be greater than the minimum required. In Unit 2 there always had been a large margin between the required flow and the actual flow, and the pumps had shown no indication of degradation since the baseline data was taken. Therefore, the Unit 2 coolers were considered operational.

The licensee was investigating possible TS revisions to reflect realistic operability considerations for the containment coolers and possible changes to the acceptance criteria curves in the test procedures to account for allowable degradation of the SW pumps and the piping downstream of the coolers.

3.4.4 Surveillance and Test Scheduling

Based on a review of several hundred test dates the team found that most testing was performed at the proper frequency. An exception noted was that seven Unit 2 SW valves discussed in Section 3.4.3.1 above, were not being tested at the correct frequency due, apparently, to a procedure error.

3.4.5 Surveillance and Test Performance

The team evaluated the performance of surveillance and testing through observation of five tests, discussions with test personnel and review of portions of about 100 test records. The team observed that testing performance was satisfactory and met the requirements of codes, standards and NRC regulations. In discussions the involved personnel proved knowledgeable concerning applicable requirements. The records also indicated satisfactory performance.

3.4.6 Licensee Evaluation of Test Data

The team found a weakness in the licensee's ability to analyze testing data and results. In the following examples, test results did not appear to have been adequately evaluated leading to dubious operability determinations.

- CR-1-89-256 identified the failure of Unit 1 SW Pump P4C for evaluation and disposition. The pump had failed to meet ASME differential pressure/flow criteria in a test on April 15, 1989, and was initially declared inoperable. The test was repeated the same day using a temporarily installed pressure test gage in place of the normal gage. Based on higher pressures obtained with the temporary gage, the licensee determined that the pump was operable. However, subsequent recalibration of the original installed pressure instrumentation, completed on April 22,1989, found the original gage to have been satisfactory. Based on additional testing and evaluation, the licensee determined that the flow transmitter had been reading low and when this was corrected the differential pressure/flow values were determined to be in the acceptable range. The values obtained were inside the licensee's "Limiting Range for Operability" (i.e., were not in the ASME "Required Action Range"), but were outside the licensee's "Acceptable Normal Range" (i.e., were in the ASME "Alert Range"). In this range the pump was still considered operable, but test frequency was required to be increased from quarterly to once every 6 weeks because of its nearness to the lower limit of acceptability. An engineering evaluation recorded in the CR stated that a review of the performance trends for A and C SW pumps indicated steady degradation and that both would become inoperable the next quarter if the trend continued. Considering that the downward trend for the pumps indicated they could not be relied upon for a long-term accident, the conservative approach would have been to declare the C pump and the SW system inoperable rather than attempting demonstrate operability through repeated retesting and evaluations that were, at least initially, erroneous. The Significance/Priority page of the CR stated that because of degraded flow problems the surveillance frequency would be increased to quarterly from 6 months. This indicated that the individual who performed this evaluation was apparently unaware of the applicable ASME test requirements which, as noted previously, required an increase in test frequency from quarterly to once every 6 weeks. It also indicated that the disposition was not reviewed by anyone with the knowledge or inclination to correct the erroneous statements. To the licensee's credit, the actions required in this CR included rebuilding of all three SW pumps and the record indicates this was completed by July 24, 1989.

- CR-1-89-410 identified the failure of Unit 1 air release vacuum valve PSV-3615 for evaluation and disposition. This valve, which failed on July 18, 1989, was said to function to release air from SW pump P4B packing on pump start to admit water for cooling the pump shaft and packing. The CR conclusion was that the pump was inoperable if the valve was inoperable since the pump shaft and packing would be damaged from overheating. If this were true, valve PSV-3615 should have been in the ASME IST program (as a valve that must function to permit safe shutdown or to mitigate the consequences of an accident). It was not. In discussions with the team, the licensee's SW System Engineer disputed the need for PSV-3615 to be operable for the pump to be operable indicating his disagreement with the CR disposition. He stated he had not been aware of the CR. The operability decision in CR-1-89-410 was, at best, questionable. Additionally, the system engineer's lack of awareness of the CR disposition suggests inadequate communications between engineering personnel.

o Unit 1 HPI Pumps experienced a step decrease in ASME Section XI IST differential pressure measurements in late 1988, when the licensee switched to the use of their Safety Parameter Display System (SPDS) from the control room panel gage previously used. The change was greatest for two of the three pumps, P36B and P36C. A decrease of about 100-200 psi was noted for P36B and about 100 psi in P36C. Test values for P36B dropped from near the upper acceptable limit to near the lower limit. The pressure tap for the panel gage was located in a header some distance from the pumps and each pump's pressure was determined from its discharge through that same header. With the change to use of SPDS, new pressure taps were installed nearer the pumps in the individual discharge lines for each pump. At these locations, increased differential pressures would have been expected rather than the reduced pressures actually experienced. Various Operations and Engineering personnel expressed concern over the change. An engineer monitoring the data reported the negative trend in a fourth quarter 1988 trend report but never obtained any explanation of the cause. The team was informed that Operations personnel had written four different JOs to correct this problem, but as of the team's visit they were unaware of any resolution. Maintenance personnel questioned by the team indicated that calibration checks showed the differences between the SPDS and panel gages were currently within ASME accuracy requirements (±2 percent) and, therefore, were acceptable. However, the previously referred to Operations and Engineering personnel were unaware of this and their concerns had not been resolved. In checking the B pump readouts the team found that the panel gage continued to show about 100 psi greater pressure than SPDS. Use of the panel gage remains an acceptable alternative when SPDS is unavailable per the test procedure. It appeared to the team that there should have been an engineering evaluation of the measurement differences and a determination of whether test data or limits needed to be normalized for use in trending and operability determinations.

As noted in 3.4.3 above, the team found that the licensee did not have available the pump flow and differential pressure design requirements needed to determine procedural limits. This data was also needed for evaluation for operability.

Paragraph 3.4.2.5 above refers to deficiencies in Engineering and Operations requirements for trending surveillance and test data. In reviewing trend data for about 100 tests the team found that the trending and identification of adverse trends appeared satisfactory. However, the causes of the trends did not appear to be clearly identified, documented or transmitted to cognizant personnel. This indicated inadequate evaluation and communication of evaluation results.

3.4.7 Check Valve Failures and Degradation

The team evaluated ANO responses to concerns regarding safety-related check valve failures reported by the various nuclear facilities. Industry guidance had been developed and issued informally late in 1987, and formally as the Electric Power Research Institute (EPRI) Report NP-5479 in February 1989. The guidance recommended, in part, a design engineering evaluation of important check valve applications in each plant to aid in identifying where corrections, deletions or monitoring would be desirable. Over 18 months after issuance of the guidance this engineering evaluation was not even begun at ANO. A contract was let to perform the evaluation while the team was on site. It should be noted that onsite engineering and maintenance personnel did promptly begin and have continued to complete other actions recommended by NP-5479. These included a review of operating experience and inspections of valves. The licensee had experienced significant problems with check valve degradation including a recent example in which failure of a pressure isolation safety injection valve (SI-15C) occurred shortly before the team's visit, necessitating shutdown for repair.

3.5 Design and Engineering Support

The evaluation of the design and engineering support for both onsite and general office organizations included the review of engineering involvement in plant modifications, resolution of plant problems and issues, major engineering programs, and the general quality and timeliness of design and engineering support activities. The team also conducted a walkdown of the SW system and reviewed licensee documents and procedures to determine the adequacy of design and configuration control.

Organizational and management changes at AP&L beginning in late 1987 had initiated broad improvements in the previous poor design and engineering support to ANO. Initial improvements focused on teamwork and communication between Engineering and ANO Nuclear Operations. These changes had split nuclear and fossil/hydro design engineering and nuclear design engineering management was changed to report to the nuclear vice president. Subsequent changes in early 1989 consolidated engineering at ANO (except for maintenance engineering) and nuclear design engineering at Little Rock under a single General Manager reporting to the nuclear vice president.

There were a number of continuing weaknesses in design and engineering support. These weaknesses included design-basis and configuration documentation; review and feedback of industry experience and lessons learned; failure to fully recognize a safety-related problem and take prompt corrective actions in some instances; and a staffing deficiency that contributed to a protracted schedule for a number of improvement programs. Communications and teamwork were also still weak in some instances. The overall trend appeared to be improving as a result of the above organizational and management changes, new and upgraded programs and procedures, and a number of recent corrective actions. However, recruitment and retention of Design Engineering staff were considered by management to be significant problems and hindrances to the success of improvement programs.

3.5.1 Organization and Resources

Engineering personnel were, for the most part, competent and conscientious with expertise in their discipline. They had recently shown the capacity to address complex technical problems in a timely and conservative manner once resources were assigned and focused, as evidenced by actions related to the Unit 1 high pressure injection (HPI) backflow event in early 1989. This effort was possible with strong contractor support. However, subsequent testing showed that vibration problems existed.

