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Licensee: Florida Power Corporation
3201 34th Street, South
St. Petersburg, Florida 33733

Facility Name: Crystal River Nuclear Generating Plant, Unit 3

Inspection At: Crystal River and Saint Petersburg, Florida

Inspection Conducted: August 24-September 4, 1987

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TABLE OF CONTENTS

LIST OF ABBREVIATIONS

AFW	auxiliary feedwater
AI	administrative instruction
ANSI	American National Standards Institute
ASME	American Society of Mechanical Engineers
CFR	Code of Federal Regulations
CR-1,-2,-3	Crystal River Generating Plant, Unit 1, 2, or 3
CWST	circulating water traveling screen
DC	decay heat closed cycle cooling water
DO	domestic water
EA	Engineering Assurance
ECCS	emergency core cooling system
FCN	field change notice
FCR	field change request
FD	flow diagram
FPC	Florida Power Corporation
FSAR	Final Safety Analysis Report
HVAC	heating, ventilation and air conditioning
I&C	instrumentation and control
IEEE	Institute of Electrical and Electronics Engineers
ISI	inservice inspection
LOCA	loss-of-coolant accident
LOOP	loss of offsite power
MAR	modification approval record
MP	maintenance procedure
NCOR	nonconforming operations report
NGRC	Nuclear General Review Committee
NOTES	Nuclear Operating Tracking System
NPSH	net positive suction head
NRC	Nuclear Regulatory Commission
NSSS	nuclear steam supply system
NSSW	nuclear services sea water
OP	operating procedure
OSIM	Operations Section Implementation Manual
OSTI	operational safety team inspection
OSTG	once-through steam generators
PACE	people achieving corporate excellence
PASS	post-accident sampling system
PRC	Plant Review Committee
QIR	quality information report
RCP	reactor coolant pump
RCS	reactor coolant system
RHR	residual heat removal
RW	raw water
RWP	raw water pump
SP	surveillance procedure
SSE	safe shutdown earthquake
SW	nuclear services closed cycle cooling water
SWP	service water pump
T-MAR	temporary modification approval record

CRYSTAL RIVER NUCLEAR GENERATING PLANT
OPERATIONAL SAFETY TEAM INSPECTION
INSPECTION REPORT 50-302/87-22

AUGUST 24-SEPTEMBER 4, 1987

1.0 INTRODUCTION AND BACKGROUND

The NRC conducted a review of Crystal River Nuclear Generating Plant, Unit 3 (CR-3) prior to the inspection to assess past performance and trends. This review included inspection reports, enforcement history, licensee event reports, systematic assessment of licensee performance, and discussions among various staff members responsible for CR-3 oversight. An operational safety team inspection was initiated to examine, in depth, four areas of licensed activities (operations, design adequacy and control, corrective action systems, and management oversight). The team was comprised of inspectors and consultants experienced in operations (including extensive direct experience with nuclear power plants using the same Babcox & Wilcox nuclear steam supply system [NSSS] as CR-3) and design engineering.

2.0 PURPOSE AND SCOPE

The purpose of the inspection was to evaluate, in depth, the licensee's operational performance and related engineering and plant support activities.

The principal focus of the inspection was operational safety performance including plant operations, maintenance, surveillance testing, and related activities. Specific emphasis was placed on the evaluation of the licensee's implementation of administrative and management controls for operations and the observation of integrated plant operations. The areas of operations support, management oversight, safety review activities, and corrective action systems also were examined.

As a separate associated effort, inspectors experienced in design engineering reviewed the design of the decay heat and nuclear services raw cooling water systems, including design control programs, conformance with the design bases, as-built installation, engineering, and operations and surveillance procedures. These inspectors used techniques developed during the NRC's safety system functional inspections (SSFIs).

The inspection was conducted at the CR-3 site from August 24 through September 4, 1987. Ten NRC staff members and consultants participated in the inspection full-time, and two participated part-time. Four inspectors observed control room and in-plant activities on an essentially continual basis from August 26 through September 1, 1987. Three inspectors reviewed the plant design for selected systems. The remainder of the team evaluated operations support, corrective action systems, and committee activities. Interviews of licensee managers were conducted at the Florida Power Corporation (FPC) offices in St. Petersburg, Florida.

3.0 SUMMARY OF FINDINGS

CR-3 was selected for this inspection in part due to a history of operational, engineering, and material and equipment problems that has been documented in previous NRC inspections and evaluations. This inspection found that the licensee has implemented a number of progressive and apparently effective programs to correct many of the problems, although full implementation and effectiveness is yet to be achieved.

The integrated plant operations observed during the inspection were conducted with no significant problems. Those problems that did occur were handled by FPC on a routine and substantially acceptable basis for the most part. The team specifically observed several strengths in the operations area which were considered noteworthy. These included a general sensitivity to strict adherence to procedures, timely and thorough shift turnovers, and support around-the-clock by the document control center, which included a serialized accounting system for issuing documents. This good operational performance, particularly the observed strong sensitivity toward procedure adherence, seems to have resulted from recent FPC initiatives to improve in this area.

However, the team identified several concerns regarding plant operations. The team considered that the licensee's evaluation of loose part monitor alarms originating from the reactor coolant system was subjective in nature, lacking a strong basis for their conclusion that the cause was not deleterious (Observation 302/87-22-07). The team also considered the problems that the licensee has experienced with seating of the reactor building ventilation containment isolation valves to represent a human factors and safety problem (Observation 302/87-22-08).

Although the team identified several programmatic and implementation weaknesses, the overall operational performance demonstrated that, especially with continued improvement and resolution of past problems, FPC has the capability to competently and safely operate the facility.

Additional weaknesses were found in the areas of licensee corrective action programs, management oversight, and committee activities. These typically involve a need for more rigorous management of existing problem correction programs and improvements in existing activities. The Plant Review Committee procedures and instructions were found to be sparse and weak. The team found the committee's use of the qualified review process and subcommittees to be a weakness (Observation 302/87-22-11). In the area of corrective actions, the team identified concerns regarding the timeliness and adequacy of some corrective actions. For example, the licensee's evaluation of past leakage in the post-accident sampling system did not adequately assess potential problems during accident conditions or establish corrective action on a timely basis (Observation 302/87-22-12).

The team identified more significant deficiencies in the area of design and design control, including problems regarding the translation of design bases into equipment design and operating or test procedures, quality and integrity of the design bases, and related issues. Specific examples illustrating these deficiencies include the design ultimate heat sink temperature (Observation 302/87-22-01), cooling water flow to safety-related components (Observation 302/87-22-05), and diesel generator loading and testing (Observation 302/87-22-06).

The team found that the facility design assumed a maximum temperature of 85°F for the ultimate heat sink, notwithstanding a technical specification limiting condition for operation of 105°F. Observed temperatures during the inspection were noted to be above the design condition. The team was concerned that the plant design may not be consistently reflected in the operation of the plant.

The team found that the licensee had no assurance of adequate cooling water flow to safety-related motor coolers. These flows were not measured during preoperational or other testing, and plant procedures allowed the operators to throttle flows for conditions of normal plant operation without an assessment of the cooling need during design bases conditions.

The team found that the licensee's surveillance requirements and procedures for testing the diesel generators exceeded the manufacturer's rated equipment performance capability. (This condition had also been recently identified by the licensee). Additionally, the surveillance procedures were inadequate in that they did not envelope the equipment's design condition.

Continued assurance that the facility can be operated safely will require that efforts be continued (and in some cases intensified) to correct the problems associated with the quality of procedures, specific equipment deficiencies, and engineering design deficiencies which are discussed in this report.

4.0 PLANT DESIGN AND DESIGN CONTROL

The team reviewed the mechanical and electrical design of the raw water system and the ancillary cooling water systems which it services. At CR-3, these systems are arranged to comprise two safety-related heat removal systems, each with redundant trains (see Figure 1). Essentially, redundant emergency seawater pumps supply cooling water to the nuclear services closed cycle heat exchangers, and redundant decay heat seawater pumps supply flow to the decay heat closed cycle heat exchangers. During normal power operation, seawater flow to the nuclear services closed cycle heat exchangers is supplied by a non-safety-related seawater pump, and the emergency nuclear services and the decay heat seawater pumps are shut down.

This seawater cooling system is referred to as the decay heat raw water and nuclear services raw water cooling (RW) system. The closed cooling water systems served by the RW system are the nuclear services closed cycle cooling (SW) and the decay heat closed cycle cooling (DC) systems. The two portions of the RW system are addressed with their ancillary systems at CR-3. For example, Operating Procedure (OP) 408, Nuclear Services Cooling System, addresses startup, operation, and valve lineups for the nuclear services closed cycle cooling (SW) and the nuclear services raw water cooling (RW) systems; and OP-404 addresses similarly the decay heat removal (DH), the decay heat closed cycle cooling (DC), and decay heat raw water (RW) systems. The team extended its review in the electric power discipline to include an examination of the ac standby power sources for these systems.

4.1 Design Document Review

The team reviewed documents which established or supported the design of CR-3. General comments regarding this review are provided below. Specific technical comments resulting from this review are provided in the mechanical and electric power sections of this report.

4.1.1 Design Bases Documents

FPC has developed design bases documentation for systems such as the decay heat and decay heat closed cycle cooling water systems. These documents represent an initial effort to gather design data for each system into one document. Each document lists system design parameters, the source for the parameter, and the reason for the parameter listed. The team reviewed design bases documents for several systems, and was impressed with the extent of the documentation identified to substantiate the system design. These documents included a comprehensive list of key design parameters for each system; however, the team identified several weaknesses with these documents and with the reflection of the design bases in plant operation.

In a May 6, 1987, memorandum to all Nuclear Operations Engineering personnel, guidance was provided on the use of the design bases documents. The rationale used in the development of these documents was attached. The memorandum indicated that because early design bases data may not have been adequately controlled, a calculation substantiating some parameters "...may no longer exist or be retrievable. New calculations or analyses were not developed under this scope to confirm any parameters such as these...." Instead, the lack of a reference to a design analysis was to indicate that "...there is no calculation for that particular parameter."

Contrary to the above, the team identified instances where unverified calculations were developed and referenced in the design bases documents to substantiate the design parameters listed. For the decay heat closed cycle heat exchangers, the design bases document (Document 6/6, Revision 0, dated November 9, 1983) identified calculations supplied by Gilbert/Commonwealth (DC-631-01 [Revision 0, dated September 22, 1983] and DC-631-02 [Revision 0, dated September 27, 1983]) as the sources for inlet and outlet heat exchanger temperatures during various operating modes. Upon examination, the team found that these calculations had not been checked nor verified and were labeled "for information only." In addition, the calculations did not list references, identify assumptions, or provide design input as required by American National Standards Institute (ANSI) N45.2.11.

The team noted that the cover page of each design bases document indicated that the document contains design bases information pertaining to the plant. The new design bases documents were used as reference documents in Modification Approval Records (MARs) which modify the plant design.

The team concluded that the cautions and philosophy in the FPC May 6, 1987 memorandum may not be consistent with the actual implementation of these documents. Although this memorandum discusses the evolution of the data provided in the design bases documents, it did not prohibit the use of any specific data in those documents. No distinction was made between the "hard, basic source documents," described in a Gilbert memorandum (attached to the May 6, 1986 FPC memorandum), and other sources, such as those calculations supplied by Gilbert that may have no firm basis. The team was concerned that an inadequate and unverified source document, such as the calculations discussed above, could be used to substantiate safety-related modifications of the plant design (Observation 302/87-22-01).

4.1.2 Control of Calculations

The team found that the control of engineering calculations was weak. Calculations were not filed in one location and used as "living documents." Instead, calculations were filed with other work documents, such as modification packages or NCORs. Calculations that are filed in this manner are not easily retrievable by engineering personnel, and since new calculations are performed for each new work item, engineers may not have the benefit of knowing how the design bases were previously addressed. The team was concerned that this practice could result in errors because of an incomplete understanding of a particular design attribute.

4.2 Mechanical Engineering

4.2.1 Design Bases Document Review

Team review of design bases documents in the mechanical engineering discipline identified several errors and inconsistencies.

4.2.1.1 Maximum Ultimate Heat Sink Temperature

The design bases document for the nuclear services and decay heat sea water system (Document 6/12, Revision 0, dated October 8, 1985), indicated that the suction design temperature was 85°F. An FPC letter dated May 9, 1967, was cited as the source of this design requirement. The FSAR also indicated the 85°F seawater design temperature by its identification in Table 9-12 as a sea cooling water temperature for the decay heat closed cycle heat exchangers and the nuclear services heat exchangers. However, Technical Specification 3.7.5.1 required that the inlet water temperature be less than or equal to 105°F as one condition for the ultimate heat sink to be operable. The team was informed that a basis for the temperature of 105°F did not exist and that design basis accident analyses assumed a maximum ultimate heat sink temperature of 85°F.

The team observed that the seawater inlet temperature was as high as 90°F during the inspection. Therefore, the team was concerned that the plant has been operated when seawater temperatures exceeded the design basis for the facility. This observation contributed to a team concern that the design basis was not consistently reflected in the operation of the plant. In addition, the licensee was unable to readily retrieve accident analyses confirming that 85°F was the basis for the plant design, which suggests a weakness in the licensee's ability to recover design calculations and analyses. The team was concerned that engineers, operators, and review committees may not have ready access to the information they need when preparing modifications, assessing plant conditions, or reviewing procedures (Observation 302/87-22-02).

4.2.1.2 Decay Heat Closed Cycle Design Temperatures

The decay heat closed cycle heat exchangers are cooled by the raw water system and supply cooling water to the decay heat removal heat exchangers and other safety-related equipment during a normal plant cooldown and during a postulated loss-of-coolant accident (LOCA). One decay heat removal heat exchanger cooled by one decay heat closed cycle heat exchanger constitutes a decay heat removal train (Figure 1). During a normal plant cooldown, both decay heat removal trains are used to cool the plant to 140°F within 14 hours. However, in the event of a LOCA, only one of the redundant decay heat removal trains is required to accommodate the high accident heat loads during reactor building sump recirculation.