The Engineering Department consisted of five sections. Two sections, ANO Engineering and Modifications, were located at the ANO site. The remaining three Design Engineering sections, the Mechanical/Civil/Structure, Electrical/I&C and Nuclear Design Services Sections, were located in the LRGO, which was approximately 75 miles from the ANO site. The support these five sections provided to the plant is discussed in Sections 3.5.2, "Engineering Support," and 3.5.3, "Design Support." The organization and resources are discussed in the following sections.

3.5.1.1 ANO Engineering Section

To improve support to the plant, ANO Engineering was in the process of transition to include system engineers. Approximately 87 mechanical and electrical systems had been identified and assigned to about 24 system engineers. A large group of support systems had not been assigned to an applicable system engineer. The system engineers also were assigned added responsibilities for design configuration management, monitoring and trending performance, and ensuring safety and regulatory compliance. The lack of systems expertise among the system engineers exacerbated the problem of added responsibilities. The licensee referred to most of these engineers as responsible engineers pending their qualification on assigned systems. The system engineer program was appropriate and would improve the engineering support for ANO, but the full potential of the program could be better realized under a more limited scope of duties.

The large backlog of action requests was indicative of a staffing deficiency in the ANO Engineering Section. Contractors were used extensively to supplement the permanent staff, and this tended to mitigate the deficiencies.

The morale of ANO Engineering was low, expecially that of the nonsupervisory personnel, partially due to the large workload and backlog of requests for support. The personnel expressed a desire to become more involved and proactive in support of plant problems, but felt unable to do so because of the large backlog and assigned actions. A number of positions recently had been added to ANO Engineering.

3.5.1.2 Modifications Section

The Modification Section had recently improved the ability of the licensee to process and effectively manage the DCP review and implementation. These improvements were evident in the decrease in the past year in required revisions to DCPs and field change requests. Some problems remained with the coordination and implementation of multidiscipline DCPs. The education and experience of the Modifications Section was adequate. Contractors were used to augment the permanent staff and appeared to add the required manpower and expertise. The combination of permanent staff and contractors resulted in the Modifications Section being the only group within the Engineering Department not understaffed.

3.5.1.3 Design Engineering

Design Engineering included the Mechanical/Civil/Structural (MCS) Design, Electrical/I&C (EIC) Design, and Nuclear Design Services in the LRGO. Design Engineering was formed in late 1987 when design personnel were incorporated into the Nuclear organization from a separate corporate engineering organization whose activities included fossil and hydro station support as well as ANO support. This reorganization initiated an evolution of improvement in design and engineering support to ANO. The improvements included improved relationships and communications with site personnel and a greater sense of ownership with regard to issues at ANO.

The general atmosphere of Design Engineering, however, was one of apprehension and low morale, especially among nonsupervisory personnel. Several contributing factors included an announced move of design personnel to the ANO site at an unspecified future date; the lack of a nuclear pay scale differential between nuclear and fossil personnel in recognition that many engineers perceived nuclear engineering to be more demanding than fossil engineering; the use of contractors, receiving significantly higher pay, for extended periods instead of the addition of permanent AP&L staff positions; and the large workload and backlog of uncompleted actions. The interest of the staff in performing in a high quality and timely manner was evident, but this interest was largely offset by the stresses and anxieties introduced by the factors mentioned above. In addition, many engineers responsible for multidiscipline projects such as DCPs felt they were not given the necessary authority to carry out responsibilities. There had been a net loss, during the previous 18 months, of 104 years of experience from the MCS and EIC design sections.

The backlog of Engineering Action Requests (EARs), CRs and other requests for support indicated that the staff's capacity was inadequate. However, some requests for support were viewed by LRGO as unnecessary and, as overloading those resources that were available. In addition to the requests for support from outside the design organization, several major improvement programs (discussed in Section 3.5.6) were being implemented, and these created further demands on the limited design resources. The staff was supplemented extensively by contractors in several areas. However, much corporate memory and experience was lost when these contractors completed an assignment and moved on. Recruitment and retention of staff was considered by management to be a significant problem and a hindrance to the success of improvement programs.

Although the Design Engineering staff had expertise in their assigned disciplines, an area needing improvement was the design engineers' knowledge and perspective concerning the overall plant systems, interactions, operations, and design bases. In 1987, the licensee had initiated a program entitled the Individual Development Plan which involved limited systems training and other technical and professional development training. The program was cancelled in 1988 because of budgetary restraints, but was being revived.

An example of Engineering capabilities and limitations was provided by an event following a reactor trip in January 1989 that resulted in a backflow of reactor coolant through a section of HPI piping. Engineering coordinated, in a timely and conservative manner, contractor and nuclear steam supply system vendor analyses, preparation of a design change to add a redundant set of check valves, assessment of the damage to HPI piping and supports, and other activities related to the resolution of the problems encountered during the event. However, several engineering personnel among those interviewed felt that coordination and communications were poor during the resolution of this event. The resources required to address these issues also resulted in significant delays of other activities such as resolution of CRs and improvement programs.

3.5.2 Engineering Support

Engineering support to the plant was weak in many instances. This was due, in part, to the large backlog of requests for support that existed at both onsite and LRGO engineering sections. The formal mechanisms for assignment of a task to the Engineering Department were the Plant Engineering Action Request (PEAR) for ANO Engineering, the EAR for the LRGO sections, and the CRS for all Engineering sections. These processes and other engineering support issues are discussed below.

3.5.2.1 Communications

Communications between the Engineering Department and other ANO organizations were weak, but actions had been taken since the 1987 reorganization for improvement. The formal communication mechanisms such as the CRs, PEARs, EARs, and internal requests for information seemed to work reasonably well, but were sometimes not augmented by informal discussions that could have expedited the resolution of some issues. Programs, such as the system engineer program, the 2-week schedule, and the 18-month plan had (among other benefits) improved communications between the Engineering Department and other ANO organizations, but these communications were still weak in some instances. The 18-month plan was a rolling schedule of Design Engineering activities which was periodically reviewed by Engineering and ANO plant organizations to ensure that engineering resources were being assigned to the most appropriate activities. Communications and teamwork within the design engineering sections had also improved since the 1988 consolidation of engineering functions, but vertical communications between management and staff regarding plans, goals, and objectives was weak in some instances.

The following discussion represents an example of weak communications and teamwork between Design Engineering, ANO Engineering and Maintenance. In Memorandum EIC 88-131 of March 18, 1988, to Maintenance, the Design Engineering staff recommended that thermal overload verification and possible replacement be placed within the MOV testing program. When the MOV test program was completed in a given outage, the Design Engineering staff would change documentation to reflect the as-built conditions and document any new thermal overloads. This methodology was not new; it was also being used to make setpoint changes to protective relays.

Plant Maintenance personnel did not agree that the methodology proposed by the Design Engineering staff to process thermal overload replacement was correct and, therefore, did not follow the recommendations of the Design Engineering staff. They were looking for either a plant change issued by ANO Engineering or a DCP issued by Design Engineering. ANO Engineering was concerned that this type of equipment change, which had a calculational basis, did not comply with the requirements for a plant change and, therefore, did not issue a plant change.

When Design Engineering received a verbal report that the MOV test program was complete, it changed the as-built documentation to reflect the correct thermal overloads. The engineering procedure was defective in that it did not require written notification from Maintenance. Therefore, Design Engineering was unaware that Maintenance had not included thermal overload replacement in the MOV testing program. During June 1989, the size of several thermal overload heaters installed in breaker cubicles for Unit 1 dc MOVs was found by Engineering to be different from that specified in design drawings. CR 1-89-308 was issued to document the discrepancy. Unit 1 MOVs did not bypass the thermal overload heaters during a safety feature actuation, therefore, the sizing of the thermal overloads could affect safety.

There was no scheduled verification and/or replacement of thermal overload heaters in dc MOVs because Design Engineering, ANO Engineering and Maintenance had not reached an agreement on the methodology that would allow verification and/or replacement of MOV thermal overload heaters. The thermal overload heaters for both Units 1 and 2 were available at ANO when the team was onsite, but neither unit had been replaced.

3.5.2.2 Condition Reporting System

The CRS, initiated in 1988, was a significant improvement in problem identification and tracking of engineering problems. Prior to that, several reporting systems were used that resulted in different priorities and a lack of focus on significant safety issues. In addition, due-in part to these problems, ANO was either late by several months to years in reporting some events to the NRC and, in some cases, events went unreported.

Although the CRS was a plant-wide system, the Engineering Department was assigned the majority of the corrective actions associated with the system. The assignment of CR action items resulted in the allocation of more than 50 percent of the engineering resources to CRs. Approximately 24 percent of the CR corrective actions assigned to the Engineering Department were not resolved by the scheduled due date.