The design bases document (Document 6/6, Revision 0, dated November 9, 1983) identified the shellside outlet temperature for the decay heat closed cycle heat exchangers as 105°F during emergency operation such as initiation of engineered safeguards. A Gilbert/Commonwealth memorandum dated November 25, 1968 from J. V. Nessia to E. R. Hottenstein was given as the source of this design parameter. The reason identified for the 105°F parameter is the "design inlet temperature to decay heat removal heat exchangers for cooldown to 140°F in 14 hrs." However, that statement is the basis for the normal cooldown operating mode using both decay heat removal trains. For emergency operation during reactor building sump recirculation, only one decay heat removal train is required, and decay heat closed cycle system temperatures depend on the heat removal capabilities of the decay heat removal and decay heat closed cycle cooling heat exchangers, acting in concert, to reject heat to the raw water system. The capability of one decay heat closed cycle heat exchanger to supply 105°F cooling water during reactor building sump recirculation cannot be inferred from its cooldown capability using two decay heat removal trains. The performance of the decay heat removal system under these accident conditions should be established through an analysis that considers the mass and energy releases to the reactor building sump and the interactions between the various cooling systems (decay heat, decay heat closed cycle, and raw water) involved.

The Gilbert memorandum referenced in the design bases document identifies 105°F as the maximum permissible cooling water temperature for safety-related motors cooled by the decay heat closed cycle cooling water system. If temperatures exceed 105°F during reactor building sump recirculation because of the above heat rejection interactions, these safety-related motors may not be capable of performing their safety function. The team was concerned that these conditions could be aggravated by ultimate heat sink supply temperatures which can exceed the existing design basis for the plant. The licensee was unable to provide an analysis to substantiate the decay heat closed cycle cooling water temperatures for emergency conditions during the inspection. This issue was under review by the licensee (Observation 302/87-22-03).

4.2.1.3 Classification of Traveling Screen

The team noted inconsistent classification and consideration of a portion of the ultimate heat sink as safety-related.

Circulating water traveling screen (CWTS)-2 is a single, dedicated traveling screen system that filters all of the seawater flow conveyed by the B train of the raw water cooling system. Train A seawater is drawn from a separate forebay area of the intake structure. The forebay area is common to all circulating water pumps, and water entering this area is filtered by seven large traveling screens (CWTS-1A) through -1G). The design arrangement ensures that the two intakes are separate because (1) a gate separating the two has been changed so that it is permanently shut and (2) CWTS-2 normally receives wash water from a dedicated water supply.

The team questioned the licensee's non-safety classification of CWTS-2 in that a safety-related method may be required to prevent accumulated debris from reaching the suction of the B train raw water pumps. The FSAR stated that one intake conduit shares a common intake structure, bar racks, and traveling screens with the circulating water system and that the other intake conduit is supplied with a bar rack and separate traveling screen located in a separate intake structure. The team was concerned with the ability of the traveling screens to withstand debris loading during design bases events and remain structurally intact. As debris accumulates at the surface of the screen, the pump suction continuously removes water from the pit causing the level in the pit to drop. As a result, debris may accumulate on the upstream side of the screen and start to form a dam, first at the surface then eventually drawn down the screens. As a consequence, an increasing differential pressure could be experienced across the screen. A sufficiently large accumulation of debris will cause the screen to fail, permitting the accumulated debris to flow to the pump suction. For train A of the emergency seawater pumps, debris may take a longer time to accumulate because the suction for this train is from a large forebay and through seven traveling screens. The team was informed that when pumps RWP-2B and RWP-3B operate simultaneously, the level in the pit is a little over 3 feet lower than the intake canal level.

The following documentation indicated that the traveling screen was not safety-related:

- The Safety Listing (Revision 23, dated January 30, 1987) did not identify any circulating water mechanical or electrical equipment as being safety-related. The concrete and trash rack for the nuclear services seawater (NSSW) intake structure were the only related structures identified as safety-related in the structural section of the Safety Listing. The NSSW intake structure is defined as a structure monolithically attached to the circulating water intake structure.

- Electrical power for the traveling screen and dedicated screen wash pump is supplied from the balance-of-plant bus and may not be available during an accident.

The following are examples of documentation which suggested that CWTS-2 was safety-related:

- A non-licensed operator training document (Lesson Plan No. ANO-83, "Nuclear Services and Decay Heat Raw Water System", Revision 1, dated August 8, 1986) stated that "unlike the remainder of the traveling screens, the B train traveling screen is a safety-related piece of equipment."

- Maintenance Procedure (MP) 501, Maintenance of CWTS-2 Nuclear Service Intake Screen and Trash Racks," Revision 4, dated May 4, 1987, indicated on the cover sheet that this procedure addressed safety-related components.

System descriptions prepared by the original architect-engineer are used for information only and have not been kept up to date since they were prepared in 1975. The design bases documents do not positively address this issue for the screens. During a system walkdown, the team was informed that traveling screen CWTS-2 is safety-related. In a Plant Review Committee meeting, committee members referred to CWTS-1A through -1G as the non-safety-related screens and to CWTS-2 as the safety-related screen. The licensee's position is that the traveling screens, including CWTS-2, do not serve a safety-related function. Instead only the conduit system consisting of the intake canal, intake structure, trash racks and the 48-inch underground pipes is safety-related.

This situation demonstrated how a misunderstanding of the design bases can be reflected in the operation of the plant. The team concluded that CTWS-2 was inconsistently classified with regard to whether it was safety-related and that the licensee did not present a clear rationale for a nonsafety-related classification (Observation 302/87-22-04).

4.2.2 Design Review

The team reviewed operating procedures, hydraulic analyses, modifications, and test procedures for the raw water, nuclear services closed cycle cooling water, and decay heat closed cycle cooling water systems. Analyses and functional testing were previously performed to substantiate the capability of the SW system to provide design flow rates to critical components under normal and emergency conditions. The team reviewed the operation of this system, taking into consideration the results of the analysis or testing performed.

The SW system is designed to supply cooling water to a number of safety-related and non-safety-related components. On an engineered safeguards signal, the nonessential services are automatically isolated, and flow to the reactor building fan coolers from the non-safety-related industrial coolers is transferred to the SW system. Among the safety-related components served are the raw water, SW, and makeup pump motor coolers.

The team reviewed OP 408, "Nuclear Services Cooling System," Revision 50, dated August 11, 1987. This document included a procedure for balancing system flow with the normal supply pump (SWP-1C). The procedure required flow to specified components to be adjusted by throttling the manual outlet valves to obtain required flows as measured by the flow indicators for each component. Flow was required to be throttled to achieve design flows for the spent fuel coolers, seal return coolers, control complex water chillers, evaporators, and letdown coolers. In addition, the valve check list attached to OP-408 indicated that flow to pump motor coolers was normally throttled by opening the manual outlet valves a specified number of turns.

The nuclear closed cycle cooling water system description ("Cooling Water Systems," dated September 10, 1975) indicated that the outlet valves on these pump motor coolers can also be throttled to accommodate changes in water temperature (e.g., changes in raw water temperatures in the winter). FPC engineering personnel confirmed that these valves were throttled for this purpose. OP-408 provided no procedures on throttling these valves to accommodate changes in cooling water temperatures. Furthermore, there was no assurance that these manual valves remained in their set positions because they were not locked in the throttled position.

The original hydraulic analysis (dated November 19, 1970) completed by Gilbert assumed that all throttle valves were wide open and concluded that adequate flow could be delivered to all safety-related services during emergency operation. The team was concerned that this conclusion may not be justified because the throttled position of the pump motor cooler outlet valves may not always correspond to the minimum required design flows. Furthermore, on an engineered safeguards signal, the SW system configuration is significantly altered because cooling flow is diverted to the reactor building fan coolers. With substantial flow diverted from nonessential services (automatically isolated) to the fan coolers, and considering the accompanying change in the system resistance and the unanalyzed throttled positions of the motor cooler outlet valves, there is no assurance that safety-related pump motor coolers will receive required design flow for emergency operation.

The team further noted that OP-408 indicated that in addition to makeup pump 1B, makeup pump 1C or 1A may be aligned so that it is cooled by the SW system. Therefore, on an engineered safeguards signal, two makeup pumps would require cooling water to be supplied by the SW system. The node map for the hydraulic analysis indicated that cooling water would be supplied to only one makeup pump. There was no assurance that the flow distribution to either pump would be adequate to meet design requirements during emergency operation.

The team reviewed Test Procedure 71267031D, "Nuclear Services Closed Cycle Cooling System Functional Test," dated October 16, 1974, to determine whether functional test results had confirmed that design flows could be delivered to these components on an engineered safeguards signal. The specific acceptance criteria in the test procedure included the following:

> The emergency nuclear service closed cycle cooling pump 3A (and B) [unit number (3) is used in conjunction with component's noun names, not to be confused with the component's tag, e.g. SWP-1A], is capable of producing flow of cooling water through all paths of the nuclear services closed cycle cooling system used during emergency LOCA or emergency steam break;
>
> The emergency nuclear service closed cycle cooling pump 3A (and B), is capable of producing not less than 8339 gpm flow through the nuclear services closed cycle cooling system when the system has been lined up for emergency LOCA or emergency steam break; and,
>
> A minimum flow of 1780 gpm passes through each reactor building fan assembly cooling loop when the system has been lined up for emergency LOCA or emergency steam break.

The team noted that these criteria only address the capability of the SW system to produce flow through the various branches when the system is aligned for emergency operation. Except for flows to the reactor building fan coolers, none of the acceptance criteria reflected the need to confirm minimum required design flows to individual safety-related components (such as pump motor coolers) under emergency conditions. Section 9.2.10.3 of the procedure provided for the measurement and recording of flows to the reactor building fan coolers. Actual flows to each fan cooler, the spent fuel cooler, and the control complex chiller were recorded. Section 9.2.10.5 had provisions to ensure that cooling water was flowing through the various pump motor coolers. However, only indication that flow through the cooler exists was recorded. In each instance, the initials of the observer indicated that flow had been observed. There were no procedures for measuring and recording the actual flow rate to the pump motor coolers, despite the fact that each cooler was equipped with flow measurement devices.

The team reviewed the results of the test performed under Surveillance Procedure (SP) 344C, Revision 2, dated October 9, 1986. This test only verified the operability of the containment cooling system supply. Flows to the reactor building fan coolers were measured to ensure that design flows could be achieved. No provisions to test flows to other safety-related components (e.g., pump motor coolers) under emergency operating conditions were included.

The team was concerned, considering the effects of valve throttling and flow diversion, that there was no documented evidence to demonstrate that required flows could be supplied to safety-related pump motor coolers (Observation 302/87-22-05).

4.2.3 Testing of Design Features Performing Safety Functions

The team reviewed design drawings, flow diagrams, design documents, modification packages, and related test procedures to confirm that plant design features were adequately tested. The team found that, in some cases, design features that were relied on to perform a safety function were not tested to confirm this capability. The team identified several cases in which check valves were not tested to confirm their capability to prevent flow in the reverse flow direction. This oversight contributed to the team's concern that the consequences of undetected check valve failures in relation to the single failure criterion were not well understood by engineering and operations personnel. Examples of these weaknesses are described below.

(1) Normally, the reactor building fan coolers are cooled by flow from the non-safety-related industrial cooling system. On an engineered safeguards signal, air-operated valves SWV-152 in the industrial cooling water supply line and valves SWV-151 and SWV-355 in the industrial cooling water return line automatically close to isolate the non-safety-related system from the SW system. Cooling water is then supplied to the fan coolers from the SW system through air-operated supply and return valves, SWV-354 and SWV-353, which open on an engineered safeguards signal. Check valve SWV-356 serves as the redundant isolation valve (to valve SWV-152) in the industrial cooling water supply line. Valve SWV-356 must perform its safety function to preclude flow (in the reverse flow direction) out of the SW system to the non-safety-related industrial cooling water system, assuming the failure of valve SWV-152 to close on demand. However, check valve SWV-356 was listed in the licensee's ASME Section XI Pump and Valve Program as exempt from testing. Therefore, the capability of this active check valve to perform its safety function has not been routinely demonstrated. Because the valve has not been tested, there was no assurance that the valve will seat properly in the reverse flow direction, that the disc has not been damaged, or that the disc has been properly installed in the valve. Assuming the single active failure of valve SWV-152 to close on an engineered safeguards signal, an undetected failure of check valve SWV-356 could result in the loss of substantial flow and inventory to the non-safety-related industrial cooling system. This flow diversion could compromise the ability of the SW system to perform its safety function.

The team considered this item a weakness in engineering evaluations related to inservice testing of active check valves. Engineering relies on these check valves to preclude single failures that could compromise the ability of safety-related systems to perform their safety function. In response to this concern, FPC stated that valve SWV-356 had been incorrectly identified as one that is exempt from testing and that it would be tested to confirm its safety function and put in the inservice test program.

(2) The team found that post-modification testing requirements in an approved modification package were not sufficient to verify the safety function of some check valves.

MAR 85-09-05-01, "RW Pump Flush Water," with approved field change notices (FCNs) 1 through 4, upgrades the bearing flush water supply to pumps RWP-1, -2A, -2B, -3A and -3B. This modification, which is scheduled to be completed during the Fall, 1987 refueling outage, adds a backup source of bearing flush water by adding new cross-connection lines from the discharge piping of the raw water pumps, through cyclone separators, and into the raw water pump bearings via the existing domestic water (DO) system flush water supply piping. Manual isolation valves and check valves will be installed in the existing domestic water flushing header. The installation of the check valves will separate the A and B trains of the flush water system for redundancy. According to the raw water pump manufacturer, loss of bearing flush water could prevent these pumps from performing their intended safety function.

The procedure to be used for post-modification testing measures the normal and backup flush water flow rates under normal conditions and compares those flow rates with the acceptance criteria. However, the backup flush water flow rate under design accident conditions can be lower if the accident occurs at minimum ultimate heat sink levels because the pump suction lift would be greater. The test procedure did not compensate for minimum ultimate heat sink levels or include any margin under these circumstances.

The lack of acceptance criteria applicable to the expected test condition versus the design basis condition may not be safety significant because the pumps can be expected to operate for some period of time with little or no cooling of the bearings. However, this condition should have been considered and assessed, and the fact that it was not demonstrates a less than thorough attention to design detail.

The team also noted deficiencies regarding the proposed testing of check valves DOV-377 and DOV-376, being installed to provide train separation and to provide automatic isolation capability if the normal source of flush water (non-safety-related domestic water system) is not available. Post-modification testing requirements specified in the MAR did not provide for the testing of these check valves to confirm that they will shut on demand. The procedure required that the domestic water manual isolation valve associated with that train be closed slowly and that flushing flow be automatically transferred to the seawater system. While the manual isolation valve is shut, which simulates that the associated check valve also is shut, the flushing flow is measured and compared with the acceptance criteria. However, the procedure did not provide for the reverse flow testing of the check valve by, for example, depressurization of the domestic water system and the opening of the manual valve in series with the check valve. Therefore, there was no assurance that the check valve would have been properly installed with a functioning disc and that the disc will be securely seated when necessary.

(3) The SW system surge tank is provided with a check valve, SWV-278, which serves as vacuum relief protection for the tank. The valve must function if the surge tank, normally pressurized with nitrogen to 75-95 psig, becomes depressurized and subjected to external pressure. Although the check valve had been included in the inservice testing program under the (incorrect) Surveillance Procedure SP-602, "Relief Valve Testing," it was removed from this procedure in Revision 12, January 30, 1987, because it is not a safety relief valve. There were no further provisions to test the valve.

The team was informed that SWV-278 will be included in a surveillance procedure for IWV 2000, Category C (self-actuating) valves.

(4) The system description and the FSAR section for the SW system indicate that the SW surge tank is pressurized with nitrogen to ensure a minimum pressure of 60 psig on the closed cycle water side of the coolers in the portion of the system located in the reactor building. The intent is to prevent backflow of contaminated containment atmosphere to the SW system following a loss-of-coolant accident. The nitrogen supply piping to the tank is non-safety-related and located upstream of normally closed manual valve, SWV-584.

FPC operations personnel told the team that the surge tank has been pressurized at least once every two weeks, and as frequently as 2-3 times per week, to accommodate leakage from the tank, including absorption into the nuclear services closed cooling water. There were no records to indicate how frequently the tank required nitrogen makeup or what quantities were required in any given time period. There was no defined method to identify severe nitrogen leakage, and there are no established maximum leakage requirements for the system.

The team was concerned that, if unmonitored, leakage could become excessive and that it may not be possible to replenish the tank during accident conditions because the nitrogen supply was non-safety-related and a reliable backup nitrogen source may not be readily available.

4.2.4 Operating and Surveillance Procedures

The team's review of operating and surveillance procedures for the selected systems revealed the following weaknesses.

4.2.4.1 OP-408, "Nuclear Services Cooling System"

Operating Procedure (OP)-408, "Nuclear Services Cooling System," Revision 50, dated August 11, 1987 established the procedures for operation of the nuclear services closed cycle cooling (SW) system and the nuclear services seawater (RW) system, which together perform heat removal from components in the primary and engineered safety feature systems. This procedure provided instructions on performing infrequent operations, including startup and shutdown operations of the raw water system and transferring SW system to the industrial cooling water system. The team identified several instances where this procedure provided inadequate guidance and direction to operators. In fact, if followed as written, some of the directions could result in degraded plant safety conditions.

(1) Section 5.12 of OP-408 provided directions for transferring heat loads from the SW system to the industrial cooling system when the plant is shut down. Section 5.12.7 directed the operator to "stop all raw water pumps." Since only one raw water pump (RWP-1) was normally operating for cooling the SW system, the operator could infer from the directions given that "all" operating raw water pumps should be stopped, including RWP-3A and RWP-3B. (Note; OP-404, versus OP-408, addressed operation of that portion of the raw water system that services the decay heat removal system, including operation of RWP-3A and -3B.) These pumps are required to operate during plant shutdown to remove decay heat from the reactor; they should never be shut down in this mode.

(2) Several note and caution statements in the instructions for operation of the raw water system were incorrect and weak.

(a) OP-408 permitted RWV-22, the RWP-1 (normal raw water pump) discharge isolation valve, to be throttled during conditions of cool seawater. This step had the following caution:

> Throttle RWV-22, RWP-1 discharge, as required to maintain the heat exchanger SWH outlet temperature greater than or equal to 80°F, but adjust to prevent Auto Start of RWP-2A and RWP-2B.

The caution (not to throttle valve RWV-22 too much) relates to low discharge pressure switch PS-63 that actuates when the pressure decreases to 12 psig. This switch only starts pump RWP-2B, not RWP-2A; therefore, the note was incorrect and misleading. Furthermore, the note was weak because it did not identify the safety significance of throttling valve RWV-22. If RWV-22 were throttled, the motive pressure of the flow path would be reduced. This flow path provided seawater coolant for the pump bearings. The as-installed design was based on valve RWV-22 being fully open. To reduce pressure by throttling the valve could cause inadequate cooling to all raw water pump bearings during a fire, such as that postulated in 10 CFR 50, Appendix R, or during a seismic event. The operator would be required to recognize these conditions so that the appropriate manual actions could be taken to provide adequate cooling for the pump bearings.

(b) The instruction for shutdown operation in OP-408 did not caution the operator about the consequences of shutting down the nuclear services closed cycle cooling portion of the raw water system if the decay heat seawater pumps are still operating. Motive pressure for the seawater backup supply to the bearings of raw water pumps (RWP-1, RWP-2A, RWP-2B, RWP-3A, and RWP-3B) is only supplied if RWP-1, RWP-2A, or RWP-2B are operating. These pumps provide seawater coolant to the nuclear services heat exchangers while RWP-3A and RWP-3B supply seawater coolant to the decay heat closed cycle heat exchangers. If the raw water system pumps (RWP-1, -2A and -2B) are secured while RWP-3A or -3B or both are still operating in support of decay heat cooling, no backup seawater coolant for the pump bearings would exist.

(c) The startup portion of OP-408 directed the operator to be sure that the heat exchangers were filled and vented and then to perform the valve lineup for the raw water system in accordance with attached valve lineup enclosure. The note preceding this step indicated that heat exchanger SWHE-1A should be in standby service when this valve lineup is performed. The note commented that when it became necessary to place SWHE-1A in service, the inlet and outlet valves should be opened, and all air should be vented out of the heat exchanger. However, contrary to the note, the valve lineup enclosure did not specify which of the four heat exchangers were in standby. The note implied that the inlet and outlet valves are specified closed by the lineup sheets, but they can be either open or closed. The actual lineup directed the operator to insure that at least 3 (of 4) SWHE's were in service.

These examples of inadequate procedural guidance could have resulted in the plant being in an unprotected condition following a fire or seismic event if valve RWV-22 were throttled during winter conditions or if raw water pumps RWP-1, RWP-2A, and RWP-2B were shutdown while RWP-3A and RWP-3B were operating. FPC operations personnel told the team that RWV-22 has been throttled during the winter season. The team also noted that MAR 85-09-05-01 stated that "... it is sometimes necessary during plant outages to shutdown RWP-1, 2A and 2B while still operating RWP-3A/3B."

(3) Section 5.2 of OP-408 described the evolutions required to fill the SW surge tank with makeup water. After an operator has performed the system venting sequence, Section 5.2.4 directed the operator to close tank fill valve SWV-277, to open the tank vent SWV-198, and then to completely fill the SW surge tank. When the tank is full, the procedure directs the operator to close tank vent valve SWV-198. The team found that having valve SWV-277 closed precludes filling and venting the tank. FPC operations personnel agreed that the procedure should indicate that valve SWV-277 should be opened after venting the system, or cycled open and closed as needed to control SW surge tank level.

4.2.4.2 SP-370, "Quarterly Cycling of Valves"

FPC's pump and valve program identified valves in the domestic water system that were to be tested in accordance with ASME Code requirements. SP-370, "Quarterly Cycling of Valves," Revision 39, dated March 17, 1987 was the procedure used for this test. The team found that this procedure did not always identify testing prerequisites or quantitative acceptance criteria.

The team found that SP-370, which described the method for performing surveillance testing, did not identify the following prerequisites:

Nuclear closed loop cooling water pumps must be running to test that DOV-209 (isolation check valve between domestic water and SW) can open, permitting flow to the bearings of the raw water pumps.

The domestic water (DO) pumps must be operable to test that pump discharge check valves DOV-118 and DOV-119 seat on demand.

Initial valve lineups were not identified and confirmed.

The team noted that SP-370 indicated that if there were not a large pressure decrease on pressure indicator DO-13-PI during the test, then check valve DOV-209 was open. Quantitative acceptance criteria was not provided. Although the procedure required that the indicated pressure be recorded after securing the normal source of flush water, it did not require that the initial pressure be recorded. Therefore, it would not be possible to independently review the observed data. In addition, the procedure did not identify what pressure range should be expected initially on the gauge. Such information would inform the technician performing the test that the system was aligned properly (e.g., intervening throttle valve DOV-255 was correctly positioned).

SP-370 stated that "each check valve shall be demonstrated OPERABLE by being exercised to the position to fulfill its function." Although check valves DOV-118 and DOV-119 were supposed to be tested using this procedure, the procedure did not address the specific inservice testing for these valves. To test these valves in their seated direction requires additional instrumentation or a method to depressurize and confirm seating, such as removing the check valve cap to confirm that the disc was functional.

The safety significance of this weakness in SP-370 lies in the fact that check valves DOV-118 and DOV-119 are required to seat to maintain a seismic boundary. It appeared that these check valves were not included in the original pump and valve test program, although they were included in the pump and valve program that was submitted to the NRC on July 1, 1985. The submittal committed to incorporate these valves into appropriate surveillance procedures within 90 days of NRC approval. To date, complete NRC approval has not been received. Nonetheless, the licensee has indicated that these valves will be tested during the second inservice inspection (ISI) interval, which begins following refueling outage 6.

4.3 Electrical Engineering

The team reviewed operating procedures, modifications, and test procedures for the raw water, nuclear services closed cycle cooling water, and decay heat closed cycle cooling water systems. The team also reviewed RW, SW and DC protective relay setting calculations and equipment elementary (schematic) diagrams and the diesel generator loading under design bases accident conditions. Weaknesses identified during these reviews are described below.

4.3.1 Operating Procedure Reviews

Team review of the licensee's operating procedures resulted in the following deficiencies;

(1) Procedure AP-770 described how to restore power to the 4160-Volt engineered safeguards bus 3A or 3B from the CR-1 and CR-2 startup transformer feeder if the normal source of power (startup transformer #3) was not available and the diesel generator failed to re-energize the bus. This condition would result in a dead engineered safeguards bus. However, for the condition described, the team could not find a procedure to describe how to restore offsite power from the normal source (startup transformer #3) to a dead engineered safeguards bus, should power from the normal startup transformer become available after a loss-of offsite-power (LOOP). The team believed there should be such a procedure because during a LOOP condition neither the normal startup transformer nor the CR-1 and CR-2 startup transformer is available; therefore, it is reasonable to assume that power may first return to the normal startup transformer source and that this may be the only offsite source available.

Furthermore, to re-energize a dead engineered safeguards bus from the normal startup transformer source, special control action must be taken by the the operator. The control switch for the circuit breaker must be held in the "close" position for more than 7.2 seconds to allow the bus loss-of-voltage relays to reset. The team noted that although this action was not written in a procedure, when an operator was questioned he correctly identified the need to hold the associated breaker control switch to allow reset of the loss-of-voltage relay. Nonetheless, the team believes that a procedure should describe this requirement. There was a similar procedure, AP-770, for re-energizing a dead bus from the CR-1 and CR-2 feeder breaker.

(2) The team noted that Operating Procedure (OP)-703, "Plant Distribution System," did not clearly describe the required alignment of the 4160-Volt engineered safeguards buses 3A and 3B with the offsite power source for normal plant startup conditions. Section 7.3 stated:

> Insure that the following buses are energized with two separate and independent backup power sources:
>
> (a) 4160 v engineered safeguards Bus 3A
> (b) 4160 v engineered safeguards Bus 3B

Offsite power is normally provided to 4160 volt engineered safeguards bus 3A and 3B from the Unit 3 startup transformer as described in FSAR Section 8.2.2.4, "4160 Volt Auxiliary System." The team believes the requirements for availability and the alignment of power sources to the 4160-Volt engineered safeguards buses should be unambiguous.

(3) The team noted that OP-402 for the make-up and purification system did not describe the requirement for make-up pump motor cooling. Make-up pump motors should not be operated without motor cooling because such action operation can lead to motor damage. On at least one occasion, a make-up pump motor failed because motor cooling was not provided. The team considered OP-402 weak because there was not a requirement nor a precaution statement to provide cooling to the motor.

The deficiencies in operating procedures identified by the team contributed to the team's concerns that similar omissions, errors, and weaknesses in procedures are common.

4.3.2 Electrical Design

4.3.2.1 Control Circuits Review

The team identified a weakness in the control design for the emergency nuclear services seawater pump RWP-2B circuit breaker that could result in an unplanned circuit breaker operation on a loss-of-offsite power (LOOP), and a lockup of the breaker anti-pump relay control circuit.

On a LOOP, the normal nuclear service seawater pump (RWP-1) trips, which results in a loss of raw water discharge pressure. An automatic control signal to start emergency nuclear services seawater pump RWP-2B is then initiated by non-safety-related pressure switch RW-63-PS1. This automatic initiation can be postulated to occur before engineered safeguards bus 3B voltage is restored by the diesel generator, resulting in an unplanned closure of the RWP-2B circuit breaker onto a dead bus. This closure would be immediately followed by an automatic trip of the breaker by the bus undervoltage relay. At this point, the circuit breaker anti-pump relay would be held energized by the automatic start control circuit for pump RWP-2B. This circuit would normally de-energize on closure of the diesel generator circuit breaker. However, if the B division diesel generator fails to start on a LOOP, the anti-pump circuit relay would remain active. This condition would preclude subsequent closure of the circuit breaker by the operator on restoration of bus voltage from an offsite source, unless the operator takes action to manually de-energize the anti-pump relay by placing the RWP-2B control switch in the "Stop" position.