The engineering staff responses to the assigned CR actions were usually adequate except for timeliness. The required actions by the engineering staff included preparation of design change packages, operability determinations, and root cause analysis. Engineering operability determinations followed initial evaluations by the shift operations supervisor and shift technical advisor and were assigned as CR corrective actions if the initial evaluations determined that equipment was operable pending engineering evaluation. The CRS required a cause analysis for all CRs and a root cause analysis for those CRs deemed significant. The organization assigned the lead for the CR performed the cause/root cause analysis. The engineering sections performed these assigned analyses in an adequate manner. However, some CRs assigned to nuclear operations personnel apparently would have better been assigned to engineering personnel (Section 3.5.4.5). If the lead for a CR involving engineering problems was not assigned to Engineering, then their involvement in operability determinations, root cause analyses and final resolution was sometimes weak due to both programmatic restraints and a lack of teamwork.

There were instances during the evaluation in which the engineering staff initiated CRs in response to team findings. The initial operability determinations by nuclear operations personnel for several of these conditions (Section 3.5.4) were considered inadequate largely because of the explanation of the issues by the engineering staff to Nuclear Operations. There had been communications difficulty in the past with operations personnel performing operability determinations for conditions such as pipe support deficiencies identified by the engineering staff. To address this problem, Design Engineering had improved CRs initiated in response to pipe support issues by including guidance and an initial engineering position on operability. A common cause of conditions identified by the engineering staff involved inadequacies in the initial design and/or design configuration issues.

The documentation of the engineering involvement in the CR process was often only that required by the CR forms, and supporting documentation was not attached or formally filed and referenced. The lack of supporting documentation was a weakness in the system that also increased the potential for later design-basis/configuration problems.

3.5.2.3 Plant Engineering Action Requests

The PEAR was the mechanism used by plant personnel to identify and request ANO Engineering support for a condition that could constitute or require a design modification. As the formal means of requesting support and ensuring that a documented response was provided, the PEAR system generally worked well. Although the engineering response was documented as part of the PEAR resolution, supporting documentation and a written account of the decision process were often not attached or formally filed and referenced. The limited documentation of some PEARs could add to later design configuration problems.

The large volume of requests led to a backlog of unresolved PEARs that contributed to weak engineering support. The number of open PEARs (approximately 1600) remained relatively high for several months before the DE. Formation of the system engineers was intended (in part) to help decrease the PEAR backlog.

3.5.2.4 Engineering Action Requests

EARs were used to initiate LRGO design engineering activities such as design changes, documentation revisions, and engineering evaluations. For those EARs that had been processed as design change packages, engineering calculations, or by some other mechanism, the process appeared to work effectively.

The backlog of EARs had continually increased over the last several years and was over 1000. Several programs were being initiated to reduce the backlog. An initial reduction effort consisted of a reexamination of the low priority (Category III) EARs by the operations and maintenance organizations. As a result of this effort, the number of backlogged Category III EARs (over 300) was being reduced significantly as the originating organizations determined that problems had been resolved by another mechanism or otherwise did not warrant dedication of engineering resources. A similar review was planned for scheduled (Category II) EARs. Category I referred to those EARs that were actively being worked on. Preliminary discussions between organizations were also being initiated to perform a better review of proposed EARs at the beginning of the process. These and other signs of increased communication between organizations, such as the engineering 18-month plan, were initiated to help gain control of the EAR backlog.

3.5.2.5 Generic Communication Review and Industry Feedback

Issues identified in NRC and industry correspondence were frequently not reviewed adequately or documented by the responsible review group. Engineering involvement in the evaluation process was weak due to programmatic weaknesses, staffing deficiencies and lack of teamwork. Examples of problems found during the team's review of PIE are discussed below and also in Section 3.5.4.2:

- The review of NRC IN 88-072, "Inadequacies in the Design of DC Motor Operated Valves," was closed by reference to PIE 88-0098-B, which provided the evaluation of similar concerns in INPO Significant Event Report 25-88, "Design Problems Affecting DC Motors Used on MOV's." PIE 88-0098-B did not address all the design issues expressed in IN 88-72 and INPO Significant Event Report 25-88. It failed to address the effect of ambient temperatures above motor design temperatures. Design Engineering indicated they planned to investigate the effect of temperature on all dc MOVs at the station.

- PIE 89-0021-B provided the evaluation of IN 89-11, "Failure of DC Motor Operated Valves To Fully Develop Rated Torque Because of Improper Cable Sizing" and concluded that the issue had been resolved by PIE 88-1003, "Response to Limitorque Maintenance Update Letter VEND-88-0817-011." The PIE stated that cables were sized for at least five times the full load current at the minimum voltage in accordance with the Limitorque letter.

  After the team questioned the PIE, the licensee indicated the cables were sized using an alternate method, specified in the Limitorque letter, which it considered adequate although not in agreement with the statements in PIE 88-1003. However, examples of calculational errors in regard to the minimum voltage available to dc MOVs were found as discussed in Section 3.5.5.4. These calculational errors might have been avoided if IN 89-11 had been properly evaluated.

- PIE 88-0151-B provided the evaluation of IN 88-94, "Potentially Undersized Valve Actuators" (pneumatic). The PIE was closed by initiation of CR C-89-082. The CR stated that there were no known problems with the pneumatic valves. This was in conflict with the PIE documentation which referenced numerous JOs on valves resulting from actuator and valve packing problems. Even though the actuators were seemingly repaired, it was possible that some of the problems were a result of improper packing or undersized actuators. Pneumatic valves continued to experience operating and maintenance problems. Section 3.5.5.4 contains further discussion of design problems with air-operated valves.

In another instance, GL 88-15, "Electric Power Systems Inadequate Control Over Design Processes," did not receive any documented review by either the plant staff or the design engineering staff. The GL did not require a written response to the NRC, however, ANO procedures required that a documented review be completed for applicability to ANO. The GL was routed for information to various groups without any specific action required and no review was documented.

3.5.3 Design Support

The design change and modification processes for ANO were controlled by a series of recently revised and new procedures that were applicable to both ANO and LRGO organizations. The formation of the procedure series, coordination of LRGO and ANO activities, and the creation of the Modifications Section had significantly improved the design change and modification processes, although there were still some coordination problems with multidiscipline DCPs.

The team reviewed some recent DCPs, including the 10 CFR 50.59 safety evaluations, and generally considered the process to be a strength although the implementation was impeded by lack of design-basis documentation. Some limited design-basis reconstitution was performed in the DCP as a compensatory measure for the lack of design-basis documentation. The Modifications Section prepared an installation plan for each DCP that included a 10 CFR 50.59 safety evaluation and required limitations and precautions for the installation phase of the modification. The post-modification testing identified by the design engineer was reviewed, expanded if required, and coordinated with plant organizations that would be involved in the testing procedure. Although, the team conducted no field observations of the installation procedures, the review of several DCPs showed that the description of the installation phase of the DCP process was generally adequate. A notable feature of the DCP process was a detailed critique of each completed DCP by the design, project, and field engineers. These critiques were subsequently used to define potential improvements in the DCP process. Recent improvements in the DCP process were apparent via the licensee's tracking of items such as the frequency and causes of DCP revisions and field change requests (FCRs).

An example of the difficulty in retrieving design information and a resultant error in the 10 CFR 50.59 safety evaluation of a DCP was found during the team's review. DCP 88-1078 called for the modification of the gear trains on four safety-related MOVs on Unit 1 as part of the MOV upgrade program. The change in gear trains was required to ensure that the actuator would provide sufficient torque to operate the associated valves. The use of new gear trains changed the stroke time of the valves from 29.5 to 56 seconds. A search of the licensing basis found no operating time for the valves. Since the new stroke time did not exceed the time of 60 seconds in the procedure, the change was deemed acceptable.

During the DE, CR 1-89-0482 was issued. It indicated that an anomaly existed between the 60-second stroke time specified in the test procedure for the isolation valves and the requirement in the ANO FSAR that the RB coolers be operable within 45 seconds.

The licensee identified a similar type of change in DCP 89-026. In that instance, a review by the nuclear safety group found that the valve timing requirement in the associated test procedure did not agree with system functional requirements specified in the TS. The nuclear safety group began in 1988 to provide a review function for DCPs to determine whether a modification affected the safety analysis assumptions.

3.5.4 Service Water Systems

The SW systems at ANO had a long history of problems, some of which had existed since initial design and construction. The responses to these problems had been extensive, but usually were reactive in nature. Corrective actions had not been timely in some cases. The Service Water Integrity Plan (SWIP) (Section 3.5.6.4) was a recent attempt by AP&L to address SW system problems in a coordinated, timely, and proactive manner. Several SW system problems were either reviewed by or identified by the team and are described in the following sections.