The team concludes that the plant operating procedures should be revised to alert the operators to this control requirement.

4.3.2.2 Diesel Generator Testing and Loading

The team found that the licensee's surveillance requirements and surveillance procedures for testing diesel generators exceeded the manufacturer's rated equipment performance capability and had inadequate testing and acceptance criteria (Observation 302/87-22-06).

FSAR Table 8-1 indicated that 3180 kW (or 3975 kVA) of load should be provided by diesel generator A during accident conditions. According to the licensee, the design basis ambient temperature for the diesel generators is 120°F. The team found that the generator rating was 3300 kW maximum for 30 minutes maximum, as described in FSAR Section 8.2.3.1(c), applied at an ambient temperature of 105°F according to a letter dated October 16, 1969, to FPC from Colt Industries, the diesel generator manufacturer. The same letter described an alternate maximum 30-minute rating of 3130kW at 120°F, which is not adequate for the accident load requirement. The team was concerned about the adequacy of diesel loading analysis, including the effects of any manually applied loads that may be needed during an accident.

Technical Specification Surveillance Requirement 4.8.1.1.2 (d) (4) requires that load testing of the diesel generator be performed at a load greater than or equal to 3000 kW. However, the actual maximum load on the generator may be higher because manually applied loads of 289 kW may also be required during accident conditions. The manually applied loads include control complex fans, chillers, and chilled water supply pumps. The total of the maximum automatically and manually applied loads is 3469 kW, which exceeds the diesel generator maximum, 30-minute overload rating of 3300 kW. The licensee prepared Nonconforming Operations Report (NCOR) 87-131, dated August 31, 1987, for evaluation of the technical specification surveillance requirement. The attachment to NCOR 87-131 indicated that since 1977, load on the diesel generator was never greater than 3100 kW when performing test SP-457. This load was less than the required automatically applied accident load of 3180 kW.

The team believes that the capability of the diesel generators to provide the maximum anticipated accident load has not been demonstrated by the surveillance testing. The diesel generators must be tested at the maximum accident load requirement to be sure that any degradation in the capacity of the unit will not go undetected, because this could result in the inability of the unit to satisfy the load requirement.

Technical Specification Surveillance Requirement 4.8.1.1.2 (d) (4) also requires that, at least once every 18 months the diesel generator be verified to operate for greater than or equal to 60 minutes while loaded to greater than or equal to 3000 kW . SP-457, "Refueling Interval ECCS Response to a Safety Injection Test Signal," implements this requirement. FSAR Section 8.2.3.1 (c), which describes the generator nameplate ratings, indicates a rating of (a) 3300 kW at a power factor of 0.8 for not more than 30 minutes, (b) 3000 kW at a power factor of 0.8 for 2000 hours and no maintenance, and (c) 2750 kW at a power factor of 0.8 continuously with an expected maintenance period.

The team noted that considering that the diesel generator unit has a net rating of 3000 kW for 2000 hours with a 10% overload capability for 30 minutes (or 3300 kW maximum), Technical Specification Surveillance Requirement 4.8.1.1.2 (d) (4) exceeds the manufacturer's stated 30-minute overload rating by testing the unit in the 10% overload range for greater than or equal to one hour.

The team also noted that procedure SP-457 acceptance criteria 4.29 and 4.30 state that diesel generators 3A and 3B shall not have operated at or above 3000 kW for more than 2000 hours. The manufacturer's stated rated overload capability of the diesel generator allows for 30 minutes of operation in the 10% overload range of 3000 kW to 3300 kW, which is not related to the net 2000-hour capability for operation at an output between 2750-3000 kW.

The licensee acknowledged that the subject criteria were erroneous.

4.4 Licensee Strengths

During the inspection, the team observed many engineering activities which indicated the licensee's efforts to design, construct, and operate CR-3 in a safe manner. Examples of such licensee strengths are given below.

(1) The team considered FPC's plans for a configuration management control program a strength. The purpose of the planned program is to improve the quality of configuration data for the CR-3 plant design bases. If properly executed, this program could be expected to improve the performance of CR-3 engineering and operations organizations and to enhance the understanding of the plant's design bases. The observations discussed in this report reinforce the need for such a program.

(2) The team found FPC's engineering management to be aware of programmatic shortcomings and knowledgeable of the safety issues identified during the inspection.

(3) The team found the documentation provided in modification packages to be a strength. Engineering instructions were detailed and clear. The team was impressed with the use of a design data sheet in conjunction with the ANSI N45.2.11 design input record. Instead of using a check list for these requirements, the responsible engineer was required to address each issue. The team found this to be a positive incentive to provide detailed and comprehensive engineering evaluations as part of the modification process.

5.0 PLANT OPERATIONS, MAINTENANCE and SURVEILLANCE ACTIVITIES

The objective of this portion of the inspection was to assess the overall adequacy of the licensee's operational management controls program implementation by continuous, in-depth, observation of plant activities. These activities and programs were evaluated by a team of NRC resident inspectors, consultants, and an NRC manager during a combination of round-the-clock on-shift inspection and routine day-shift inspection. The inspection emphasized direct observation of implementation of the licensee's programs, versus review of the program content.

Round-the-clock shift coverage of control room and in-plant activities was conducted from August 26 through September 2, 1987. To the extent possible, the inspectors made sampling observations of all key maintenance, surveillance, and operations activities occurring during the shifts.

The team had a unique opportunity to evaluate the licensee's operational activities. The plant was in cold shutdown (Mode 5) at the beginning of the inspection with the reactor coolant system (RCS) loops partially drained to replace the "C" reactor coolant pump seal. During the inspection, the seal was replaced, the RCS refilled, and the plant started up through modes 5 to 1.

In addition to the observation of maintenance and startup activities, plant operators and support staff personnel were interviewed to confirm their understanding of the licensee's programs and the plant and to obtain insight into the effectiveness of the licensee's programs and management communications. Areas reviewed included; the responsibilities and authorities of their respective job positions; understanding of the specific functions assigned the individuals by specific operating and technical procedures, including interfaces with other parts of the organization; current plant problems and ongoing plant evolutions; the adequacy of supervisory and management overview of activities at various levels of the organization; and the responsiveness and adequacy of plant and corporate staff engineering and maintenance support activities.

5.1 Plant Operations

5.1.1 Control Room Activities

The team observed the conduct of operations in the control room.

Access to the "controls area" was restricted as required by procedures and NUREG-0737, Item I.C.4. At CR-3 the controls area is distinguished by red carpeting, a visual aid which facilitates enforcement of the access controls. Control room noise level was controlled and reasonable. Although relatively small, the control room was clean, uncluttered, and well organized with no extraneous material evident. Professional attitudes and decorum were maintained and distractions such as music, non-job related reading materials, and horse-play were excluded.

Operators and senior operators remained within the controls area and were cognizant of plant status. Necessary plant administrative and technical business was conducted in locations and in a manner that did not compromise the attentiveness of the operator at the controls.

Operating procedures and references were readily available with the latest revisions and indices. Drawings, prints, charts, and operator aids in the control room were current, approved revisions. Status boards were usually maintained up to date.

Plant management, including senior management, were periodically present in the control room and were involved and aware of ongoing plant operations.

Shift staffing requirements for the various operator positions met or exceeded the technical specification minimum requirements, including fire brigade assignments. The team questioned the licensee's implementation of administrative controls for limitation of personnel overtime.

NUREG 0737, Item I.A.1.3, provides guidelines for control of personnel overtime. The licensee implemented its commitment to Item I.A.1.3 through provisions in Administrative Instruction (AI) 100, "Facility Administrative Policy." The team noted that AI-500 implements the NRC guidelines as recommendations. These guidelines are imposed as requirements at other facilities.

Review of overtime work records for operations personnel and discussions with licensee management indicated that, although the operators were not inordinately exceeding the guidelines of Item I.A.1.3, individuals periodically overran the guidelines by one to several hours. Further, the as-worked schedules occasionally did not meet the objective of Item I.A.1.3, i.e., a normal 8 hour day, 40-hour week schedule while the plant was operating. Operators at CR-3 were in a 5 shift rotation and attend annual requalification training.

Licensee management acknowledged the above finding and stated that additional operators were expected to be available from the licensed operator training program by the end of the year, alleviating the need for operators to work in excess of the above objectives. Additional trainees have recently been entered in the operator training program for later (1988-89) licensing.

This area appears to warrant continued attention from licensee management to ensure that the guidelines are not abused until additional operators can be licensed.

5.1.2 Shift Turnover and Relief Activities

The team noted that turnover checklists for all shift positions contained sufficient information to ensure adequate turnover. All turnover checklists were fully completed and signed prior to relief as required by plant procedures and NUREG-0737, I.C.2. Sufficient time was allowed and used by each shift position to ensure an effective turnover. Walkdown reviews of the control panel and significant alarms were completed by each shift position before relief. Shift logs and records were reviewed by designated personnel as required by procedure.

The team observed that significant maintenance and surveillance activities in progress, planned, or completed were adequately reviewed between shifts. Significant personnel assignments were identified and incumbents briefed for routine and non-routine activities. Sufficient information regarding plant status, operating events, and abnormal system alignments was transferred during turnovers.

A shift briefing for the oncoming shift was conducted by shift supervision to ensure that personnel were aware of planned evolutions, unusual plant conditions, night orders, and other areas critical to safe operation. Maintenance, health physics, chemistry, security, and other personnel were included in the briefing, as appropriate.

The licensee's practices for pre-shift briefings were considered a strength.

5.1.3 Administration of Control Room Operations

The team observed that plant evolutions, including startup activities and surveillance tests, were performed step-by-step using approved plant procedures. Operators responded promptly and adequately to control room alarms and used applicable alarm response procedures. Control room operators relied on and responded to alarm and instrumentation indication, using redundant instrumentation or inferential methods to confirm questionable indications. Shift supervision was kept aware of significant alarm status.

Plant operations, such as surveillance testing and system realignment, which could affect unit operation, cause alarms or change control room instrument indications, were brought to the attention of the necessary personnel prior to performance. Surveillance testing was adequately planned, coordinated, conducted, and documented. Operators reviewed the tests for plant impact and properly authorized their performance.

Communications within the control room and by telephone, radio, and page-party systems were generally clear and concise. Directions were explicit and usually understandable. Slang and extraneous communications were minimized.

However, problems were observed with the formality and integrity of voice communications as further discussed below.

The plant public address system was routinely used for operational and safety announcements. In many areas of the plant, public address announcements essentially were unintelligible because of either high or low volume and poor modulation. Although the team noted that operators primarily use hand-held radios for operational messages, they appeared to have little difficulty in interpreting public address announcements. However, the team was concerned that non-permanent plant personnel would be unable to distinguish important announcements, such as local evacuation or emergencies. Licensee management stated that periodic audibility surveys of the system had been performed in the past but the status of the last survey and plans for future surveys could not be established.

The operators used a combination of radio, telephone, and the public address system to control and monitor evolutions between the control room and in-plant locations. Standard industry practices include the "read-back" of transmitted instructions before performing the instruction; the inspectors observed only sporadic (less than 50%) use of the read back convention. Additionally, the operators frequently used "10-Codes" (10-4, 10-20, etc.) rather than standard operational terminology, a technique considered a poor practice by the team.

The operators conducted system and equipment alignment or status changes in accordance with licensee procedures. Senior reactor operator review of the activities and their effect on the plant was adequate. Independent verification of safety-related equipment "return-to-service" was conducted as required by plant procedures. Jumpers, lifted leads, and controlled keys, were issued and controlled in accordance with procedures.

Clearance documentation was found to be deficient for extensive or complex tagouts. The following problems with equipment clearances were observed and represent a potential for the licensee to lose control of the equipment clearance posting and restoration process.

The team noted several cases in which extensive or complex clearances underwent numerous revisions and corrections during their development and possibly after their posting. The dates were frequently missing to indicate when changes were made or any other notation indicating when and why the changes occurred. Most notably, Clearance No. 8-169, RCP Seal Package, included numerous corrections to the extent that it was very difficult to determine the equipment status, the chronology, or reasons for the various changes.

Additionally, there was no formal requirement for a detailed review of outstanding clearances or clearance log book before major evolutions or after an outage or extended shutdown. The licensee acknowledged this finding and stated that, although not formalized, such reviews were routinely done at the initiative of shift supervision. However, the absence of an implementing procedure requirement describing this practice allows the potential for omission of such reviews. This omission could have a negative effect on plant operation or equipment operability.

5.1.4 Shift Logs and Record Reviews

Shift logs and records were reviewed to confirm that the shift supervisor, control room operator, and non-licensed operator log books were properly completed.

The team observed that log entries were neat and legible. Errors were properly corrected, initialled, and dated. Significant operational events, unusual conditions, and alterations to safety-related alignments were recorded. Entry into and exit from technical specification limiting condition for operation action statements were recorded accurately and promptly. Log entries were made on a real time basis (versus keeping an unofficial "scratch paper" log and later transcribing to the official log). Management and supervisory reviews of the logs were completed and documented as required by procedures.

Control room recorders and charts were operating properly, checked and dated periodically, and the charts changed and retained as required. Plant equipment data logs sheets were complete with no missing entries. Out-of-tolerance readings were highlighted and brought to the attention of shift supervision.

Miscellaneous logs and records were completed on a timely basis and in accordance with the applicable procedures for the required reading book, system/equipment out of service log, annunciator status/out of service log, controlled key log, maintenance work request log, radiation work permit log, and surveys.

The team noted that auxiliary operators and occasionally other operators did not review or sign all the logs required by AI-500 before turnover. AI-500, "Conduct of Operations," Section 2.1.7, requires that oncoming operators review and sign the appropriate operator's log, short term instructions, equipment out of service log, annunciator/link out of service log and shift relief checklists. Additionally, the "shiftly" shift supervisor tour recommended by AI-500 was not consistently completed. While plant conditions or evolutions may require some tours to be omitted, the team noted periods of 24 hours without documented tours.

5.1.5 Operational Observations

The team observed operational evolutions from the control room and at local operating stations. These observations included system and equipment realignment for clearances, surveillance testing; plant fill, vent, and heatup operations; reactor plant startup-to-power operations. The team examined whether;

(a) Each activity was conducted in accordance with approved procedures and technical specifications.

(b) Procedure discrepancies were identified and corrected via approved change before proceeding with the activity.

(c) Integrated or complex activities were subject to a pre-performance briefing, including support personnel (such as maintenance, quality control, and health physics).

(d) Adequate levels of operations and support staff supervision were provided for each evolution.

(e) The personnel performing the activities were familiar with and appeared adequately trained to conduct the evolutions.

(f) Unsatisfactory conditions or results were recognized, received adequate response, and were documented for further corrective and preventive action or management followup.

(g) Pre- and post-evolution system and equipment alignment and conditions were in accordance with procedures and appropriate for current plant conditions and technical specification requirements.

The team also observed plant material condition, and system and equipment status during plant tours and in plant operations and maintenance observations. Extended tours were made in the control complex; intermediate, auxiliary, reactor, and turbine buildings, and outside areas. Auxiliary building, turbine building, and chief operators were accompanied on their normal rounds. The team observed system alignments and clearances, surveillance, logging and routine system and equipment operation.

Although the results of these observations were generally satisfactory, several concerns were identified by the team as discussed below.

5.1.5.1 Radiological Protection Surveys

Radiological protection surveys were maintained in the access point field office and were found to be complete and current. Further, it appeared that the licensee had an aggressive survey and decontamination program in place.

However, several cubicles and areas in the plant bear special entry requirements for high radiation fields and high levels of loose surface contamination. In many of these cases, the levels vary substantially within the cubicles, for example, the decay heat removal (DHR) pump cubicle overheads. The licensee does not provide local postings of the latest survey data at the entrances to such areas. The team believed that such postings could permit further reduction of exposure by providing on-the-spot information of the variations in the radiation field and contamination level within these spaces.

5.1.5.2 Reactor Vessel Level Indication While Drained Down

While the reactor coolant loops were partially drained in cold shutdown, a transparent tubing standpipe inside the reactor building was used to indicate reactor vessel level. There was no remote loop level indication available. An operator had to monitor the standpipe inside containment during evolutions that changed or had the potential to change reactor vessel level. These reactor building entries also were required for level checks every 4 hours when such evolutions were not occurring. Such entries could result in additional radiation exposure and generation of radioactive waste. Moreover, the team noted that several unexpected level changes occurred during the replacement of the RCP seal and, although the licensee provided adequate monitoring of and response to these changes, the lack of on-line instrumentation could have resulted in operational difficulties. The licensee stated that a system was to be installed during the next two refueling outages to provide remote indication.

On the basis of the foregoing, the team considered that extended periods of operation in a drained down condition without remote level indication was a weakness. The team believes that the licensee should consider accelerating the schedule to install remote indication.

5.1.5.3 RCS Loose Parts Monitor Alarms

During the inspection, while the reactor coolant loops were partially drained, numerous loose parts monitor alarms were received. The alarms were determined to be valid because the impact-like noise and vibration could be heard and felt in the reactor building, but the cause could not be conclusively determined. No similar, previous occurrences had been experienced.

Further investigation by the licensee's engineering staff concluded that the noise and vibration was caused by cycling of reactor vessel internal vent valves. The once through steam generators (OTSGs) had been maintained hot (>240°F) by the deaerator. The licensee believed that the elevated temperatures of the OTSGs caused periodic flashing of steam in the RCS, which cycled the vent valves.

Although the licensee varied decay heat removal flow as part of the investigative process (with no apparent effect), no structured root cause analysis, other diagnostic evaluation, or corrective action appeared to be taken. The licensee assumed that the vibration and its cause were not and would not be deleterious. The team considered the licensee's conclusions to be based on subjective judgment and that additional, more rigorous evaluation and response were warranted (Observation 302/87-22-07).

5.2 Maintenance and Surveillance Activities

The team observed ongoing maintenance and surveillance activities to determine whether they were accomplished in accordance with approved procedures and were adequately controlled with respect to plant and system conditions. The specific activities observed included:

- modification and testing of emergency diesel generator relays
- replacement of "C" reactor coolant pump seal
- repair and testing of containment purge and exhaust valves
- inservice testing of feedwater and makeup system valves
- testing of the decay heat removal system pump mechanical seal
- inservice testing of containment isolation valves
- repair of the "B" vital power inverter
- calibration of reactor coolant pump seal flow indicators
- pre-startup surveillance tests

These activities were reviewed to ascertain whether:

- Surveillance testing was scheduled in a controlled and coordinated manner to insure that technical specification frequency requirements were satisfied.

- Procedures used for testing and maintenance complied with administrative control requirements for content, format, and processing.

- Surveillance procedures met the requirements of technical specifications and objectively determined the operability of the subject equipment.

- Pre-work briefings were conducted for complex or hazardous activities.

- Radiological, security, and other controls were properly integrated into job planning.

- Equipment clearances were properly implemented, including independent verification of return-to-service activities.

- Activities were conducted by qualified individuals and received adequate supervision.

- Activities that could affect or be affected by plant conditions were adequately coordinated with the control room.

- Quality assurance and control provisions were adequate, were conducted when and where required, and inspection results were documented.

- Discrepancies were recognized, properly identified, dispositioned, and documented. Appropriate actions were taken for discrepant technical specification surveillance test data.

- Support from the engineering and management staff was adequate, timely, and properly coordinated.

The results of these reviews by the team were generally positive. Specific concerns identified are discussed below.

5.2.1 Purge and Vent Valve Seating

The team witnessed the testing of reactor building purge and vent valves as required by SP-177, "Local Leak Rate Test of AHV-1A Thru 1D." During this test, the team was informed that valve seating problems occurred during every shutdown in which these valves were used. Personnel were frequently required to enter the ventilation line between the inside and outside valves to make necessary repairs and to enable the valves to seat well enough to pass the test. Such entries required the operators to use time-limited self-contained breathing apparatus. The team was told that this had previously resulted in a worker being temporarily trapped between the valves as the air supply neared exhaustion. These practices present a safety hazard to personnel working inside the duct and also cause an increase in radiation exposure to personnel. Further, the poor valve integrity limits the licensee's ability to purge the reactor building and to maintain optimal containment environmental conditions for personnel working inside the reactor building. As a result, relatively high containment internal temperature and humidity during short duration outages present a human factors and safety consideration. For instance, during this inspection, several licensee personnel suffered from heat exhaustion during work inside the reactor building while containment purge capability was suspended to support valve repair and testing. These episodes occurred even though the licensee limited work time in the reactor building and provided ice vests and used other measures to improve working conditions.

The team considered this condition a weakness that merits further evaluation by the licensee to correct this recurring problem (Observation 302/87-22-08).

5.2.2 Reactor Building Paint

During the various reactor building tours, the team noted that the paint on the walls and floors within the building had deteriorated and, in some areas, was flaking off the concrete. The team was concerned with the potential for concrete contamination and blockage of ECCS sumps and components from paint residue. The team also noted paint degradation, allowing rust, on carbon steel cooling water piping inside the containment.

The licensee gave an oral presentation to the team and provided relevant correspondence detailing its evaluation and plans concerning the condition. The licensee indicated that it had evaluated the contamination and clogging potential and found negligible safety impact as long as the loose paint was removed periodically (ongoing since 1986) and the surfaces within 6 feet of floor levels within the reactor building were repainted eventually. These activities are planned for the Fall 1987 outage, with a continuous program to follow in later outages.

5.2.3 Use and Control of Scaffolding

The team observed extensive scaffolding installations in the auxiliary building seawater room and at the 119' elevation of the containment penetration area. These scaffolds were properly identified by installation tags as required by Administrative Inspection (AI) 1803, "Safety Standards for Ladders, Scaffolds, and Ancillary Equipment"; however, the scaffolds were installed over or in close proximity to safety-related equipment. Examples included:

- Tag Nos. 0205, 0060, 0050, installed during April-May, 1987, between and above the SW system expansion tank SWT-1, pump SWP-1C, and associated electrical conduit

- Tag Nos. 0206, 0257, installed during May-July 1987, over decay heat/SW heat exchangers SWHE-1C and -1D and adjacent aisles

- Tag No. 212, installed in May 1987, adjacent to raw water pump RWP-3B and resting against associated RW and SW piping in the overhead area

- Tag No. 174, installed in May 1987, in the 119' elevation penetration area over core flood system valves and valve operating accumulators

The team determined that neither AI-1803 nor any other licensee procedure included considerations to ensure the continued operability of safety-related systems and equipment in the event of scaffolding failure or an accident in the handling of loads during erection of or during work using the scaffold. Similarly, evaluation of seismic considerations for long-term scaffolding installations or overhead work conditions was not addressed. The team was informed that FPC was obtaining example procedures from other utilities and would incorporate appropriate considerations into its program (Observation 302/87-22-09).

5.2.4 Component Labeling

During plant tours, the team raised questions regarding the labeling of various plant components.

During a 10 minute tour to examine instrumentation labeling had the team noted the following instruments had tags missing.

- makeup pump C motor bearing resistance temperature devices
- flowmeter downstream of DCV-42 (cooling water to makeup pump C)
- flowmeter in cooling water line to makeup pump A
- solenoid on the air operator for valve SWV-277
- resistance temperature devices on the end bells of heat exchangers SWHE-1A, SWHE-1C, DCHE-A, DCHE- (no component label on heat exchanger)

Although many instruments were labeled in the plant, the fact that numerous missing instrument tags were identified in a short time indicated that the licensee was not aggressively retagging instrumentation with missing tags.

During plant tours, the team also noted that the licensee did not generally tag instrumentation valves. Instrumentation root valves at the process taps were tagged, controlled by operators, and depicted on the CR-3 drawings. Instrument valving other than root valves was controlled by instrumentation and control (I&C) technicians. As a result of this observation, the team investigated FPC's requirements and ongoing efforts in this area.

The team noted that NRC inspection report 81-06 had noted that instrumentation valves were not present on drawings and lineups and that the licensee would revise flow diagrams and valve lineups to include these valves. This issue had been identified as an unresolved item 81-02-06. NRC inspection report 81-15 updated this item noting that revisions were in progress and that the drawing revisions and new valve lineups would be in place by the next outage. To address this item, FPC engineering had developed an instrument valve identification and numbering scheme that would provide unique identifiers (tags) for all valving. This scheme was incorporated on flow diagram (FD) 302-002, Sheet 2. Surveillance Procedure (SP)-111, "Valve Lineup Verification for Critical Instrumentation," was established in 1981 to verify valve lineups for a limited set of critical instruments (approximately 140 instruments). However, this procedure did not implement the unique numbering scheme depicted on FD-302-002, Sheet 2, but rather used a generic approach to identify valves (e.g., V1-high pressure vent valve, V2-low pressure vent valve, V3-equalizing valve). Moreover, team discussions with I&C technicians revealed that the generic tags were in place on some valves (missing on many others) and that it was sometimes difficult to distinguish the high-pressure versus low-pressure taps because of different configurations. However, the required configuration was not in jeopardy because both high- and low-pressure valves are always required to be open, and the other valves, such as drain and equalizing valves were obvious. The licensee stated that there were no other valves in any instrument sense lines between the instrumentation root valves and the generic valves depicted in SP-111. Based on this statement, the team concluded that alignment of valves for the instruments specified in SP-111 was not a problem.

Quality Programs Surveillance Report 86-RDS-11, June 1986 addressed instrument valve tagging. As a result of this surveillance, engineering, by memorandum dated July 15, 1986, clarified its position by stating that it was never their intent to revise applicable drawings to show instrument valving because of the large number of instruments (approximately 40,000). The scheme provided on FD 302-002, sheet 2 was developed to give operations and maintenance personnel the direction necessary to place tags on instrument valves.

Another FPC internal report on an evaluation of the emergency feedwater system, issued March 30, 1987, noted (Concern No. 2) the lack of unique tags for instrumentation valves and the inconsistency between the generic approach used in SP-111 and the approach defined by engineering on drawing FD-302-002, sheet 2. This item was given to nuclear engineering for further evaluation.

The team considered the licensee's tagging of instrument valves at CR-3 a weakness, and specifically noted that the lack of unique identification tags for these valves could lead to improper valving. The team found no evidence of system or component inoperabilities caused by such valving errors and did acknowledge that CR-3 at least has a procedure (SP-111) that verifies alignment of selected critical instruments.

The team noted that the licensee had undertaken several recent initiatives in the area of systems and component labeling. These included Quality Programs Surveillance Report 86-RDS-28, which noted numerous inconsistencies in tagging of plant equipment; CR-3 Equipment Tag Number Convention Study Report dated February, 1987, which assessed the various tag conventions, the issuance of a new procedure in the Operations Section Implementation Manual (OSIM), Section VII, dated May 13, 1987, which addressed system and component labeling guidelines; and various portions of the Configuration Management Program Plan, dated June 30, 1987, which is based to a large extent on equipment tag numbers. The team reviewed these efforts during the inspection and found that CR-3 uses the tag number (derived from the main entry in the computerized master equipment list maintained by nuclear operations engineering) as the primary identifier for all plant components. The noun name for equipment also was taken from this listing. Some confusion arose from use of the noun name for equipment because the unit number (3) was often used, and trained equipment was often only provided a train letter (e.g., A or B) and the unit number. Thus numbers in equipment names were not consistent with the numbers used for the equipment tags. For example, Makeup and Purification Pump 3A had a tag number MUP-1A and MUP-3A is Makeup and Purification Pump 3A Backup Lube Oil Pump. Various CR-3 personnel indicated to the team that this was a minimal problem because components were referenced by tag number, not by their name. Nonetheless, the licensee planned to replace the labeling in the control room and motor control centers during the upcoming refueling outage to eliminate the unit number from the noun name. When the inspectors looked at Ventilation Motor Control Centers 3A and 3B, which had been completely relabeled, they found the corrections to match the provisions of the program and the conventions of the licensee's operating procedure. In addition, OSIM Section VII, issued May 13, 1987, stated that the unit number will not be used in the name or description of a component. These changes are considered improvements.