3.5.4.1 Service Water System Pump Room Ventilation

During the evaluation, it was determined that the ventilation system in the Unit 1 SW structure might not be adequate to ensure the operability of the SW pump motors during emergency safeguards operation. During a loss-of-offsite power (LOOP), natural (free) convection ventilation was assumed. Calculation 3600-139 assumed that there were two openings, each 7 square feet in area, located in the SW structure at an elevation below the SW pump motors to provide an inlet for cooling air. These openings, however, did not exist and apparently had not existed since initial startup of the unit. A grated door had been added to the north end of the intake structure to provide makeup air for free convection (DCP 80-1048). However, the north outside solid door was closed, defeating the purpose of the grated door. Immediate corrective action was taken to remove the solid door to provide an inlet for cooling air. CR 1-89-453 was issued to document the discrepancy. The team found the discrepancy to be an example of both a design and/or construction deficiency and a lack of configuration control.

3.5.4.2 Service Water Cross-Connect Valves

During the evaluation, it was determined that Unit 1 operating procedures resulted in a single failure vulnerability in the system. Unit 1 operating procedures allowed operation of SW swing pump P4B with the cross-connect valves in a configuration that, with a loss of one EDG, could have resulted in inadequate SW flow to the SW loop remaining in service. SW swing pump P4B was used to replace either pump P4A or P4C. The discharge line from pump P4B was cross-connected to the discharge lines of pumps P4A and P4C pumps through two sets of two isolation valves in series. The original design required that these valves remain closed during normal operation and that they be opened as required to facilitate proper alignment of pump P4B during ESF actuation. The two valves in series were, therefore, supplied power from the same EDG to ensure that both valves could be opened. In 1981, the cross-connect valves were opened during normal operation to allow operation with three SW pumps instead of two pumps because of system flow and pressure drop deficiencies. The operating procedures were changed at that time to allow the valves to remain open. With the valves open, failure of a EDG would render its associated SW pump inoperable and result in the alignment of the remaining pump, P4B, to both SW loops. A single pump aligned to both loops would not provide sufficient flow to perform the required SW function during an accident. CR 1-89-456 was written to document this problem.

As a result, temporary changes were made to procedures while the team was onsite, to provide the operator with guidance on preventing the above scenario if the swing pump was placed in service. The team found this problem to be the result of a lack of design-basis documentation, configuration control problems, and failure to promptly evaluate industry feedback.

IN 89-49, "Failure To Close Service Water Cross-Connect Isolation Valves" was issued in May 1989. A prompt evaluation of this IN would very likely have uncovered the above problem earlier. The PIE for this IN had not been completed when the team was on site.

3.5.4.3 Auxiliary Cooling Water Isolation Valve

During the evaluation, it was determined that Unit 1 operating instructions did not direct the operator to align the power source for the auxiliary cooling water isolation valve (CV-3643) to the EDG used to power SW swing pump P4B, if that pump was in service. Had the operator failed to do so, it would have resulted in another single failure vulnerability in the SW system. Operating procedures directed the operator to operate a manual transfer switch to properly align the power source to the pump. It did not direct the operator to also align the power source to the auxiliary cooling water system isolation valve CV 3643. If valve CV 3643 and SW pump P4B were receiving power from different EDGs during a LOOP and EDG actuation, a single failure of the EDG supplying CV 3643 would result in the failure to isolate the auxiliary cooling water system and SW pump P4B would provide insufficient flow to the emergency safeguards equipment. Temporary procedure changes were implemented while the team was onsite to ensure that the swing pump and auxiliary cooling water system isolation valve were powered from the same electrical bus. The team found that poor communications and configuration control were the major causes for this problem.

3.5.4.4 Service Water Pump Motor Operating Limits

During the evaluation, it was determined that Unit 1 procedures did not include the manufacturer's operating limits for the SW pump motors. The licensee indicated that these procedures would be updated using the requirements specified on the motor nameplates. The team did not determine if there had been any instances in which these requirements were not followed and there was no indication that the licensee planned to evaluate past operations to determine if the nameplate requirements had been exceeded or if there had been any unusual motor degradation.

3.5.4.5 Service Water Pump Shaft Damage

During June 1989, Unit 1 SW pump P4A failed a surveillance test for differential pressure. During subsequent maintenance, the licensee discovered that the shaft stuffing box had seized to the shaft. The engineering staff was not assigned any responsibility in the closeout of CR 1-89-375, written in response to this event, and no root cause analysis was performed. The other Unit 1 SW pumps were evaluated and found to be operable during the closeout of the CR. The operability evaluation concluded, however, that this shaft stuffing box problem could have been the cause of pump degradation, leading to failure of the surveillance test. The proximate cause was attributed to sufficient wear on the guide bushings in the casing spiders to allow the pump shaft to come into contact with the stuffing box bushing. Corrective action was the replacement of the stuffing box bushing. Before the closeout of the above CR on August 2, 1989, SW pump P4B experienced a similar event (CR 1-89-409) except the shaft on this pump was completely sheared. The team requested the root cause analysis for the second event, but it was not provided by the time the team left the site in mid-September.

The root cause analysis for the second event was later completed by the licensee, and the root cause was found to be both personnel error in running in new shaft packing and an inadequate post-maintenance run-in procedure. Both these root causes are potential common mode failure mechanisms. The team concluded that a root cause analysis had not been conducted in a timely manner.

3.5.4.6 Service Water System Waterhammer

Waterhammer had been reported in the Unit 2 SW system on at least five occasions since 1982. As a result, leaks (tube and piping) in the safety-related containment coolers had occurred on four of these occasions. The 1985 waterhammer caused a gasket leak on a EDG cooler. However, on the basis of a study completed in 1985 by the engineering staff, no corrective action had been taken by the licensee. The study was flawed in that it failed to recognize that during previous events the likely worst-case scenario had not been experienced. The study also concluded that this safety-related equipment was still capable of performing its function and that the potential cost of repairs as a result of probable future waterhammer would probably be small compared to the cost of corrective actions. It, therefore, concluded that no corrective action was warranted. The study failed to recognize that the cooler tubes and piping were one of the two containment barriers against a potential radioactive release and although the coolers may have remained functional for heat transfer, this barrier function was degraded. There also was a problem with the air-operated valve that represented the second and final containment barrier as discussed in Section 3.5.5.4.

The containment coolers were supplied with service water through two containment isolation valves, one on the inlet side and one on the outlet side. During an accident these valves would move to the open position to carry out their primary safety function of supplying water to the containment coolers. During a subsequent LOOP, these valves would remain open. The containment coolers were elevated well above their SW return lines. Therefore, following a LOOP, the SW water would drain toward the system discharge and create voids in the system, thereby setting up a waterhammer environment when the SW pumps were restarted.

During the worst-case scenario, the cooler isolation valves would remain open following a LOOP and the temperature of the water leaving the coolers might be as high as 200°F. Therefore, the tendency for column separation voiding would be substantially higher than it was during the tests when waterhammer actually occurred. Both these considerations would tend to significantly increase both the probability and the severity of waterhammer occurrence.

The study also attempted to minimize the waterhammer concern by noting that corrosion of the cooler tubes by the SW contributed to their tendency to leak following a waterhammer occurrence. Corrosion of these tubes had been a significant problem. This reasoning should have increased the concern because the corrosion was another recurring common mode failure mechanism along with waterhammer, both of which might actually be worse during the postulated LOCA than that experienced during previous events. The licensee had performed a study to determine more corrosion resistant tubing material and replacement was included in the SWIP (Section 3.5.6.4).

After the team raised the issue of waterhammer in the SW system, the licensee completed an informal evaluation for worst-case forces. This evaluation showed that waterhammer forces could exceed those produced during a seismic event. At the conclusion of the DE, the licensee planned to reassess the waterhammer phenomenon and to take whatever corrective actions were required. The licensee had failed to fully recognize the significance of this safety-related issue and to take prompt and aggressive corrective actions.

3.5.4.7 Service Water Pump Snap Rings

Since 1981, there had been repeated failures of the impeller snap rings on the Unit 2 SW pumps. These rings transmitted the thrust loads from the pump impellers to the shaft, and their failure rendered the pump inoperable. The snap ring problem started in 1981 when the originally supplied carbon steel snap rings were discovered to be in a seriously degraded condition. They were replaced with stainless steel rings, but in 1984 these were also replaced because of a failure. Although the engineering staff recommended replacement with cadmium coated carbon steel rings, they were not available, and uncoated carbon steel rings were used again. In 1986 and 1987 during pump overhauls, the rings were replaced again with uncoated carbon steel rings. The uncoated carbon steel rings usually failed after about 2 years, although those on one pump failed after only 16 months.