The team noted that CR-3 equipment tags did not generally provide a noun name in addition to the component tag number. OSIM Section VII, issued May 13, 1987, stated that the label on a component should include the name or description if room permits and that major components also should include the name or description (e.g., EGDG-1A A Emergency Diesel Generator). The component tag number was always required. The team considers this approach a good practice in that it promotes personnel's understanding of the plant and provides a second check that the right component has been identified. In practice, components such as valves, pumps, and instruments were not tagged with noun names at CR-3. This aspect of plant labeling is considered a weakness, although there are no specific regulatory requirements regarding inclusion of name/descriptions on equipment.

5.3 Licensee Strengths

The team observed many operational practices and activities which were considered to be strengths. The following examples were observed.

Because there had been an ongoing history of problems with the quality of and operator adherence to procedures, FPC had instituted many performance improvement actions to correct these types of problems. The team concluded that these improvement programs have been working. The team observed that, although some of the previous procedure problems remain (such as they sometimes cannot be performed exactly as written or have ambiguous wording), the operators appeared to be highly sensitive to strict procedure adherence and proper procedure correction before performing a function where adherence with "as-written" procedure was inappropriate. For example, while the reactor coolant loops were partially drained and numerous loose parts monitor alarms were received, the licensee's immediate response included strict adherence to the applicable abnormal procedures.

At the beginning of each shift, the shift supervisor conducted a briefing for lead shift personnel from each plant department. Key activities that had occurred since the shift's last duty, ongoing and upcoming activities, and problems were discussed. The team found the meetings to be effective in establishing a general work plan for each shift and highlighting areas for special attention.

The licensee appeared to have an effective document control and distribution system in place for continuous support of plant activities. A document control center operated continuously, providing ready access to controlled documents. Each document to be used in a safety-related activity was discretely issued, labeled as such, and serialized by the center. This serialization permits accountability for the return of completed documents as quality records.

During various plant startup evolutions the licensee assigned reactor operator trainees to the control room to obtain experience as required by 10 CFR 55 and the licensee's training program. Four trainees were observed conducting control board operations under the supervision of licensed operators. The trainees wore conspicuous vests to distinguish their status on shift and were well controlled and monitored by the cognizant licensed operators. The team considers the licensee's efforts to integrate the trainees into plant operations and the methods to control these activities to be an asset.

Overall plant housekeeping and cleanliness conditions were found to be good. Equipment generally appeared to be well tended with fresh lubricant, preservatives, and paint evident. Building spaces were well policed with tools, equipment, trash, and flammables properly stored. Combustible and radiological trash appeared to be controlled. In particular, difficult to maintain areas, such as the seawater room and the chemical addition area, were found to be in good condition.

Only minor exceptions to the above conditions were found, most notably the intake structure area, makeup valve alley, portions of the reactor buliding, and a few others.

The team observed surveillance and maintenance activities on multiple shifts, including departmental or task oriented pre-work briefings and work preparations. These briefings were typically quite detailed and involved the lead group (such as maintenance I&C) and support groups such as health physics and quality control. Specifically, the pre-work briefings and preparations for the RCP seal work were extensive and considered both the radiological and environmental working conditions; tools, equipment, and procedures needed inside the reactor building; task and sub-task assignments.

5.4 Conclusions

The plant activities observed were conducted in compliance with the various procedures and requirements with essentially no personnel-induced problems. The team found the licensee's adherence to procedures and recognition of procedures needing correction very good.

Licensee personnel handled those equipment or procedural problems that arose well, with the few exceptions noted herein. The operators appeared perceptive of plant and equipment conditions and trends and were knowledgeable of the plant and procedures.

Documentation and implementation problems persist, for example, the continuing need to upgrade procedures, improve personnel communications and equipment clearance. The licensee appeared cognizant of and sensitive to the need to continue upgrading these areas.

6.0 ENGINEERING SUPPORT TO PLANT OPERATIONS

The team evaluated the engineering support of plant operations by examining the formal and informal interface mechanisms between engineering and operations including communications concerning day-to-day technical support and those interface mechanisms used for the plant modification process. The team also examined engineering's capability to support plant operations. The team considered engineering management's understanding of significant issues affecting plant design bases and the impact of those issues on operations, as well as FPC's plans for expanding the nuclear engineering staff.

The team reviewed procedural controls and program documents and held interviews with plant and engineering personnel. Personnel interviews were conducted to gain additional insight into aspects of the processes not specifically addressed by procedure and to evaluate plant and engineering personnel's level of understanding of procedures, programs, and issues in general.

The interface, both formal and informal, between operations and engineering seemed to be appropriate. Mechanisms existed for day-to-day technical support on several levels, and programs to assure long-term improvements were in place.

Engineering management personnel demonstrated a reasonably good understanding of the issues affecting the development and maintenance of plant design bases and the reflection of those design bases in plant operations. This understanding was evident in management's efforts to methodically develop design bases information and integrate that information into various plant and engineering processes throughout the configuration control program.

6.1 Organization and Interfaces

Within the FPC organization, Nuclear Operations Engineering and Projects consisted of four major subdivisions. Of these the Nuclear Operations Engineering and Site Nuclear Engineering Services Departments provided the traditional design and site engineering support functions. The Site Nuclear Engineering Services Department had recently been reorganized to incorporate a former group of plant engineers. This department, located on site, provided the day-to-day engineering support of operations activities.

Administrative Instruction AI-410, "Preparation and Handling of Field Problem Reports," provided a formal means of communication from operations to engineering. Field problem reports document various types of identified or perceived problems and may be originated by any plant department. Site Nuclear Engineering Services maintained a centralized log of the reports and coordinated their resolution and closeout. A weighting system was used prioritize the reports and to focus attention on the "Top 20" reports to ensure responsiveness to critical issues.

A less formal means of communication between the plant and engineering personnel was handled by engineering representatives on standing committees and regular plant meetings. The Site Nuclear Engineering Services group currently had two representatives on the plant review committee and regularly sent representatives to the daily planning meeting where plant activities and problems were discussed.

The reorganization of the Site Nuclear Engineering Services Department to incorporate plant engineers and the development of the systems engineering approach to operations support, provided enhanced mechanisms for day-to-day interactions with the operations staff. Although only recently established, the systems engineering group was receiving excellent training in plant operations. Face-to-face meetings and telephone communications between operations and engineering personnel were already routine for some systems. Systems engineers have the responsibility for many surveillance procedures associated with their systems, and the review and approval process of these procedures further emphasizes this interface. Interviews with plant personnel indicated that they understood the communication tools available to them and were generally satisfied with the engineering interface.

6.2 Modification Control

The team performed a detailed review of the process controlling plant modifications focused on the interactions of plant operations staff with the modification process. The team was particularly interested in the ability of operations personnel to input to the planning and design phases of plant modifications, including establishing controls to ensure that operator training was conducted and procedures and drawings were appropriately updated to support plant changes.

Operations personnel had several ways of identifying problems that required plant modifications. The field problem report (already discussed) served as a key mechanism to initiate the modification process through the Site Nuclear Engineering Services Department. Once modifications were initiated, the operations department participated in the planning and prioritizing as part of the modification budget and planning committee for large modifications and the change review team for small modifications. Operations also had the opportunity to participate in the design process and where warranted, would be a part of the project team for significant modifications.

The team's interviews with plant personnel indicated they were generally satisfied with their ability to affect the modification process. Not all aspects of the modification process were equally understood by all operations personnel, however. For example, the operations representative to the modification budget and planning committee was unknown to several key operations personnel. Hence, this avenue of input to the prioritization process was somewhat limited.

The licensee had controls to assure that plant procedures were revised to reflect modifications. However, there was no method to identify those procedures requiring changes other than individual judgment. Once identified as being affected by a modification, the required changes were carefully tracked to ensure that they were made before the modified system was released for operation.

Similar controls had been established for the training of operators in conjunction with modifications. Each modification was individually evaluated to determine the extent and method of training necessary to support the modification. The training plans were completed, training was initiated, and, if necessary, completed for all shifts before the modification was turned over to operations.

By the time a modification was completed and the system released to operations, a selected set of control room drawings was typically updated. This set of drawings, consisting of process flow diagrams and electrical breaker arrangement drawings, was selected jointly by operations and engineering personnel. These drawings were used by operations personnel to develop clearance tagging lists. In the team's judgment, this represented a minimal set of drawings to support the day-to-day needs of personnel for as-built information. The team noted that other facilities maintain much larger sets of drawings to provide detailed as-built information, for example, elementary wiring diagrams, logic diagrams (voided for CR-3), and single line electrical drawings.

The team questioned the timeliness of drawing updates to reflect as-built information. For affected drawings other than those required in the control room at the time of turnover, revisions to reflect the as-built condition averaged 6 months to complete. Although a process existed to provide current information on drawings to support work activities, it was difficult to use. Personnel must be able to identify modifications in progress so that they are aware of the need to investigate affected drawings. Modifications that might impact a specific drawing were identified only on specially marked copies of the drawings that were issued as a part of the modification process. Furthermore, once the applicable modifications had been identified, personnel must review the corresponding documentation to determine the details of the modifications and must ascertain the implementation status of the modifications if they impacted portions of the drawing being relied on by the user.

The team determined from its review of procedures and interviews with plant and engineering personnel that the process to provide current physical status for drawings was not commonly understood. AI-405, Control of Drawings, required that "working copies" of drawings be used to support all work request related activities. Working copies of drawings were issued by the document control group and identified modifications in progress that might affect the particular drawings. The team questioned representatives from the mechanical, electrical, and I&C maintenance shops about the use of drawings in the field to support work request activities. The representative of the I&C shop indicated that the controlled series of drawings maintained in the shop occasionally were used in the field to support work request activities. This particular finding identified the failure of personnel to meet a specific procedural requirement; more generally, it indicated a lack of clear understanding about the process for obtaining current information on plant configuration (Observation 302/87-22-10).

The team also evaluated the controls for temporary modifications to the plant as part of its review of the modification process and in conjunction with the inspection of operations activities. The temporary modification approval record (T-MAR) is the primary mechanism used to control temporary plant changes such as jumpers and lifted wires. The T-MAR is used for any temporary change to equipment that is to be considered available for operations, and it undergoes the same review, approval, and documentation process as a regular plant modification. The total number of T-MARs generated has been declining over the last several years (only nine were generated in the first half of 1987) and the total number that remain open was relatively low (an average of approximately 30 for the last year). Temporary changes can be made as part of the work request process to support troubleshooting or maintenance, but these changes must be restored to the original condition before the equipment is returned to service. Because of these tight controls and the relatively low number of T-MARs generated and open, the control of temporary modifications was considered to be a strength.

6.3 Design Bases Awareness

The team evaluated engineering personnel awareness of design bases issues because of questions raised by other inspection team activities regarding the availability and accuracy of plant design bases information. Team interviews with engineering personnel and discussions about both the current status of design bases information and maintenance of that information indicated a reasonably good understanding of the importance of design bases development and control. Engineering personnel displayed an understanding of the condition of the existing design bases, the activities necessary to update these design bases, the importance of the information to plant operations, and the mechanics of integrating related activities and document sources. This observation was further supported by the program plans for configuration management. The configuration management plans detail a long-term plan for the development of an integrated configuration control process.

The plans for the continued development of design bases information, for the control of that information through configuration management, and the on-going evaluation of plant operation against the design bases requirements requires substantial manpower resources. The team considered CR-3 engineering staff to be too small to support these new activities and to provide day-to-day technical support. In 1986, a manning study was performed for the nuclear organization. This comprehensive study considered work activities, then identified and made recommendations for staffing increases. The plan recommended the addition of almost 50 positions to the two major engineering groups over the next three years. Just under 80 percent of these new additions were for the Site Nuclear Engineering Services group. The planned openings will require individuals with a balanced range of experience and would be filled over the next three years. The team considered these planned expansion activities a step in the right direction. The detailed configuration management plans which have been developed within the last year outlined a substantial engineering work load which should be factored into the manpower study results (Observation 302/87-22-11).

7.0 SAFETY REVIEW AND COMMITTEE ACTIVITIES

Evaluation of management's oversight of and involvement in the operation of CR-3 focused on the activities of the onsite and offsite review committees. At CR-3, these are the plant review committee (PRC) and the nuclear general review committee (NGRC), respectively.

The inspection emphasis in this area was threefold, involving: (1) observation of committee meetings, (2) review of committee instructions, procedures, and minutes, and (3) interviews of members of the committees. Since attendance was possible at just a few PRC meetings and no NGRC meetings were scheduled during the period of the inspection, the review of relevant documents and interviews were essential to the inspection in this area. The team also attended daily (morning) staff meetings held throughout the inspection.

7.1 PRC Meetings

The PRC met regularly twice a week and more often during outages. Additional meetings were frequently held as needed to support plant operations. PRC meetings attended during this inspection were held on August 25, 26, and 28 and September 3, 1987.

At the first meeting attended, August 25, an interim procedure approval request and several modification approval record (MAR) work packages were presented for approval. The team considered that this meeting was marked by limited member participation. The second PRC meeting was held to review and approve a work package concerning the replacement and testing of relays to determine the effects of off-site voltage drops and to review and approve six work packages concerning the replacement of SPM type switches. In both cases, the PRC members questioned the need for PRC review and approval and exhibited a detailed interest in the technical requirements for the testing and the effect the proposed modifications and testing would have on the operation of the facility. During the third meeting attended (August 28), the PRC reviewed and approved changes to the conduct of operation procedure (AI-500), temporary procedure changes, results of several biennial procedure reviews, approval of several vendor manuals for use, a major revision to procedure CP-18 (work requests and work plans), and approval of a portion of a MAR dealing with installation of reactor vessel level indication during cold shutdown conditions. Several PRC members expressed concern with the fragmented approach currently being used to implement modifications, which allowed the modification to be installed and approved in a "package" fashion consisting of several distinct packages, versus the previous integrated single MAR approach.

At the meetings, a representative from the area requesting PRC review and approval read a brief description of the change and the reason for it, and stated that there were no unreviewed safety questions associated with the change. None of the other members had in hand, during the meeting, a description of the change. If no objections were voiced, unanimous approval was assumed and the next change was presented.

The team identified the following concerns relating to PRC activities.

(1) The licensee uses a qualified reviewer process, according to which material to be reviewed goes through a review cycle that consists of an intradepartmental review by a qualified reviewer and an interdisciplinary review by qualified reviewer(s) in interfacing departments.

As an example, the team was advised that pre-meeting distribution of Administrative Instructions to all PRC members was not routinely practiced. Consequently, the only way a PRC member was likely to see the description of a proposed change is if the member happens to have been designated as a qualified reviewer for its review.

(2) During the course of the inspection, the team noted that the seawater inlet temperature exceeded the suction design temperature for the plant. The plant had apparently been operated in the past when seawater temperatures exceeded the design basis for the facility.

The licensee subsequently concluded that it was safe to return to power on September 1, 1987 for two and a half weeks and conclude the current fuel cycle. On September 3, the PRC met to discuss justification for continued power operation with respect to the potential violation of the design basis and its impact upon the technical specifications.

At the start of the meeting, PRC members were given a packet of correspondence from Gilbert Associates, the facility architect engineer, with assurances that the preliminary analysis showed it was safe to operate with the elevated injection temperatures and that a more detailed analysis would be forthcoming to verify this position.

The presentation was made by the Manager, Site Nuclear Licensing, rather than by a manager of engineering, such as the Manager, Nuclear Operations Engineering. There was a brief discussion of relevant plant parameters, what recommended actions would need to be taken in event of an accident, and what long range corrective actions were anticipated. The meeting primarily involved a dissemination of available data and a brief discussion of how to implement the architect-engineer recommendations in the event of an accident.

The initial architect-engineer analysis was not available and no analytical data was available for review or discussion. However, when it was asked if any PRC members or attendees had any safety concerns, the response was that there were none due to conservative component design. The matter was not pursued further.

The team found that participation in PRC meetings was weak, possibly a result of little pre-meeting preparation, lack of in-hand descriptions or copies of the material being reviewed, and lack of meeting focus on matters of most importance to the committee. In particular, the team found that the way PRC meetings are organized and conducted has the potential for putting too much emphasis on the qualified reviewer process and discouraging member participation in the meeting process with its accompanying valuable synergism.

7.2 Committee Documentation

The team reviewed the charters, procedures and instructions, meeting agenda, and meeting minutes of the PRC and the NGRC.

7.2.1 NGRC Documentation

The NGRC charter described the FPC policy with regard to the NGRC, the NGRC regulatory bases, its authority, and the policy concerning its procedures. The NGRC procedures described in sufficient detail and clarity the procedures concerning NGRC organization and activities (e.g., meetings, interfaces, action and follow-up items), its subcommittee activities (e.g., their makeup, duties, and responsibilities), and its administration. Based on a spot check of a half dozen meeting agenda, they were found to be clear, concise, and in keeping with procedures. Similarly, on reviewing minutes from three NGRC meetings they were found to be clear, concise, in keeping with procedures, and informative.

The team found acceptable documentation (i.e., charter, procedures, agenda, and minutes) for the NGRC.

7.2.2 PRC Documentation

The PRC Charter described the responsibility of the committee and provided very brief guidance on membership, meeting requirements, and records. There was no other separate document on PRC Procedures. The team noted that the charter provided no guidance requiring the PRC Vice Chairman to be a PRC member. The PRC meeting on September 3, 1987, for example, was chaired by a Vice Chairman who was not a PRC member (or member at large). The team would consider membership on the committee by the Vice Chairman an enhancement which would aid continuity. This approach is the typical industry practice.

CR-3 technical specifications sections 6.5.1.6(a), 6.8.1, and 6.8.2(b) specify the procedures for which the qualified reviewer process may be used. The qualified reviewer process can be used to review the procedures listed in section 6.8.1 prior to implementation, except for review of the emergency plan, security plan, fire protection plan and implementing procedures, Administrative Instructions, and those test procedures associated with plant modifications. There are no provisions in the technical specifications or the PRC Charter for use of the qualified reviewer process by the PRC in discharging its responsibilities as outlined in Technical Specifications Sections 6.5.1.6(b) through 6.5.1.6(j). Yet the team observed that the PRC relies heavily on the qualified reviewer process in meeting these responsibilities.

While it is in keeping with NRC regulatory policy to allow the PRC to establish subcommittees, there are no procedures in the PRC Charter for doing so. The PRC has one subcommittee. The charter delegates to the Compliance Department responsibility for Technical Specification 6.5.1.6(e), "investigation of all violations of the technical specifications including the preparation and forwarding of reports covering evaluation and recommendations to prevent recurrence to the Vice President, Nuclear Operations and to the Chairman of Nuclear General Review Committee". Yet there were no procedures provided to guide the subcommittee. In addition, the team noted that the Compliance Department has among its normal responsibilities the responsibility for the preparation and forwarding of reports covering evaluation and recommendations to prevent recurrence, which constitutes a potential conflict of interest.

There were no procedures in the PRC Charter for meeting agenda. A spot check was made of meeting minutes from ten PRC meetings that took place between July 2 and August 7, 1987. The minutes tended to be brief, confusing, uninformative, and not in keeping with procedures. For six of these meetings the minutes state "none" under the subheading "Discussion." Frequently, items are listed as removed from the agenda without even a brief indication of why they were removed as required by the charter. Items were listed under Discussion with no comment on the discussion that took place. Minutes for the July 7, 1987 meeting showed an item that was not approved for the following reason; "Following a lengthy discussion on this subject, individual members were polled to determine approval/disapproval of this procedure. The procedure was disapproved with a vote of four to three." There was no indication of what the pros and cons were, and the Discussion subheading statement was "none". The PRC Charter, Section 4.4.1(d) states that minutes must include "a report of general discussion items which summarizes the concerns expressed by committee members and their disposition".

The procedures or instructions for PRC guidance were found to be sparse and weak resulting in apparent poor control and distribution of responsibilities. In particular, the team found the committee's use of the qualified reviewer process and its subcommittee, without appropriate procedures, to be a weakness (Observation 302/87-22-12).

7.3 Interviews

The team interviewed six PRC members and six NGRC members. The objectives of the interviews were stated at the beginning of each interview; they were to determine what capabilities the individual members bring to their respective committees to enable the committees to discharge their responsibilities, how the committees operate to meet their charters and technical specifications requirements, how effective the committees were at discharging their responsibilities and contributing to the safe operation of the plant. The following points were identified during these interviews.

(1) The team noted that those interviewed, the PRC members in particular, uniformly expressed a strong commitment to the verbatim use of plant procedures. The discussions indicated that the processes for identifying and resolving procedural inadequacies were sufficient and that the plant staff was aware of management's commitment to compliance with procedures.

(2) The interviews confirmed that the PRC members rely upon the Qualified Reviewer process to ensure the technical adequacy of procedures and modifications under review. The members appeared to bring sufficient, specialized technical talents to the PRC.

(3) Discussions with an NGRC member revealed that the NGRC, as part of its responsibility to oversee PRC activities, previously had a recommendation approved requiring that the PRC revise its procedures for the preparation of meeting minutes due to their lack of specificity and the inability of the NGRC to effectively use them to audit PRC activities. Although the resolution of this recommendation was not pursued, the team also noted similar inadequacies in the PRC minutes.

(4) Team discussions raised a question regarding whether all NGRC members were sufficiently aware of the design bases as stated in the Final Safety Analysis Report (FSAR) or the guidance and/or requirements of the various Regulatory Guides and 10 CFR 50 to effectively contribute to fulfilling the responsibilities of the NGRC. The team did not consider that the collective effect degraded the overall performance of the NGRC.

(5) The scope of the NGRC activities seemed broader than required, yet manageable. It was apparent that all members of the NGRC and PRC felt free to investigate, question, and critique all aspects of CR-3 operation.

(6) The team noted a potential conflict of interest in the assignment of an NGRC member to a subcommittee of three members, one of whom attends few subcommittee meetings. The subcommittee is responsible for reviews and audits of the work effort safety evaluations of a department for which the member is directly responsible. This appeared to be the result of a change in work assignments without a similar change in the NGRC subcommittee assignment.

(7) The charters of both committees and the Technical Specifications emphasized the roles of the committees in ensuring nuclear safety. The PRC and NGRC are required by technical specifications Sections 6.5.2.8 and 6.8.2, respectively, to review the safety evaluations completed under the

provisions of 10 CFR 50 50.59, which involves the determination of the existence of unreviewed safety questions.

CR-3 Special Technical Training Manual ST-09, which is used for Qualified Reviewer Training, describes the reasons for safety evaluations, discusses how to determine whether or not a procedure change constitutes an unreviewed safety question and now to perform a safety evaluation.

Each of the PRC and NGRC members interviewed were questioned as to the definition of an unreviewed safety question and the personal methods utilized to make this determination. The majority of the members were unclear in the definition of an unreviewed safety question and vague in the methods used to make such a determination. This is considered to be a weakness in that the primary responsibility of the NGRC and a fundamental responsibility of the PRC is the evaluation of the 10 CFR 50.59 safety evaluation.

8.0 CORRECTIVE ACTIONS AND MANAGEMENT OVERSIGHT

8.1 Corrective Actions

Corrective action programs were inspected for their effectiveness in identification of problem root causes and the adequacy, timeliness, and management involvement in the corrective and preventive actions.

Both the licensee and NRC had previously identified repetitive examples of personnel errors involving failure to follow procedures. Procedure adherence had been a long term problem spanning several years.
A significant contributing cause of the procedure adherence problem was inadequate procedures. Major contributors to this problem were inadequate technical reviews, frequent revisions without sound technical evaluations and failure to "dry run" the procedures before implementation.

The team also found examples of inadequate or untimely correct actions for long term problems, where symptoms and not root causes were addressed. For example, the post accident sampling system (PASS) had repeatedly experienced uncontrolled and unmonitored radioactive releases due to design and fabrication problems.

These and other identified weaknesses appeared to be the result of management's failure to identify root causes and take rigorous corrective actions. However, major changes were being implemented to correct these weaknesses, as further discussed below. Most of these actions were too new for full results to be seen.

8.1.1 Adequacy of Corrective Actions

Procedure adherence weaknesses reviewed by the team were extensive, recurring problems which had resulted in multiple violations (more than 20) since March 1986. These violations cover all plant disciplines. A major contributor to the failure to follow procedures identified by the licensee was the plant staff's lack of confidence in the technical adequacy of the existing procedures. The technical inadequacy of procedures was being addressed by the licensee.

The inspectors observed that strict procedure adherence, with interim changes if required, was strongly promoted by management. As indicated in the operations section of this report (section 5), this practice, in conjunction with a long term program for procedure improvement, appears to be potentially effective if rigorously implemented.

The long term procedure inadequacy problems have resulted in missed surveillances, inadequate surveillance tests, system valve misalignments, missed or improper post-modification tests, reactor operation problems and noncompliance with technical specifications. The team reviewed more than 10 violations, above and beyond the procedure adherence violations discussed above, that have occurred since March 1986. These problems were recognized by the licensee as early as 1985, when a task group was formed to address the problem. This group was not totally successful in resolving the procedure deficiencies, many of which still existed at the time of the inspection.

A special program, the people achieving corporate excellence (PACE) team, was formed in May, 1986 to address procedure inadequacies. The PACE team identified several reasons for the problem, the most significant was inadequate technical reviews. A comprehensive technical review check sheet was implemented in August, 1987 with a training film on its use shown to all responsible disciplines. The team believed this technical reviewer guidance, in conjunction with training, procedure user's feedback form, and strict procedure adherence emphasis, when and if fully implemented will correct this long standing problem. Additional examples were found where symptoms, instead of root causes, appeared to have been addressed when determining necessary corrective actions. Examples were:

(1) General design criteria (GDC) 16, 60 and 64 were apparently not met for the post accident sampling system (PASS), resulting in unmonitored and uncontrolled radioactive gaseous releases. These releases were documented by NCORs 87-44, 87-48, 87-64 and 87-89. The leak-prone PASS piping lines are routed through the intermediate building, which has no radiation monitors and is vented to the atmosphere. Compression type mechanical fittings were used on the PASS samples lines instead of welded fittings, which is an apparent root cause of the leakage.

    Although the licensee performed calculations which show no site radioactive release limits were exceeded for various uncontrolled releases, the team was concerned that similar system leakage under accident conditions when the PASS would be used have not been assessed. The plant staff could also receive unnecessary and excessive exposures or have their access to critical areas impeded. This aspect was not evaluated by the licensee. Long term corrective actions are under evaluation by the licensee but no firm resolution or corrective action schedule had been established (Observation 302/87-22-13).

    Further, the team considered that the prior leakage and radioactive release episodes appeared to be reportable as required by 10 CFR 50.73(a)(2)(v)(c) as conditions that alone could have prevented fulfillment of the safety function of a system that is needed to control the release of radioactive material. This is because potential release paths are assessed in the FSAR and systems to control and monitor such paths, for example the auxiliary building ventilation system, were bypassed by this design. This is addressed further in report Section 8.1.2.

(2) The six toxic gas monitors had an extensive failure history dating back to 1982. During the last five years approximately one work request per month had been written for these monitors. Although no toxic gas releases were found to have occurred during the frequent periods when these monitors were out of service, their monitoring effectiveness was reduced. The licensee did not have a firm plan to correct the frequent failure problems, but replacement of these monitors was being considered.

(3) Reactor makeup pumps had a history of vibration induced cracks in the recirculating vent valve line and casing drain lines. NCOR 87-52, dated March 18, 1987, identified the recurrence of flow induced cracks had resulted in 13 previous NCORs and 7 licensee event reports. However, team review of historical data for the makeup pumps indicated a higher number of line cracks than reflected by the number of NCORs issued. The team did not find examples of catastrophic line failures, however the repetitive problems resulted in reduced availability of the makeup pumps.

The licensee's inability to resolve the fatigue cracking problem should be evaluated further to determine adequacy of corrective actions.

(4) The technical interface of the CR-3 nuclear unit staff and the adjacent FPC fossil unit staffs has been unsatisfactory. Since October 1984, six NCORs were generated relative to fossil and CR-3 interface; five of which resulted in licensee event reports and an NRC violation for inadequate corrective actions.