During June 1988, SW pump 2P-4B began to show high motor current for several minutes after starting. These symptoms continued for 4 months. This overcurrent resulted in an overcurrent trip of the power supply breaker on one occasion and a motor overload alarm on another. The licensee did not recognize the overcurrent at the time as a symptom of snap ring failure despite the failures prior to 1988. The high current trips were attributed to improper pump to motor coupling and the coupling was adjusted several times. During October 1988, SW pump 2P-4B was finally disassembled and the snap rings were found to be failed. The snap rings were replaced and the pump was returned to service. The snap rings on the two remaining pumps were not inspected following failure of 2P-4B. This failure of pump 2P-4B was followed by the discovery one month later of the failure of pump 2P-4A snap rings after experiencing high motor current. Following the failure of 2P-4A, the licensee concluded that following a complete failure of the snap rings, the impeller would drop down on the shaft and interact with the pump bowl. Subsequent pump starting would cause a significant increase in motor amperage and/or shift vibrations for several minutes. These symptoms would usually last only temporarily, probably because of a film of water developing between the bowl and the impeller. However, a later transient such as stopping or starting would again cause elevated motor amperage and/or shaft vibration.

Following the failure of pump 2P-4A, the third pump, 2P-4C, was designated as operable while 2P-4A was repaired since it did not exhibit any high motor currents. Pump 2P-4C was allowed to operate for several months until early

1989 before it was inspected even though it already had a total run time on the snap rings of almost 27 months. The snap rings on this pump were found to be severely corroded and parts were missing. The licensee noted that the third pump was actually a spare, since only two SW pumps were required.

In response to the above failures, the licensee instituted a replacement interval of 14 months based on an erroneous understanding that the shortest failure interval had been 22 months. The team was not provided adequate technical basis for the 14-month replacement interval. A 14-month interval would indicate a wastage of about 60 percent of the snap ring margin-to-failure based on a 22-month failure interval. The operating conditions (steady-state vs transients) prior to the above failures were apparently not considered in the technical basis. Other factors that apparently were not considered were the minimum material required to withstand transient loads, a margin for possible abnormal loads (e.g., waterhammer as described earlier), a margin for inaccuracies in measuring system degradation, and some safety margin. The team considered waterhammer in the SW system to be a potential common mode failure mechanism for degraded SW pump snap rings. While the team was on site, the Unit 2 SW pumps had service times of approximately 9, 10, and 11 months since the snap rings were replaced.

The licensee discounted the 16-month failure case by referring to a hose that was caught in the suction of the pump before the failure. The hose was assumed to have resulted in additional stresses on the snap rings. The team observed that an SW pump in Unit 1 experienced severe vibrations during August 1989. These vibrations were not reported in a CR until the team was on site and began its evaluation. The CR assumed that some foreign object was temporarily caught in the SW pump suction. This scenario suggested that not all events of this type in the Unit 2 SW system would be investigated for the potential for accelerated snap ring failure. Therefore, objects caught in the suction of the SW pumps potentially causing accelerated snap ring failure would be an additional concern of the team.

Although there was evidence that the licensee had studied this problem after the failures occurred, it appeared that the necessary aggressive actions to resolve the problem had not been taken. The actions taken had been reactive and provided only temporary repairs. As a result, the problem appeared to be no closer to resolution than when it was first discovered. The licensee failed to fully recognize the significance of this safety-related problem and take prompt aggressive corrective action to resolve it.

3.5.4.8 Failure of Nonseismic Service Water Piping

The Unit 1 SW system was equipped with two 2-inch nonseismically designed lines which supplied seal water to the circulating water pumps, plus three 1-inch nonseismic vacuum breaker lines. There was no design-basis documentation to demonstrate the capability of the system to provide the required flow with the loss of these lines in a seismic event. Evaluation by the licensee showed that the SW system could support shutdown of the unit after loss of the lines, but would not provide required flows for LOCA conditions. The licensee acknowledged the design deficiency and was investigating potential changes to the nonseismic lines to correct it. According to NRC guidance in GL 87-02, the SW system was considered to remain operable while corrective actions were under way.

3.5.4.9 Service Water Intake Bay Level and Level Instrumentation

The allowable levels for the operation of the SW intake bays in the post-LOCA operational mode were not well defined in the design-basis documentation. In addition, the instrumentation for monitoring the level in the SW intake bays in Unit 2 did not have the range to cover the levels that were likely to be experienced following an accident and was dependent on a non-Class 1E power source.

A drop in intake bay level due to plugging of the intake screens from the lake or emergency cooling pond (ECP) could, at some point, cause a differential pressure (dp) across the screens that would stop the traveling screens and defeat the screen wash system. Subsequent increases in dp across the screens could result in structural failure of the screens. This could cause rapid fouling of the SW system strainers and heat exchangers and possible damage to SW pumps from debris and/or loss of net positive suction head. The SW strainers were single inline units that had to be manually cleaned. Since this could affect all three SW bays, it was a common mode failure mechanism. The licensee did not know the maximum allowable dp across the screens. Plugging of the lake intake screens was very credible because Class 1E power was not supplied to the traveling screens or the screen wash system and because the plant had experienced excessive foliage in the fall and shad runs in the lake in the winter, both of which had caused plugging of these screens. Although the ECP was the ultimate heat sink, there was the potential that the SW system could be fouled or damaged prior to switching to the ECP. Plugging of the ECP screens was also credible because operation in the accident mode would significantly raise the pond temperature, potentially causing much of the aquatic life in the pond to die (Section 3.5.4.10).

At the close of the DE, the licensee was investigating the level limits on the Unit 2 intake bay and the required instrumentation range and power source. This discrepancy was caused by a design-basis deficiency, a lack of design-basis documentation and inadequate or weak design of instrumentation important to safety.

3.5.4.10 Aquatic Life in the Emergency Cooling Pond

The team identified a potential mechanism by which the ECP intake screens might be clogged by fish and other aquatic life killed by the elevated temperatures in the ECP during a design-basis accident. The design-basis documentation was deficient in that it did not provide for the control or monitoring of aquatic life in the ECP. The licensee initiated CR (1-89-0090) and after the DE collected 1600 pounds of fish following chemical treatment of the ECP The licensee planned to repeat this treatment in the summer of 1990 and then decide on the long-term corrective actions.

3.5.5 Selected Programs and Issues

In addition to the routine requests for plant modifications and engineering studies and the support of the improvement programs discussed in Section 3.5.6, engineering resources had been strained by other major efforts and issues such as the RCP seal, fire protection and valve reliability programs, anticipated transient without scram modifications, control system upgrades, human factor improvements, breaker coordination studies, dc system upgrades, and response to unanticipated concerns requiring quick resolution such as the Unit 1 HPI backflow event, high containment temperature, and the addition of flow venturis to HPI piping to satisfy small-break LOCA assumptions. The team's review of several of these programs and issues is provided in the following sections.

3.5.5.1 Breaker Coordination

The Engineering Department had performed extensive protective device coordination studies for Unit 1 and Unit 2, which demonstrated proper coordination of all branch circuit breakers with the upstream main bus feeder breaker. These studies showed that where non-1E loads were supplied from Class 1E buses, a fault on a non-Class 1E circuit could not cause the entire Class 1E bus to be deenergized. The coordination studies were completely redone in 1984 to ensure accurate as-built information. The auxiliary electrical system was modeled in a computer program to determine available fault currents and other parameters for selection of appropriate protective setpoints. Design Engineering Directive (DED) T-266, dated May 10, 1989, required that the protective device coordination study be updated to reflect any plant design changes. The above is an example of a proactive effort to address a generic industry problem.

3.5.5.2 Battery Replacement and DC System Improvements

The replacement of Unit 2 station batteries was an example of good engineering practice. In 1982, the results of performance discharge tests on the Unit 2 batteries indicated that 86 percent and 89 percent capacity remained in batteries 2D11 and 2D12, respectively. The replacement criteria required the batteries to be replaced within the next cycle if the capacity fell below 80 percent. The 1985 service discharge test did not indicate any further degradation; however, several cells were showing signs of deterioration beyond that expected. Therefore, the decision was made to replace battery 2D11 (with the lowest capacity factor) during outage 2R5 and to replace battery 2D12 during outage 2R6.

In addition to replacing the batteries, the licensee made other improvements in the dc system. These improvements included the addition of battery disconnects, blown fuse indication, bus metering enhancements, and breaker replacements that were needed because of increased fault currents. To resolve overvoltage problems on continuously energized dc components, the battery voltage was reduced by decreasing the number of cells in each battery to 58. This allowed a reduction in equalizing and float charging voltage so that they were within component ratings. The capacity was also increased from 1350 ampere hours to 2064 ampere hours and the 200-ampere battery chargers were replaced with 400-ampere battery chargers.

3.5.5.3 Fire Protection

The team did not evaluate the licensee's fire protection program. However, it did identify several concerns related to fire protection issues and these are discussed in the following sections.

3.5.5.3.1 Potential Seismically Induced Fire

The team identified a potential seismically induced fire that would also degrade the fire protection system and could also provide a fire source in the SW pump P4B power supply. This situation was in conflict with 10 CFR Part 50, Appendix R, which requires that in-situ fire hazards be identified and protected against.

The fuel oil day tank for the diesel-driven fire pump was in a room adjacent to the SW pump P4B power supply room. The tank was positioned in a saddle approximately 5 feet off the floor, but was not attached to the saddle. In a seismic event the tank could have slid out of the saddle, ruptured and provided a fuel source for a fire. The diesel's battery was below the tank and, if struck by the tank, it could have caused fuel ignition. Although the wall and the door separating the two rooms had fire ratings of 3 hours, there were no provisions for preventing flammable liquids from passing under the door. Therefore, such a fire could have potentially threatened the pump P4B power supply in the adjacent room. (The National Fire Protection Association code requires that doors be protected to prevent flow through the doorways.)

As a result of this observation, the licensee planned to modify the tank support by adding straps to hold it in place during a seismic event and to install a curb at the door between the adjacent rooms to prevent the spread of any flammable liquid that could be released onto the floor.

3.5.5.3.2 Potential Fire Damage to Both Diesel Generators

The doorways between the two EDG rooms for both Units 1 and 2 were not protected to prevent flow of flammable liquids through the doorways. As a result an oil fire in either room would threaten not only the EDG in that room, but also the EDG in the adjacent room. The licensee was investigating the installation of barriers between the rooms to prevent potential carryover of oil between the rooms.

3.5.5.4 Valve Program

The AP&L Valve Program included the analyses testing efforts required to respond to IE Bulletin 85-03, INPO SOER 86-03 and GLs 88-14 and 89-10. The valve testing aspects of the program were discussed in Section 3.3. The Valve Program was included among the list of the licensee's improvement programs (Section 3.5.6), but is discussed here because of the numerous problems noted.

3.5.5.4.1 Response To NRC Bulletin 85-03

The response of the Engineering Department to NRC Bulletin 85-03, "Motor-Operated Valve Common Mode Failures During Plant Transients Due to Improper Switch Settings," was to perform setpoint calculations for those MOVs addressed in the bulletin and an additional set of MOVs identifed by the licensee. The Valve Program established a small group of design personnel that was generally dedicated to valve issues. The concerns in GL 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance," were to be resolved by means of a project involving in-house staff and contractor support. A positive action by the licensee was the development of a guideline relating to the design and operability criteria associated with MOVs.

Testing of Unit 1 HPI valves in response to NRC Bulletin 85-03 had revealed some engineering design problems. The sizing of motor operators for Unit 1 HPI valves CV-1219, CV-1220, CV-1227, and CV-1228 and Unit 2 valve 2CV-0789-1 was marginal in providing the required thrust range for proper valve operation. This condition was found by the licensee as a result of diagnostic testing conducted during late 1986 in response to NRC Bulletin 85-03. In early 1987, the design engineering staff prepared a project scoping report that recommended replacing the valves because of prior experience with unusually high unwedging forces in the open direction. Implementation of the DCPs was planned for 1R8 refueling outage in late 1988. However, during that outage, significant design, manpower and procurement problems were identified and the design modifications were deferred.

In the interim, while the design engineering staff was preparing the DCPs for valve modifications, valve thrust ratings were increased to approximately 110 percent of rated design. However, the useful life of the valves would be limited to 100 cycles. This limitation was based primarily on generic vendor guidance and not on specific vendor design studies or testing for the specific application involved.

On April 5, 1989, Unit 1 RCS HPI valve CV-1227 failed to open during surveillance testing. Valve failure was attributed to lack of adequate lubrication of the stem. As part of the long-term corrective actions, the maintenance staff requested that more priority be placed on the implementation of DCPs for all valves limited to 100 cycles. The maintenance staff also requested that the engineering staff approve a new stem lubricant that had better lubrication properties. At the time of the DE, the engineering staff had not approved the new stem lubricant for use, and further work on DCPs for valve modifications was on hold pending the results of a study that would allow the design thrust ratings of the valve operator to be further increased to 120 percent of rated design and, thus, eliminate the 100-cycle limit and the need for implementing the DCPs. Results of the study were not expected until December 1989.

Although several interim corrective actions had been taken, these actions had not always been effectively implemented because of poor coordination and interface of activities among the various licensee organizations. Because of the generic applicability and safety significance of the HPI valves and the duration of the condition, the team concluded that the licensee had not taken timely correction actions to resolve this problem.

3.5.5.4.2 DC-Powered Motor-Operated Valves

The team found several deficiencies in the calculations for dc MOVs. There were five dc MOVs in Unit 1 and nine in Unit 2 in the EFW system. There were also two dc MOVs in Unit 2 associated with the emergency core cooling system vents.

Calculations, revised in 1986, to determine the dc voltage available at the actuator motor terminals were available for Unit 1, but not for Unit 2. A calculation for Unit 2, prepared during the DE, was incomplete because several design criteria were incorrectly assumed to be insignificant or not applicable. For example, the battery end-of-life voltage was not considered. In addition, the resistance values for the thermal overload heaters were not included. The team also reviewed mechanical calculations for valves CV-2627 and CV-2620, which showed that the valves were marginal in regard to the amount of torque their operators could develop. A major input to these calculations was the motor terminal voltage. The original mechanical calculations assumed a minimum dc voltage at the motor terminals of 80 percent of the 125-V dc rating, or 100 volts, instead of the results of electrical calculations that concluded a minimum of 90-V dc would be available. The licensee did not provide the team any plans for corrective actions.

3.5.5.4.3 Check Valves

The design engineering studies to resolve industry check valve issues identified in INPO SOER 86-03 had not been initiated. Plans to use the same consultant firm to resolve both the industry check valve issues and the MOV issues in GL 89-10 were initiated because of perceived financial benefits. The Check Valve Program was further delayed because the licensee was waiting for the issuance of GL 89-10. The resource limitations within design engineering and lack of aggressive management support also contributed to the failure to initiate the design studies of check valves.

Several check valve failures (some recurring) had occurred at ANO since the issuance of SOER 86-03. The licensee indicated plans had been revised to request separate proposals for the check valve and MOV projects, with scheduled resolution of SOER 86-03 issues within approximately 1 year.

3.5.5.4.4 Air-Operated Valves

The licensee's design-basis documentation for the proper sizing of air-operated valves was weak. The licensee did not know the differential and line pressure design requirements for Unit 1 containment cooler SW outlet valves (CV-3812 and CV-3814). In addition, the licensee's Valve Program did not provide adequate guidance for the sizing of air-operators or the air supply to air-operated valves. Therefore, the team could not verify that air-operated valves were properly sized to meet differential pressure requirements for valve operation until sizing information was obtained.

In addition, no design-basis was provided to the team for the sizing of the Unit 1 safety-related backup air supplies for the above valves. The only design-basis information provided to the team for the backup air supplies was the results of a surveillance test during which the ability of the air supply to hold the valve shut for thirty minutes was verified. This duration appeared to be unreasonably short and no justification was provided. The valves need to remain shut following the postulated LOCA until containment isolation is no longer required.

The licensee's response to GL 88-14, "Instrument Air Supply System Problems Affecting Safety-Related Equipment," was inadequate. GL 88-14 requested that licensees verify that the design of the entire IA system including air or other pneumatic accumulators was in accordance with its intended function and that they verify by test that air-operated safety-related components would perform as expected during all design-basis events, including a loss of the normal IA system. The design verification did not ensure that safety-related air-operated valves were sized properly to meet differential pressure requirements for valve operation for all design-basis events. In response to the team's concern, this issue was scheduled to be addressed under the Valve Program.

3.5.5.5 As-Built Electrical Deficiencies

The team conducted a limited as-built field evaluation of Unit 1 SW switchgear cubicles and their associated wiring installations in engineered safety feature (ESF) panel C18 in the control room. The team found numerous discrepancies existed between actual field installations and the design drawings. For example, extra wires were found in the field but were not depicted on the design drawings; external wiring had been adjusted during a 1974 installation to match existing internal wiring, but the drawings had not been corrected; jumpers existed in the field but were not shown on the drawings; external conductor color codes shown on the drawing did not match the as-installed configuration; and various drafting errors on the drawings resulted in discrepancies in the actual field installation. The licensee had performed a field inspection of the 4.16-kV and 6.9-kV switchgears in early 1988 and found discrepancies similar to those found by the team. However, the controlled ANO drawings had not yet been corrected to reflect this 1988 inspection and further inspections were not conducted.

The team found a deficiency where an extra relay contact was wired into the initiation logic circuitry of SW pumps P4A and P4C. The licensee issued CR 1-89-481, on September 12, 1989, documenting this deficiency. This relay was not shown on Schematic Diagram E275, Revision 17, and had not been identified by the licensee. The ANO Engineering staff initially informed the team that this extra contact would not affect the functional logic of the circuit and closed the CR. The team then requested that a more thorough analysis be performed to determine the potential consequences of this discrepancy. The results of the licensee's detailed analysis resulted in declaring Unit 1 SW pumps P4A and P4C inoperable because of the logic error. This logic error had existed since 1974 and was a result of incorrect circuit modifications. In the as-found configuration, on a reactor trip coincident with an ESF actuation, SW pumps A and C would fail to restart on a slow (10-cycle to 2-second) transfer from the auxiliary transformer to the startup transformer because of action of the anti-pump circuitry (NRC IN 88-75 describes events where the anti-pump circuitry prevented the desired closure of circuit breakers). The licensee issued CR 1-89-484, dated September 13, 1989, to document this problem and issued a modification package to remove the improperly wired contacts and restore the circuits to their original design-basis requirements.