These interface problems included the following typical events:

- A toxic gas leak from fossil Unit 1 was not identified to CR-3, precluding licensee evaluation and response and resulted in a late report to the NRC.

- Modifications to the 230 kV switchyard made by the fossil units were not in conformance with the FSAR design requirements.

- Fossil Units 1 and 2 battery profiles were degraded beyond design conditions over a several year period without the knowledge of the CR-3 staff.

- Sulfur dioxide tanks installed at Units 1 and 2 resulted in apparent violation of general design criteria 19.

- A untested battery charger was installed in CR-2 which rendered the CR-3 power supply technically inoperable.

A task force consisting of fossil plant and CR-3 staff was formed in April 1987. This task force appeared to be reasonably effective in identification of necessary corrective actions and was implementing procedural controls to correct the interface problems. However, this long term interface problem illustrated past shortcomings of the licensee's corrective action program for prompt problem resolution.

8.1.2 Reportability Determinations

The NCORs reviewed as part of this inspection were also evaluated by the team to assess reportability of the nonconforming condition to NRC. In addition to the PASS design concerns described earlier in the report, the following items appeared to represent potentially reportable conditions that had not been reported by the licensee. At the close of the inspection, the items were under reevaluation by the licensee with no conclusions regarding reportability provided to the team.

- NCOR 86-33 addressed decay heat removal system piping hangers damaged by a water slug caused by low reactor vessel level. The corrective actions revised Operating Procedure (OP)-404 to include instructions for controlling reactor vessel level with the RCS partially drained. The team questioned the reportability of this NCOR due to the significance of piping hanger damage and the potential for decay heat removal pumps to become air or steam bound.

- NCOR 87-92 identified the failure to notify the NRC of tests impractical to perform (As required by 10 CFR 50.55a(g) (5)(iii)). These tests were not included in the pump and valve submittals in 1976 and 1982. The reportability of this item was being evaluated by the licensee at the close of the inspection.

- NCOR 87-42 identified the failure to document unacceptable steam generator pressure relief valve settings when outside of the $\pm 1\%$ range. (NRC Inspection and Enforcement Notice 86-56 also addresses this subject). This example appeared reportable to the team, appears to have not been evaluated for reportability, and demonstrates an apparent lack of sensitivity to reporting.

Collectively, the reportability of NCORs was of concern to the team (Observation 302/87-22-14).

8.2 Management Oversight

CR-3's history of recurring personnel errors, procedure inadequacies, fossil plant interface problems, missed surveillances, design deficiencies and other miscellaneous weaknesses illustrated the inadequacies of past management controls. However, the team found numerous examples of management's commitment to correct these problems. Examples of programs that had recently been implemented or were in the process of implementation were:

- a new commitment tracking system, the Nuclear Operating Tracking System (NOTES), was implemented this year

- the CR-3 and fossil plant interface task force actions

- the procedure adequacy problem being addressed by implementation of the PACE team recommendations

The NOTES system should help to alleviate the problem of missed commitments. Daily tickler reports were issued to remind responsible personnel of upcoming commitments. Additionally, the system provided trending information for management which appeared to be well used by most departments.

These efforts will take time to correct the identified problems and should continue to be followed.

8.3 Inspection Findings Indicative of Licensee Strengths

- The quality assurance organization had taken several actions to improve performance. The quality program groups have recently started to perform vertical audits similar to the NRC's safety system functional inspections. Technical audit team members for all audit areas will be obtained in-house or through the use of consultants.

- The 1987 audits reviewed by the team showed some technical findings in addition to the more common administrative findings. Interviews and documentation reviews indicated that more emphasis was being placed on performance based audits. CR-3 appeared to have a good start towards enhanced, performance based audits.

- The quality assurance group recently compiled all regulatory requirements and commitments into one manual which should help to reduce the occurrence of missed commitments.

- The compliance department committed to perform or observe five plant walkdowns of new or infrequently used procedures in 1987. This should enhance the licensee's procedure adherence and improvement efforts.

9.0 MEETINGS

Table 9.1 provides a matrix of meeting attendance and lists principal persons contacted for the meetings conducted at CR-3 during the inspection. Other licensee personnel were also contacted.

On August 24, 1987, the NRC held an entrance meeting. The NRC reviewed the inspection team's plans to inspect operational safety at CR-3, including proposed operations shift-coverage for a several day period.

On September 4, 1987, the NRC held an exit meeting to summarize the results of the inspection team's efforts.

TABLE 9.1 - MEETINGS

Name	Organization	Title	Meeting Attended 8/24/87	9/24/87
R. Architzel	NRC/NRR/RSIB	Team Leader	x	x
T. Stetka	NRC	SRI	x	x
D. Beckman	NRC/Parameter	Consultant	x	x
W. Wilgus	FPC	V.P., Nuclear Ops.	x	x
R. Widell	FPC	Dir., Nuc. Ops Eng. Projects	x	x
K. Wilson	FPC	Mgr., Nuc. Licen.	x	x
S. Klein	NRC/WESTEC	Consultant	x	x
S. Kobylarz	NRC/WESTEC	Consultant	x	x
G. Overbeck	NRC/WESTEC	Consultant	x	x
F. Baily	FPC	Supt. Projects	x	
E. Ford	SAIC/FPC	Licen. Specialist	x	x
S. Powell	FPC	Quality Sys. Supv.	x	
F. Good	FPC	Sr. Nuc. Lic. Eng.	x	
R. Finnin	B&W	Resident Engineer	x	x
S. Ulin	FPC	Nuc. Elec. Engineer	x	
G. Obetindorfer	FPC	Mgr., Procure. QA	x	
C. Doyel	FPC	Nuc. Eng. Supv. I&C	x	
P. Tanguay	FPC	Mgr. Nuc. Ops. Eng.	x	x
D. Shook	FPC	Mgr. Nuc.Elec./I&C Engineer	x	
K. Baker	FPC	Mgr., Nuc. Eng. Assur.	x	x
T. Catchpole	FPC	Sr. Nuc. Eng. Assurance Spec.	x	x
E. Froats	FPC	Supv., Nuc. Licen.	x	
J. Tunstill	FPC	Sr. Nuc. Licen. Eng.	x	
J. Smith	NRC	Ops. Eng. (SIB)	x	x
B. Hickle	FPC	Mgr. Nuc. Plant Ops.	x	x
P. McKee	FPC	Dir., Nuc. Plant Ops.	x	x
W. Marshall	FPC	Acting Ops. Supv.	x	
G. Becker	FPC	Mgr., Site Nucl. Eng. Serv.	x	x
J. Alberdi	FPC	Asst. Dir. PH. Ops.	x	
M. Bellamy	FPC	Supv. Records Mgmt.	x	
T. Peebles	NRC	RII Section Chief	x	
J. Schiffgens	NRC	Project Engineer	x	x
J. Lingenfelter	NRC/NEAC	NRC Inspec. Team Member	x	x
S. Varga	NRC	Div. Director	x	
M. Mann	FPC	Nuc. Compli. Spec.	x	x
J. Tedrow	NRC	Resident Inspector	x	x
P. Skinner	NRC	SRI-Oconee Nuc. Sta.	x	
L. Wert	NRC	RI-Oconee Nuc. Sta.	x	x

TABLE 9.1 - MEETINGS

Name	Organization	Title	Meeting Attended 8/24/87	Meeting Attended 9/24/87
W. Rossfeld	FPC	Mgr. Nuc. Comp.	x	x
M. Collins	FPC	Safety & Reli. Supt.		x
J. Lander	FPC	Mgr. Maint. & Out.		x
F. Bailey	FPC	Supt. Projects		x
E. Renfro	FPC	Dir., NOME		x
G. Westafer	FPC	Dir., Quality Prog.		x
B. Wilson	NRC/RII	Section Chief		x
G. Lainas	NRC/NRR	Asst. Director, RPII		x
E. Simpson	FPC	Dir., Nuc. Ops. Site Support		x
L. Reyes	NRC/RII	Dir., Div. of Reac. Project		x
C. Haughney	NRC/NRR	Chief, RSIB		x
J. Stolz	NRC/NRR	Director, I-4		x
H. Silver	NRC/NRR	Project Mgr., CR-3		x
M. Jacobs	FPC	Area Pub. Info. Coor.		x
K. Lancaster	FPC	Mgr., Site Nuc. QA		x
P. Breedlove	FPC	Records Mgmt. Supv.		x
R. Murgatroyd	FPC	Nuc. Maint. Supv.		x

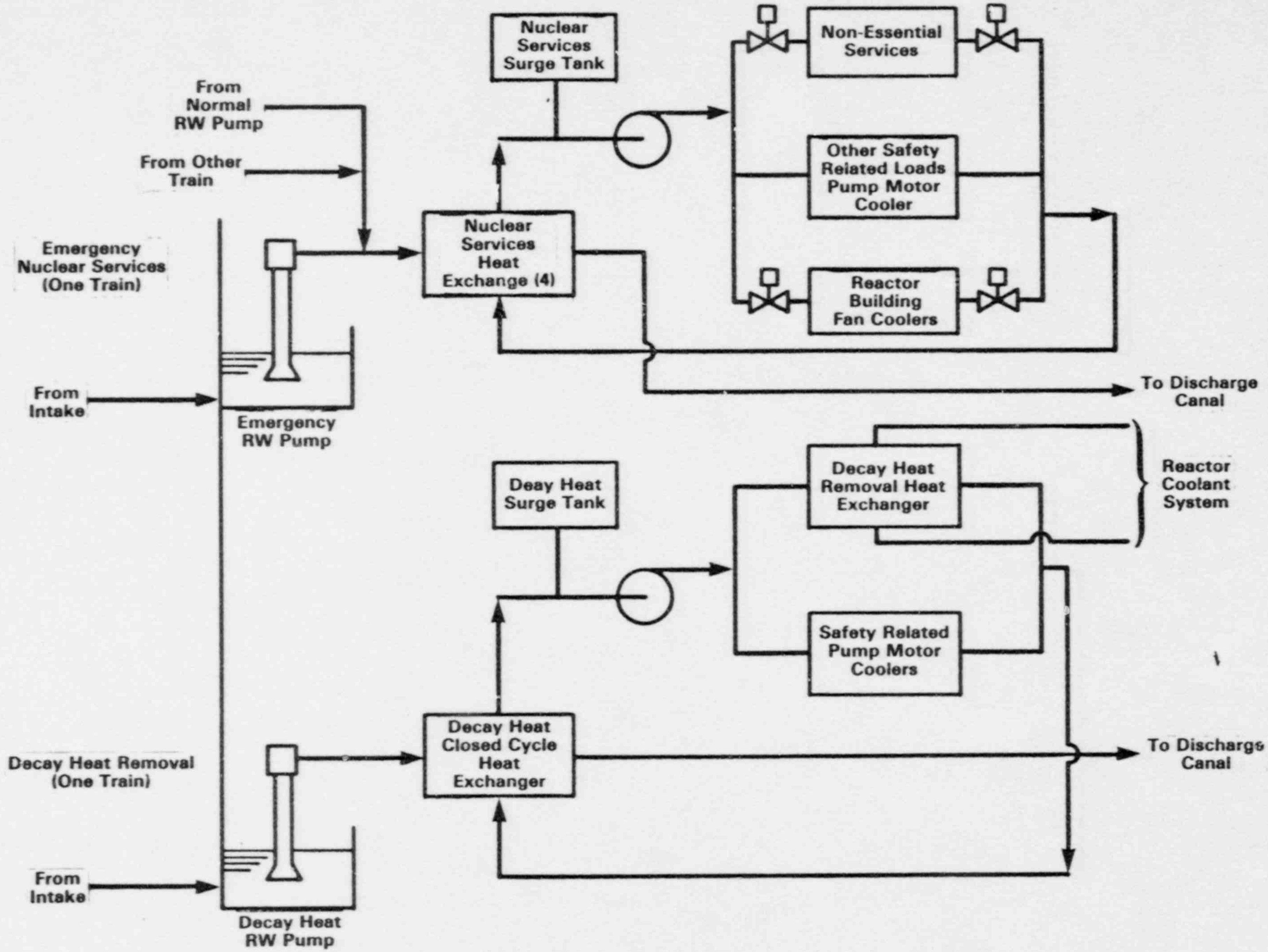

Figure 1 RAW WATER AND AUXILIARY COOLING WATER SYSTEMS

APPENDIX A

This appendix identifies observations noted during the operational safety team inspection which require a response from the licensee to address NRC concerns. Several of these items, noted with an asterisk (*), have previously been identified by the NRC in prior correspondence.

Observation 302/87-22-01, Control of Design Basis Document Input, is addressed in report section 4.1.1.

Observation 302/87-22-02, Maximum Ultimate Heat Sink Temperature, is addressed in report section 4.2.1.1.*

Observation 302/87-22-03, Maximum Temperature of Decay Heat Closed Cycle Cooling Water during Emergency Operation, is addressed in report section 4.2.1.2.*

Observation 302/87-22-04, Safety Classification of Travelling Screen CWTS-2, is addressed in report section 4.2.1.3.

Observation 302/87-22-05, Cooling Water Flow to Safety-Related Components, is addressed in report section 4.2.2.*

Observation 302/87-22-06, Diesel Generator Loading and Testing, is addressed in report section 4.3.2.2.*

Observation 302/87-22-07, RCS Loose Parts Monitor Alarms, is addressed in report section 5.1.5.3.

Observation 302/87-22-08, Purge and Vent Valve Seating, is addressed in report section 5.2.1.

Observation 302/87-22-09, Control of Scaffolding, is addressed in report section 5.2.3.

Observation 302/87-22-10, Control of As-Configured Information on Drawings, is addressed in report section 6.2.

Observation 302/87-22-11, Engineering Staffing, is addressed in report section 6.3.

Observation 302/87-22-12, Qualified Reviewer Process for PRC Reviews and Use of Subcommittees, is addressed in report section 7.2.

Observation 302/87-22-13, Post Accident Sampling System Leakage, is addressed in report section 8.1.1.

Observation 302/87-22-14, Reportability of Selected NCORs, is addressed in report section 8.1.2.