While the team was on site, the licensee performed further as-built inspections of the ESF panels in the control room. During these inspections, the licensee identified additional as-built and other deficiencies. For example, because the SW pump auto trip alarm circuit was not wired as required by the design drawings, the circuit was inoperable (CR 1-89-491). Also, during the testing performed by the licensee to verify operability of the SW pump after the removal of the extraneous circuit previously identified, the pump control switch located in control room panel C18 failed to function as a result of the accumulation of dust on the switch contacts (CR 1-89-487). During the DE, the team informed the licensee of the excessive accumulation of dust in panel C18.

In addition, in September 1988, the licensee had discovered an improperly terminated wire that would have prevented the automatic starting of the swing HPI pump during ESF actuation and had reported it in LER 88-013.

The causes of the miswiring appeared to be failure to properly implement field modifications, lack of adequate quality control during construction and subsequent circuit modifications, failure to correct known wiring deficiencies and an inadequate testing program to detect extraneous sneak circuits. There was no concerted effort to take effective and timely corrective actions to correct the as-built electrical deficiencies at ANO.

3.5.6 Improvement Programs

In response to the various problems that had affected ANO, the Engineering Department had initiated numerous improvement programs. Some initiatives suffered from a protracted schedule and a lack of priority and management attention, such as the PM and lubrication programs. The licensee's understanding of the scope of the problem continued to grow in some cases and this also contributed to delays in some programs, such as resolution of the original as-built drawing and calculational discrepancies for Class 1 piping and supports. Other initiatives reflected recent generic industry problems, such as the secondary pipe wall thinning program. Finally some initiatives were proactive in nature such as the safety system functional inspections.

The resources required to support these improvement programs represented approximately 18 percent of the AP&L nuclear engineering staff and approximately 50 percent of the large engineering contractor staff (including the Valve Program discussed in Section 3.5.5.4).

A major program had not been implemented to resolve design and installation deficiencies related to electrical and instrumentation systems. The lack of such a program was considered to be significant because of the as-built deficiencies identified by the licensee and the team as discussed earlier.

Selected improvement programs are discussed in the following sections.

3.5.6.1 Configuration Management and Design Configuration Documentation Programs

Many of the ongoing problems at ANO could be traced to the poor documentation and control of the design bases and associated design configurations. The deficiencies were compounded by the lack of documentation turnover from the A/E after construction and by poor documentation of modifications during the first years of operation.

The Configuration Management program was a preliminary step to identify the documentation that defined the ANO design configuration, establish programs to ensure the design configuration was maintained, and coordinate the results of the Design Configuration Documentation (DCD) Program with the established Configuration Management Programs. The program was in the initial planning phase. Outside contractors were being hired, and the program was scheduled to be completed in 1990.

The DCD Program was initiated in late 1987 in response to the problems associated with the lack of design-basis information that was made evident by the high containment temperature issue at ANO Unit 1. The scoping and definition phase of the program was recently completed, and the program was beginning its implementation phase. The goals of the program included the collection of design-basis information, preparation of systems descriptions and other documentation, verification of the design information, and implementation of an information management system to allow access of design documentation to all potential users. Completion of the program was scheduled for the mid-1990s.

The Configuration Management and DCD Programs were a major commitment of staff and contractor resources to address the design-basis/configuration problems at ANO. Because the programs were in their early stages, the team could not judge or predict their success.

3.5.6.2 Isometric Update Program

The Isometric Update Program involved the certification that the drawings for seismic Class 1 piping and supports agreed with the as-built plant condition, the reconciliation of drawings and as-built conditions, and the analysis of discrepancies as required. The program was initiated in 1986 as an attempt by ANO Engineering to resolve drawing discrepancies. The program was expanded to include verification of configuration in late 1987. At the same time, arrangements were made for contractor support to perform calculation reconciliations based as-found conditions. The walkdown efforts were refined in late 1988 in order to improve the accuracy required for design reconciliation, and an overall program manager was assigned in early 1989. The level of funding supported a completion schedule of approximately 10 years. A lack of documentation had contributed to the delay in this program.

3.5.6.3 Safety System Functional Inspection

In May 1989, the licensee performed a self-initiated SSFI SSFI of the DHR system. The quality of the SSFI appeared adequate and a number of significant safety concerns were found. Shortly after the SSFI was completed, the SSFI team was disbanded, the open items were put into the CR tracking system with all of the other plant CRs, and the status of the inspection findings ceased to be tracked as a separate entity. However, a cursory review by the team of followup to the SSFI revealed no significant discrepancies.

3.5.6.4 Service Water Integrity Plan

The SWIP was expanded to its existing scope in 1986 from smaller projects that had been formed to address concerns such as biofouling and corrosion. A committee representing various ANO organizations and chaired by the SW system engineer met periodically to define the required actions for upcoming outages and nonoutage periods. The plan included routine maintenance and surveillance activities, inspection and repair efforts, and studies to identify the cause of problems and determine necessary corrective actions. Significant efforts included preparation of a system hydraulic model, development of actions to increase Unit 1 flow margins, thermal monitoring, replacement of heat exchanger cooling coils, and increased performance trending. Those activities performed under the SWIP had been significant and effective in addressing some problems, but many problems with the ANO SW system remained and the team was unable to speculate on the ultimate success of the SWIP.

4.0 EXIT MEETING

On October 18, 1989, the Director, AEOD, the Regional Administrator, Region IV, the ANO DET Manager and Deputy Manager, together with the Acting Director Division of Reactor Projects, III, IV, V and Special Projects, NRR and other NRC personnel, met at the AP&L General Office in Little Rock, Arkansas, with the Chairman, AP&L, President and CEO, SERI Co, System Energy AP&L Vice President, Nuclear and ANO management officials, to provide a briefing on the preliminary results of the ANO Diagnostic Evaluation. The list of attendees is provided at the end of this section. The briefing notes, which provided the team's preliminary findings and conclusions, are attached as Appendix A.

E. L. Jordan, Director, AEOD, began the meeting by introducing the NRC meeting participants, and T. G. Cambell, Vice President, Nuclear, introduced AP&L management in attendance. Mr. Jordan, followed these introductions by summarizing the purpose of the NRC Diagnostic Evaluation Program and the evaluation process and indicated the need for AP&L management to understand the team's findings fully to ensure overall success of the evaluation. Following these remarks, he summarized the team's findings and noted that engineering support to the plants, although not identified on the slide, was viewed by the team as a significant weakness underlying the continuing equipment deficiencies at the station.

G. G. Zech, ANO DET Manager, presented the preliminary results of the DET evaluation in each of the functional areas, as well as in the areas of management and organization.

Mr. Jordan, provided the team's conclusions on the root causes for past performance problems and noted that the team observed few strengths in its evaluation. Weaknesses were much more evident, with improvement efforts underway in a number of areas. Noted was the NRC's view that AP&L management did not appear to have a sufficiently heightened concern and aggressive approach to resolving permanently the reliability and performance issues associated with the valves on the 100 cycle watch list in the Unit 1 HPI system.

Mr. Campbell gave his perspectives on AP&L's efforts to ensure reliability of these valves.

N. S. Carns, Director, Nuclear Operations, added that the decision had recently been made to replace, during the upcoming mid-cycle outage, valves in the Unit 1 low pressure injection system that were on the 100 cycle watch list.

D. Hintz, Chief Operating Officer, System Energy, questioned the team's view that meeting schedules were overly emphasized at ANO, especially in light of the recent lengthy outages, which he viewed as indicative of a willingness to take the time to complete needed work.

Mr. Zech indicated that the team's overall observation was that power production had a higher priority than fixing problems.

S. D. Rubin, Deputy Team Manager, added that it was evident to the team that power production placed pressure on the ANO support staff to move on to the next problem before the last problem had been effectively evaluated for root causes and that this had led to inadequate corrective actions and repetitive failures.

Mr. Hintz asked if the NRC's earlier views had changed regarding AP&L's perceived lack of condor and openess and, defensiveness.

Mr. Jordan stated that such concerns were there in the past, that the team had observed a much more positive attitude toward the NRC and that it was also important for both sides to realize that they shared the common goal of safe plant operations.

R. Martin, Administrator, Region IV, agreed that recent organizational changes clearly showed that AP&L management was making a substantial effort to improve relations with the NRC, but that it should not be surprising to continue to find isolated pockets of the old attitudes within the lower levels of the ANO staff.

W. Cavanaugh CEO, SERI, asked for and was provided a clarification on the team's findings related to material control, spare parts dedication and maintenance information system weaknesses. In addition, he questioned whether the team had a clear understanding of the Engineering Department's success in hiring engineers to replace those who had departed.

Mr. Zech indicated that the team had received very recent data from AP&L on the subject and the issue was really one of a net loss in the level of design engineering experience and "corporate memory" of plant design and design basis.

Mr. Rubin added that the team understood that a substantial percentage of the remaining design engineers were actively looking to leave, and that the team was concerned that the loss of experience could get worse in the future.

Mr. Campbell provided closing remarks by stating that the Diagnostic Evaluation was totally different than any evaluation they had ever received. He indicated that although the evaluation had resulted in a large manpower drain, it would provide a large benefit in underscoring the direction in which they were trying to go.

J. Maulden, Chairman and CEO, AP&L, stated that the team had done a quality job, and in doing so they now knew more about the challenges that lay ahead. He stated that the success of their efforts would be in meeting the challenges and not simply understanding them. He thanked the team for having effectively discharged its responsibilities.

ATTENDEES LIST

AP&L/NRC ANO DET Exit Meeting
October 18, 1989

Edward L. Jordan	Director, Office for Analysis and Evaluation of Operational Data, NRC
Robert Martin	Regional Administrator, Region IV, NRC
Gary M. Holahan	Acting Director, Division of Reactor Projects-III/IV/V, NRR/NRC
Gary G. Zech	Team Manager, Arkansas Nuclear One, Diagnostic Evaluation Team, AEOD/NRC
Stuart D. Rubin	Deputy Team Manager, Arkansas Nuclear One, Diagnostic Evaluation Team, AEOD/NRC
Frederick J. Hebdon	Project Directorate-IV, NRR/NRC
Thomas P. Gwynn	Deputy Director, Division of Reactor Projects, Region IV, NRR/NRC
Dwight D. Chamberlain	Section Chief, Region IV, NRC
Clay C. Warren	Senior Resident Inspector, Arkansas Nuclear One, Region IV, NRC
Craig Harbuck	Project Manager, NRR/NRC
Chet Poslusny	Project Manager, NRR/NRC
Jerry Maulden	Chairman & ECO, AP&L
T. G. Campbell	Vice President/Nuclear, AP&L
Neil S. Carns	Director/Nuclear Operations, AP&L
Early C. Ewing	General Manager/Technical Support Assessment, AP&L
William T. Craddock	General Manager/Nuclear Support, AP&L
Larry W. Humphrey	General Manager/Nuclear Quality, AP&L
George T. Jones	General Manager/Engineering, AP&L
Keith Wire	Manager/Plant Assessment, AP&L
James J. Fisicaro	Manager/Licensing, AP&L
Robert Fenech	Unit 2 Plant Manager, AP&L
Jimmy D. Vandengrift	Unit 1 Plant Manager, AP&L
William Cananaugh	President & CEO SERI
Donald Hintz	COO SERI

APPENDIX A

ARKANSAS POWER AND LIGHT COMPANY/NRC

EXIT MEETING ON THE RESULTS OF THE

DIAGNOSTIC EVALUATION

OCTOBER 18, 1989

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ARKANSAS NUCLEAR ONE DIAGNOSTIC EVALUATION

- Summary
- Strengths, Weaknesses and Improvements
- Root Causes

SUMMARY

- Lack of documented design basis impacting maintenance, engineering and operations activities
- Multitude of equipment reliability and design deficiency problems
- Numerous maintenance program deficiencies
- Organization in period of transition
- Staffing issues impacting routine/betterment activities
- Cultural issues

DESIGN AND ENGINEERING SUPPORT

- o Improvements
  - o Reorganization and consolidation of design and engineering support
  - o Problem identification
  - o Work planning to enhance communications
  - o Design Change Package (DCP) program
  - o System engineer program plan

- o Weaknesses
  - o Poor design basis and configuration documentation
    - Continues to impact maintenance, engineering and operations efforts
  - o Communications within engineering and with other ANO departments
    - MOV thermal overloads
    - Handling of industry experience
  - o Lack of aggressive support to other departments
    - Operability determinations
    - Root cause determinations
    - CR, pears, ears backlogs
  - o Loss of engineering talent - impact on improvement efforts, large backlog
  - o As-built deficiencies
    - Piping
    - Electrical

MAINTENANCE AND SURVEILLANCE

- Improvements
  - Organizational changes
  - Operations/Maintenance Interface
  - Preventive Maintenance Program Plan
    - Vendor manual upgrades
- Weaknesses
  - Material condition problems
  - Management emphasis on schedules
  - Inadequate maintenance on S-R equipment
  - Rework not tracked
    - Recurring equipment problems
    - Poor root cause determinations
    - Inadequate corrective actions
  - No equipment failure trending
  - Material controls problems
    - Spare parts availability
    - Weak dedication process
  - Maintenance information
    - Difficult retrieval
    - Poor quality
  - Inadequate programs
    - Fuse control
    - Backlog reduction
  - Potential staffing impacts
    - Unitization of plant crafts
    - Implementation of PM program
    - ASME IST program
  - Surveillance testing weaknesses
    - SOER 86-03 design evaluation not performed
    - Not all SW components included
    - Nonconservative operability determinations

OPERATIONS AND TRAINING

- o Strengths
  - o Strong licensed operator staffing and pipeline
  - o Good operations/training interface
  - o Good support to plant during outages
  - o Commitment to high quality training program
- o Weaknesses
  - o Chronic material and equipment deficiencies impacting operations
    - U1 DHR cooler outlet valves failed open
    - Inadequate valve maintenance
    - Steam generator blowdown drag valves
  - o Administrative procedures/guidance
    - Use of rough logs
    - Night orders
    - Independent verification of actions
    - Second party verification of valve lineups
  - o Procedural quality and adherence
    - EOPS difficult to use
    - Inappropriate temporary changes
    - Control over deviations from system valve lineups
  - o Tech Spec interpretations
    - Not entering LCO for surveillance tests
    - Incorrect interpretations

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MANAGEMENT AND ORGANIZATION

- o Improvements
  - o Management and organization changes
  - o Consolidation of engineering/design functions
  - o Increased teamwork and sense of ownership
  - o Increased encouragement to identify problems
- o Weaknesses
  - o Fragmented problem integration, evaluation and prioritization process
  - o Absence of clearly defined organizational goals related to individual performance and communicated to staff
  - o Self assessment activities
    - Root cause determinations
    - Trending of repetitive failures/rework
    - Trending of condition reports
    - Effective utilization of QC resources
  - o Critical staffing issues
    - System engineers
    - LRGO engineers
  - o Lingering cultural problems
    - Willingness to live with problems
    - Nonconservative operability determinations
    - Nonconservative Tech Spec interpretations
    - Emphasis on schedules

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ROOT CAUSES OF POOR OVERALL PLANT PERFORMANCE

- Inadequate corporate leadership, oversight and involvement to address station management and organizational weaknesses
- Past station leadership weaknesses
  - Reliance on administrative programs
  - Individual performance expectations not communicated
  - Micromanagement/Staff not held accountable for performance
  - Poor design documentation at time of construction
  - Delay in initiating design reconstitution
  - As-built design discrepancies
- Sense of complacency regarding plant performance
  - Weak assessment performance monitoring
  - Compliance vs safety approach
  - Lack of outside experience with higher industry performance standards
  - Previous assessments by outside organization not sufficiently critical
- Failure to clearly document or reconstitute the plant design basis
- Inadequate technical/engineering support to address plant needs
  - Organizational structure
  - Design and equipment problems
  - As-built deficiencies
  - Configuration management controls

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APPENDIX B

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

JUN 29 1989

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

FROM: Victor Stello, Jr.
Executive Director for Operations

SUBJECT: DIAGNOSTIC EVALUATIONS

By this memorandum you are directed to conduct diagnostic evaluations of Arkansas Nuclear One and Palo Verde Nuclear Generating Station. You should plan to conduct these diagnostic evaluations so that you can report your findings at the next NRC Senior Management Meeting in January 1990. Support for the diagnostic evaluation teams will be provided, as necessary, by NRR and the regional offices.

As you know, these plants were discussed during the last Senior Management Meeting. From these discussions, which addressed the regulatory and operational performance history at both nuclear stations, it became apparent that additional information would be needed to make an adequately informed decision regarding their overall performance. I have determined that diagnostic evaluations of these plants are the most effective means of obtaining this information. These evaluations should be broadly structured to assess overall plant operations and the adequacy of both licensees' major programs for supporting safe plant operation.

Please forward your specific plans regarding schedule, team composition, and evaluation methodology when they are formulated.

Victor Stello, Jr.
Executive Director for Operations

cc: T. E. Murley, NRR
J. M. Taylor, DEDO
R. D. Martin, RIV
J. B. Martin, RV